e-FILING REPORT COVER SHEET

REPORT NAME: FERC Form 1 Report for 2019

COMPANY NAME: Idaho Power Company

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes

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

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

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

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

If Yes, enter docket number: RE 78

Key words:

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

☐ Corporate Analysis and Water Regulation

☐ Economic and Policy Analysis

☐ Electric and Natural Gas Revenue Requirements

☐ Electric Rates and Planning

☐ Natural Gas Rates and Planning

☐ Utility Safety, Reliability & Security

☐ Administrative Hearings Division

☐ Consumer Services Section

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

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

LISA D. NORDSTROM
Lead Counsel
lnordstrom@idahopower.com

May 1, 2020

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 2019 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, 2019. Also included is the IDACORP 2019 Annual Report.

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

Very truly yours,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:kkt

Enclosures

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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

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 2019/Q4

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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
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Form 3-Q Approved
OMB No.1902-0205
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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 2019/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, 2019, 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, 2019, 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 14, 2020

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

IDENTIFICATION

01 Exact Legal Name of Respondent Idaho Power Company	02 Year/Period of Report End of 2019/Q4
03 Previous Name and Date of Change *(if name changed during year)*	/ /
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1221 W Idaho St, P.O. Box 70 Boise, Id 83707-0070	
05 Name of Contact Person Ken Petersen	06 Title of Contact Person VP, Controller and CAO
07 Address of Contact Person *(Street, City, State, Zip Code)* 1221 W Idaho St, P.O. Box 70 Boise, Id 83707-0070	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(208) 388-2761	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020

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	04/14/2020
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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".

Stockholders' Reports Check appropriate box:

- [ ] Two copies will be submitted
- [ ] No annual report to stockholders is prepared

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* 04/14/2020	Year/Period of Report End of 2019/Q4

GENERAL INFORMATION

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

Ken Petersen Vice President, Controller and CAO, Idaho Power Company
1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070

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

Idaho, June 30, 1989

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

Not Applicable

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

Class of Utility Service	State
Electric	Idaho
Electric	Oregon

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* 04/14/2020	Year/Period of Report End of 2019/Q4

CONTROL OVER RESPONDENT

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

Idaho Power Company is a subsidiary of IDACORP, INC

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	04/14/2020	End of 2019/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	Chief Executive Officer, Idaho Power Company (1)	Darrel T. Anderson	900,000
3	President & CEO, Idaho Power Company (2)		
4			
5	President, Idaho Power Company (3)	Lisa Grow	590,000
6	Senior Vice President, COO (2)		
7			
8	Senior Vice President, CFO & Treasurer	Steven Keen	463,000
9			
10	Senior Vice President & General Counsel	Brian R. Buckham	385,000
11			
12	Senior Vice President & Chief Operating Officer (3)	Adam J. Richins	350,000
13	VP, Customer Operations & Bus. Develpment (2)		
14			
15	Senior Vice President, Public Affairs	Jeffrey Malmen	320,000
16			
17	VP, T&D Engineering & Construction and CSO (2)	Vern Porter	315,000
18	Vice President, Idaho Power Company (1 & 4)		
19			
20	Vice President, Power Supply	Tessia R. Park	305,000
21			
22	Vice President, Corporate Controller & CAO	Ken W. Petersen	275,000
23			
24	Vice President, Corporate Services & CIO (5)	Jeff Glenn	270,000
25			
26	Vice President, Regulatory Affairs	Tim Tatum	230,000
27			
28	Vice President, Human Resources (3)	Sarah E. Griffin	210,000
29			
30	Vice President, Customer Operations & CSO (3)	Bo Hanchey	200,000
31			
32	Corporate Secretary	Patrick Harrington	220,000
33			
34	Vice President, Corporate Services & Communiations (3)	Debra H. Leithauser	217,000
35			
36	Vice President, T&D Engineering & Construction (3)	Ryan N. Adelman	190,000
37			
38	(1) Title change effective 10/01/19		
39	(2) Vacated position 10/01/19		
40	(3) Appointed to position 10/01/19		
41	(4) Retirement effective 12/31/19		
42	Salary shows YTD wages		
43	(5) Retired from position 10/01/19		
44	Salary shows YTD wages		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1		
2	Judith A. Johansen	10446 E. Palo Brea Dr., Scottsdale, Arizona 85262
3		
4	Christine King, 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	Robert A. Tinstman (1)	4433 W. Quail Point Court, Boise, Idaho 83703
13		
14	Richard Dahl, Board Chair & Corp Gov Chair, *** (2)	60 Laiki Pl.
15		Kailua, Hawaii 96734-1905
16		
17	Dennis L. Johnson, Corp Gov Committee, (2)	926 W Oakhampton Dr, Eagle, Idaho 83616
18		
19	Ronald W. Jibson	417 Aerie Circle, North Salt Lake City, Utah 84054
20		
21	Richard J. Navarro, Audit Chair, *** (2)	1256 E. Candleridge Ct., Boise, Idaho 83712
22		
23	Annette G. Elg	3475 E. Rivernest Lane, Boise, Idaho 83706-6928
24		
25	(1) Retired on May 16, 2019	
26	(2) Title effective on May 16, 2019	
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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

Does the respondent have formula rates?

[X] Yes
[ ] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff	
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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	20190828-5141	08/28/0019	ER09-1641-000	Idaho Power Company	FERC Electric Tariff
2				2019 Annua	
3				Informational Filing	
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	04/14/2020	End of 2019/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	04/14/2020	End of 2019/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 August 2019, Idaho Power purchased and remarketed two of its outstanding series of pollution control tax-exempt bonds, one in the aggregate principal amount of $49.8 million issued in 2003 by Humboldt County, Nevada and due in 2024, and the other in the aggregate principal amount of $116.3 million issued in 2006 by Sweetwater County, Wyoming and due in 2026. The bonds were remarketed with substantially the same terms, but with lower term interest rates. In 2006, Idaho Power received orders from the Idaho Public Utilities Commission, Oregon Public Utilities Commission, and Wyoming Public Service Commission authorizing Idaho Power to change interest rate modes on each of the bonds at any time until the final maturity dates.
7. None
8. Effective 12/28/19, a 2.75% general wage adjustment was implemented.
9. None
10. None
11. Reserved
12. None
13. Officer Changes in 2019
    - Darrel T. Anderson's title changed from "President and Chief Executive Officer of Idaho Power" to "Chief Executive Officer of Idaho Power" effective October 1, 2019.
    - Lisa A. Grow's title changed from "Senior Vice President and Chief Operating Officer of Idaho Power " to "President of Idaho Power" effective October 1, 2019.
    - Adam J. Richins' title changed from "Vice President of Customer Operations and Business Development of Idaho Power" to "Senior Vice President and Chief Operating Officer of Idaho Power" effective October 1, 2019.
    - Vern Porter's title changed from Vice President of Transmission and Distribution Engineering and Construction and Chief Safety Officer of Idaho Power" to "Vice President of Idaho Power" effective October 1, 2019. He retired as "Vice President of Idaho Power" effective December 31, 2019.
    - Ryan N. Adelman was appointed "Vice President of Transmission and Distribution Engineering and Construction of Idaho Power" effective October 1, 2019.
    - Bo D. Hanchey was appointed " Vice President of Customer Operations and Chief Safety Officer of Idaho Power" effective October 1, 2019.
    - Debra Leithauser was appointed "Vice President of Corporate Services and Communications of Idaho Power" effective October 1, 2019.
    - Sarah E. Griffin was appointed "Vice President of Human Resources of Idaho Power" effective October 1, 2019.
    - Jeff Glenn retired as "Vice President of Corporate Services and Chief Information Officer" effective October 1, 2019.
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	04/14/2020	End of 2019/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	6,117,438,884	6,108,607,184
3	Construction Work in Progress (107)	200-201	552,498,787	480,258,675
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		6,669,937,671	6,588,865,859
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,341,467,978	2,394,578,627
6	Net Utility Plant (Enter Total of line 4 less 5)		4,328,469,693	4,194,287,232
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)		4,328,469,693	4,194,287,232
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	3,653,100
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	25,515,916	57,026,771
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)		42,737,920	36,487,611
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		71,906,936	97,167,482
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		72,428,510	86,225,120
36	Special Deposits (132-134)		4,254,912	1,167,693
37	Working Fund (135)		11,500	7,000
38	Temporary Cash Investments (136)		26,510,194	79,228,007
39	Notes Receivable (141)		-81,730	-84,743
40	Customer Accounts Receivable (142)		74,131,805	79,182,408
41	Other Accounts Receivable (143)		13,107,045	6,330,066
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,744,072	1,989,131
43	Notes Receivable from Associated Companies (145)		20,021,988	0
44	Accounts Receivable from Assoc. Companies (146)		0	0
45	Fuel Stock (151)	227	57,447,554	47,979,122
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	54,238,962	53,553,674
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	2,420,600	1,433,652
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		17,520,138	16,373,874
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		169,371	56,822
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		64,545,373	69,318,168
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		404,917	3,655,138
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		405,387,067	442,436,870
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		14,384,541	15,958,660
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	1,383,059,324	1,214,174,417
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)		2,111,199	2,005,924
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	71,312,712	73,405,043
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)		41,772,825	42,445,540
82	Accumulated Deferred Income Taxes (190)	234	302,161,031	293,383,262
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,814,801,632	1,641,372,846
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,620,565,328	6,375,264,430

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [x] An Original (2) [ ] A Resubmission	04/14/2020	end of 2019/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	1,480,751,865	1,354,681,706
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	23,052,822	54,563,677
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)	-36,283,823	-22,843,785
16	Total Proprietary Capital (lines 2 through 15)		2,275,558,404	2,194,439,138
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,835,460,000	1,835,460,000
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)		4,301,181	4,598,059
24	Total Long-Term Debt (lines 18 through 23)		1,851,043,819	1,850,746,941
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)		1,748,351	1,811,302
29	Accumulated Provision for Pensions and Benefits (228.3)		519,659,093	431,492,131
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		152,686,978	136,505,890
32	Long-Term Portion of Derivative Instrument Liabilities		23,995	63,744
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		28,191,027	26,791,608
35	Total Other Noncurrent Liabilities (lines 26 through 34)		702,309,444	596,664,675
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		134,005,122	134,836,251
39	Notes Payable to Associated Companies (233)		0	4,552,447
40	Accounts Payable to Associated Companies (234)		2,053,220	2,088,345
41	Customer Deposits (235)		1,070,057	1,342,506
42	Taxes Accrued (236)	262-263	2,114,255	1,306,621
43	Interest Accrued (237)		21,222,675	23,857,084
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)		2,682,810	2,224,148
48	Miscellaneous Current and Accrued Liabilities (242)		68,348,276	56,428,043
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		846,256	974,268
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		23,995	63,744
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)		232,318,676	227,545,969
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		6,011,590	5,156,242
57	Accumulated Deferred Investment Tax Credits (255)	266-267	94,805,870	92,789,836
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	8,035,785	8,306,007
60	Other Regulatory Liabilities (254)	278	349,006,644	351,782,980
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		933,469,366	908,615,099
64	Accum. Deferred Income Taxes-Other (283)		168,005,730	139,217,543
65	Total Deferred Credits (lines 56 through 64)		1,559,334,985	1,505,867,707
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,620,565,328	6,375,264,430

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	1,343,223,427	1,361,957,450		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	774,637,775	800,135,259		
5	Maintenance Expenses (402)	320-323	65,021,961	69,035,321		
6	Depreciation Expense (403)	336-337	160,145,693	156,332,587		
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	7,169,554	6,981,078		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	15,018	15,018		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		8,730,518	6,802,055		
13	(Less) Regulatory Credits (407.4)		3,221,217	2,167,344		
14	Taxes Other Than Income Taxes (408.1)	262-263	34,045,010	34,792,143		
15	Income Taxes - Federal (409.1)	262-263	18,660,529	20,035,445		
16	- Other (409.1)	262-263	-4,663,949	-2,242,797		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	25,440,561	37,060,319		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	15,033,334	44,435,246		
19	Investment Tax Credit Adj. - Net (411.4)	266	2,016,034	5,405,098		
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)		284,504	154,940		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		232,951	227,740		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,073,479,265	1,088,388,401		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		269,744,162	273,569,049		

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
1,343,223,427	1,361,957,450					2
						3
774,637,775	800,135,259					4
65,021,961	69,035,321					5
160,145,693	156,332,587					6
566,665	566,665					7
7,169,554	6,981,078					8
15,018	15,018					9
						10
						11
8,730,518	6,802,055					12
3,221,217	2,167,344					13
34,045,010	34,792,143					14
18,660,529	20,035,445					15
-4,663,949	-2,242,797					16
25,440,561	37,060,319					17
15,033,334	44,435,246					18
2,016,034	5,405,098					19
						20
						21
284,504	154,940					22
						23
232,951	227,740					24
1,073,479,265	1,088,388,401					25
269,744,162	273,569,049					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	04/14/2020	End of 2019/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)		269,744,162	273,569,049		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		3,913,358	3,971,967		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		4,427,209	4,003,151		
33	Revenues From Nonutility Operations (417)		22,503	25,046		
34	(Less) Expenses of Nonutility Operations (417.1)		30,125	12,425		
35	Nonoperating Rental Income (418)		-53,401	-3,351		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	8,489,145	8,813,793		
37	Interest and Dividend Income (419)		10,967,595	8,923,003		
38	Allowance for Other Funds Used During Construction (419.1)		27,112,279	24,352,523		
39	Miscellaneous Nonoperating Income (421)		435,869	79,416		
40	Gain on Disposition of Property (421.1)			264,632		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		46,430,014	42,411,453		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			48,950		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		824,587	811,136		
46	Life Insurance (426.2)		-4,104,372	-2,779,387		
47	Penalties (426.3)		56,757	40,155		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,039,769	1,203,610		
49	Other Deductions (426.5)		7,283,056	7,820,081		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,099,797	7,144,545		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	23,370	19,680		
53	Income Taxes-Federal (409.2)	262-263	893,117	627,071		
54	Income Taxes-Other (409.2)	262-263	271,449	193,942		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	7	261,601		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,250,246	770,831		
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)		-62,303	331,463		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		41,392,520	34,935,445		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		82,457,050	84,407,634		
63	Amort. of Debt Disc. and Expense (428)		1,318,427	1,606,787		
64	Amortization of Loss on Reaquired Debt (428.1)		2,530,546	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)		287,350	279,757		
68	Other Interest Expense (431)		10,809,334	7,874,386		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		10,702,847	10,151,313		
70	Net Interest Charges (Total of lines 62 thru 69)		86,699,860	86,170,203		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		224,436,822	222,334,291		
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)		224,436,822	222,334,291		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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		1,341,408,600	1,221,586,621
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)		215,947,677	213,520,498
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			-129,877,518	(121,790,727)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-129,877,518	(121,790,727)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		40,000,000	24,000,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,467,478,759	1,341,408,600
	APPROPRIATED RETAINED EARNINGS (Account 215)			

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)		1,480,751,865	1,354,681,706
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		54,563,677	69,749,884
50	Equity in Earnings for Year (Credit) (Account 418.1)		8,489,145	8,813,793
51	(Less) Dividends Received (Debit)		40,000,000	24,000,000
52				
53	Balance-End of Year (Total lines 49 thru 52)		23,052,822	54,563,677

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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)	224,436,822	222,334,291
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	160,712,358	156,332,587
5	Amortization of	12,492,435	12,186,464
6			
7			
8	Deferred Income Taxes (Net)	17,892,072	-1,689,885
9	Investment Tax Credit Adjustment (Net)	698,798	1,496,757
10	Net (Increase) Decrease in Receivables	-4,934,190	633,606
11	Net (Increase) Decrease in Inventory	-11,114,312	9,463,201
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-8,690,771	-9,272,216
14	Net (Increase) Decrease in Other Regulatory Assets	-19,029,252	30,090,539
15	Net Increase (Decrease) in Other Regulatory Liabilities	14,719,412	18,301,367
16	(Less) Allowance for Other Funds Used During Construction	27,112,279	24,352,523
17	(Less) Undistributed Earnings from Subsidiary Companies	-6,936,420	-15,186,207
18	Other (provide details in footnote):	-23,495,357	-12,704,289
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	343,512,156	418,006,106
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-305,819,097	-302,175,811
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	-27,112,279	-24,352,523
31	Other (provide details in footnote):	6,561,916	25,112,774
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-272,144,902	-252,710,514
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	-3,013	-1,655
40	Contributions and Advances from Assoc. and Subsidiary Companies		469,143
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-10,896,289	-11,390,307
45	Proceeds from Sales of Investment Securities (a)	5,080,351	5,007,519

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
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-277,963,853	-257,830,358
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	166,100,000	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)	166,100,000	220,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-166,100,000	-130,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-2,180,708	-7,570,541
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-129,877,518	-121,790,727
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-132,058,226	-39,361,268
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-66,509,923	120,814,480
87			
88	Cash and Cash Equivalents at Beginning of Period	165,460,127	44,645,647
89			
90	Cash and Cash Equivalents at End of period	98,950,204	165,460,127

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

Amortization

Plant	7,184,572
Unamortized debt expense	3,897,301
Unamortized discount	296,879
Water rights	1,042,009
Other	71,674
	12,492,435

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

Cash (received) paid during the period for:

Income taxes	15,544,584
Interest (net of amount capitalized)	85,197,945

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

Cash Flow from Operating Activities (Other)

Pension and postretirement benefit plan expense	27,787,890
Contributions to pension and postretirement benefit plans	(48,508,880)
Changes in unbilled revenues	4,783,664
Accrued interest	(2,634,409)
Changes in prepayments	(2,490,337)
Other	(2,433,285)
	(23,495,357)

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

Non-cash investing activities:

Additions to PP&E in accounts payable	38,815,004

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

Other Cash Flows from Plant

Payments received from joint funding partners	2,442,204
Sale of renewable energy certificates and emission allowances	4,119,712
	6,561,916

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

Other Financing Cash Flows

Debt issuance costs	(2,180,708)
Discount on debt issuance	
	(2,180,708)

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				(26,872,209)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				2,885,872
3	Preceding Quarter/Year to Date Changes in Fair Value				1,142,552
4	Total (lines 2 and 3)				4,028,424
5	Balance of Account 219 at End of Preceding Quarter/Year				(22,843,785)
6	Balance of Account 219 at Beginning of Current Year				(22,843,785)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				1,952,226
8	Current Quarter/Year to Date Changes in Fair Value				(15,392,264)
9	Total (lines 7 and 8)				(13,440,038)
10	Balance of Account 219 at End of Current Quarter/Year				(36,283,823)

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			(26,872,209)		
2			2,885,872		
3			1,142,552		
4			4,028,424	222,334,291	226,362,715
5			(22,843,785)		
6			(22,843,785)		
7			1,952,226		
8			(15,392,264)		
9			(13,440,038)	224,436,822	210,996,784
10			(36,283,823)		

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

IDAHO POWER COMPANY
NOTES TO 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 (Jim Bridger 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 meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Idaho Power's financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment; regulatory assets and liabilities; operating revenues; operation and maintenance expense; depreciation expense; and income tax expense. 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 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, 2019 and 2018. Once a receivable is determined to be impaired, any further interest income recognized is fully reserved.

Derivative Financial Instruments

Financial instruments such as commodity futures, forwards, options, and swaps are used to manage exposure to commodity price risk in the electricity and natural gas markets. All derivative instruments are recognized as either assets or liabilities at fair value on the balance sheet unless they are designated as normal purchases and normal sales. With the exception of forward contracts for the purchase of natural gas for use at Idaho Power's natural gas generation facilities and a nominal number of power transactions, Idaho Power’s physical forward contracts are designated as normal purchases and normal sales. Because of Idaho Power’s regulatory accounting mechanisms, Idaho Power records the changes in fair value of derivative instruments related to power supply as regulatory assets or liabilities.

Revenues

Operating revenues 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 2.9 percent in 2019 and 2.8 percent in 2018.

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 2019 or 2018.

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 2019 and 2018.

Income Taxes

Idaho Power accounts for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method (commonly referred to as normalized accounting), deferred tax assets and liabilities are determined based on the differences between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. In general, deferred income tax expense or benefit for a reporting period is recognized as the change in deferred tax assets and liabilities from the beginning to the end of the period. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date unless Idaho Power's primary regulator, the Idaho Public Utilities Commission (IPUC), orders direct deferral of the effect of the change in tax rates over a longer period of time.

Consistent with orders and directives of the IPUC, unless contrary to applicable income tax guidance, Idaho Power does not 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. Idaho Power recognizes 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.

Idaho Power uses 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.

Investment tax credits earned on regulated assets are deferred and amortized to income over the estimated service lives of the related properties.

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.

New and Recently Adopted Accounting Pronouncements

Recently Adopted Accounting Pronouncements

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, intended to improve financial reporting on 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. Idaho Power adopted ASU 2016-02 on January 1, 2019. The adoption did not have a material impact on its financial statements. Idaho Power does not have material agreements that meet the definition of a lease under ASU 2016-02.

Recent Accounting Pronouncements Not Yet Adopted

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*, to provide financial statement users with more information about expected credit losses on financial instruments. The ASU revises the incurred loss impairment methodology to reflect current expected credit losses and requires consideration of a broader range of information to estimate credit losses. The new standard is effective for interim and annual reporting periods beginning after December 15, 2019, with early adoption permitted. Idaho Power is finalizing the assessment of the financial impacts of adoption, but does not believe that the adoption of ASU 2016-13 will have a material impact on its financial statements.

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 recognition of such implementation costs with the accounting for costs incurred to implement an internal-use software solution. However, the balance sheet line item for presentation of capitalized implementation costs for a cloud arrangement that is a service contract should be the same as that for the prepayment of fees related to the same arrangement, while capitalized implementation costs for internal-use software solutions are often included in property, plant, and equipment as an intangible asset. The new standard is effective for interim and annual reporting periods beginning after December 15, 2019, with early adoption permitted. Idaho Power is finalizing the assessment of the financial impacts of adoption, but does not believe the adoption of ASU 2018-15 will have a material impact on its financial statements.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2019, up to February 20, 2020, the date that Idaho Power Company's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 14, 2020. 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):

	2019	2018
Federal income tax expense at 21% statutory rate	52,662	50,078
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(1,783)	(1,851)
AFUDC	(7,941)	(7,246)
Capitalized interest	976	928
Investment tax credits	(6,252)	(2,929)
Bond redemption costs	-	(1,029)
Removal costs	(3,139)	(3,471)
Capitalized overhead costs	(7,140)	(6,720)
Capitalized repair costs	(18,480)	(17,850)
State income taxes, net of federal benefit	8,401	8,532
Depreciation	14,641	13,110
Excess deferred income tax reversal	(6,181)	(7,289)
Remeasurement of deferred taxes	-	(5,620)
Income tax return adjustments	1,131	(4,882)
Other, net	(561)	2,374
Total income tax expense	$ 26,334	$ 16,135
Effective tax rate	10.50%	19.20%

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

	2019	2018
Income taxes current:		
Federal	$ 19,554	$ 20,663
State	(4,393)	(2,049)
Total	15,161	18,614
Income taxes deferred:		
Federal	(897)	(13,309)
State	10,054	5,425
Total	9,157	(7,884)
Investment tax credits:		
Deferred	8,268	8,334
Restored	(6,252)	(2,929)
Total	2,016	5,405
Total income tax expense	$ 26,334	$ 16,135

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

	2019	2018
Deferred tax assets:		
Regulatory liabilities	$ 96,599	$ 98,042
Deferred compensation	21,946	21,826
Deferred revenue	39,039	35,137
Tax credits	24,489	44,408
Retirement benefits	114,124	91,867
Other	5,964	9,121
Total	302,161	300,401
Deferred tax liabilities:		
Property, plant and equipment	286,583	294,471
Regulatory assets	646,886	614,144
Fixed Cost Adjustment	0	0
Retirement benefits	132,764	108,440
Other	35,242	37,795
Total	1,101,475	1,054,850
Net deferred tax liabilities	$ 799,314	$ 754,449

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 2019 and prior tax years. Idaho Power 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 2019 for federal and 2016-2019 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 2019, the IRS completed its examination of the 2018 tax year with no unresolved income tax issues.

Income Tax Reform

On December 22, 2017, the Tax Cuts and Jobs Act was signed into law, which significantly reformed 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 full 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. As shown in the table 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.

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. See Note 3 - "Regulatory Matters" for more information.

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 PL 19-2-000 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 percent 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). All of Idaho Power's excess ADIT is protected. Unprotected temporary differences were either subject to either Idaho Power's flow-through regulatory income tax accounting method or the remeasured amounts were immaterial.

The following table presents the activity of Idaho Power's regulatory liability for excess deferred income taxes (in thousands of dollars):

	Amount
December 31, 2017, balance[(1)]	$ 193,991
Remeasurement	3,360
Excess deferred tax amortization	(7,289)
December 31, 2018, balance	190,062
Excess deferred tax amortization	(6,181)
December 31, 2019, balance	$ 183,881

(1) The December 31, 2017, balance was recorded due to income tax reform remeasurement as described above.

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). The amortization of excess ADIT will be recorded in account 411.1. 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, 2019 Earning a Return[1]	As of December 31, 2019 Not Earning a Return	Total as of December 31, 2019	Total as of December 31, 2018
Regulatory Assets:					
Income taxes[2]		$ -	$ 646,886	$ 646,886	$ 614,144
Unfunded postretirement benefits[3]		0	347,935	347,935	278,674
Pension expense deferrals[4]		150,350	22,287	172,637	147,836
Energy efficiency program costs[5]		1,465	0	1,465	1,398
Fixed cost adjustment[6]	2020-2021	35,208	18,808	54,016	42,503
North Valmy plant settlements[6]	2020-2028	107,525	0	107,525	77,512
Asset retirement obligations[7]		0	18,835	18,835	17,655
Long-term service agreement	2020-2043	15,412	10,178	25,590	26,748
Other	2020-2055	2,804	5,366	8,170	7,704
Total		$ 312,764	$ 1,070,295	$ 1,383,059	$ 1,214,174
Regulatory Liabilities:					
Income taxes[8]		$ -	$ 96,599	$ 96,599	$ 98,042
Depreciation-related excess deferred income taxes[9]		183,881	0	183,881	190,062
Energy efficiency program costs[5]		0	0	0	5,259
Power supply costs[6]	2020-2021	46,022	2,470	48,492	42,322
Settlement agreement sharing mechanism[6]		0	0	0	5,025
Tax reform accrual for future amortization[10]		0	9,139	9,139	0
Other		6,636	4,259	10,895	11,073
Total		$ 236,539	$ 112,467	$ 349,006	$ 351,783

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. Idaho Power records a regulatory asset for the difference between net periodic pension cost and pension cost considered for rate-making purposes relating to Idaho Power's defined benefit pension plan. In its Idaho jurisdiction, Idaho Power's inclusion of pension costs for the establishment of retail rates is based upon contributions made to the pension plan. This regulatory asset account represents the difference between cumulative cash contributions and amounts collected in rates. Deferred costs are amortized into expense as the amounts are provided for in Idaho retail revenues.
5. The energy efficiency asset includes the Oregon jurisdiction balance at December 31, 2019 and 2018. The Idaho jurisdiction balance was an asset at December 31, 2019, and a liability at December 31, 2018.
6. This item is discussed in more detail in this Note 3 - "Regulatory Matters."
7. Asset retirement obligations are discussed in Note 13 - "Asset Retirement Obligations (ARO)."
8. 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."
9. In 2017, income tax reform reduced 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.
10. Represents amount accrued under the May 2018 Idaho Tax Reform Settlement Stipulation (described below) for the future amortization of existing or future unspecified regulatory deferrals that would otherwise be a future liability recoverable from Idaho customers.

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 Idaho Power (5 percent), with the exceptions of expenses associated with PURPA power purchases and demand response incentive payments, which are allocated 100 percent to customers; and
- a sales-based adjustment intended to ensure that power supply expense recovery resulting solely from sales changes does not distort the results of the mechanism.

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

Effective Date	$ Change (millions)		Notes
1-Jun-19	$	(50.1)	The $50.1 million decrease includes a $5.0 million credit to customers for sharing of 2018 earnings under the IPUC order approving the extension, with mo difications, of the terms of the December 2011 Idaho settlement stipulation for the period from 2015 through 2019 (October 2014 Idaho Earnings Support and Sharing Settlement Stipulation) and a $2.7 million credit for income tax reform benefits related to Idaho Power's OATT rate under a May 2018 Idaho tax reform settlement stipulation as described below in this Note 3 - Regulatory Matters.
1-Jun-18	$	(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 as described below in this Note 3 - Regulatory Matters.

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. Oregon jurisdiction power supply cost changes under the APCU and PCAM during each of 2019 and 2018 did not have a material impact on Idaho Power's financial statements.

Notable Idaho Base Rate Adjustments

Idaho base rates were most recently established through a general rate case in 2012, and adjusted in 2014, 2017, 2018, and 2019.

January 2012 and June 2014 Idaho Base Rate Adjustments: 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.

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.

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 - Idaho Regulatory Treatment" below.

In 2019, Idaho Power recorded no provision against current revenue for sharing with customers, as its full-year return on year-end equity in the Idaho jurisdiction (Idaho ROE) was between 9.5 percent and 10.0 percent. In 2018, Idaho Power recorded a $5.0 million provision against current revenue for sharing with customers as Idaho ROE was above 10.0 percent. Accordingly, at December 31, 2019, the full $45 million of additional ADITC remained available for future use under the terms of the May 2018 Idaho Tax Reform Settlement Stipulation described in "Income Tax Reform - Idaho Regulatory Treatment" below.

May 2018 Idaho Tax Reform Settlement Stipulation: 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 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 provided 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 was 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 decreased 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 became applicable 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 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.

The May 2018 Idaho Tax Reform Settlement Stipulation did not impose a moratorium on Idaho Power filing a general rate case or other form of rate proceeding in Idaho during its respective term.

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. 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, and (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. 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 February 2019, Idaho Power reached an agreement with NV Energy that facilitates the planned end of Idaho Power's participation in coal-fired operations at units 1 and 2 of its jointly-owned North Valmy coal-fired power plant in 2019 and 2025, respectively. In May 2019, the IPUC issued an order approving the North Valmy plant agreement and allowing Idaho Power to recover through customer rates the $1.2 million incremental annual levelized revenue requirement associated with required North Valmy plant investments and other exit costs, effective June 1, 2019, through December 31, 2028. In December 2019, as planned, Idaho Power ended its participation in coal-fired operations of North Valmy plant unit 1.

Other Notable Idaho Regulatory Matters

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. The IPUC has discretion to cap the annual increase in the FCA recovery 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)
2018	June 1, 2019-May 31, 2020	$34.80
2017	June 1, 2018-May 31, 2019	$15.60

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 Public Utility Commission of Oregon (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 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. In December 2019, Idaho Power filed an application with the OPUC requesting approval of Idaho Power’s quantification of $1.5 million in annualized Oregon jurisdictional benefits associated with federal and state income tax changes resulting from tax reform and adjusting customer rates to reflect this amount, effective June 1, 2020, until its next general rate case or other proceeding where the tax-related revenue requirement components are reflected in rates.

In June 2017, the OPUC approved a settlement stipulation allowing for (1) accelerated depreciation of North Valmy plant units 1 and 2 through December 31, 2025, (2) cost recovery of incremental North Valmy plant investments through May 31, 2017, and (3) forecasted North Valmy plant 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. In October 2019, the OPUC approved the North Valmy plant agreement and authorized Idaho Power to adjust customer rates in Oregon, effective January 1, 2020, to reflect a decrease in the annual levelized revenue requirement of $3.2 million, which mostly relates to the decrease in depreciation expense and other costs associated with the December 2019 end of Idaho Power's participation in coal-fired operations of North Valmy plant unit 1.

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 actual financial and operational data Idaho Power files with the FERC and allows Idaho Power to recover costs for FERC-approved expenditures associated with its transmission system. 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, 2019 to September 30, 2020	$ 27.32
October 1, 2018 to September 30, 2019	$ 31.25
October 1, 2017 to September 30, 2018	$ 34.90

Idaho Power's current OATT rate is based on a net annual transmission revenue requirement of $107.0 million, which represents the OATT formulaic determination of Idaho Power's net cost of providing OATT-based transmission service.

4. REVENUES

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 (Topic 606)*. Idaho Power assesses revenues on a contract-by-contract basis to determine the nature, amount, timing, and uncertainty, if any, of revenues being recognized.

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 $2.6 million, $3.6 million, and $4.7 million for 2019 and 2018, respectively.

<u>Residential Customers</u>: 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.

<u>Commercial Customers</u>: 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 2019 Idaho ROE, Idaho Power recorded no provision against current revenues for sharing of earnings with customers for 2019. Idaho Power recorded $5.0 million of sharing of earnings with customers during 2018 and no provision was recorded during 2017. 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-Related 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-related revenues consist of a single performance obligation satisfied as capacity on Idaho Power's transmission system is provided to the third party. Transmission wheeling-related 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, 2019, Idaho Power's energy efficiency rider balances were a $0.3 million regulatory asset in the Idaho jurisdiction and a $1.2 million regulatory asset in the

Oregon jurisdiction.

Alternative Revenue Programs and Derivative 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.

5. LONG-TERM DEBT

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

	2019	2018
First mortgage bonds:		
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	220,000
Total first mortgage bonds	1,665,000	1,665,000
Pollution control revenue bonds:		
1.45% Series due 2024(1)	49,800	49,800
1.70% 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	(4,301)	(4,598)
Total Idaho Power outstanding debt(2)	$ 1,851,044	$1,850,747

(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, 2019, to $1.831 billion. These two bonds were purchased and remarketed in August of 2019. See "Long-Term Debt Issuances, Maturities, and Redemptions" below.

(2) At December 31, 2019 and 2018, the overall effective cost rate of Idaho Power's outstanding debt was 4.50 percent and 4.83 percent, respectively.

At December 31, 2019, the maturities for the aggregate amount of Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

2020	2021	2022	2023	2024	Thereafter
$ 100,000	$ -	$ 75,000	$ 75,000	$ 49,800	$ 1,555,545

Long-Term Debt Issuances, Maturities, and Redemptions

In March 2018, Idaho Power issued $220.0 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, $130.0 million in principal amount of 4.50% first mortgage bonds, secured 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 from the March 2018 sale of first mortgage bonds, medium-term notes to effect the redemption.

In April 2020, Idaho Power issued an additional $230.0 million in principal amount of 4.20% first mortgage bonds, secured medium-term notes, Series K, maturing on March 1, 2048, bringing the total principal amount of Series K bonds outstanding to $450 million. The bonds were issued at a premium of approximately $32 million.

In August 2019, Idaho Power purchased and remarketed two of its outstanding series of pollution control tax-exempt bonds, one in the aggregate principal amount of $49.8 million issued in 2003 by Humboldt County, Nevada and due in 2024, and the other in the aggregate principal amount of $116.3 million issued in 2006 by Sweetwater County, Wyoming and due in 2026. The bonds were remarketed with substantially the same terms, but with lower term interest rates. The term interest rate of the series due in 2024 decreased from 5.15 percent to 1.45 percent and the term interest rate of the series due in 2026 decreased from 5.25 percent to 1.70 percent.

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 2019, Idaho Power received orders from the IPUC, OPUC, and WPSC authorizing the company 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, 2022, 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.

In May 2019, Idaho Power filed a shelf registration statement with the SEC, which became effective upon filing, for the offer and sale of an unspecified principal amount of its first mortgage bonds. The issuance of first mortgage bonds requires that Idaho Power meet interest coverage and security provisions set forth in the Idaho Power's Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented from time to time (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.

As of the date of this report, Idaho Power has not entered into a selling agency agreement under the new shelf agreement. 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 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, 2019, 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, 2019, was limited to approximately $669 million under the Indenture.

6. NOTES PAYABLE

Credit Facilities

On December 6, 2019, Idaho Power entered into amendments to its outstanding Credit Agreement, which provides a credit facility that may be used for general corporate purposes and commercial paper backup. Idaho Power's credit facility consists of a revolving line of credit, through the issuance of loans and standby letters of credit, not to exceed the aggregate principal amount at any one time outstanding of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million, and letters of credit in an aggregate principal amount at any time outstanding not to exceed $50 million. Idaho Power has the right to request an increase in the aggregate principal amount of the facility to $450 million, subject to certain conditions.

The interest rates for any borrowings under the facility 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 Market Index rate plus 1.0 percent, or (2) the LIBOR Market Index rate, plus, in each case, an applicable margin, provided that the federal funds rate and LIBOR rate will not be less than zero percent. An alternate benchmark rate selected by the administrative agent for the credit facility and Idaho Power will apply during any period in which the

LIBOR rate is unavailable or unascertainable. The applicable margin is based on Idaho Power's senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreement. Under its 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 facility provides for an original maturity date of December 6, 2024, the credit agreement grants Idaho Power the right to request up to two one-year extensions, subject to certain conditions.

At December 31, 2019, no loans were outstanding under Idaho Power's facility. At December 31, 2019, Idaho Power had regulatory authority to incur up to $450 million in principal amount of short-term indebtedness at any one time outstanding. Idaho Power's short-term borrowings were zero at December 31, 2019 and 2018.

7. COMMON STOCK

Idaho Power Common Stock

No contributions were made to Idaho Power in 2019 or 2018 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 a leverage ratio of consolidated indebtedness to consolidated total capitalization, as defined therein, of no more than 65 percent at the end of each fiscal quarter. At December 31, 2019, the leverage ratio for Idaho Power was 45 percent. Based on these restrictions, Idaho Power’s dividends were limited to $1.3 billion at December 31, 2019. 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, 2019, 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, 2019, Idaho Power's common equity capital was 55 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, 2019, the maximum number of shares available under the LTICP was 613,394.

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 shares of IDACORP common stock:

	Number of Shares/Units	Weighted-Average Grant Date Fair Value	
Nonvested shares/units at January 1, 2019	204,859	$	81.31
Shares/units granted	98,362		92.59
Shares/units forfeited	(4,640)		94.57
Shares/units vested	(96,761)		71.95
Nonvested shares/units at December 31, 2019	201,820	$	90.99

The total fair value of shares vested was $9.4 million in 2019 and $8.3 million in 2018. At December 31, 2019, Idaho Power had $7.8 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 2019, a total of 9,594 shares of IDACORP common stock were awarded to directors of IDACORP and Idaho Power at a grant date fair value of $98.41 per share. Directors elected to defer receipt of 3,198 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):

		2019		2018
Compensation cost	$	8,639	$	9,276
Income tax benefit[(1)]		2,224		2,388

(1) Due to tax reform, the effective income tax rate was reduced in 2018 for 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, 2019, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2020	2021	2022	2023	2024	Thereafter
Cogeneration and power production	$ 241,835	$ 248,481	$ 251,964	$ 262,735	$ 266,061	$ 2,739,123
Fuel	55,693	36,069	8,389	8,379	8,371	75,074

As of December 31, 2019, Idaho Power had 1,136 MW nameplate capacity of PURPA-related projects on-line, with an additional 11 MW nameplate capacity of projects projected to be on-line by 2022. 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 $187 million in 2019 and $190 million in 2018.

Also, in March 2019, Idaho Power signed a 20-year power purchase agreement to purchase the output from a planned 120-megawatt solar facility. The agreement was approved by the IPUC in December 2019 and is, as of the date of this report, pending approval by the OPUC. If approved, the agreement would increase contractual obligations by $136 million over the 20-year term.

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

	2020	2021	2022	2023	2024	Thereafter
Joint-operating agreement payments(1)	$ 2,678	$ 2,678	$ 2,678	$ 2,678	$ 2,678	$ 13,391
Easements and other payments	269	1,124	1,072	1,062	1,055	16,408
Maintenance and service agreements(1)	47,547	13,797	16,468	7,143	7,354	55,768
FERC and other industry-related fees(1)	14,178	13,874	13,056	13,056	13,056	65,278

(1) Approximately $27 million, $48 million, and $131 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 2019 and 2018.

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 $58.3 million at December 31, 2019, representing IERCo's one-third share of BCC's total reclamation obligation of $175.0 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2019, the value of the reclamation trust fund was $139.5 million. During 2019, the reclamation trust fund made no 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.

In May 2019, the state of Wyoming enacted legislation that limits a mine operator's maximum amount of self-bonding. Idaho Power and the co-owners of BCC have until December 2020 to comply with the new regulations, which would reduce the portion of Idaho Power's guarantee of reclamation activities and obligations at BCC that Idaho Power is allowed to self-bond. As of the date of this report, Idaho Power believes the cost of any insurance, third-party assurance, or additional collateral that might be required for this guarantee due to the new law would be immaterial to its consolidated financial statements.

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 evaluate the likelihood of incurring costs under such indemnities based on its historical experience and the evaluation of the specific indemnities. As of December 31, 2019, 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 expects 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 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, tax, 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 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, Idaho Power believes that resolution of existing claims will not have a material adverse effect on its 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.

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

	Pension Plan		SMSP	
	2019	2018	2019	2018
Change in projected benefit obligation:				
Benefit obligation at January 1	$ 951,857	$ 999,344	$ 102,318	$ 110,303
Service cost	34,061	37,836	(181)	(316)
Interest cost	42,312	38,833	4,575	4,248
Actuarial loss (gain)	147,784	(84,758)	17,888	(7,050)
Plan amendment	-	-	2,839	-
Benefits paid	(41,262)	(39,398)	(4,996)	(4,867)
Projected benefit obligation at December 31	1,134,752	951,857	122,443	102,318
Change in plan assets:				
Fair value at January 1	650,604	697,683	-	-
Actual return (loss) on plan assets	113,777	(47,681)	-	-
Employer contributions	40,000	40,000	-	-
Benefits paid	(41,262)	(39,398)	-	-
Fair value at December 31	763,119	650,604	0	0
Funded status at end of year	$ (371,633)	$ (301,253)	$ (122,443)	$ (102,318)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ -	$ -	$ (5,911)	$ (5,158)
Noncurrent liabilities	(371,633)	(301,253)	(116,532)	(97,160)
Net amount recognized	$ (371,633)	$ (301,253)	$ (122,443)	$ (102,318)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 347,785	$ 278,720	$ 45,851	$ 30,496
Prior service cost	56	62	3143	399
Subtotal	347,841	278,782	48,994	30,895
Less amount recorded as regulatory asset[1]	(347,841)	(278,782)	-	-
Net amount recognized in accumulated other comprehensive income	$ -	$ -	$ 48,994.00	$ 30,895.00
Accumulated benefit obligation	$ 958,586	$ 814,549	$ 109,966	$ 94,630

[1] Changes in the funded status of the pension plan that would be recorded in accumulated other comprehensive income for an unregulated entity are recorded as a regulatory asset for Idaho Power as Idaho Power believes it is probable that an amount equal to the regulatory asset will be collected through the setting of future rates.

The actuarial losses reflected in the benefit obligations for the pension and SMSP plans in 2019 are due primarily to decreases in the assumed discount rates of both plans from December 31, 2018, to December 31, 2019. The actuarial gains affecting the benefit obligations for the pension and SMSP plans in 2018 are due primarily to increases in the assumed discount rates from December 31, 2017, to December 31, 2018. For more information on discount rates, see "Plan Assumptions" below in this Note 1.

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 $97.6 million and $92.5 million at December 31, 2019 and 2018, 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	
	2019	2018	2019	2018
Service cost	$ 34,061	$ 37,836	$ (181)	$ (316)
Interest cost	42,312	38,833	4,575	4,248
Expected return on assets	(48,623)	(52,302)	-	-
Amortization of net loss	13,564	13,558	2,533	3,788
Amortization of prior service cost	6	6	96	98
Net periodic pension cost	41,320	37,931	7,023	7,818
Regulatory deferral of net periodic benefit cost[1]	(39,379)	(36,153)	-	-
Previously deferred pension cost recognized[1]	17,154	17,154	-	-
Net periodic benefit cost recognized for financial reporting[1][2]	$ 19,095	$ 18,932	$ 7,023	$ 7,818

(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 $15.1 million and $15.2 million, respectively, was recognized in "Other operations and maintenance" and $11.0 million and $11.6 million, respectively, was recognized in "Other expense, net" on the consolidated statements of income for the twelve months ended December 31, 2019 and 2018.

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

	Pension Plan		SMSP	
	2019	2018	2019	2018
Actuarial (loss) gain during the year	$ (82,631)	$ (15,226)	$ (17,888)	$ 7,049
Plan amendment service cost	-	-	(2,839)	-
Reclassification adjustments for:				
Amortization of net loss	13,564	13,558	2,533	3,788
Amortization of prior service cost	6	6	96	98
Adjustment for deferred tax effects	17,776	428	4,658	(2,815)
Adjustment due to the effects of regulation	51,285	1,234	0	0
Other comprehensive (loss) income recognized related to pension benefit plans	$ -	$ -	$ (13,440)	$ 8,120

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

	2020	2021	2022	2023	2024	2025-2029
Pension Plan	$ 40,727	$ 42,674	$ 44,576	$ 46,670	$ 48,694	$ 273,700
SMSP	6,010	6,186	6,281	6,700	6,724	33,304

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 2019, 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. As of the date of this report, Idaho Power's minimum required contribution to the pension plan is estimated to be $14 million during 2020. Depending on market conditions and cash flow considerations in 2020, Idaho Power could contribute up to $40 million to the pension plan during 2020 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):

		2019		2018
Change in accumulated benefit obligation:				
Benefit obligation at January 1	$	66,453	$	70,051
Service cost		853		1,051
Interest cost		2,989		2,643
Actuarial loss (gain)		5,298		(2,688)
Benefits paid (1)		(4,564)		(4,604)
Plan amendments				0
Benefit obligation at December 31		71,029		66,453
Change in plan assets:				
Fair value of plan assets at January 1		33,391		38,294
Actual return (loss) on plan assets		7,269		(1,330)
Employer contributions (1)		3,529		1,031
Benefits paid (1)		(4,564)		(4,604)
Fair value of plan assets at December 31		39,625		33,391
Funded status at end of year (included in noncurrent liabilities)	$	(31,404)	$	(33,062)

(1) Contributions and benefits paid are each net of $3.3 million and $3.1 million of plan participant contributions for 2019 and 2018, respectively.

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

		2019		2018
Net loss	$	(81)	$	(330.0)
Prior service cost		174		222
Subtotal		93		(108)
Less amount recognized in regulatory assets		(93)		108
Net amount recognized in accumulated other comprehensive income	$	-	$	-

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

	2019	2018
Service cost	$ 853	$ 1,051
Interest cost	2,989	2,643
Expected return on plan assets	(2,220)	(2,467)
Immediate recognition of loss from temporary deviation (1)	-	4,216
Amortization of prior service cost	48	47
Net periodic postretirement benefit cost	$ 1,670	$ 5,490

(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 statement of income.

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

	2019	2018
Actuarial loss during the year	$ (249)	$ (1,109)
Prior service cost arising during the year	0	0
Reclassification adjustments for:		
Immediate recognition of loss from temporary deviation (1)	0	4,216
Reclassification adjustments for amortization of prior service cost	48	47
Adjustment for deferred tax effects	52	270
Adjustment due to the effects of regulation	149	(3,424)
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.

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

	2020	2021	2022	2023	2024	2025-2028
Expected benefit payments	$ 5,552	$ 4,932	$ 4,750	$ 4,532	$ 4,289	$ 19,133

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	
	2019	2018	2019	2018	2019	2018
Discount rate	3.60%	4.55%	3.65%	4.60%	3.60%	4.60%
Rate of compensation increase[1]	4.37%	4.25%	4.75%	4.75%	--	--
Medical trend rate	--	--	--	--	6.7%	6.3%
Dental trend rate	0.0%	--	--	--	4.0%	4.0%
Measurement date	12/31/2019	12/31/2018	12/31/2019	12/31/2018	12/31/2019	12/31/2018

(1) The 2019 rate of compensation increase assumption for the pension plan includes an inflation component of 2.40% plus a 1.97% 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 0.6% 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	
	2019	2018	2019	2018	2019	2018
Discount rate	4.55%	3.95%	4.60%	3.95%	4.60%	3.95%
Expected long-term rate of return on assets	7.50%	7.50%	—	—	6.75%	6.75%
Rate of compensation increase	4.37%	4.25%	4.75%	4.75%	—	—
Medical trend rate	—	—	—	—	6.7%	6.3%
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 6.7 percent in 2019 and is assumed to decrease to 5.9 percent in 2020, 5.2 percent in 2021, 5.1 percent in 2022 and to gradually decrease to 3.9 percent by 2091. 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.

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2019, for the pension asset portfolio by asset class is set forth below:

Asset Class	Target Allocation	Actual Allocation December 31, 2019
Debt securities	24%	23%
Equity securities	56%	59%
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. 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 30 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, 2019				
Cash and cash equivalents	$ 10,878	$ -	--	$ 10,878
Short-term bonds	21,628	--	--	21,628
Intermediate bonds	22,369	134,931	--	157,300
Long-term bonds	0	--	--	--
Equity Securities: Large-Cap	92,852	--	--	92,852
Equity Securities: Mid-Cap	81,663	--	--	81,663
Equity Securities: Small-Cap	67,075	--	--	67,075
Equity Securities: Micro-Cap	31,469	--	--	31,469
Equity Securities: International	13,817	--	--	13,817
Equity Securities: Emerging Markets	8,245	--	--	8,245
Plan assets measured at NAV -not subject to hierarchy disclosure)				
Commingled Fund: Equity Securities: Global and International				114,975
Commingled Fund: Equity Securities: Emerging Markets				40,059
Commingled Fund: Commodities fund				34,793
Real estate				47,570
Private market investments				40,795
Total	$349,996	$134,931	$ -	$763,119
Postretirement plan assets-(1)	$ 641	$ 38,984	$ -	$ 39,625

	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)				
Commingled Fund: Equity Securities: International				95,653
Commingled Fund: Equity Securities: Emerging Markets				29,757
Commingled Fund: Commodities fund				30,842
Real estate				39,846
Private market investments				35,041
Total	$290,962	$128,503	$ -	$650,604
Postretirement plan assets[1]	$ 758	$ 32,633	$ -	$ 33,391

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

For the years ended December 31, 2019 and 2018, 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 international and 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 open-end and closed-end 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 on the open-end funds 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. The closed-end funds are formed for a stated life of 7 to 9 years. 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.

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 in both 2019 and 2018.

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, 2019, and 2018, 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, 2019 and 2018 (in thousands of dollars):

	2019			2018		
		Balance	Avg Rate		Balance	Avg Rate
Production	$	2,535,938	3.19%	$	2,654,201	3.10%
Transmission		1,220,703	1.89%		1,201,092	1.89%
Distribution		1,882,136	2.25%		1,792,284	2.24%
General and Other		478,662	6.17%		461,030	6.40%
Total in service and held for future use		6,117,439	2.87%		6,108,607	2.84%
Accumulated provision for depreciation		(2,341,468)			(2,394,579)	
In service and held for future use - net	$	3,775,971		$	3,714,028	

At December 31, 2019, Idaho Power's construction work in progress balance of $552.5 million included relicensing costs of $326.0

million for the HCC, Idaho Power's largest hydropower complex. In 2019 and 2018, Idaho Power had IPUC authorization to include in its Idaho jurisdiction rates $6.5 million annually ($8.8 million when grossed-up for the effect of 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, 2019, Idaho Power's accumulated provision for rate refunds for collection of AFUDC relating to the HCC was $151.7 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, 2019 (in thousands of dollars):

Name of Plant	Location	Utility Plant in Service	Construction Work in Progress	Accumulated Provision for Depreciation	Ownership %	MW (1)(2)
Jim Bridger units 1-4	Rock Springs, WY	$ 745,096	$ 4,622	$ 353,254	33	771
Boardman	Boardman, OR	82,501	12	78,411	10	64
North Valmy unit 2 (2)	Winnemucca, NV	252,921	217	166,419	50	145

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

(2) Idaho Power ended its participation in coal-fired operations at unit 1 of the North Valmy plant on December 31, 2019.

IERCo, Idaho Power’s wholly-owned subsidiary, is a joint venturer in BCC. Idaho Power’s coal purchases from the joint venture were $73.6 million in 2019 and $81.8 million in 2018.

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 $8.6 million in 2019 and $9.7 million in 2018.

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 reclamation and removal costs at its jointly-owned coal-fired generation facilities.

Idaho Power also has additional AROs associated with its transmission system, hydropower 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):

	2019	2018
Balance at beginning of year	$ 26,792	$ 26,415
Accretion expense	1,115	1,055
Revisions in estimated cash flows	365	(751)
Liability incurred	-	129
Liability settled	(81)	(56)
Balance at end of year	$ 28,191	$ 26,792

14. INVESTMENTS

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

	2019	2018
Idaho Power investments:		
IERCO	$ 25,516	$ 57,026
Exchange traded short-term bond funds and cash equivalents	42,648	36,471
Executive deferred compensation plan investments	90	17
Total Idaho Power investments	68,254	93,514

Investments in Equity Securities

Investments in equity securities are reported at fair value. Any unrealized gains or losses on equity securities are included in income. Unrealized gains and losses on equity securities were immaterial at December 31, 2019 and December 31, 2018. The following table summarizes sales of equity securities (in thousands of dollars):

	2019	2018	2017
Proceeds from sales	$ 5,080	$ 5,007	$ 4,989
Gross realized gains from sales	--	--	--

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, 2019 and 2018 (in thousands of dollars):

	Location of Realized Gain (Loss) on Derivatives Recognized in Income	Gain(Loss) on Derivatives Recognized in Income (1) 2019	2018
Financial swaps	Operating revenues	$ 904	$ 1,316
Financial swaps	Purchased power	(2,183)	7,828
Financial swaps	Fuel expense	13,811	22,563
Financial swaps	Other operations and maintenance	-	118
Forward contracts	Operating revenues	285	41
Forward contracts	Purchased power	(270)	(54)
Forward contracts	Fuel expense	565	(186)

(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, 2019 and 2018 (in thousands of dollars):

	Balance Sheet Location	Asset Derivatives Gross Fair Value	Asset Derivatives Amounts Offset	Asset Derivatives Net Assets	Liability Derivatives Gross Fair Value	Liability Derivatives Amounts Offset	Liability Derivatives Net Liabilities
December 31, 2019							
Current:							
Financial swaps	Other current assets	$ 2,426	$ (2,034)	$ 392	$ 2,034	$ (2,034)	$ -
Financial swaps	Other current liabilities	134	(134)	--	924	(134)	790
Forward contracts	Other current assets	13	--	13	--	--	--
Forward contracts	Other current liabilities	--	--	--	32	--	32
Long-term:							
Financial swaps	Other assets	3	(3)	--	27	(3)	24
Total		$ 2,576	$ (2,171)	$ 405	$ 3,017	$ (2,171)	$ 846
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

[1] Current asset derivative amounts offset include $45 thousand of collateral payable at December 31, 2018.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2019 and 2018 (in thousands of units):

Commodity	Units	December 31, 2019	December 31, 2018
Electricity purchases	MWh	91	52
Electricity sales	MWh	138	39
Natural gas purchases	MMBtu	14,053	7,514
Natural gas sales	MMBtu	78	446

Credit Risk

At December 31, 2019, 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, 2019, was $3.0 million. Idaho Power posted $1.4 million cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2019, Idaho Power would have been required to pay or post collateral to its counterparties up to an additional $6.7 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 has the ability to access.

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

Idaho Power Level 2 inputs for derivative instruments 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, 2019 and 2018.

The following table presents information about Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2019 and 2018 (in thousands of dollars):

	December 31, 2019				December 31, 2018			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Money market funds and commercial paper	$ 26,510	$ —	$ —	$ 26,510	$ 79,228	$ —	$ —	$ 79,228
Derivatives	392	13	--	405	3,655	--	--	3,655
Equity securities	42,738	--	--	42,738	36,488	--	--	36,488
Liabilities:								
Derivatives	$ 814	$ 32	$ —	$ 846	$ 870	$ 104	$ —	$ 974

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, 2019 and 2018, using available market information and appropriate valuation methodologies (in thousands).

	December 31, 2019		December 31, 2018	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(thousands of dollars)			
Liabilities:				
Long-term debt -including current portion (1)	$ 1,836,659	$ 2,083,931	$ 1,834,788	$ 1,942,773

(1) Long-term debt is categorized Level 2 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, 2019 and 2018 (in thousands of dollars). Items in parentheses indicate reductions to AOCI.

	2019	2018
Defined benefit pension items		
Balance at beginning of period	$ (22,844)	$ (30,964)
Other comprehensive income before reclassifications	(15,392)	5,234
Amounts reclassified out of AOCI to net income	1,952	2,886
Net current-period other comprehensive income	(13,440)	8,120
Cumulative effect of change in accounting principle (1)	—	—
Balance at end of period	$ (36,284)	$ (22,844)

(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, 2019 and 2018 (in thousands of dollars). Items in parentheses indicate increases to net income.

	Amount Reclassified from AOCI Year Ended December 31,	
	2019	2018
Amortization of defined benefit pension items (1)		
Prior service cost	$ 96	$ 98
Net loss	2,533	3,788
Total before tax	2,629	3,886
Tax benefit (2)	(677)	(1,000)
Net of tax	1,952	2,886
Total reclassification for the period	$ 1,952	$ 2,886

(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 $0.8 million in 2019 and $0.7 million in 2018.

At December 31, 2019 and 2018, Idaho Power had a $1.9 million payable to IDACORP, which was included in its accounts payable to affiliates balance on its consolidated balance sheets.

Ida-West: Ida-West Energy Company (Ida-West) is a wholly-owned subsidiary of IDACORP and is an operator of small hydropower generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978. Idaho Power purchases all of the power generated by four of Ida-West's hydropower projects located in Idaho. Idaho Power paid Ida-West $8.6 million in 2019 and $9.7 million in 2018 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	04/14/2020	End of 2019/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)	6,112,816,292	6,112,816,292
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	6,112,816,292	6,112,816,292
9	Leased to Others		
10	Held for Future Use	3,871,699	3,871,699
11	Construction Work in Progress	552,498,787	552,498,787
12	Acquisition Adjustments	750,893	750,893
13	Total Utility Plant (8 thru 12)	6,669,937,671	6,669,937,671
14	Accum Prov for Depr, Amort, & Depl	2,341,467,978	2,341,467,978
15	Net Utility Plant (13 less 14)	4,328,469,693	4,328,469,693
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,313,565,686	2,313,565,686
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	27,839,718	27,839,718
22	Total In Service (18 thru 21)	2,341,405,404	2,341,405,404
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	62,574	62,574
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,341,467,978	2,341,467,978

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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	33,498,042	784,118
4	(303) Miscellaneous Intangible Plant	29,028,326	11,573,558
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	62,532,071	12,357,676
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,722,421	
9	(311) Structures and Improvements	156,069,228	2,111,918
10	(312) Boiler Plant Equipment	763,836,141	15,335,849
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	172,389,727	1,294,280
13	(315) Accessory Electric Equipment	74,658,335	111,433
14	(316) Misc. Power Plant Equipment	22,031,279	228,765
15	(317) Asset Retirement Costs for Steam Production	14,156,745	584,151
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,204,863,876	19,666,396
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	31,655,065	269,265
28	(331) Structures and Improvements	199,926,283	8,714,255
29	(332) Reservoirs, Dams, and Waterways	275,186,449	8,668,581
30	(333) Water Wheels, Turbines, and Generators	291,046,612	1,883,361
31	(334) Accessory Electric Equipment	63,782,202	2,315,954
32	(335) Misc. Power PLant Equipment	26,619,157	1,308,162
33	(336) Roads, Railroads, and Bridges	11,881,733	119,572
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	900,097,501	23,279,150
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,699,794	
38	(341) Structures and Improvements	143,338,791	10,256,874
39	(342) Fuel Holders, Products, and Accessories	10,714,867	
40	(343) Prime Movers	227,443,929	1,817,339
41	(344) Generators	66,714,048	
42	(345) Accessory Electric Equipment	91,837,192	195,607
43	(346) Misc. Power Plant Equipment	6,491,088	258,973
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	549,239,709	12,528,793
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,654,201,086	55,474,339

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
			34,282,160		3
4,559,559			36,042,325		4
4,559,559			70,330,188		5
					6
					7
			1,722,421		8
25,456,769			132,724,377		9
95,950,017			683,221,973		10
					11
21,695,066			151,988,941		12
16,990,156			57,779,612		13
3,506,357			18,753,687		14
			14,740,896		15
163,598,365			1,060,931,907		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			31,924,330		27
476,842			208,163,696		28
92,955			283,762,075		29
1,057,282			291,872,691		30
493,214			65,604,942		31
309,028			27,618,291		32
			12,001,305		33
					34
2,429,321			920,947,330		35
					36
			2,699,794		37
169,333			153,426,332		38
276,619			10,438,248		39
7,122,304			222,138,964		40
			66,714,048		41
36,376			91,996,423		42
104,937			6,645,124		43
					44
7,709,569			554,058,933		45
173,737,255			2,535,938,170		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	04/14/2020	End of 2019/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	38,923,537	86,564
49	(352) Structures and Improvements	81,023,794	1,199,316
50	(353) Station Equipment	441,025,698	15,662,807
51	(354) Towers and Fixtures	211,357,840	3,749,251
52	(355) Poles and Fixtures	195,207,683	13,875,825
53	(356) Overhead Conductors and Devices	233,163,083	9,112,908
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)	1,201,091,901	43,686,671
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	6,553,285	831,412
61	(361) Structures and Improvements	40,283,756	7,626,265
62	(362) Station Equipment	254,363,384	18,088,390
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	271,695,898	14,246,292
65	(365) Overhead Conductors and Devices	140,485,165	5,534,717
66	(366) Underground Conduit	52,238,001	2,346,727
67	(367) Underground Conductors and Devices	275,969,031	18,221,495
68	(368) Line Transformers	587,592,181	33,854,487
69	(369) Services	61,919,728	1,528,445
70	(370) Meters	93,327,295	7,740,607
71	(371) Installations on Customer Premises	3,124,332	86,066
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,588,885	100,244
74	(374) Asset Retirement Costs for Distribution Plant	142,630	-142,630
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,792,283,571	110,062,517
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	17,743,554	62,673
87	(390) Structures and Improvements	127,518,769	6,264,328
88	(391) Office Furniture and Equipment	48,506,483	5,789,019
89	(392) Transportation Equipment	92,865,678	8,129,169
90	(393) Stores Equipment	3,023,105	544,044
91	(394) Tools, Shop and Garage Equipment	11,094,864	866,055
92	(395) Laboratory Equipment	13,703,530	1,635,713
93	(396) Power Operated Equipment	19,234,311	3,625,092
94	(397) Communication Equipment	51,929,302	1,049,390
95	(398) Miscellaneous Equipment	7,376,604	376,755
96	SUBTOTAL (Enter Total of lines 86 thru 95)	392,996,200	28,342,238
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)	392,996,200	28,342,238
100	TOTAL (Accounts 101 and 106)	6,103,104,829	249,923,441
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)	6,103,104,829	249,923,441

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
			39,010,101		48
591,258			81,631,852		49
19,597,540			437,090,965		50
			215,107,091		51
2,093,564			206,989,944		52
1,793,402			240,482,589		53
					54
					55
			390,266		56
					57
24,075,764			1,220,702,808		58
					59
			7,384,697		60
149,605			47,760,416		61
2,983,896			269,467,878		62
					63
2,425,242			283,516,948		64
1,686,997			144,332,885		65
340,375			54,244,353		66
2,550,150			291,640,376		67
6,593,742			614,852,926		68
257,898			63,190,275		69
3,176,938			97,890,964		70
14,599			3,195,799		71
					72
30,919			4,658,210		73
					74
20,210,361			1,882,135,727		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			17,806,227		86
792,670			132,990,427		87
9,235,375			45,060,127		88
3,959,610			97,035,237		89
31,810			3,535,339		90
290,670			11,670,249		91
442,959			14,896,284		92
922,146			21,937,257		93
1,837,526			51,141,166		94
116,273			7,637,086		95
17,629,039			403,709,399		96
					97
					98
17,629,039			403,709,399		99
240,211,978			6,112,816,292		100
					101
					102
					103
240,211,978			6,112,816,292		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	04/14/2020	End of 2019/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			423,089
5	Transmission Lines			195,489
6	Distribution Stations			1,289,207
7	Homedale Substation	2/29/08	2035	109,453
8	Line #854 500 Kv	3/31/09	2024	308,066
9	Distribution Line			25,581
10				
11				
12	Column B and C if no date listed it is various			
13				
14				
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	Underground Vault, Blaine County	8/30/16	2023	443,545
26				
27				
28				
29	Column B and C if no date listed it is various			
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47	Total			3,871,699

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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	122,479,532
2	ROLLUP RELIC COST HELLS CANYON	83,404,313
3	GATEWAY WEST 500KV LINE	41,232,517
4	ROLLUP RELIC COST OXBOW	38,802,953
5	HELLS CANYON RELICENSING OUTSI	35,835,692
6	B2H PERMITTING 11/1/2011 & FOR	19,813,179
7	BROWNLEE UNIT 2 TURBINE REFURB	13,639,700
8	SHOSHONE FALLS UPGRADE - REPLA	10,418,344
9	BOARDMAN - HEMINGWAY 500 KV LI	10,052,793
10	HCC WATERSHED ENHANCEMENT PROG	8,324,787
11	LOWER SALMON UNIT 2 REFURB	8,305,369
12	UPPER MALAD FISH LADDER	6,995,933
13	WQ HCC401 CERTIFICATION OPS AN	6,785,453
14	LEGAL DEPT. LABOR FOR RELICENS	6,169,360
15	BAYHA ISLAND RESEARCH PROJECT	5,205,770
16	CDAL160001	4,246,380
17	REL-HCC OREGON REAUTHORIZATION	4,233,025
18	BULL TROUT PROGRAM - ADMINISTR	3,850,716
19	B2H TLINE CONSTRUCTION COSTS	3,481,629
20	STAT160001 NEW MC	3,268,151
21	GRAND VIEW IRRIGATION UPGRADE	3,164,201
22	BIRD NET REPLACEMENT 2017 CAPI	2,927,105
23	WDRI-KCHM NEW 138KV	2,874,380
24	PTSN PURCHASE AND INSTALL NEW	2,725,174
25	FALL CHINOOK PROGRAM - REDD SU	2,707,656
26	WQ HCC401 APPLICATION, REVISIO	2,633,266
27	HBND-041:ALT LINE ROUTE TO GAR	2,593,928
28	BROWNLEE UNIT 5 REWIND	2,406,256
29	LOWER SALMON UNIT 1 REFURBISHM	2,245,087
30	LOWER SALMON UNIT 3 REFURB	2,215,551
31	HCC RELICENSING WATER QUALITY	2,183,963
32	BROWNLEE SECURITY ENHANCEMENT	1,961,732
33	BOBN170004 REPLACE C231 SERIES	1,913,677
34	HC SEDIMENT PROGRAMS	1,833,366
35	HOURLY SETTLEMENT BILLING	1,718,972
36	SMART KEY FOBS & CORES	1,701,552
37	BOCB170034 - MBE 9 PURCHASE A	1,629,243
38	VARI160010 - PLANNING, SCOPING	1,552,435
39	REPORTING MODEL FOR SNAKE RIVE	1,480,435
40	WHITE STURGEON PROGRAM - HCC R	1,455,662
41	VARI160010 - MOBILE VEHICLE RA	1,381,534
42	BLISS CONCRETE REPAIR	1,378,661
43	TOTAL	552,498,787

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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	04/14/2020	End of 2019/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	HCC SNAKE RIVER ENHANCEMENT RE	1,344,839
2	CDAL170001 - EXTEND 230KV SERV	1,206,949
3	HELLS CANYON ROCKFALL MITIGATI	1,030,713
4	HCC RELICENSING: HART AND 401	1,011,333
5	BOC SITE EXPANSION: NEW STC B	1,004,474
6	Other Minor Projects Under $1,000,000	63,671,047
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43	TOTAL	552,498,787

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	2,369,301,348	2,369,301,348		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	160,145,693	160,145,693		
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	4,921,624	4,921,624		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	241,578	241,578		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	165,875,560	165,875,560		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	235,652,420	235,652,420		
13	Cost of Removal	14,947,193	14,947,193		
14	Salvage (Credit)	1,041,889	1,041,889		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	249,557,724	249,557,724		
16	Other Debit or Cr. Items (Describe, details in footnote):	27,946,502	27,946,502		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,313,565,686	2,313,565,686		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	592,496,235	592,496,235		
21	Nuclear Production				
22	Hydraulic Production-Conventional	446,783,960	446,783,960		
23	Hydraulic Production-Pumped Storage				
24	Other Production	120,948,585	120,948,585		
25	Transmission	371,992,159	371,992,159		
26	Distribution	657,914,261	657,914,261		
27	Regional Transmission and Market Operation				
28	General	123,430,486	123,430,486		
29	TOTAL (Enter Total of lines 20 thru 28)	2,313,565,686	2,313,565,686		

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

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	04/14/2020	End of 2019/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			54,563,677
5				
6	Subtotal Idaho Energy Resources Company			57,026,771
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42	Total Cost of Account 123.1 $ 2,463,094		TOTAL	57,026,771

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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
8,489,145	40,000,000	23,052,822		4
				5
8,489,145	40,000,000	25,515,916		6
				7
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8,489,145	40,000,000	25,515,916		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	47,979,122	57,447,554	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			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)	17,733,796	18,044,916	
8	Transmission Plant (Estimated)	9,422,601	7,751,239	
9	Distribution Plant (Estimated)	27,160,500	27,522,183	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	-763,223	920,624	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	53,553,674	54,238,962	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)	1,433,652	2,420,600	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	102,966,448	114,107,116	

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

This amount represents miscellaneous inventory that is not yet assigned to a particular function.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	IPCL TRANS SIS 88754178	48,318	186623	(61,993)	186623
3	BPAP NETWORK SIS 90030618	4,343	186623	(10,000)	186623
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21	**Generation Studies**				
22	BAKER CITY 1 SOLAR	(176)	186623		
23	WARM SPRINGS HYDRO #526			28,983	186623
24	AMALGAMATED SUGAR #531			17,724	186623
25	CAT CREEK PUMP STORAGE #530	38,303	186623	(58,943)	186623
26	GEM-VALE #534 300MW	11,716	186623	(86,730)	186623
27	GEM-VALE WIND #53 500MW	9,327	186623	55,124	186623
28	VERDE LIGHT POWER #532 3MW	7,304	186623	(16,372)	186623
29	BORREGO SOLAR #533			3,693	186623
30	OLD CAMP SOLAR 80MW	11,228	186623	(50,823)	186623
31	MASON DAM HYDRO #538 2MW	500	186623		
32	OPAL SOLAR #539	677	186623	(677)	186623
33	MOONSTONE SOLAR #541	6,276	186623	(10,677)	186623
34	FRANKLIN SOLAR #549	12,035	186623	(50,000)	186623
35	ADA COUNTY BIOMASS #554	1,866	186623	(1,866)	186623
36	PRAIRIE CITY SOLAR #556	18,356	186623	(60,000)	186623
37	ARH SOLAR #558	2,190	186623	(60,000)	186623
38	BLACK MESA ENERGY #557	6,395	186623	(10,000)	186623
39	MC6 HYDRO #559	2,166	186623	(10,000)	186623
40	BENNETT SOLAR 1 #551	6,222	186623	(20,000)	186623

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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20					
21	**Generation Studies**				
22	BENNETT SOLAR 2 #552	4,030	186623	(20,000)	186623
23	BENNETT SOLAR 3 #553	2,935	186623	(20,000)	186623
24	BENNETT SOLAR 4 #560	4,746	186623	(10,000)	186623
25	COLEMAN HYDRO #548	3,294	186623	(11,000)	186623
26	MIDPOINT SOLAR #561			(10,000)	186623
27	MOORE HOLLOW SOLAR #561			(20,000)	186623
28	DURKEE SOLAR #546	2,132	186623	(11,000)	186623
29	PLEASANT VALLEY SOLAR #568	1,947	186623	(20,000)	186623
30	ARCO WIND 950MW #563			(10,000)	186623
31	ARCO SOLAR 950MW #563	6,722	186623		
32	PIGEON COVE HYDRO- MV90 METER INSL			(1,500)	186623
33	SAWTOOTH SOLAR #572	783	186623	(783)	186623
34	MOON CRATER SOLAR #57	293	186623	(30,000)	186623
35	MAGIC VALLEY ENERGY #572	1,221	186623	(30,000)	186623
36	OLD OREGON TRAIL 1 #568			(10,000)	186623
37	JACOBSON SOLAR #566			(1,000)	186623
38					
39					
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Schedule Page: 231   Line No.: 23   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 Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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)	34,502,069	35,208,267	400	34,502,069	35,208,267
2	Order Pending (Amort period 06/20 thru 05/21					
3						
4	AOCI Impact of Unfunded Post Retirement Liability	(107,935)	248,407	2283	47,270	93,202
5	Order #30256 (182306)					
6						
7	FCA Calender Mo Adjustment	881,510	2,059,340			2,940,850
8						
9	Prior Year FCA - Order #33527 (182309)	7,119,639	34,788,276	400	26,040,501	15,867,414
10	Order $34346 (Amortization period 06/19 thru 05/20)					
11						
12	AOCI Impact of Unfunded Pension Liability	278,781,669	82,630,675	2283	13,571,003	347,841,341
13	Order #30256 (182320)					
14						
15	Deferred Pension Expense Net of Contributions	21,024,974	39,379,047	1823	38,116,777	22,287,244
16	Order #30333 (182321)					
17						
18	FAS 109 Unfunded (182322)	358,202,341	41,065,081			399,267,422
19	Accum Deferred Income Noncurrent					
20						
21	Idaho Pension Cash - Order #32248 (182327)	126,810,747	40,692,724	Various	17,153,713	150,349,758
22	(Amort period beginning 06/11 thru indefinite)					
23						
24	ASC 815 Mark to Market Short-Term (182330)	910,525		244	88,264	822,261
25						
26	Oregon Pension Expense Capitalized (182339)	4,896,573	699,265	4073	153,953	5,441,885
27	Order #10-064					
28						
29	Asset Retirement Obligations (182341)	17,563,478	1,226,009			18,789,487
30	IPUC Order #29414-OPUC Order #04-585					
31						
32	RA-Hells Canyon-Baker Co (182360)	313,506				313,506
33	Order #33948					
34						
35	Lidar Surveys - Order #32426 (182361)	130,814		402	43,605	87,209
36	(Amort period 01/12 thru 12/21)					
37						
38	RA-Intervenor Funding-Idaho (182387)	192,471	3,719			196,190
39	Mulitple IPUC Orders					
40						
41	RA-CONTRA-DEF INC TAX (182389)	255,941,746		Various	8,323,141	247,618,605
42						
43	Idaho Boardman ARO - Order # 29414 (182393					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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	Langley Revenue Accrual (182398)	1,282,099	102,724			1,384,823
2	Advice #12-226					
3						
4	RA-OR Langley Rev Int Res (182399)	(159,711)		4190	38,114	-197,825
5						
6	Siemens Long Term Deferred Rate Base (182410)	10,338,443		4073	431,488	9,906,955
7	Order #33420 (Amort period 01/16 thru 12/43)					
8						
9	Siemens Long Term Deferred Rate Base (182411)	15,427,037		4073	643,866	14,783,171
10	Order #33420 (Amort period 01/16 thru 12/43)					
11						
12	Siemens Long Term Deferred Rate Base (182412)	415,298	31,785	Various	44,047	403,036
13	Order #15-387 (Amort period 01/16 thru 12/36)					
14						
15	Siemens Long Term Deferred Rate Base (182413)	668,368		4073	39,316	629,052
16	Order #15-387 (Amort period 01/16 thru 12/36)					
17						
18	Seimens Long Term Interest Reserve (182414)	(100,562)		4190	31,785	-132,347
19						
20	RA-Valmy O&M ID (182432)	(2,708,051)	4,323,199	Various	207,828	1,407,320
21	IPUC Order #33771					
22						
23	RA-Valmy OR Depr Adj 17-325 (182434)	888,513		403	888,513	
24	(Amort period 06/17 thru 12/25)					
25						
26	RA-Valmy Acctg Adj ID (182435)	77,249,844	28,137,497			105,387,341
27	IPUC Order #33771					
28						
29	RA-Valmy Decomm OR (182436)	1,997,400	299,752	Various	1,643,007	654,145
30	OPUC Advice #17-235 (Amort period 06/17 thru 12/25					
31						
32	Idaho Boardman Decomissioning (182493)	(5,438,694)	5,438,694			
33	IPUC Order #32549 & #32457					
34						
35	RA-ID Boardman Decomm (182495)	5,292,856		254	5,292,856	
36	IPUC Order #32457					
37						
38	RA-OR Boardman Decomm (182496)	237,789		254	237,789	
39	OPUC Advice #12-235					
40						
41	Idaho DSM Rider		38,069,980	Various	37,758,935	311,045
42	IPUC Order #28661					
43						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	Oregon DSM Rider (254202)	1,397,749	1,881,768	Various	2,125,237	1,154,280
2	Advice #05-03					
3						
4	Minor Items (9)	221,912	223,310	Various	201,535	243,687
5						
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43						
44	**TOTAL :**	1,214,174,417	356,509,519		187,624,612	1,383,059,324

Schedule Page: 232.1 Line No.: 32 Column: a

During 2019, this balance was reclassed to a Regulatory Liability for financial statement presentation.

Schedule Page: 232.1 Line No.: 35 Column: a

During 2019, this balance was reclassed to a Regulatory Liability for financial statement presentation.

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

During 2019, this balance was reclassed to a Regulatory Liability for financial statement presentation.

Schedule Page: 232.1 Line No.: 41 Column: a

During 2019, this balance was reclassed from a Regulatory Liability to a Regulatory Asset for financial statement presentation.

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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	04/14/2020	End of 2019/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	746,660	1,647,040	Various	1,192,140	1,201,560
2	Amortization period 12/19-12/24					
3						
4	Prepaid Services (LT) 186052	3,673,840		Various	609,703	3,064,137
5	Amortization periods - multiple					
6						
7	Workers Compensation 186121	1,118,612		401	156,354	962,258
8						
9	Prepaid ROW (LT) 186160	618,779		401	43,902	574,877
10	Amortization periods - multiple					
11						
12	Prepaid Services (LT) 186255		189,930	401	15,430	174,500
13	Amortization periods - multiple					
14						
15	CARB Inventory 186650	843,050	428,350	242	275,967	995,433
16						
17	Coal Royalties 186709	943,618		151	71,673	871,945
18						
19	Stable Value Life Inv 186719	45,435,744	3,181,628			48,617,372
20						
21	Security Plan 186720	10,567,539	127,320	4262	4,387,108	6,307,751
22	Net Insurance Asset					
23						
24	Retiree Medical-COLI 186726	3,849,093	301,710	4262	153,551	3,997,252
25						
26	American Falls Water Rts 186727	6,338,887		401	1,042,009	5,296,878
27	Amortization period 01/06-02/25					
28						
29	American Falls Bond Refi 186770	295,995		401	47,999	247,996
30	Amortization period 12/09-02/25					
31						
32	Regulatory Reserves 186800	-1,122,387		4190	64,609	-1,186,996
33						
34	Minor Items (6)	95,613	2,382,374	Various	2,290,238	187,749
35						
36						
37						
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41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	73,405,043				71,312,712

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2			
3			
4			
5	Other Electric (See footnote)	96,930,307	84,487,160
6			
7	Other (See footnote)	178,068,785	198,768,052
8	TOTAL Electric (Enter Total of lines 2 thru 7)	274,999,092	283,255,212
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other Non Electric (See footnote)	18,384,170	18,905,819
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	293,383,262	302,161,031

Notes

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

	Beginning Balance	Ending Balance
Construction Advances	1,082,811	1,262,434
Postretirement Benefits	313,224	419,012
USBR-American Falls O&M Costs Settlement	64,475	55,478
Non-VEBA Pension and Benefits	(468,289)	(557,867)
Executive Deferred Compensation	4,427	4,341
Stock Based Compensation	3,437,429	3,036,306
Pension Expense-Oregon	3,019,304	3,378,637
Bridger Revenue Deferral	499,057	652,901
Asset Retirement Obligation (ARO)	1,423,588	1,629,409
Incentive Deferral-Profit Sharing-Not in Rates	3,491,132	3,464,858
OR Reconnect Fees Adv	955	1,718
Tax Reform Regulatory Stipulation	0	2,497,753
Rate Case Disallowance	1,268,220	1,191,952
Unrealized Loss on Investments	0	129
Provision for Rate Refunds	0	349,943
Prov for Rate Refund-HC Relicensing (AFUDC)	35,136,616	39,039,171
Revenue Sharing	1,293,322	0
VEBA-Post Retirement Benefits	8,976,089	8,714,850
Deferred Idaho ITC	26,408,291	19,346,135
Deferred GBC Federal	10,979,656	0
Total Other Electric	96,930,307	84,487,160

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

	Beginning Balance	Ending Balance
Pension-FAS 158	72,101,874	89,534,362
Regulatory Liability-FAS 109	98,042,217	96,598,638
Minimum Pension Liability	7,952,476	12,611,062
Postretirement Plan-FAS 158	(27,782)	23,990
Total Other	178,068,785	198,768,052

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

	Beginning Balance	Ending Balance
Senior Management Security Plan	18,384,170	18,905,819
Total Non Electric	18,384,170	18,905,819

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common Stock all of which is held by	50,000,000	2.50	
3	IdaCorp, Inc. and not traded			
4	Total Common Stock	50,000,000	2.50	
5				
6	Account 204 - None			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,150,812	97,877,030					2
						3
39,150,812	97,877,030					4
						5
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	04/14/2020	End of 2019/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		
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9		
10	Explanation of Changes during the year:	
11		
12		
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21		
22	TOTAL	2,096,925

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	5.50% Series due 2033	70,000,000	728,701
4			36,400 D
5			
6	3.40% Series due 2020	100,000,000	1,159,871
7			499,000 D
8			
9	5.30% Series Due 2035	60,000,000	3,849,739
10			408,600 D
11			
12	4.00% Series due 2043	75,000,000	742,017
13			194,250 D
14			
15	6.00% Series due 2032	100,000,000	1,191,216
16			544,000 D
17			
18	5.875% Series due 2034	55,000,000	585,759
19			748,000 D
20			
21	5.50% Series due 2034	50,000,000	524,419
22			383,500 D
23			
24	4.85% Series Due 2040	100,000,000	1,284,871
25			170,000 D
26			
27	6.30% Series due 2037	140,000,000	1,500,031
28			278,600 D
29			
30	6.25% Series due 2037	100,000,000	1,227,490
31			268,000 D
32			
33	TOTAL	2,021,445,000	33,876,373

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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
5/13/03	4/01/33	5/13/03	3/31/33	70,000,000	3,850,000	3
						4
						5
8/30/10	11/01/20	8/30/10	11/01/20	100,000,000	3,400,000	6
						7
						8
8/26/05	8/15/35	8/26/05	8/15/35	60,000,000	3,180,000	9
						10
						11
4/08/13	4/01/43	4/08/13	4/01/43	75,000,000	3,000,000	12
						13
						14
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	6,000,000	15
						16
						17
8/16/04	8/15/34	8/16/04	8/15/34	55,000,000	3,231,250	18
						19
						20
3/26/04	3/15/34	3/26/04	3/15/34	50,000,000	2,750,000	21
						22
						23
8/30/10	8/15/40	8/30/10	8/15/40	100,000,000	4,850,000	24
						25
						26
6/22/07	6/15/37	6/22/07	6/15/37	140,000,000	8,820,000	27
						28
						29
10/18/07	10/15/37	10/18/07	10/15/37	100,000,000	6,250,000	30
						31
						32
				1,855,345,000	82,457,050	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	04/14/2020	End of 2019/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	Port of Morrow Variable due 2027	4,360,000	189,597
2			
3	Humboldt 5.15% due 2024	49,800,000	1,309,010
4			
5	Humboldt 1.45% due 2024	49,800,000	396,278
6			
7	Sweetwater 5.25% due 2026	116,300,000	3,044,152
8			
9	Sweetwater 1.70% due 2026	116,300,000	908,982
10			
11	2.50% Series due 2023	75,000,000	648,267
12			374,250 D
13			
14	4.30% Series Due 2042	75,000,000	802,240
15			49,500 D
16			
17	2.95% Series Due 2022	75,000,000	708,490
18			128,250 D
19			
20	3.65% Series Due 2045	250,000,000	2,559,510
21			1,715,000 D
22			
23	4.05% Series Due 2046	120,000,000	1,311,383
24			309,600 D
25			
26	4.20% Series Due 2048	220,000,000	2,283,400
27	Idaho Order #33513 (4/27/16)		814,000 D
28	Oregon Order #16-151 (4/21/16)		
29	Wyoming Docket #20005-37-ES16 (5/17/16)		
30			
31	Subtotal Account 221	2,001,560,000	33,876,373
32			
33	TOTAL	2,021,445,000	33,876,373

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
5/17/00	2/01/27	05/17/00	02/01/27	4,360,000	74,135	1
						2
8/20/09	12/01/24	8/20/09	12/01/24		1,638,558	3
						4
8/21/19	12/01/24	8/21/19	12/01/24	49,800,000	260,758	5
						6
8/20/09	7/15/26	8/20/09	7/15/26		3,900,896	7
						8
8/21/19	7/15/26	8/21/19	7/15/26	116,300,000	713,953	9
						10
4/08/13	4/01/23	4/08/13	4/01/23	75,000,000	1,875,000	11
						12
						13
4/13/12	4/01/42	4/13/12	4/01/42	75,000,000	3,225,000	14
						15
						16
4/13/12	4/01/22	4/13/12	4/01/22	75,000,000	2,212,500	17
						18
						19
3/06/15	3/01/45	3/06/15	3/01/45	250,000,000	9,125,000	20
						21
						22
3/10/16	3/01/46	3/10/16	3/1/46	120,000,000	4,860,000	23
						24
						25
3/16/18	3/01/48	3/16/18	3/01/48	220,000,000	9,240,000	26
						27
						28
						29
						30
				1,835,460,000	82,457,050	31
						32
				1,855,345,000	82,457,050	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	04/14/2020	End of 2019/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 222 - Reaquired Bonds		
2			
3	Account 223: Advances for Associated Companies		
4			
5	Account 224:		
6	Bond Guarantee - American Falls	19,885,000	
7	Subtotal Account 224	19,885,000	
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
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19			
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28			
29			
30			
31			
32			
33	TOTAL	2,021,445,000	33,876,373

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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
						3
						4
						5
4/26/00	2/01/25			19,885,000		6
				19,885,000		7
						8
						9
						10
						11
						12
						13
						14
						15
						16
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						30
						31
						32
				1,855,345,000	82,457,050	33

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Schedule Page: 256.1 Line No.: 26 Column: a

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

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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	04/14/2020	End of 2019/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)	224,436,822
2		
3		
4	Taxable Income Not Reported on Books	
5		38,303,996
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		191,835,823
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		78,774,257
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		198,930,795
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	176,871,589
28	Show Computation of Tax:	
29	Tentative Federal Tax @ 21%	37,143,034
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

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

4005-AVOIDED COST	4,645,489
4003-CONSTRUCTION ADVANCES	855,349
4013-CIAC - TAXABLE - ACCT 107	17,117,820
4021-ENGINEERING FEES - TAXABLE - ACCT 107	427,934
4024-RENEWABLE ENERGY CERTIFICATES (REC) SALES	3,360,669
5058-FIXED COST ADJUSTMENT	10,625,805
5066-BOARDMAN DECOMMISSION	1,270,930
Total	**38,303,996**

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

Total Federal and State taxes deducted on books	**26,334,168**
5024-NON-DEDUCTIBLE MEALS	499,000
5010-POSTEMPLOYMENT BENEFITS-SFAS112	172,130
5035-PCA EXPENSE DEFERRAL	0
5047-EXECUTIVE DEFERRED COMP	0
5053-STOCK BASED COMPENSATION	116,188
5061-PENSION EXPENSE - OREGON	1,396,012
5067-ASSET RETIREMENT OBLIGATION (ARO)	799,616
5071-INCENTIVE DEFERRAL-PROFIT SHARING-NOT IN RATES	59,842
5078-TAX STIP	7,417,848
5504-NON-DEDUCTIBLE POLITICAL EXPENSES	805,700
5505-SMSP - NET	2,026,609
7010-PROV FOR RATE REFUND - HC RELICENSING (AFUDC)	16,520,970
8009-DEPR TIMING DIFF - OPERATING - FEDERAL	130,732,744
8042-GAIN/LOSS ON REACQUIRED DEBT	2,316,696
8703-IPCO-162(m) THRESHHOLD	2,638,300
Total	**191,835,823**

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

5074-VALMY SETTLEMENT ADJUSTMENT	1,450,044
5077-VALMY DEPRECIATION ADJUSTMENT	27,063,729
5501-SMSP - INSURANCE COSTS	3,273,415
7501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES	8,489,145
7502-ALLOWANCE FOR OFUDC	27,112,279
7503-ALLOWANCE FOR BFUDC	10,702,847
7509-SMSP - INSURANCE PROCEEDS	682,798
Total	**78,774,257**

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

5001-BAD DEBT EXPENSE	245,060
5002-INVENTORY RESERVE ADJUSTMENT	1,654,824
5008-GAIN/LOSS ON REACQUIRED DEBT	1,643,981
5022-263A CAPITALIZED OVERHEADS	34,000,000
5023-PENSION EXPENSE	25,438,738
5060-OREGON - PCAM	1,355
5070-INCENTIVE DEFERRAL-CRI & RELIABILITY-INCLUDED IN RATES	369,148
5075-EIM DEFERRAL	2,802

5538-STOCK BASED COMP - STOCK	3,519,749
7012-REVENUE SHARING	5,024,562
8001-VEBA - POST RETIREMENT BENEFITS	1,480,025
8009A-VALMY1 BOOK BASIS ADJUSTMENT	18,322,835
8020-CONSERVATION EXPENSES	41,168
8034-REMOVAL COSTS	14,947,193
8059-SOFTWARE - LABOR COSTS DEDUCTED - ACCT 107	4,744,000
8072-RELICENSING - LABOR COSTS DEDUCTED - ACCT 107	2,570,000
8073-REPAIRS DEDUCTION	88,000,000
8077-PREPAID INSURANCE & OTHER EXPENSES	733,260
8702-STOCK BASED COMP - DIVIDENDS	705,440
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN	(4,513,345)
Total	**198,930,795**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	-7,619,635		21,193,445	19,947,719	
3	Social Security - (FOAB)	377,660		16,370,738	15,807,436	
4	Unemployment	39,391		92,008	578,568	
5	Subtotal Federal	-7,202,584		37,656,191	36,333,723	
6						
7	State of Idaho:					
8	Income	-2,711,454		-5,087,002	-5,061,934	
9	Unemployment	14,073		202,781	200,852	
10	Property	10,107,466		21,874,411	22,352,722	
11	Non-Operating	8,824		21,368	19,508	
12	kWh	86,873		1,934,493	1,939,721	
13	Regulatory Commission			3,092,482	3,092,482	
14	Business License - Sho Ban			150	150	
15	Subtotal Idaho	7,505,782		22,038,683	22,543,501	
16						
17	State of Oregon					
18	Income	-321,948		715,811	650,074	
19	Unemployment	3,042		40,734	41,244	
20	Property		1,780,237	3,695,451	3,828,710	
21	Non-Operating Property		1,029	2,002	1,946	
22	Regulatory Commission			263,573	263,573	
23	Franchise	199,684		851,644	836,083	
24	Subtotal Oregon	-119,222	1,781,266	5,569,215	5,621,630	
25						
26	State of Montana:					
27	Property	169,975		358,390	349,371	
28	Subtotal Montana	169,975		358,390	349,371	
29						
30	State of Nevada:					
31	Property		422,251	776,752	705,192	
32	Subtotal Nevada		422,251	776,752	705,192	
33						
34	State of Wyoming					
35	Property	712,218		1,346,901	1,385,668	
36	Corporate License			3,982	3,982	
37	Subtotal Wyoming	712,218		1,350,883	1,389,650	
38						
39						
40						
41	TOTAL	1,306,621	2,203,517	51,026,961	66,712,682	-274,548

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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
-6,373,909		18,660,529			2,532,916	2
940,962		16,370,738				3
-447,169		92,008				4
-5,880,116		35,123,275			2,532,916	5
						6
						7
-2,736,522		-5,340,313			253,311	8
16,002		202,781				9
9,629,156		21,873,280			1,131	10
10,684					21,368	11
81,645		1,934,493				12
		3,092,482				13
		150				14
7,000,965		21,762,873			275,810	15
						16
						17
-256,211		702,252			13,559	18
2,532		40,734				19
	1,913,496	3,538,946			156,505	20
	973				2,002	21
		263,573				22
215,244		851,644				23
-38,435	1,914,469	5,397,149			172,066	24
						25
						26
178,994		358,390				27
178,994		358,390				28
						29
						30
	350,691	776,752				31
	350,691	776,752				32
						33
						34
673,450		1,346,901				35
		3,982				36
673,450		1,350,883				37
						38
						39
						40
2,114,255	2,265,160	48,041,590			2,985,371	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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		4,416	7,416	
3	Subtotal Washington	11,000		4,416	7,416	
4						
5	Other States Income	209,241		-21,308	8,725	
6	Canada GST Tax	20,211			-246,526	-274,548
7	Payroll Tax Credit			-16,706,261		
8						
9						
10						
11						
12						
13						
14						
15						
16						
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31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	1,306,621	2,203,517	51,026,961	66,712,682	-274,548

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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
8,000		4,416				2
8,000		4,416				3
						4
179,208		-25,887			4,579	5
-7,811						6
		-16,706,261				7
						8
						9
						10
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						12
						13
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2,114,255	2,265,160	48,041,590			2,985,371	41

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

```
Account 409.2       $    893,116
Account 426.5       $    140,517
Account 409.1       $  1,499,283
                      ------------
Total               $  2,532,916
```

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

Account 409.2 $ 253,311

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

Account 107 $ 1,131

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

Account 408.2 $ 21,368

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

Account 409.2 $ 13,559

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

Account 107 $ 156,505

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

Account 408.2 $ 2,002

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

Account 409.2 $ 4,579

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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	243,760			411.401	29,617	
4	7%						
5	10%	13,611,193			411.401	1,621,862	
6	Other - Federal	11,973,700		4,362,046		476,129	
7	Other - State	66,961,183	411.402	3,905,612	411.402	4,124,016	
8	TOTAL	92,789,836		8,267,658		6,251,624	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	11%	1,063,916			411.401	22,269	
11	30%	10,909,784	411.401	4,362,046	411.401	453,860	
12	Total Line No. 6	11,973,700		4,362,046		476,129	
13							
14							
15	State of Idaho	66,961,183	411.402	3,905,612	411.402	4,124,016	
16							
17							
18							
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
214,143	8.23		3
			4
11,989,331	8.39		5
15,859,617	24.04		6
66,742,779	16.24		7
94,805,870			8
			9
1,041,647	47.77		10
14,817,970	24.04		11
15,859,617			12
			13
			14
66,742,779			15
			16
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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	04/14/2020	End of 2019/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	1,595,437	Various	1,151,675	1,051,788	1,495,550
2						
3	FTV Dark Fiber Rental 253202	1,266,666	400	400,000		866,666
4	Amortization period 03/98-02/23					
5						
6	Escrow Deposits 253350				92,147	92,147
7						
8	Sho-Ban Scholarships 253480	142,500	242	15,000		127,500
9	Amortization period 01/05-12/27					
10						
11	Operations Accruals 253550	496,950	Various	94,127		402,823
12						
13	Postretirement Benefits 253960	1,455,732			172,130	1,627,862
14						
15	Directors Deferred Compensation	3,348,722	401	213,912	288,427	3,423,237
16	253970-253999					
17						
18						
19						
20						
21						
22						
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44						
45						
46						
47	TOTAL	8,306,007		1,874,714	1,604,492	8,035,785

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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	289,283,288	4,534,691	17,916,129
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	289,283,288	4,534,691	17,916,129
6	Non-Operating Property			
7	Other - Regulatory Asset	614,144,086		
8	Like Kind Exchange- Reclass No	5,187,725		
9	TOTAL Account 282 (Enter Total of lines 5 thru	908,615,099	4,534,691	17,916,129
10	Classification of TOTAL			
11	Federal Income Tax	733,509,326	4,465,977	17,821,965
12	State Income Tax	175,105,774	68,714	94,164
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
	687,000	254		282/254	6,402,462	281,617,312	2
							3
							4
	687,000				6,402,462	281,617,312	5
							6
				182	32,741,941	646,886,027	7
				282	-221,698	4,966,027	8
	687,000				38,922,705	933,469,366	9
							10
	687,000	254		182/254	29,842,245	749,308,583	11
				182	9,080,459	184,160,783	12
							13

NOTES (Continued)

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

Account (a)	2019 Beginning Balance b	Changes during Year DR to 410.1 c	CR to 411.1 d	CR to 411.2 f	Adjustments Credits Acct. debited i	Amount j	2019 Ending Balance k
Depreciation Timing Diff-Operating	473,935,322	4,750,413	13,669,343	687,000		-	464,329,392
Like Kind Exchange - Reclass Non-Rate Base	(5,187,725)	-	-	-	282111	221,698	(4,966,027)
Excess Deferred Tax on Depreciation (Reg Liab)	(190,062,340)	-	-	-	254967	6,180,764	(183,881,576)
CIAC-Taxable-Acct 107	(3,596,029)	-	4,083,909	-		-	(7,679,938)
Engineering Fees-Taxable-Acct 107	(446,619)	-	162,877	-		-	(609,496)
Software-Labor Costs Deducted-Acct 107	2,836,797	(788,474)	-	-		-	2,048,323
Intangible-Labor Costs Deducted-Acct 107	11,803,882	572,752	-	-		-	12,376,634
TOTAL	289,283,288	4,534,691	17,916,129	687,000		6,402,462	281,617,312

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Other Electric -- See Note	67,157,877	15,464,314	4,118,795
4				
5				
6				
7				
8	Other -- See Note	72,074,092		
9	TOTAL Electric (Total of lines 3 thru 8)	139,231,969	15,464,314	4,118,795
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	-14,426	6	41,597
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	139,217,543	15,464,320	4,160,392
20	Classification of TOTAL			
21	Federal Income Tax	106,765,901	11,859,584	3,190,604
22	State Income Tax	32,451,641	3,604,736	969,788
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) 04/14/2020	Year/Period of Report End of 2019/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
						78,503,396	3
							4
							5
							6
							7
				190	17,484,259	89,558,351	8
					17,484,259	168,061,747	9
							10
							11
							12
							13
							14
							15
							16
							17
						-56,017	18
					17,484,259	168,005,730	19
							20
				190	13,408,675	128,843,556	21
				190	4,075,585	39,162,174	22
							23

NOTES (Continued)

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

Account	2019 Beginning Balance	Changes during Year DR to 410.1	Changes during Year CR to 411.1	2019 Ending Balance
Renewable Energy Certificates (REC) Sales	(194,769)	693,082	865,036	(366,723)
Royalty Income	233,398	1,989	-	235,387
Gain/Loss on Reaqcuired Debt	-	423,161	-	423,161
Pension Expense	36,366,190	6,839,037	-	43,205,227
PCA Expense	-	-	-	-
Intervenor Funding Orders	58,708	2,656	-	61,364
Fixed Cost Adjustment	10,940,327	-	2,735,082	8,205,245
PS & I Costs	34,336	-	34,336	-
Oregon PCAM	1,863	349	-	2,212
2011 LIDAR Surveys Deferral	44,895	-	11,223	33,672
Boardman Decommission	(1,648)	-	327,137	(328,785)
Valmy Settlement Adjustment	5,917,771	474,266	-	6,392,037
EIM Deferral	9,001	721	-	9,722
Valmy Depreciation Adjustment	13,298,364	6,966,205	101,025	20,163,544
Langley Revenue Accrual	(32,355)	32,355	-	-
Conservation Expenses	326,219	10,597	-	336,816
Siemens LTP Contract	58,849	17,213	-	76,062
Prepaid Credit Facility	106,572	-	36,539	70,033
Siemens OR DRB Interest Reserve	(17,468)	-	8,417	(25,885)
Boardman Removal Costs	7,624	2,683	-	10,307
TOTAL	67,157,877	15,464,314	4,118,795	78,503,396

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

Account	2019 Beginning Balance	Adjustments Credits Acct. debited	Adjustments Credits Amount	2019 Ending Balance
Pension-FAS 158	72,101,875	190	17,432,486	89,534,361
Postretirement Plan-FAS 158	(27,783)	190	51,773	23,990
TOTAL	72,074,092		17,484,259	89,558,351

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

Account	2019 Beginning Balance	Changes during Year DR to 410.1	Changes during Year CR to 411.1	2019 Ending Balance
EDC-Unrealized Gain/Loss From Rabbit Trust	(63)	-	253	(316)

SMSP-Unrealized Gain/Loss From Rabbi Trust	(14,622)	-	41,344	(55,966)
Oregon Non-Op Prop Tax Adj	259	6	-	265
TOTAL	(14,426)	6	41,597	(56,017)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Market to Market Short Term (254001)	3,700,413	175	3,295,496		404,917
2	IPUC Order #28661					
3						
4	Oregon Solar Rider (254005)	66,574	Various	39,011	112,879	140,442
5	Advice #10-198					
6						
7	Idahe Revenue Sharing (254101)	5,024,562	1823	5,068,654	44,092	
8	IPUC Order #34351					
9						
10	Idaho DSM Rider (254201)	5,258,957	Various	38,069,980	32,811,023	
11	IPUC Order #29026					
12						
13	BPA Credit Residential Idaho (254401)	1,897,389	Various	10,330,420	12,565,924	4,132,893
14	Advice #15-13					
15						
16	BPA Credit Residential Oregon (254402)	95,684	Various	399,946	450,869	146,607
17	Advice #15-11					
18						
19	BPA Credit Farm Idaho (254403)	338,459	Various	1,539,416	2,086,812	885,855
20	Advice #15-13					
21						
22	BPA Credit Farm Oregon (254404)	14,490	Various	85,628	113,993	42,855
23	Advice #15-11					
24						
25	Oregon Green Tags (254415)	171,832	401	118,040	243,469	297,261
26	Advice #11-086					
27						
28	Idaho Tax Settlement (254451)	1,721,624			7,417,848	9,139,472
29	IPUC Order #34071					
30						
31	Oregon Tax Settlement (254452)	564,308				564,308
32	OPUC Advice #18-199					
33						
34	Bridger Depreciation (254800)	2,536,525			597,686	3,134,211
35	OPUC Order #12-296					
36						
37	RL-WAQC CRYOVR (254901)	130,384			26,406	156,790
38	IPUC Order #29505					
39						
40	Unfunded Accum Def Income Tax (254966)	32,162,811			698,798	32,861,609
41	TOTAL	351,782,980		109,423,538	106,647,202	349,006,644

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	RL-DEF INC TAX-ARAM (254967)	190,062,341	282	6,180,764		183,881,577
2						
3	RL-DEF INC TAX-ARAM GROSS-UP (254968)	65,879,405	190	2,142,376		63,737,029
4						
5	Idaho PCA Deferral (254425)	42,153,807	1823	42,153,807	48,194,075	48,194,075
6	IPUC Order Pending					
7						
8	Boardman Decommissioning (254426)				1,277,331	1,277,331
9	Advice #12-235, IPUC Order #32457					
10						
11	Minor Items (2)	3,415			5,997	9,412
12						
13						
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41	TOTAL	351,782,980		109,423,538	106,647,202	349,006,644

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Schedule Page: 278 Line No.: 10 Column: a

During 2019, this balance flipped from a liability to a receivable and was reclassed to a Regulatory Asset for financial statement presentation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	528,572,308	533,062,028
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	428,953,227	466,201,600
5	Large (or Ind.) (See Instr. 4)	181,871,403	191,175,361
6	(444) Public Street and Highway Lighting	3,850,765	4,032,545
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,143,247,703	1,194,471,534
11	(447) Sales for Resale	101,908,387	79,156,537
12	TOTAL Sales of Electricity	1,245,156,090	1,273,628,071
13	(Less) (449.1) Provision for Rate Refunds	8,440,245	19,972,541
14	TOTAL Revenues Net of Prov. for Refunds	1,236,715,845	1,253,655,530
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	4,661,497	4,463,096
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	16,936,179	16,048,736
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	41,061,301	36,461,056
22	(456.1) Revenues from Transmission of Electricity of Others	43,848,605	51,329,032
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	106,507,582	108,301,920
27	TOTAL Electric Operating Revenues	1,343,223,427	1,361,957,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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
5,272,659	5,134,576	471,298	459,128	2
				3
5,819,993	6,049,156	90,164	88,929	4
3,412,410	3,370,566	127	118	5
31,652	32,224	3,488	3,280	6
				7
				8
				9
14,536,714	14,586,522	565,077	551,455	10
2,850,922	2,863,637			11
17,387,636	17,450,159	565,077	551,455	12
				13
17,387,636	17,450,159	565,077	551,455	14

Line 12, column (b) includes $ -4,965,101 of unbilled revenues.

Line 12, column (d) includes -47,683 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)	$4,329,171
Misc. Under $250,000	332,326
Total Account 451	$4,661,497

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

This amount consists of:

DSM Activity	$40,127,871
Alternate Distribution Service	781,431
Misc. Under $250,000	151,999
Total Account 456	$41,061,301

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	5,254,337	513,939,911	466,314	11,268	0.0978
3	03 - Residential Master Meter	4,775	446,002	22	217,045	0.0934
4	05 - Residential - TOD	18,258	1,722,654	1,101	16,583	0.0944
5	06 - Residential On-Site Generati	21,589	2,243,302	3,861	5,592	0.1039
6	15 - Dusk to dawn lighting	2,629	631,874			0.2403
7	Unbilled Revenues	-28,929	-2,509,684			0.0868
8	Other Revenues		12,098,249			
9	Total 440	5,272,659	528,572,308	471,298	11,188	0.1002
10						
11	442-Commercial & Industrial Sales					
12	07 - General service	151,532	18,354,328	31,322	4,838	0.1211
13	08 - General service On-Site Gene	189	23,754	49	3,857	0.1257
14	09P - General service	543,454	34,037,685	251	2,165,155	0.0626
15	09S - General service	3,359,350	238,316,059	36,196	92,810	0.0709
16	09T - General service	6,826	463,220	5	1,365,200	0.0679
17	15 - Dusk to Dawn Light	4,305	735,379			0.1708
18	19P - Uniform rate contracts	2,377,050	131,548,822	120	19,808,750	0.0553
19	19S - Uniform rate contracts	6,122	372,074	1	6,122,000	0.0608
20	19T - Uniform rate contracts	137,223	8,073,315	3	45,741,000	0.0588
21	24S - Irrigation Pumping	1,759,137	135,912,726	21,321	82,507	0.0773
22	40 - General service	10,904	909,458	1,020	10,690	0.0834
23	Special Contracts	894,992	42,800,315	3	298,330,667	0.0478
24	Commercial & Industrial Unbill	-18,681	-2,441,220			0.1307
25	Other Revenues		1,718,715			
26	Total 442	9,232,403	610,824,630	90,291	102,252	0.0662
27						
28	444 - Public Street Lighting:					
29	40 - General service	792	66,418	474	1,671	0.0839
30	41 - Street lighting	28,368	3,630,775	2,357	12,036	0.1280
31	42 - Traffic control lighting	2,565	153,884	657	3,904	0.0600
32	Unbilled	-73	-14,197			0.1945
33	Other Revenues		13,885			
34	Total 444	31,652	3,850,765	3,488	9,075	0.1217
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	14,584,397	1,148,212,804	565,078	25,810	0.0787
42	Total Unbilled Rev.(See Instr. 6)	-47,683	-4,965,101	0	0	0.1041
43	TOTAL	14,536,714	1,143,247,703	565,078	25,725	0.0786

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	3 Phases Renewables Inc.	SF	WSPP	n/a	n/a	n/a
2	ADM Investor Services, Inc.	OS	WSPP	n/a	n/a	n/a
3	Arizona Public Service Co.	SF	WSPP	n/a	n/a	n/a
4	Avangrid Renewables (IBERDROLA)	OS	OATT	n/a	n/a	n/a
5	AVANGRID RENEWABLES, LLC	SF	WSPP	n/a	n/a	n/a
6	Avista Corp.	SF	WSPP	n/a	n/a	n/a
7	Avista Corp. - WWP Div.	OS	OATT	n/a	n/a	n/a
8	Basin Electric Power Cooperative	SF	WSPP	n/a	n/a	n/a
9	Black Hills Power Inc.	SF	WSPP	n/a	n/a	n/a
10	Bonneville Power	OS	OATT	n/a	n/a	n/a
11	Bonneville Power Administration	SF	WSPP	n/a	n/a	n/a
12	BP Energy Company	SF	WSPP	n/a	n/a	n/a
13	British Columbia Hydro and Power Author	OS	WSPP	n/a	n/a	n/a
14	Brookfield Energy Marketing	OS	OATT	n/a	n/a	n/a
	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.
337,775		10,451,762		10,451,762	1
			818,050	818,050	2
78		1,404		1,404	3
			10,026	10,026	4
7,063		243,075		243,075	5
177,311		10,200,203		10,200,203	6
			10,633	10,633	7
5,325		28,230		28,230	8
85,688		932,522		932,522	9
			2,960,056	2,960,056	10
287,774		11,035,406		11,035,406	11
20,673		420,438		420,438	12
3			111	111	13
			2,285	2,285	14
0	0	0	0	0	
2,850,922	0	90,262,681	11,645,706	101,908,387	
2,850,922	**0**	**90,262,681**	**11,645,706**	**101,908,387**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Brookfield Renewable Trading & Marketin	OS	OATT	n/a	n/a	n/a
2	Brookfield Renewable Trading and Market	SF	WSPP	n/a	n/a	n/a
3	California Independent System Operator	SF	CAISO	n/a	n/a	n/a
4	Chelan Co PUD	SF	WSPP	n/a	n/a	n/a
5	Citigroup Energy Inc.	SF	ISDA	n/a	n/a	n/a
6	Clatskanie PUD	SF	WSPP	n/a	n/a	n/a
7	Clean Power Alliance of Southern Califo	SF	WSPP	n/a	n/a	n/a
8	Direct Energy Business Marketing, LLC	SF	WSPP	n/a	n/a	n/a
9	DTE Energy Trading, Inc.	SF	WSPP	n/a	n/a	n/a
10	EDF Trading North America	OS	OATT	n/a	n/a	n/a
11	EDF Trading North America, LLC	SF	WSPP	n/a	n/a	n/a
12	Energy Keepers, Inc	SF	WSPP	n/a	n/a	n/a
13	Energy Keepers, Inc.	OS	OATT	n/a	n/a	n/a
14	Eugene Water & Electric Board	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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.
			48,223	48,223	1
12,045		502,062		502,062	2
238,742		13,701,154		13,701,154	3
936		17,514		17,514	4
103		2,458		2,458	5
1,308		37,418		37,418	6
107,250		2,824,477		2,824,477	7
10,000		375,908		375,908	8
245,800		6,584,616		6,584,616	9
			1,936	1,936	10
3,025		80,872		80,872	11
1,243		9,371		9,371	12
			3,371	3,371	13
10,213		391,906		391,906	14
0	0	0	0	0	
2,850,922	0	90,262,681	11,645,706	101,908,387	
2,850,922	**0**	**90,262,681**	**11,645,706**	**101,908,387**	

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 long-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.

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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	Exelon Generation Company, LLC	SF	WSPP	n/a	n/a	n/a
2	J.Aron & Company LLC	OS	ISDA	n/a	n/a	n/a
3	Macquarie Energy LLC	OS	OATT	n/a	n/a	n/a
4	Macquarie Energy LLC	SF	WSPP	n/a	n/a	n/a
5	MAG Energy Solutions	OS	OATT	n/a	n/a	n/a
6	Morgan Stanley Capital Group Inc.	OS	OATT	n/a	n/a	n/a
7	Morgan Stanley Capital Group Inc.	SF	ISDA	n/a	n/a	n/a
8	Nevada Power	OS	OATT	n/a	n/a	n/a
9	Nevada Power Company, dba NV Energy	OS	WSPP	n/a	n/a	n/a
10	Nevada Power Company, dba NV Energy	SF	WSPP	n/a	n/a	n/a
11	NorthWestern Energy	SF	WSPP	n/a	n/a	n/a
12	NorthWestern Energy NWDS	OS	OATT	n/a	n/a	n/a
13	PacifiCorp	OS	T-7	n/a	n/a	n/a
14	PacifiCorp	OS	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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.
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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.
626		33,487		33,487	1
			86,048	86,048	2
			8,539	8,539	3
112,688		1,360,451		1,360,451	4
			43,760	43,760	5
			1,199,515	1,199,515	6
31,459		398,031		398,031	7
			1,787	1,787	8
16,788			738,672	738,672	9
6,028		172,711		172,711	10
4,120		80,972		80,972	11
			369	369	12
99			2,935	2,935	13
3			89	89	14
0	0	0	0	0	
2,850,922	0	90,262,681	11,645,706	101,908,387	
2,850,922	**0**	**90,262,681**	**11,645,706**	**101,908,387**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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:

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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	PacifiCorp	OS	WSPP	n/a	n/a	n/a
2	PacifiCorp	SF	WSPP	n/a	n/a	n/a
3	PacifiCorp Inc.	OS	OATT	n/a	n/a	n/a
4	Portland General Electric Company	OS	OATT	n/a	n/a	n/a
5	Portland General Electric Company	SF	WSPP	n/a	n/a	n/a
6	Powerex Corp.	OS	OATT	n/a	n/a	n/a
7	Powerex Corp.	SF	WSPP	n/a	n/a	n/a
8	Puget Sound Energy, Inc.	OS	T-7	n/a	n/a	n/a
9	Puget Sound Energy, Inc.	SF	WSPP	n/a	n/a	n/a
10	Rainbow Energy Marketing Corporation	OS	OATT	n/a	n/a	n/a
11	Rainbow Energy Marketing Corporation	SF	WSPP	n/a	n/a	n/a
12	Seattle City Light	SF	WSPP	n/a	n/a	n/a
13	Shell Energy North America (US), L.P.	OS	OATT	n/a	n/a	n/a
14	Shell Energy North America (US), L.P.	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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.
250			3,500	3,500	1
137,261		2,886,775		2,886,775	2
			4,948,449	4,948,449	3
			40,387	40,387	4
17,411		425,969		425,969	5
			134,230	134,230	6
27,508		513,100		513,100	7
4			111	111	8
15,442		357,392		357,392	9
			16,327	16,327	10
125,792		1,736,012		1,736,012	11
176,821		9,769,454		9,769,454	12
			422,509	422,509	13
435,523		10,450,009		10,450,009	14
0	0	0	0	0	
2,850,922	0	90,262,681	11,645,706	101,908,387	
2,850,922	**0**	**90,262,681**	**11,645,706**	**101,908,387**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Sierra Pacific Power Co., dba NV Energy	OS	T-7	n/a	n/a	n/a
2	Snohomish County PUD	SF	WSPP	n/a	n/a	n/a
3	Tacoma Power	SF	WSPP	n/a	n/a	n/a
4	Tenaska Power Services Co.	OS	OATT	n/a	n/a	n/a
5	Tenaska Power Services Co.	SF	WSPP	n/a	n/a	n/a
6	The Energy Authority, Inc.	OS	OATT	n/a	n/a	n/a
7	The Energy Authority, Inc.	SF	WSPP	n/a	n/a	n/a
8	TransAlta Energy Marketing (U.S.) Inc.	OS	OATT	n/a	n/a	n/a
9	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	n/a	n/a	n/a
10	Transmission Penalty Distribution	OS	-	n/a	n/a	n/a
11	Utah Associated Municipal Power Systems	OS	OATT	n/a	n/a	n/a
12	Utah Associated Municipal Power Systems	SF	WSPP	n/a	n/a	n/a
13	Western Area Power Administration (WAC	OS	T-7	n/a	n/a	n/a
14	Western Area Power Administration (WAC	OS	WSPP	n/a	n/a	n/a
	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,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.
36			1,159	1,159	1
3,457		109,966		109,966	2
10,410		240,300		240,300	3
			37,968	37,968	4
67,390		639,932		639,932	5
			15,101	15,101	6
26,581		1,080,894		1,080,894	7
			72,764	72,764	8
46,395		1,411,920		1,411,920	9
			14,562	14,562	10
			1,154	1,154	11
36,430		754,510		754,510	12
27			560	560	13
18			520	520	14
0	0	0	0	0	
2,850,922	0	90,262,681	11,645,706	101,908,387	
2,850,922	**0**	**90,262,681**	**11,645,706**	**101,908,387**	

Schedule Page: 310 Line No.: 2 Column: b
ADM Investor Services, Inc Futures Account Document, dated May 5, 2015
Schedule Page: 310 Line No.: 4 Column: b
Financial Transmission Losses
Schedule Page: 310 Line No.: 7 Column: b
Financial Transmission Losses
Schedule Page: 310 Line No.: 10 Column: b
Financial Transmission Losses
Schedule Page: 310 Line No.: 13 Column: b
Spinning or Operating Reserves
Schedule Page: 310 Line No.: 14 Column: b
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 1 Column: b
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 10 Column: b
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 13 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 2 Column: b
ISDA Master Agreement with J. Aron & Company dated April 30, 2014
Schedule Page: 310.2 Line No.: 3 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 5 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 6 Column: b
Financial Transmission Losses
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.: 12 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 13 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 14 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 1 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 3 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 4 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 6 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 8 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 10 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 13 Column: b
Financial Transmission Losses
Schedule Page: 310.4 Line No.: 1 Column: b
Financial Transmission Losses
Schedule Page: 310.4 Line No.: 4 Column: b
Financial Transmission Losses

FOOTNOTE DATA

Schedule Page: 310.4 Line No.: 6 Column: b
Financial Transmission Losses
Schedule Page: 310.4 Line No.: 8 Column: b
Financial Transmission Losses
Schedule Page: 310.4 Line No.: 10 Column: b
Transmission penalty distribution credits
Schedule Page: 310.4 Line No.: 11 Column: b
Financial Transmission Losses
Schedule Page: 310.4 Line No.: 13 Column: b
Financial Transmission Losses
Schedule Page: 310.4 Line No.: 14 Column: b
Financial Transmission Losses

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,533,140	1,204,942
5	(501) Fuel	105,256,975	115,523,971
6	(502) Steam Expenses	10,783,230	9,912,734
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,894,278	1,868,433
10	(506) Miscellaneous Steam Power Expenses	9,195,043	9,134,293
11	(507) Rents	224,649	250,861
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	128,887,315	137,895,234
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	139,168	213,256
16	(511) Maintenance of Structures	295,201	349,423
17	(512) Maintenance of Boiler Plant	10,532,166	10,847,201
18	(513) Maintenance of Electric Plant	4,078,463	4,545,026
19	(514) Maintenance of Miscellaneous Steam Plant	6,024,870	7,142,704
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	21,069,868	23,097,610
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	149,957,183	160,992,844
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	5,775,190	5,629,020
45	(536) Water for Power	6,626,256	9,123,648
46	(537) Hydraulic Expenses	14,697,182	15,387,250
47	(538) Electric Expenses	2,049,374	1,884,840
48	(539) Miscellaneous Hydraulic Power Generation Expenses	5,798,449	5,600,843
49	(540) Rents	252,726	246,704
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	35,199,177	37,872,305
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	134,465	93,530
54	(542) Maintenance of Structures	646,148	745,081
55	(543) Maintenance of Reservoirs, Dams, and Waterways	633,585	332,571
56	(544) Maintenance of Electric Plant	2,369,254	2,988,299
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,804,309	2,666,883
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,587,761	6,826,364
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	41,786,938	44,698,669

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	671,349	648,947
63	(547) Fuel	51,615,143	17,673,949
64	(548) Generation Expenses	4,395,345	4,513,426
65	(549) Miscellaneous Other Power Generation Expenses	633,622	1,406,549
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	57,315,459	24,242,871
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		40
70	(552) Maintenance of Structures	207,999	215,293
71	(553) Maintenance of Generating and Electric Plant	260,734	124,643
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,840,749	2,641,004
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	3,309,482	2,980,980
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	60,624,941	27,223,851
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	280,320,697	287,762,141
77	(556) System Control and Load Dispatching	4,948	5,331
78	(557) Other Expenses	6,759,649	46,535,908
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	287,085,294	334,303,380
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	539,454,356	567,218,744
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,163,972	3,318,397
84			
85	(561.1) Load Dispatch-Reliability	22,832	10,084
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,389,656	2,117,726
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,042,766	1,440,842
88	(561.4) Scheduling, System Control and Dispatch Services	9,944	6,438
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	30,393	35,961
92	(561.8) Reliability, Planning and Standards Development Services	2,001,275	1,715,639
93	(562) Station Expenses	2,816,318	2,855,188
94	(563) Overhead Lines Expenses	896,240	878,708
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	2,844,842	3,602,155
97	(566) Miscellaneous Transmission Expenses		15,165
98	(567) Rents	3,934,696	2,710,673
99	TOTAL Operation (Enter Total of lines 83 thru 98)	19,152,934	18,706,976
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	-40,993	712,201
102	(569) Maintenance of Structures		-2,653
103	(569.1) Maintenance of Computer Hardware	34,910	33,857
104	(569.2) Maintenance of Computer Software	1,176,214	1,024,304
105	(569.3) Maintenance of Communication Equipment	16,080	15,553
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,616,137	1,721,024
108	(571) Maintenance of Overhead Lines	991,062	832,096
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	470	
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,793,880	4,336,382
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	22,946,814	23,043,358

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	611,254	411,723
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	611,254	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)	611,254	411,723
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	4,385,764	4,550,906
135	(581) Load Dispatching	4,529,601	4,354,562
136	(582) Station Expenses	1,601,059	1,565,905
137	(583) Overhead Line Expenses	4,095,135	3,896,819
138	(584) Underground Line Expenses	3,628,041	3,392,139
139	(585) Street Lighting and Signal System Expenses	61,704	157,861
140	(586) Meter Expenses	4,402,350	4,570,706
141	(587) Customer Installations Expenses	1,231,750	1,287,251
142	(588) Miscellaneous Expenses	4,492,746	4,939,645
143	(589) Rents	332,764	1,203,806
144	TOTAL Operation (Enter Total of lines 134 thru 143)	28,760,914	29,919,600
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	-274,492	604,934
147	(591) Maintenance of Structures	68,850	-1,048
148	(592) Maintenance of Station Equipment	4,143,359	4,482,318
149	(593) Maintenance of Overhead Lines	16,936,900	17,401,297
150	(594) Maintenance of Underground Lines	726,528	703,795
151	(595) Maintenance of Line Transformers	51,099	45,593
152	(596) Maintenance of Street Lighting and Signal Systems	260,970	589,313
153	(597) Maintenance of Meters	910,486	911,444
154	(598) Maintenance of Miscellaneous Distribution Plant	198,923	214,170
155	TOTAL Maintenance (Total of lines 146 thru 154)	23,022,623	24,951,816
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	51,783,537	54,871,416
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	941,128	1,116,501
160	(902) Meter Reading Expenses	1,801,856	1,790,512
161	(903) Customer Records and Collection Expenses	13,233,844	13,951,112
162	(904) Uncollectible Accounts	2,249,077	3,350,112
163	(905) Miscellaneous Customer Accounts Expenses	114	-4
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	18,226,019	20,208,233

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	786,744	802,563
168	(908) Customer Assistance Expenses	47,188,829	42,486,187
169	(909) Informational and Instructional Expenses	165,868	341,699
170	(910) Miscellaneous Customer Service and Informational Expenses	619,951	627,857
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	48,761,392	44,258,306
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	89,843,262	88,828,776
182	(921) Office Supplies and Expenses	14,655,584	14,790,380
183	(Less) (922) Administrative Expenses Transferred-Credit	33,154,579	29,219,811
184	(923) Outside Services Employed	9,431,043	7,744,133
185	(924) Property Insurance	3,437,586	3,010,285
186	(925) Injuries and Damages	5,349,936	5,617,495
187	(926) Employee Pensions and Benefits	52,072,747	52,315,074
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	5,320,889	5,021,358
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	46,762	603,786
192	(930.2) Miscellaneous General Expenses	3,634,788	3,605,153
193	(931) Rents		
194	TOTAL Operation (Enter Total of lines 181 thru 193)	150,638,018	152,316,629
195	Maintenance		
196	(935) Maintenance of General Plant	7,238,346	6,842,171
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	157,876,364	159,158,800
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	839,659,736	869,170,580

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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)	
43,224				1,262,802		1,262,802	1
43,611				1,283,686		1,283,686	2
18,955				1,539,999		1,539,999	3
2,757			51,102	139,080		190,182	4
648				39,559		39,559	5
8,964				532,333		532,333	6
39,824				2,660,042		2,660,042	7
28,425				1,689,340		1,689,340	8
11,962				1,079,967		1,079,967	9
9,513				606,613		606,613	10
194				7,405		7,405	11
1,517				74,353		74,353	12
887				63,151		63,151	13
56,106				3,458,016		3,458,016	14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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					
5	Grove Solar Center, LLC	LU		N/A	N/A	N/A
6	Hyline Solar Center, LLC	LU		N/A	N/A	N/A
7	Open Range Solar Center, LLC	LU		N/A	N/A	N/A
8	Railroad Solar Center, LLC	LU		N/A	N/A	N/A
9	Vale Air Solar Center, LLC	LU		N/A	N/A	N/A
10	Thunderegg Solar Center, LLC	LU		N/A	N/A	N/A
11	City of Hailey	LU	-	N/A	N/A	N/A
12	City of Pocatello	LU	-	N/A	N/A	N/A
13	Clear Springs Food Inc.	LU	-	N/A	N/A	N/A
14	Clifton E. Jenson - Birch Creek	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)	
16,303				553,963		553,963	1
65,323				5,393,008		5,393,008	2
18,646				964,518		964,518	3
							4
13,397				852,031		852,031	5
20,130				1,279,640		1,279,640	6
22,836				1,452,994		1,452,994	7
9,996				637,586		637,586	8
21,793				1,387,340		1,387,340	9
22,371				1,425,547		1,425,547	10
96				6,332		6,332	11
1,420				104,310		104,310	12
3,434				208,203		208,203	13
355			14,583	16,058		30,641	14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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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	Cold Springs Windfarm, LLC	LU	-	N/A	N/A	N/A
2	College of Southern Idaho - Pristine S	LU	-	N/A	N/A	N/A
3	College of Southern Idaho - Pristine S	LU	-	N/A	N/A	N/A
4	Consolidated Hydro Inc. / Enel					
5	Barber Dam	LU	-	N/A	N/A	N/A
6	Dietrich Drop	LU	-	N/A	N/A	N/A
7	Lowline #2	LU	-	N/A	N/A	N/A
8	Rock Creek #2	LU	-	N/A	N/A	N/A
9	Crystal Springs Hydro	LU	-	N/A	N/A	N/A
10	Curry Cattle Company	LU	-	N/A	N/A	N/A
11	Cycle Horseshoe Bend Wind, LLC	LU	-	N/A	N/A	N/A
12	David R Snedigar	LU	-	N/A	N/A	N/A
13	Desert Meadow Windfarm	LU	-	N/A	N/A	N/A
14	Durbin Creek Windfarm	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 Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
50,137				3,925,652		3,925,652	1
751				48,500		48,500	2
1,416				90,586		90,586	3
							4
13,076				653,058		653,058	5
12,904				728,079		728,079	6
1,908				69,802		69,802	7
1,053				39,541		39,541	8
11,923				807,757		807,757	9
749				63,975		63,975	10
16,483				1,021,329		1,021,329	11
1,266				87,180		87,180	12
56,858				4,462,530		4,462,530	13
26,115				1,538,879		1,538,879	14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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	Eightmile Hydro Corp	LU	-	N/A	N/A	N/A
2	El Dorado Hydro - Elk Creek	LU	-	N/A	N/A	N/A
3	Enerparc Solar Development LLC					
4	Baker Solar Center	LU		N/A	N/A	N/A
5	Brush Solar	LU		N/A	N/A	N/A
6	Morgan Solar	LU		N/A	N/A	N/A
7	Vale I Solar	LU		N/A	N/A	N/A
8	Faulkner Brothers Hydro Inc.	LU	-	N/A	N/A	N/A
9	Fisheries Development	LU	-	N/A	N/A	N/A
10	Fossil Gulch Wind	LU	-	N/A	N/A	N/A
11	G2 Energy Hidden Hollow	LU	-	N/A	N/A	N/A
12	Golden Valley Wind Park	LU	-	N/A	N/A	N/A
13	Grand View PV Solar Two, LLC	LU	-	N/A	N/A	N/A
14	Hammett Hill 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.

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)	
1,517				94,752		94,752	1
3,718				256,831		256,831	2
							3
7				176		176	4
75				1,926	-11,960	-10,034	5
					-15,022	-15,022	6
1				20	-14,219	-14,199	7
3,293				258,023		258,023	8
492				11,399		11,399	9
24,819				1,574,056		1,574,056	10
25,495				1,766,390		1,766,390	11
30,219				1,858,364		1,858,364	12
179,177				9,975,950		9,975,950	13
51,737				4,064,045		4,064,045	14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
22,447				1,612,342		1,612,342	1
92,795				5,008,281		5,008,281	2
1,707				100,525		100,525	3
37,422				2,715,208		2,715,208	4
37,139				2,461,725		2,461,725	5
94,464				4,996,178		4,996,178	6
54,367				4,777,574		4,777,574	7
65,655				3,539,376		3,539,376	8
1,336				118,272		118,272	9
28,489				1,703,175		1,703,175	10
646				36,129		36,129	11
14,645				1,242,783		1,242,783	12
4,364				320,761		320,761	13
3,926				224,759		224,759	14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Lateral 10 Ventures	LU	-	N/A	N/A	N/A
2	Lemhi Hydro Power Co.- Schaffner	LU	-	N/A	N/A	N/A
3	Lime Wind	LU		N/A	N/A	N/A
4	Little Mac Power Co./Cedar Draw	LU	-	N/A	N/A	N/A
5	Little Wood River Irrigation District	LU	-	N/A	N/A	N/A
6	Mainline Windfarm	LU	-	N/A	N/A	N/A
7	Marco Rancher's Irrigation Inc.	LU	-	N/A	N/A	N/A
8	Marysville Hydro Partners- Falls River	LU	-	N/A	N/A	N/A
9	McCollum Enterprises -Canyon Springs	LU	-	N/A	N/A	N/A
10	Milner Dam Wind Park	LU		N/A	N/A	N/A
11	Mountain Home Solar I, LLC	LU		N/A	N/A	N/A
12	Mud Creek White Hydro, Inc	LU	-	N/A	N/A	N/A
13	Murphy Flat Power, LLC	LU		N/A	N/A	N/A
14	New Energy One - Rock Creek Dairy	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.
7,020				442,904		442,904	1
1,250				94,576		94,576	2
5,900				471,307		471,307	3
5,822				317,066		317,066	4
8,444				606,130		606,130	5
55,289				4,329,143		4,329,143	6
2,929				196,249		196,249	7
47,835				3,232,520		3,232,520	8
610				36,749		36,749	9
51,216				3,152,330		3,152,330	10
49,741				1,982,523		1,982,523	11
527				35,591		35,591	12
46,119				1,465,286		1,465,286	13
9,526				904,828		904,828	14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	North Gooding Main, Hydro	LU	-	N/A	N/A	N/A
2	North Side Energy Company Inc					
3	Bypass Limited	LU	-	N/A	N/A	N/A
4	Hazelton A	LU	-	N/A	N/A	N/A
5	Head of U Canal	LU	-	N/A	N/A	N/A
6	Orchard Ranch Solar, LLC	LU		N/A	N/A	N/A
7	Oregon Trail Wind Park	LU		N/A	N/A	N/A
8	Owyhee Irrigation District					
9	Mitchell Butte	LU	-	N/A	N/A	N/A
10	Owyhee Dam	LU	-	N/A	N/A	N/A
11	Tunnel #1	LU	-	N/A	N/A	N/A
12	Payne's Ferry Wind Park	LU		N/A	N/A	N/A
13	Pico Energy - B6 Anaerobic Digester	LU		N/A	N/A	N/A
14	Pigeon Cove Power	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
4,812				404,569		404,569	1
							2
25,904				1,403,268		1,403,268	3
23,166				1,948,018		1,948,018	4
4,494				408,422		408,422	5
48,214				1,404,475		1,404,475	6
36,487				2,268,033		2,268,033	7
							8
6,794				193,133		193,133	9
21,878				522,227		522,227	10
22,316				712,989		712,989	11
61,653				5,122,773		5,122,773	12
15,633				1,379,581		1,379,581	13
7,730			331,258	306,734		637,992	14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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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	Pilgrim Stage Station Wind Park	LU		N/A	N/A	N/A
2	Prospector Windfarm	LU		N/A	N/A	N/A
3	Reynolds Irrigation District	LU	-	N/A	N/A	N/A
4	Richard Kaster					
5	Box Canyon	LU	-	N/A	N/A	N/A
6	Briggs Creek	LU	-	N/A	N/A	N/A
7	Riverside Hydro - Mora Drop	LU		N/A	N/A	N/A
8	Riverside Investments					
9	Arena Drop	LU		N/A	N/A	N/A
10	Fargo Drop	LU		N/A	N/A	N/A
11	Rockland Wind Project	LU		N/A	N/A	N/A
12	Ryegrass Windfarm	LU		N/A	N/A	N/A
13	Salmon Falls Wind Park	LU		N/A	N/A	N/A
14	Shingle Creek 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.

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.
31,677				1,966,421		1,966,421	1
28,126				1,671,437		1,671,437	2
1,086				80,568		80,568	3
							4
1,942				123,203		123,203	5
3,624				247,188		247,188	6
4,545				294,421		294,421	7
							8
1,585				142,606		142,606	9
3,760				226,058		226,058	10
247,583				17,192,513		17,192,513	11
52,259				4,094,862		4,094,862	12
60,456				3,728,612		3,728,612	13
1,064				63,513		63,513	14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	Shorock Hydro Inc.					
2	Rock Creek #1	LU		N/A	N/A	N/A
3	Shoshone CSPP	LU	-	N/A	N/A	N/A
4	Shoshone #2	LU	-	N/A	N/A	N/A
5	Simcoe Solar, LLC	LU		N/A	N/A	N/A
6	Snake River Pottery	LU	-	N/A	N/A	N/A
7	South Forks Joint Venture-Lowline Cana	LU	-	N/A	N/A	N/A
8	Tamarack Energy Partnership	LU	-	N/A	N/A	N/A
9	Tasco - Nampa	OS	-	N/A	N/A	N/A
10	Tasco - Twin Falls	OS		N/A	N/A	N/A
11	Thousand Springs Wind Park	LU		N/A	N/A	N/A
12	Tiber Montana LLC - Tiber Dam	LU		N/A	N/A	N/A
13	Tuana Gulch Wind Park	LU		N/A	N/A	N/A
14	Tuana Springs Expansion	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
11,216				648,188		648,188	2
1,802				106,474		106,474	3
2,825				190,810		190,810	4
48,273				1,534,554		1,534,554	5
415				27,695		27,695	6
26,280				1,903,709		1,903,709	7
25,192				1,459,648		1,459,648	8
14				149		149	9
							10
30,707				1,902,970		1,902,970	11
27,814				1,727,874		1,727,874	12
28,917				1,796,995		1,796,995	13
70,139				5,728,505		5,728,505	14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	Twin Falls Energy-Lowline Midway Hydro	LU		N/A	N/A	N/A
2	Two Ponds Windfarm	LU	-	N/A	N/A	N/A
3	White Water Ranch	LU	-	N/A	N/A	N/A
4	William Arkoosh-Littlewood/Arkoosh	LU	-	N/A	N/A	N/A
5	William Arkoosh- Littlewood River Ranc	LU		N/A	N/A	N/A
6	Willow Spring Windfarm	LU		N/A	N/A	N/A
7	Wilson Power Company	LU	-	N/A	N/A	N/A
8	Wood Hydro					
9	Black Canyon #3	LU		N/A	N/A	N/A
10	Jim Knight	LU		N/A	N/A	N/A
11	Magic Reservoir	LU	-	N/A	N/A	N/A
12	Mile 28	LU		N/A	N/A	N/A
13	Sagebrush	LU		N/A	N/A	N/A
14	Yahoo Creek 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.
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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)	
8,735				533,344		533,344	1
50,458				3,983,861		3,983,861	2
681				46,497		46,497	3
4,331				318,083		318,083	4
4,822				327,736		327,736	5
32,023				1,884,034		1,884,034	6
25,269				1,813,266		1,813,266	7
							8
404				28,778		28,778	9
1,055				74,558		74,558	10
29,810				1,518,840		1,518,840	11
926			-116,312	67,869		-48,443	12
972				69,251		69,251	13
62,906				5,249,623		5,249,623	14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Scheduling Deviation	OS		N/A	N/A	N/A
2	Other Purchased Power					
3	3 Phases Renewables Inc.	SF	WSPP	N/A	N/A	N/A
4	ADM Investor Services, Inc.	OS	WSPP	N/A	N/A	N/A
5	Arizona Public Service Co.	SF	WSPP	N/A	N/A	N/A
6	AVANGRID RENEWABLES, LLC	OS	WSPP	N/A	N/A	N/A
7	AVANGRID RENEWABLES, LLC	SF	WSPP	N/A	N/A	N/A
8	Avista Corp.	OS	T-12	N/A	N/A	N/A
9	Avista Corp.	OS	WSPP	N/A	N/A	N/A
10	Avista Corp.	SF	WSPP	N/A	N/A	N/A
11	Black Hills Power Inc.	SF	WSPP	N/A	N/A	N/A
12	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
13	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
14	Bonneville Power Administration	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.
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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)	
20,555							1
							2
20,087				409,825		409,825	3
					2,210,772	2,210,772	4
23,800				662,800		662,800	5
3					6	6	6
7,300				161,322		161,322	7
18					497	497	8
					97,079	97,079	9
8,474				219,107		219,107	10
40				120		120	11
110					2,838	2,838	12
					284,079	284,079	13
29,388				771,753		771,753	14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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	BP Energy Company	SF	WSPP	N/A	N/A	N/A
2	California Independent System Operator	SF	CAISO	N/A	N/A	N/A
3	Chelan Co PUD	OS	WSPP	N/A	N/A	N/A
4	Chelan Co PUD	SF	WSPP	N/A	N/A	N/A
5	Citigroup Energy Inc.	OS	ISDA	N/A	N/A	N/A
6	Citigroup Energy Inc.	SF	ISDA	N/A	N/A	N/A
7	Citigroup Energy Inc.	SF	WSPP	N/A	N/A	N/A
8	Clatskanie PUD	SF	WSPP	N/A	N/A	N/A
9	Clean Power Alliance of Southern Calif	SF	WSPP	N/A	N/A	N/A
10	Douglas County PUD	OS	WSPP	N/A	N/A	N/A
11	DTE Energy Trading, Inc.	SF	WSPP	N/A	N/A	N/A
12	EDF Trading North America, LLC	OS	WSPP	N/A	N/A	N/A
13	EDF Trading North America, LLC	SF	WSPP	N/A	N/A	N/A
14	Energy Keepers, 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)	
644,225				17,961,511		17,961,511	1
581,888				6,376,029		6,376,029	2
2					4	4	3
26,800				655,632		655,632	4
					-27,836	-27,836	5
47,800				1,879,550		1,879,550	6
10,000				375,908		375,908	7
157				79,632		79,632	8
150				1,316		1,316	9
2					4	4	10
529				12,761		12,761	11
1,360				56,225		56,225	12
28,160				867,415		867,415	13
4,928				131,380		131,380	14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	Exelon Generation Company, LLC	SF	WSPP	N/A	N/A	N/A
2	Grant CO Public Utility District #2 --	OS	WSPP	N/A	N/A	N/A
3	Gridforce Energy Management, LLC	OS	WSPP	N/A	N/A	N/A
4	Macquarie Energy LLC	SF	WSPP	N/A	N/A	N/A
5	Morgan Stanley Capital Group Inc.	SF	ISDA	N/A	N/A	N/A
6	Neal Hot Springs Unit #1	LU	-	N/A	N/A	N/A
7	Nevada Power Company, dba NV Energy	SF	WSPP	N/A	N/A	N/A
8	NorthWestern Energy	OS	T-7	N/A	N/A	N/A
9	NorthWestern Energy	SF	WSPP	N/A	N/A	N/A
10	NorthWestern Energy (Transmission)	OS	WSPP	N/A	N/A	N/A
11	NorthWestern Energy (Transmission)	OS	WSPP	N/A	N/A	N/A
12	Oregon Solar Customers	OS	-	N/A	N/A	N/A
13	PacifiCorp	OS	T-13	N/A	N/A	N/A
14	PacifiCorp	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
5,560				131,985		131,985	1
9					173	173	2
4					222	222	3
6,287				157,429		157,429	4
1,207				63,728		63,728	5
185,455				21,382,507		21,382,507	6
4,930				172,650		172,650	7
12					610	610	8
2,865				85,375		85,375	9
7					14	14	10
					1,204	1,204	11
785					32,791	32,791	12
100					3,207	3,207	13
8,600				200,404		200,404	14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					34,893	34,893	1
25					767	767	2
10,565				265,863		265,863	3
10,524				402,570		402,570	4
400				12,360		12,360	5
30					1,036	1,036	6
36,800				868,634		868,634	7
95,617				6,590,616		6,590,616	8
472				17,974		17,974	9
250				9,250		9,250	10
11					274	274	11
8,871				195,458		195,458	12
19,205				518,789		518,789	13
46					1,214	1,214	14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
2	Tacoma Power	OS	WSPP	N/A	N/A	N/A
3	Tacoma Power	SF	WSPP	N/A	N/A	N/A
4	Telocaset Wind Power Partners LLC	LU	APP-A	N/A	N/A	N/A
5	Tenaska Power Services Co.	SF	WSPP	N/A	N/A	N/A
6	The Energy Authority, Inc.	SF	WSPP	N/A	N/A	N/A
7	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	N/A	N/A	N/A
8	Tri-State Generation and Transmission	SF	WSPP	N/A	N/A	N/A
9	Western Area Power Administration (WA	OS	WSPP	N/A	N/A	N/A
10	NorthWestern Energy	EX	-			
11	PacifiCorp Inc.	EX	-			
12	Sierra Pacific Power Co., dba NV Energ	EX	-			
13	Clatskanie PUD	EX	153			
14	Acctg Valuation of Clatskanie PUD	OS	0	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.
1,650				37,260		37,260	1
5					166	166	2
181				3,258		3,258	3
306,220				19,863,581		19,863,581	4
404				26,008		26,008	5
1,000				28,550		28,550	6
67,477				1,834,250		1,834,250	7
400				26,000		26,000	8
10					397	397	9
		94					10
		91,519					11
		3,690					12
	59,640	53,175					13
					-166,066	-166,066	14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	Demand Response Avoided Energy	OS	-	N/A	N/A	N/A
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					6,996,236	6,996,236	1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
5,194,040	59,640	148,478	280,631	270,606,686	9,433,380	280,320,697	

Schedule Page: 326.3 Line No.: 5 Column: b
Delay Damages

Schedule Page: 326.3 Line No.: 6 Column: b
Delay Damages

Schedule Page: 326.3 Line No.: 7 Column: b
Delay Damages

Schedule Page: 326.4 Line No.: 1 Column: b
Ida West, a subsidiary of IdaCorp (Idaho Power Company's parent company), has partial ownership of these projects.

Schedule Page: 326.5 Line No.: 8 Column: b
Ida West, a subsidiary of IdaCorp (Idaho Power Company's parent company), has partial ownership of these projects.

Schedule Page: 326.8 Line No.: 7 Column: b
Ida West, a subsidiary of IdaCorp (Idaho Power Company's parent company), has partial ownership of these projects.

Schedule Page: 326.8 Line No.: 9 Column: b
Non Firm Purchases

Schedule Page: 326.8 Line No.: 10 Column: b
Non Firm Purchases

Schedule Page: 326.9 Line No.: 7 Column: b
Ida West, a subsidiary of IdaCorp (Idaho Power Company's parent company), has partial ownership of these projects.

Schedule Page: 326.10 Line No.: 1 Column: b
Difference between booked and scheduled energy

Schedule Page: 326.10 Line No.: 4 Column: b
ADM Investor Services, Inc Futures Account Document, dated May 5, 2015

Schedule Page: 326.10 Line No.: 6 Column: b
Spinning or Operating Reserves

Schedule Page: 326.10 Line No.: 8 Column: b
Spinning or Operating Reserves

Schedule Page: 326.10 Line No.: 9 Column: b
Financial Transmission Losses

Schedule Page: 326.10 Line No.: 12 Column: b
Spinning or Operating Reserves

Schedule Page: 326.10 Line No.: 13 Column: b
Financial Transmission Losses

Schedule Page: 326.11 Line No.: 3 Column: b
Spinning or Operating Reserves

Schedule Page: 326.11 Line No.: 5 Column: b
ISDA Master Agreement With Citigroup, dated March 7, 2011

Schedule Page: 326.11 Line No.: 10 Column: b
Spinning or Operating Reserves

Schedule Page: 326.11 Line No.: 12 Column: b
Non Firm Purchases

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

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

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

Schedule Page: 326.12 Line No.: 10 Column: b
Spinning or Operating Reserves

Schedule Page: 326.12 Line No.: 11 Column: b
Financial Transmission Losses

Schedule Page: 326.12 Line No.: 12 Column: b
Schedule 88 Oregon Solar

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

Schedule Page: 326.13 Line No.: 1 Column: b
Financial Transmission Losses

Schedule Page: 326.13 Line No.: 2 Column: b
Spinning or Operating Reserves

Schedule Page: 326.13 Line No.: 6 Column: b
Spinning or Operating Reserves

Schedule Page: 326.13 Line No.: 11 Column: b
Spinning or Operating Reserves

Schedule Page: 326.13 Line No.: 14 Column: b
Spinning or Operating Reserves

Schedule Page: 326.14 Line No.: 2 Column: b
Spinning or Operating Reserves

Schedule Page: 326.14 Line No.: 9 Column: b
Spinning or Operating Reserves

Schedule Page: 326.14 Line No.: 10 Column: b
Physical Transmission Losses

Schedule Page: 326.14 Line No.: 11 Column: b
Physical Transmission Losses

Schedule Page: 326.14 Line No.: 12 Column: b
Physical Transmission Losses

Schedule Page: 326.14 Line No.: 13 Column: b
Energy exchange between Clatskanie PUD and Idaho Power Company at Arrowrock Dam

Schedule Page: 326.14 Line No.: 14 Column: b
Energy exchange between Clatskanie PUD and Idaho Power Company at Arrowrock Dam

Schedule Page: 326.15 Line No.: 1 Column: b
Incentive program for customers to reduce demand during peak hours

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	FNO
2	Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Reclamati	FNO
3	Bonneville Power Administration - 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	American Falls Solar			NF
19	Avangrid Renewables, LLC	PacifiCorp East	Bonneville Power Administration	NF
20	Avangrid Renewables, LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
21	Avangrid Renewables, LLC	PacifiCorp East	Bonneville Power Administration	NF
22	Avangrid Renewables, LLC	PacifiCorp East	Sierra Pacific Power	NF
23	Avangrid Renewables, LLC	Idaho Power Company	Bonneville Power Administration	NF
24	Avangrid Renewables, LLC	Bonneville Power Administration	PacifiCorp East	NF
25	Avangrid Renewables, LLC	Bonneville Power Administration	Sierra Pacific Power	NF
26	Avangrid Renewables, LLC	Avista	Sierra Pacific Power	NF
27	Avangrid Renewables, LLC	Sierra Pacific Power	Bonneville Power Administration	NF
28	Avangrid Renewables, LLC	PacifiCorp West	PacifiCorp East	NF
29	Avangrid Renewables, LLC	PacifiCorp West	Sierra Pacific Power	NF
30	Avista Corporation	Avista	PacifiCorp East	NF
31	Avista Corporation	Avista	Sierra Pacific Power	NF
32	Bell Rapids/Thousand Springs			NF
33	Black Hills Power	NorthWestern/PacifiCorp East	PacifiCorp East	NF
34	Black Hills Power	Avista	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.
9				329,400	329,400	1
9				181,845	181,845	2
9				1,313,505	1,313,505	3
Legacy	Minidoka, Idaho	Various in Idaho		9,082	9,082	4
4				363,903	363,903	5
9				2,063	2,063	6
Legacy	LaGrande, Oregon	Various in Idaho		16,612	16,612	7
5/6	BRDY	IPCOEAST		2,756	2,756	8
5/6	JEFF	IPCOEAST		13,086	13,086	9
						10
7/8	BORA	LAGRANDE		1,134,195	1,134,195	11
7/8	KPRT	HURR		808,805	808,805	12
7/8	BORA	HURR		1,178,874	1,178,874	13
7/8	LYPK	LAGRANDE		19,434	19,434	14
7/8	M500	KPRT		68,115	68,115	15
7/8	SMLK	KPRT		251,216	251,216	16
						17
11						18
7/8	BORA	LAGRANDE		609	609	19
7/8	BPAT.NWMT	M345		24	24	20
7/8	BRDY	LAGRANDE		230	230	21
7/8	BRDY	M345		187	187	22
7/8	IPCOGEN	LAGRANDE		75	75	23
7/8	LAGRANDE	BORA		1,769	1,769	24
7/8	LAGRANDE	M345		1,162	1,162	25
7/8	LOLO	M345		423	423	26
7/8	M345	LAGRANDE		2,509	2,509	27
7/8	SMLK	BORA		566	566	28
7/8	SMLK	M345		270	270	29
7/8	LOLO	BRDY		275	275	30
7/8	LOLO	M345		2,173	2,173	31
11						32
7/8	BPAT.NWMT	JBSN		71	71	33
7/8	LOLO	JBSN		40	40	34
			0	**7,886,493**	**7,886,493**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Bonneville Power Administration	PacifiCorp East	PacifiCorp West	SFP
2	Bonneville Power Administration	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
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	Avista	PacifiCorp East	NF
11	Bonneville Power Administration	Avista	PacifiCorp East	NF
12	Bonneville Power Administration	Avista	Bonneville Power Administration	NF
13	Bonneville Power Administration	Avista	Sierra Pacific Power	NF
14	Bonneville Power Administration	PacifiCorp West	Sierra Pacific Power	NF
15	Bonneville Power Administration	PacifiCorp West	PacifiCorp East	SFP
16	Bonneville Power Administration	PacifiCorp West	Sierra Pacific Power	NF
17	Bonneville Power Administration	PacifiCorp West	Sierra Pacific Power	SFP
18	Brookfield Energy Marketing LP	PacifiCorp West	PacifiCorp East	NF
19	Brookfield Energy Marketing LP	PacifiCorp East	PacifiCorp West	NF
20	Brookfield Energy Marketing LP	PacifiCorp East	PacifiCorp West	SFP
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	EDF Trading North America, LLC	Bonneville Power Administration	Sierra Pacific Power	NF
26	Energy Keepers, Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
27	Energy Keepers, Inc.	PacifiCorp East	Sierra Pacific Power	NF
28	Energy Keepers, Inc.	PacifiCorp East	Sierra Pacific Power	SFP
29	Energy Keepers, Inc.	Avista	Sierra Pacific Power	NF
30	Guzman Energy Group			NF
31	Huntington Wind			NF
32	Idaho Solar I			NF
33	Lime Wind			NF
34	Macquarie Energy, LLC	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	BORA	H500		7,051	7,051	1
7/8	BPAT.NWMT	BPASID		280	280	2
7/8	BPAT.NWMT	M345		375	375	3
7/8	BPAT.NWMT	M345		12,519	12,519	4
7/8	BRDY	M345		274	274	5
7/8	LAGRANDE	BORA		746	746	6
7/8	LAGRANDE	KPRT		4,449	4,449	7
7/8	LAGRANDE	LAGRANDE		14,368	14,368	8
7/8	LAGRANDE	M345		5,547	5,547	9
7/8	LOLO	BORA		67	67	10
7/8	LOLO	KPRT		82	82	11
7/8	LOLO	LAGRANDE		2,340	2,340	12
7/8	LOLO	M345		5,280	5,280	13
7/8	M500	M345		4	4	14
7/8	SMLK	BORA		10,626	10,626	15
7/8	SMLK	M345		232	232	16
7/8	SMLK	M345		86,709	86,709	17
7/8	H500	BORA		2,800	2,800	18
7/8	BORA	H500		6,000	6,000	19
7/8	BORA	H500		34,811	34,811	20
7/8	BPAT.NWMT	LAGRANDE		87	87	21
7/8	BRDY	LAGRANDE		879	879	22
7/8	JEFF	LAGRANDE		489	489	23
7/8	LAGRANDE	BRDY		142	142	24
7/8	LAGRANDE	M345		240	240	25
7/8	BPAT.NWMT	LAGRANDE		10	10	26
7/8	BRDY	M345		922	922	27
7/8	BRDY	M345		1,557	1,557	28
7/8	LOLO	M345		496	496	29
7/8						30
11						31
11						32
11						33
7/8	BRDY	LAGRANDE		5	5	34
			0	**7,886,493**	**7,886,493**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	PacifiCorp East	Sierra Pacific Power	NF
2	Macquarie Energy, LLC	PacifiCorp East	NorthWestern/PacifiCorp East	NF
3	Macquarie Energy, LLC	PacifiCorp East	Bonneville Power Administration	NF
4	Macquarie Energy, LLC	PacifiCorp East	Sierra Pacific Power	NF
5	Macquarie Energy, LLC	PacifiCorp East	PacifiCorp East	NF
6	Macquarie Energy, LLC	PacifiCorp East	Bonneville Power Administration	NF
7	Macquarie Energy, LLC	PacifiCorp East	Sierra Pacific Power	NF
8	Macquarie Energy, LLC	Bonneville Power Administration	Sierra Pacific Power	NF
9	Macquarie Energy, LLC	Avista	Sierra Pacific Power	NF
10	Macquarie Energy, LLC	Sierra Pacific Power	PacifiCorp East	NF
11	Mag Energy Solutions	Idaho Power Company	PacifiCorp East	NF
12	Mag Energy Solutions	PacifiCorp East	Sierra Pacific Power	NF
13	Mag Energy Solutions	PacifiCorp East	Sierra Pacific Power	NF
14	Mag Energy Solutions	Sierra Pacific Power	PacifiCorp East	NF
15	Mountain Home Solar			NF
16	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
17	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
18	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
19	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
20	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	SFP
21	Morgan Stanley Capital Group Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
22	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
23	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	SFP
24	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
25	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	SFP
26	Morgan Stanley Capital Group Inc.	PacifiCorp East	Avista	NF
27	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
28	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
29	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
30	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
31	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	SFP
32	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
33	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
34	Morgan Stanley Capital Group Inc.	PacifiCorp East	NorthWestern/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	04/14/2020	End of 2019/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
7/8	BRDY	M345		193	193	1
7/8	JBSN	BPAT.NWMT		693	693	2
7/8	JBSN	LAGRANDE		462	462	3
7/8	JBSN	M345		434	434	4
7/8	JEFF	BORA		75	75	5
7/8	JEFF	LAGRANDE		15	15	6
7/8	JEFF	M345		541	541	7
7/8	LAGRANDE	M345		145	145	8
7/8	LOLO	M345		100	100	9
7/8	M345	BORA		48	48	10
7/8	BGSY	JEFF		606	606	11
7/8	BRDY	M345		15,916	15,916	12
7/8	JEFF	M345		2,061	2,061	13
7/8	M345	GSHN		606	606	14
11						15
7/8	AVAT.NWMT	BORA		22	22	16
7/8	AVAT.NWMT	BORA		5,385	5,385	17
7/8	AVAT.NWMT	LAGRANDE		1,013	1,013	18
7/8	AVAT.NWMT	M345		16,861	16,861	19
7/8	BGSY	JEFF		1,163	1,163	20
7/8	BORA	BPAT.NWMT		1,171	1,171	21
7/8	BORA	BRDY		846	846	22
7/8	BORA	BRDY		12,709	12,709	23
7/8	BORA	LAGRANDE		5,275	5,275	24
7/8	BORA	LAGRANDE		25,319	25,319	25
7/8	BORA	LOLO		50	50	26
7/8	BORA	M345		106	106	27
7/8	BPAT.NWMT	BORA		929	929	28
7/8	BPAT.NWMT	BRDY		3,600	3,600	29
7/8	BPAT.NWMT	LAGRANDE		2,188	2,188	30
7/8	BPAT.NWMT	LAGRANDE		512	512	31
7/8	BPAT.NWMT	M345		12,909	12,909	32
7/8	BPAT.NWMT	M345		123,337	123,337	33
7/8	BRDY	AVAT.NWMT		164	164	34
			0	**7,886,493**	**7,886,493**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
7/8	BRDY	BORA		402	402	1
7/8	BRDY	BORA		10,487	10,487	2
7/8	BRDY	BPAT.NWMT		170	170	3
7/8	BRDY	BPAT.NWMT		1,008	1,008	4
7/8	BRDY	GSHN		1,163	1,163	5
7/8	BRDY	LAGRANDE		9,437	9,437	6
7/8	BRDY	LAGRANDE		1,200	1,200	7
7/8	BRDY	LOLO		491	491	8
7/8	BRDY	M345		14,927	14,927	9
7/8	BRDY	M345		130,303	130,303	10
7/8	H500	M345		169	169	11
7/8	IPCOGEN	LAGRANDE		100	100	12
7/8	JBSN	BORA		351	351	13
7/8	JBSN	LAGRANDE		845	845	14
7/8	JBSN	M345		11	11	15
7/8	JEFF	BORA		12,704	12,704	16
7/8	JEFF	BORA		1,555	1,555	17
7/8	JEFF	LAGRANDE		1,118	1,118	18
7/8	JEFF	LOLO		412	412	19
7/8	JEFF	M345		52,036	52,036	20
7/8	JEFF	M345		7,484	7,484	21
7/8	LAGRANDE	BORA		3,195	3,195	22
7/8	LAGRANDE	BRDY		1,424	1,424	23
7/8	LAGRANDE	JBSN		140	140	24
7/8	LAGRANDE	M345		59,254	59,254	25
7/8	LAGRANDE	M345		965	965	26
7/8	LOLO	BORA		10,269	10,269	27
7/8	LOLO	BORA		10,661	10,661	28
7/8	LOLO	BRDY		576	576	29
7/8	LOLO	LAGRANDE		2,416	2,416	30
7/8	LOLO	LAGRANDE		21,957	21,957	31
7/8	LOLO	M345		75,192	75,192	32
7/8	LOLO	M345		37,168	37,168	33
7/8	LYPK	BORA		876	876	34
			0	**7,886,493**	**7,886,493**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	SFP
2	Morgan Stanley Capital Group Inc.	Idaho Power Company	NorthWestern/PacifiCorp East	NF
3	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
4	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	SFP
5	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	SFP
6	Morgan Stanley Capital Group Inc.	Idaho Power Company	Avista	NF
7	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	NF
8	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	SFP
9	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
10	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
11	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	PacifiCorp East	NF
12	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
13	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	Avista	NF
14	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	NF
15	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	SFP
16	Morgan Stanley Capital Group Inc.	PacifiCorp West	Sierra Pacific Power	NF
17	Morgan Stanley Capital Group Inc.	PacifiCorp West	Sierra Pacific Power	SFP
18	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
19	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	NF
20	Murphy Flat Solar			NF
21	NorthWestern Energy	PacifiCorp East	Bonneville Power Administration	NF
22	NorthWestern Energy	PacifiCorp East	Bonneville Power Administration	NF
23	Nevada Power Company	PacifiCorp East	Bonneville Power Administration	NF
24	Nevada Power Company	PacifiCorp East	Sierra Pacific Power	NF
25	Nevada Power Company	Sierra Pacific Power	Bonneville Power Administration	NF
26	Orchard Ranch Solar			NF
27	PacifiCorp Inc.	PacifiCorp East	Avista	SFP
28	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	NF
29	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	SFP
30	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	NF
31	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	NF
32	PacifiCorp Inc.	PacifiCorp East	Bonneville Power Administration	NF
33	PacifiCorp Inc.	PacifiCorp East	Avista	NF
34	PacifiCorp Inc.	PacifiCorp West	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	04/14/2020	End of 2019/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	LYPK	BORA		25,827	25,827	1
7/8	LYPK	BPAT.NWMT		256	256	2
7/8	LYPK	BRDY		573	573	3
7/8	LYPK	BRDY		240	240	4
7/8	LYPK	JBSN		56	56	5
7/8	LYPK	LOLO		2	2	6
7/8	LYPK	M345		1,475	1,475	7
7/8	LYPK	M345		314,810	314,810	8
7/8	M345	AVAT.NWMT		200	200	9
7/8	M345	BPAT.NWMT		630	630	10
7/8	M345	BRDY		2,350	2,350	11
7/8	M345	LAGRANDE		4,538	4,538	12
7/8	M345	LOLO		77	77	13
7/8	SMLK	BORA		2,235	2,235	14
7/8	SMLK	BORA		4,781	4,781	15
7/8	SMLK	M345		4,513	4,513	16
7/8	SMLK	M345		600	600	17
7/8	WALLAWALLA	BORA		293	293	18
7/8	WALLAWALLA	M345		198	198	19
11						20
7/8	BRDY	LAGRANDE		380	380	21
7/8	JEFF	LAGRANDE		150	150	22
7/8	BORA	LAGRANDE		45	45	23
7/8	BORA	M345		550	550	24
7/8	M345	LAGRANDE		40	40	25
11						26
7/8	BORA	LOLO		374,286	374,286	27
7/8	BRDY	BORA		5,722	5,722	28
7/8	BRDY	BORA		255	255	29
7/8	BRDY	BRDY		2,045	2,045	30
7/8	BRDY	HURR		584	584	31
7/8	BRDY	LAGRANDE		2,799	2,799	32
7/8	BRDY	LOLO		1,501	1,501	33
7/8	HURR	BORA		3,749	3,749	34
			0	**7,886,493**	**7,886,493**	

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	PacifiCorp Inc.	PacifiCorp East	Idaho Power Company	NF
2	PacifiCorp Inc.	Bonneville Power Administration	PacifiCorp East	NF
3	PacifiCorp Inc.	Avista	PacifiCorp East	NF
4	PacifiCorp Inc.	Avista	PacifiCorp East	NF
5	PacifiCorp Inc.	Avista	PacifiCorp West	NF
6	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
7	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
8	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
9	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
10	Portland General Electric	PacifiCorp East	Bonneville Power Administration	SFP
11	Portland General Electric	PacifiCorp East	Bonneville Power Administration	SFP
12	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
13	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
14	Powerex Corporation	PacifiCorp East	Avista	NF
15	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	NF
16	Powerex Corporation	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
17	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
18	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
19	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
20	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
21	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	SFP
22	Powerex Corporation	PacifiCorp East	Avista	NF
23	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
24	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
25	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
26	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
27	Powerex Corporation	PacifiCorp East	PacifiCorp West	NF
28	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
29	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
30	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
31	Powerex Corporation	Bonneville Power Administration	PacifiCorp East	NF
32	Powerex Corporation	Bonneville Power Administration	PacifiCorp East	NF
33	Powerex Corporation	Bonneville Power Administration	Sierra Pacific Power	NF
34	Powerex Corporation	Avista	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	JEFF	BGSY		2,073	2,073	1
7/8	LAGRANDE	BORA		244	244	2
7/8	LOLO	BORA		1,072	1,072	3
7/8	LOLO	BRDY		2,450	2,450	4
7/8	LOLO	HURR		183	183	5
7/8	SMLK	BORA		7,780	7,780	6
7/8	SMLK	BRDY		2,231	2,231	7
7/8	WALLAWALLA	BORA		182	182	8
7/8	WALLAWALLA	BRDY		50	50	9
7/8	BORA	LAGRANDE		13,581	13,581	10
7/8	BRDY	LAGRANDE		2,396	2,396	11
7/8	BORA	BPAT.NWMT		431	431	12
7/8	BORA	LAGRANDE		2,577	2,577	13
7/8	BORA	LOLO		80	80	14
7/8	BPAT.NWMT	BORA		95	95	15
7/8	BPAT.NWMT	M345		109	109	16
7/8	BRDY	AVAT.NWMT				17
7/8	BRDY	BORA		257	257	18
7/8	BRDY	BPAT.NWMT		21	21	19
7/8	BRDY	LAGRANDE		15,064	15,064	20
7/8	BRDY	LAGRANDE		4,282	4,282	21
7/8	BRDY	LOLO		570	570	22
7/8	BRDY	M345		286	286	23
7/8	GSHN	LAGRANDE		164	164	24
7/8	HURR	BORA		464	464	25
7/8	JBSN	BPAT.NWMT		64	64	26
7/8	JBSN	HURR		50	50	27
7/8	JBSN	LAGRANDE		3,781	3,781	28
7/8	JEFF	BORA		422	422	29
7/8	JEFF	LAGRANDE		12	12	30
7/8	LAGRANDE	BORA		1,215	1,215	31
7/8	LAGRANDE	BRDY		1,876	1,876	32
7/8	LAGRANDE	M345		2,833	2,833	33
7/8	LOLO	BORA		186	186	34
			0	**7,886,493**	**7,886,493**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
7/8	LOLO	LAGRANDE		4,460	4,460	1
7/8	LOLO	M345		300	300	2
7/8	M345	BORA		41	41	3
7/8	M345	BPAT.NWMT		560	560	4
7/8	M345	HURR		4	4	5
7/8	M345	LAGRANDE		1,719	1,719	6
7/8	M345	LOLO		19	19	7
7/8	POP	HURR		287	287	8
7/8	POP	HURR		332	332	9
7/8	SMLK	BORA		4,870	4,870	10
7/8	SMLK	BRDY		226	226	11
7/8	SMLK	M345		600	600	12
7/8	WALLAWALLA	BORA		45,282	45,282	13
7/8	WALLAWALLA	BRDY		1,169	1,169	14
7/8	WALLAWALLA	M345		2,121	2,121	15
7/8	BGSY	JEFF		2,837	2,837	16
7/8	BRDY	GSHN		1,845	1,845	17
7/8	BRDY	LAGRANDE		400	400	18
7/8	BRDY	LOLO		2,381	2,381	19
11						20
11						21
7/8	BORA	LAGRANDE		8,659	8,659	22
7/8	BORA	M345		305	305	23
7/8	BORA	M500		44,232	44,232	24
7/8	BPAT.NWMT	BRDY		25	25	25
7/8	BPAT.NWMT	M345		1,992	1,992	26
7/8	BPAT.NWMT	M345		280	280	27
7/8	BRDY	AVAT.NWMT		788	788	28
7/8	BRDY	BPAT.NWMT		878	878	29
7/8	BRDY	LAGRANDE		10,427	10,427	30
7/8	BRDY	LAGRANDE		2,851	2,851	31
7/8	BRDY	LOLO		1,879	1,879	32
7/8	BRDY	LOLO		37,624	37,624	33
7/8	BRDY	M345		8,750	8,750	34
			0	**7,886,493**	**7,886,493**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
7/8	BRDY	M345		2,545	2,545	1
7/8	BRDY	M500		2,467	2,467	2
7/8	BRDY	M500		2,850	2,850	3
7/8	HURR	LAGRANDE		15	15	4
7/8	IPCOGEN	LOLO		1,598	1,598	5
7/8	IPCOGEN	M500		1,212	1,212	6
7/8	IPCOGEN	M500		550	550	7
7/8	JBSN	BRDY		174	174	8
7/8	JBSN	LAGRANDE		10,862	10,862	9
7/8	JBSN	LOLO		49	49	10
7/8	JBSN	M345		1,054	1,054	11
7/8	JBSN	M500		1,437	1,437	12
7/8	JEFF	M345		240	240	13
7/8	LAGRANDE	BORA		2,850	2,850	14
7/8	LAGRANDE	BRDY		1,271	1,271	15
7/8	LAGRANDE	JBSN		1,980	1,980	16
7/8	LAGRANDE	M345		24,735	24,735	17
7/8	LAGRANDE	M345		642	642	18
7/8	LOLO	BORA		2,085	2,085	19
7/8	LOLO	BRDY		25	25	20
7/8	LOLO	BRDY		613	613	21
7/8	LOLO	M345		35,994	35,994	22
7/8	LOLO	M345		4,351	4,351	23
7/8	M345	LAGRANDE		5,947	5,947	24
7/8	M345	LOLO		600	600	25
7/8	M345	M500		32	32	26
7/8	SMLK	BORA		300	300	27
7/8	SMLK	BRDY		248	248	28
7/8	SMLK	M345		402	402	29
7/8	WALLAWALLA	BORA		17,352	17,352	30
7/8	WALLAWALLA	BRDY		2,942	2,942	31
7/8	WALLAWALLA	M345		14,915	14,915	32
11						33
7/8						34
			0	**7,886,493**	**7,886,493**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	Tenaska Power Services	PacifiCorp East	Sierra Pacific Power	NF
2	Tenaska Power Services	PacifiCorp East	Sierra Pacific Power	SFP
3	Tenaska Power Services	Bonneville Power Administration	PacifiCorp East	NF
4	Tenaska Power Services	Bonneville Power Administration	Sierra Pacific Power	NF
5	Tenaska Power Services	Avista	Sierra Pacific Power	NF
6	The Energy Authority, Inc.	PacifiCorp East	Bonneville Power Administration	NF
7	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
8	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
9	The Energy Authority, Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
10	The Energy Authority, Inc.	PacifiCorp East	Bonneville Power Administration	NF
11	The Energy Authority, Inc.	PacifiCorp East	Avista	NF
12	The Energy Authority, Inc.	PacifiCorp East	PacifiCorp West	NF
13	The Energy Authority, Inc.	Bonneville Power Administration	PacifiCorp East	NF
14	The Energy Authority, Inc.	Bonneville Power Administration	PacifiCorp East	NF
15	The Energy Authority, Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
16	The Energy Authority, Inc.	Avista	PacifiCorp East	NF
17	The Energy Authority, Inc.	Avista	PacifiCorp East	NF
18	The Energy Authority, Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
19	The Energy Authority, Inc.	Sierra Pacific Power	Avista	NF
20	The Energy Authority, Inc.	PacifiCorp West	PacifiCorp East	NF
21	The Energy Authority, Inc.	Idaho Power Company	Sierra Pacific Power	NF
22	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Bonneville Power Administration	NF
23	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Sierra Pacific Power	NF
24	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	PacifiCorp West	NF
25	Transalta Energy Marketing (U.S.) Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
26	Transalta Energy Marketing (U.S.) Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
27	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Bonneville Power Administration	NF
28	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Sierra Pacific Power	NF
29	Transalta Energy Marketing (U.S.) Inc.	Idaho Power Company	Sierra Pacific Power	NF
30	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Bonneville Power Administration	NF
31	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Sierra Pacific Power	NF
32	Transalta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	PacifiCorp East	NF
33	Transalta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	PacifiCorp East	NF
34	Transalta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
7/8	BRDY	M345		842	842	1
7/8	BRDY	M345		40,812	40,812	2
7/8	LAGRANDE	BRDY		157	157	3
7/8	LAGRANDE	M345		192	192	4
7/8	LOLO	M345		1,421	1,421	5
7/8	BORA	LAGRANDE		3,795	3,795	6
7/8	BPAT.NWMT	BRDY		79	79	7
7/8	BPAT.NWMT	M345		276	276	8
7/8	BRDY	BPAT.NWMT		444	444	9
7/8	BRDY	LAGRANDE		3,307	3,307	10
7/8	BRDY	LOLO		284	284	11
7/8	BRDY	M500		250	250	12
7/8	LAGRANDE	BORA		541	541	13
7/8	LAGRANDE	BRDY		928	928	14
7/8	LAGRANDE	M345		1,001	1,001	15
7/8	LOLO	BORA		26	26	16
7/8	LOLO	BRDY		380	380	17
7/8	M345	LAGRANDE		4,108	4,108	18
7/8	M345	LOLO		275	275	19
7/8	SMLK	BORA		2,261	2,261	20
7/8	WALLAWALLA	M345		101	101	21
7/8	BORA	LAGRANDE		2,007	2,007	22
7/8	BORA	M345		83	83	23
7/8	BORA	M500		25	25	24
7/8	BPAT.NWMT	LAGRANDE		30	30	25
7/8	BPAT.NWMT	M345		23	23	26
7/8	BRDY	LAGRANDE		889	889	27
7/8	BRDY	M345		117	117	28
7/8	IPCOGEN	M345		50	50	29
7/8	JBSN	LAGRANDE		713	713	30
7/8	JBSN	M345		912	912	31
7/8	LAGRANDE	BORA		10,515	10,515	32
7/8	LAGRANDE	BRDY		73	73	33
7/8	LAGRANDE	M345		13,636	13,636	34
			0	**7,886,493**	**7,886,493**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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.	Avista	PacifiCorp East	NF
2	Transalta Energy Marketing (U.S.) Inc.	Avista	PacifiCorp East	NF
3	Transalta Energy Marketing (U.S.) Inc.	Avista	Sierra Pacific Power	NF
4	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	PacifiCorp East	NF
5	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
6	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	PacifiCorp West	NF
7	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
8	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	Avista	NF
9	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp West	PacifiCorp East	NF
10	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp West	Sierra Pacific Power	NF
11	Transalta Energy Marketing (U.S.) Inc.	Idaho Power Company	PacifiCorp East	NF
12	Transalta Energy Marketing (U.S.) Inc.	Idaho Power Company	Sierra Pacific Power	NF
13	Utah Associated Municipal Power Systems	PacifiCorp East	Sierra Pacific Power	NF
14	Utah Associated Municipal Power Systems	PacifiCorp East	Sierra Pacific Power	NF
15	Utah Associated Municipal Power Systems	Idaho Power Company	PacifiCorp East	NF
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
7/8	LOLO	BORA		2,331	2,331	1
7/8	LOLO	BRDY		119	119	2
7/8	LOLO	M345		4,100	4,100	3
7/8	M345	BORA		106	106	4
7/8	M345	BPAT.NWMT		73	73	5
7/8	M345	HURR		60	60	6
7/8	M345	LAGRANDE		11,393	11,393	7
7/8	M345	LOLO		50	50	8
7/8	SMLK	BORA		2,142	2,142	9
7/8	SMLK	M345		260	260	10
7/8	WALLAWALLA	BORA		7,351	7,351	11
7/8	WALLAWALLA	M345		4,443	4,443	12
7/8	BORA	M345		1,429	1,429	13
7/8	BRDY	M345		81	81	14
7/8	WALLAWALLA	BORA		100	100	15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**7,886,493**	**7,886,493**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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.
1,688,834	125,112		1,813,946	1
1,625,030	148,642		1,773,672	2
6,634,105	451,782		7,085,887	3
	14,712		14,712	4
	118,040		118,040	5
10,978	933		11,910	6
	54,857		54,857	7
	2,761		2,761	8
	13,107		13,107	9
				10
	4,388,846		4,388,846	11
	3,753,220		3,753,220	12
	7,294,564		7,294,564	13
	3,057,058		3,057,058	14
	3,026,790		3,026,790	15
	3,026,790		3,026,790	16
				17
	3,906		3,906	18
	4,951		4,951	19
	195		195	20
	1,870		1,870	21
	1,520		1,520	22
	610		610	23
	14,383		14,383	24
	9,447		9,447	25
	3,439		3,439	26
	20,399		20,399	27
	4,602		4,602	28
	2,195		2,195	29
	2,842		2,842	30
	22,455		22,455	31
	100		100	32
	502		502	33
	283		283	34
9,958,947	**33,889,659**	**0**	**43,848,605**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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.
	8,504		8,504	1
	338		338	2
	452		452	3
	15,100		15,100	4
	330		330	5
	900		900	6
	5,366		5,366	7
	17,330		17,330	8
	6,690		6,690	9
	81		81	10
	99		99	11
	2,822		2,822	12
	6,368		6,368	13
	5		5	14
	12,816		12,816	15
	280		280	16
	104,582		104,582	17
	10,241		10,241	18
	21,944		21,944	19
	127,316		127,316	20
	359		359	21
	3,624		3,624	22
	2,016		2,016	23
	585		585	24
	990		990	25
	82		82	26
	7,520		7,520	27
	12,700		12,700	28
	4,046		4,046	29
	4		4	30
	2,277		2,277	31
	5,809		5,809	32
	88		88	33
	57		57	34
9,958,947	**33,889,659**	**0**	**43,848,605**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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.
	2,208		2,208	1
	7,929		7,929	2
	5,286		5,286	3
	4,966		4,966	4
	858		858	5
	172		172	6
	6,190		6,190	7
	1,659		1,659	8
	1,144		1,144	9
	549		549	10
	3,985		3,985	11
	104,659		104,659	12
	13,553		13,553	13
	3,985		3,985	14
	3,205		3,205	15
	43		43	16
	10,472		10,472	17
	1,970		1,970	18
	32,790		32,790	19
	2,262		2,262	20
	2,277		2,277	21
	1,645		1,645	22
	24,715		24,715	23
	10,258		10,258	24
	49,238		49,238	25
	97		97	26
	206		206	27
	1,807		1,807	28
	7,001		7,001	29
	4,255		4,255	30
	996		996	31
	25,104		25,104	32
	239,856		239,856	33
	319		319	34
9,958,947	**33,889,659**	**0**	**43,848,605**	

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.
	782		782	1
	20,394		20,394	2
	331		331	3
	1,960		1,960	4
	2,262		2,262	5
	18,352		18,352	6
	2,334		2,334	7
	955		955	8
	29,029		29,029	9
	253,403		253,403	10
	329		329	11
	194		194	12
	683		683	13
	1,643		1,643	14
	21		21	15
	24,706		24,706	16
	3,024		3,024	17
	2,174		2,174	18
	801		801	19
	101,196		101,196	20
	14,554		14,554	21
	6,213		6,213	22
	2,769		2,769	23
	272		272	24
	115,233		115,233	25
	1,877		1,877	26
	19,970		19,970	27
	20,733		20,733	28
	1,120		1,120	29
	4,698		4,698	30
	42,700		42,700	31
	146,228		146,228	32
	72,281		72,281	33
	1,704		1,704	34
9,958,947	**33,889,659**	**0**	**43,848,605**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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.
	50,226		50,226	1
	498		498	2
	1,114		1,114	3
	467		467	4
	109		109	5
	4		4	6
	2,868		2,868	7
	612,218		612,218	8
	389		389	9
	1,225		1,225	10
	4,570		4,570	11
	8,825		8,825	12
	150		150	13
	4,346		4,346	14
	9,298		9,298	15
	8,777		8,777	16
	1,167		1,167	17
	570		570	18
	385		385	19
	5,309		5,309	20
	1,636		1,636	21
	646		646	22
	287		287	23
	3,509		3,509	24
	255		255	25
	5,809		5,809	26
	2,508,983		2,508,983	27
	38,357		38,357	28
	1,709		1,709	29
	13,708		13,708	30
	3,915		3,915	31
	18,763		18,763	32
	10,062		10,062	33
	25,131		25,131	34
9,958,947	**33,889,659**	**0**	**43,848,605**	

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.
	13,896		13,896	1
	1,636		1,636	2
	7,186		7,186	3
	16,423		16,423	4
	1,227		1,227	5
	52,152		52,152	6
	14,955		14,955	7
	1,220		1,220	8
	335		335	9
	85,467		85,467	10
	15,078		15,078	11
	2,721		2.721	12
	16,269		16,269	13
	505		505	14
	600		600	15
	688		688	16
				17
	1,623		1,623	18
	133		133	19
	95,103		95,103	20
	27,033		27,033	21
	3,599		3,599	22
	1,806		1,806	23
	1,035		1,035	24
	2,929		2,929	25
	404		404	26
	316		316	27
	23,870		23,870	28
	2,664		2,664	29
	76		76	30
	7,671		7,671	31
	11,844		11,844	32
	17,885		17,885	33
	1,174		1,174	34
9,958,947	**33,889,659**	**0**	**43,848,605**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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.
	28,157		28,157	1
	1,894		1,894	2
	259		259	3
	3,535		3,535	4
	25		25	5
	10,852		10,852	6
	120		120	7
	1,812		1,812	8
	2,096		2,096	9
	30,745		30,745	10
	1,427		1,427	11
	3,788		3,788	12
	285,876		285,876	13
	7,380		7,380	14
	13,390		13,390	15
	15,627		15,627	16
	10,163		10,163	17
	2,203		2,203	18
	13,115		13,115	19
	15,571		15,571	20
	2,878		2,878	21
	52,336		52,336	22
	1,843		1,843	23
	267,342		267,342	24
	151		151	25
	12,040		12,040	26
	1,692		1,692	27
	4,763		4,763	28
	5,307		5,307	29
	63,022		63,022	30
	17,232		17,232	31
	11,357		11,357	32
	227,403		227,403	33
	52,886		52,886	34
9,958,947	**33,889,659**	**0**	**43,848,605**	

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
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REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	15,382		15,382	1
	14,911		14,911	2
	17,226		17,226	3
	91		91	4
	9,658		9,658	5
	7,325		7,325	6
	3,324		3,324	7
	1,052		1,052	8
	65,651		65,651	9
	296		296	10
	6,370		6,370	11
	8,685		8,685	12
	1,451		1,451	13
	17,226		17,226	14
	7,682		7,682	15
	11,967		11,967	16
	149,501		149,501	17
	3,880		3,880	18
	12,602		12,602	19
	151		151	20
	3,705		3,705	21
	217,551		217,551	22
	26,298		26,298	23
	35,944		35,944	24
	3,626		3,626	25
	193		193	26
	1,813		1,813	27
	1,499		1,499	28
	2,430		2,430	29
	104,877		104,877	30
	17,782		17,782	31
	90,148		90,148	32
	7,813		7,813	33
	13		13	34
9,958,947	**33,889,659**	**0**	**43,848,605**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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.
	3,298		3,298	1
	159,834		159,834	2
	615		615	3
	752		752	4
	5,565		5,565	5
	21,479		21,479	6
	447		447	7
	1,562		1,562	8
	2,513		2,513	9
	18,717		18,717	10
	1,607		1,607	11
	1,415		1,415	12
	3,062		3,062	13
	5,252		5,252	14
	5,665		5,665	15
	147		147	16
	2,151		2,151	17
	23,250		23,250	18
	1,556		1,556	19
	12,797		12,797	20
	572		572	21
	11,522		11,522	22
	476		476	23
	144		144	24
	172		172	25
	132		132	26
	5,104		5,104	27
	672		672	28
	287		287	29
	4,093		4,093	30
	5,236		5,236	31
	60,364		60,364	32
	419		419	33
	78,281		78,281	34
9,958,947	**33,889,659**	**0**	**43,848,605**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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.
	13,382		13,382	1
	683		683	2
	23,537		23,537	3
	609		609	4
	419		419	5
	344		344	6
	65,404		65,404	7
	287		287	8
	12,297		12,297	9
	1,493		1,493	10
	42,200		42,200	11
	25,506		25,506	12
	8,791		8,791	13
	498		498	14
	615		615	15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
9,958,947	**33,889,659**	**0**	**43,848,605**	

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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	04/14/2020	2019/Q4

FOOTNOTE DATA

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-Frim Point-to-Point Transmission Service

Schedule Page: 328 Line No.: 18 Column: e
11, Open Access Transmission Tariff, Unreserved Use Penalty

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp-WWP Div	NF	12,056	12,056		101,679		101,679
2	Avista Corp-WWP Div	SFP	91,749	91,749		310,760		310,760
3	Bonneville Power Admin	LFP	250,983	250,983		1,146,750		1,146,750
4	Bonneville Power Admin	SFP	420	420		4,822		4,822
5	Bonneville Power Admin	NF	3,940	3,940		20,135		20,135
6	Bonneville Power Admin	OS					236,426	236,426
7	Bonneville Power Admin	OS					5,065	5,065
8	Bonneville Power Admin	OS	45,469	45,469				
9	Bonneville Power Admin	OS	3,545	3,545				
10	Bonneville Power Admin	OS	2,699	2,699				
11	Bonneville Power Admin	OS	8,614	8,614				
12	Bonneville Power Admin	OS	5,549	5,549				
13	Bonneville Power Admin	OS					5,000	5,000
14	NorthWestern Energy	SFP	603	603		12,616		12,616
15	NorthWestern Energy	NF	260	260		6,559		6,559
16	NorthWestern Energy	OS					760	760
	TOTAL		453,446	453,446		2,585,398	259,444	2,844,842

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	PacifiCorp Inc.	LFP	8,800	8,800		712,333		712,333
2	PacifiCorp Inc.	SFP	1,496	1,496		15,396		15,396
3	PacifiCorp Inc.	NF	17,263	17,263		123,569		123,569
4	PacifiCorp Inc.	OS					34,068	34,068
5	PacifiCorp Inc.	AD					-237	-237
6	PacifiCorp Inc.	AD					-1,094	-1,094
7	PacifiCorp Inc.	AD					-20,544	-20,544
8	Puget Sound Energy, Inc	SFP				11,050		11,050
9	Seattle City Light	SFP				4,185		4,185
10	Shell Energy North Ame.	SFP				14,650		14,650
11	Snohomish County PUD	SFP				77,462		77,462
12	Tacoma Power	SFP				23,432		23,432
13								
14								
15								
16								
	TOTAL		453,446	453,446		2,585,398	259,444	2,844,842

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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
BPAT is provider for capacity reassignment settled with Shell Energy.
Schedule Page: 332 Line No.: 13 Column: b
Processing Fee for Transmission Service
Schedule Page: 332 Line No.: 16 Column: b
Ancillary Services
Schedule Page: 332.1 Line No.: 1 Column: b
Contract Expiration Date 05/31/2024
Schedule Page: 332.1 Line No.: 4 Column: b
Ancillary Services
Schedule Page: 332.1 Line No.: 5 Column: b
2016 Unreserved Use Refund
Schedule Page: 332.1 Line No.: 6 Column: b
2017 Unreserved Use Refund
Schedule Page: 332.1 Line No.: 7 Column: b
2017 PTP True-Up
Schedule Page: 332.1 Line No.: 8 Column: b
Capacity reassignment, BPAT is provider
Schedule Page: 332.1 Line No.: 9 Column: b
Capacity reassignment, BPAT is provider
Schedule Page: 332.1 Line No.: 10 Column: b
Capacity reassignment, BPAT is provider
Schedule Page: 332.1 Line No.: 11 Column: b
Capacity reassignment, BPAT is provider
Schedule Page: 332.1 Line No.: 12 Column: b
Capacity reassignment, BPAT is provider

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	550,939
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,601,473
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	127,162
6		
7	Director Fees and Expenses	
8	Annette Elg	88,061
9	Christine King	99,764
10	Dennis Johnson	91,400
11	Judith Johansen	89,106
12	Richard Dahl	164,238
13	Richard Navarro	98,105
14	Robert Tinstman	64,466
15	Ronald Jibson	82,038
16	Thomas Carlile	81,454
17	Travel & Lodging	26,289
18		
19	Corporate Memberships and Subscriptions	
20	Associated Taxpayers of Idaho	26,000
21	Bannock Development Corp	6,000
22	Boise Vallley Economic Par	25,000
23	Business Plus Inc	5,000
24	CEATI International Inc	59,500
25	Chartwell Inc	50,388
26	ESource	15,729
27	IBISWorld Inc	8,500
28	Idaho Association of Commerce	16,500
29	National Hydropower Association	93,280
30	North American Energy Standard	7,500
31	Oregon State University	15,000
32	Pacific NW Utilities	51,958
33	Southern Idaho Economic Development	5,000
34	Misc. Memberships or Subscriptions under $5000	32,038
35		
36	Chamber of Commerce and Other Civic Organizations	52,900
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	3,634,788

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

Recipient	Purpose	Amount
BLOOMBERG FINANCE LP	MISC EXPENSE	$ 24,467
BROADRIDGE FINANCIAL SOLUTIONS	MISC EXPENSE	52,168
DEUTSCHE BANK	BROKER FEES	30,000
D F KING & COMPANY INC-Proxy Printers	MISC EXPENSE	39,515
EQ SHAREOWNER SERVICES	MGMT EXPENSE	127,392
MODERN NETWORKS IR, LLC	MISC EXPENSE	11,821
NASDAQ CORPORATE SOLUTIONS LLC	MGMT EXPENSE	55,114
NEW YORK STOCK EXCHANGE I	LISTING SERVICES	66,980
OKAPI PARTNERS LLC	MGMT EXPENSE	19,800
PAYROLL RELATED	MISC EXPENSE	177,200
PR NEWSWIRE	MISC EXPENSE	18,169
RIVEL RESEARCH GROUP INC	MGMT EXPENSE	15,840
Stock based compensation	MISC EXPENSE	934,704
Travel Expense-Stock related	MISC EXPENSE	28,303
		$ 1,601,473

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

Recipient	Purpose	Amount
BANK OF NEW YORK	REVENUE BONDS	$ 7,096
INVESTIS, INC	WEBSITE DESIGN	39,959
MOODY'S ANALYTICS INC	FINANCIAL SOFTWARE	37,570
RETIREMENT RELATED EXPENSE	MISC EXPENSE	23,629
UNION BANK, N.A.	MISC EXPENSE	9,610
MISCELLANEOUS UNDER $5000	MISC EXPENSE	9,298
		$ 127,162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

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

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

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			7,169,554		7,169,554
2	Steam Production Plant	48,018,617	566,665			48,585,282
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	16,909,368				16,909,368
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	16,072,061				16,072,061
7	Transmission Plant	22,815,296				22,815,296
8	Distribution Plant	41,127,966				41,127,966
9	Regional Transmission and Market Operation					
10	General Plant	15,202,385				15,202,385
11	Common Plant-Electric					
12	TOTAL	160,145,693	566,665	7,169,554		167,881,912

B. Basis for Amortization Charges

See Footnote

Schedule Page: 336 Line No.: 1 Column:

Acct 404	Balance 1/1/2019	2019 Amortization	Balance 12/31/2019	Remaining Months
(1) Shoshone Bannock Agreement	48,000	12,000	36,000	36
(2) Mid Snake Relicensing	8,214,978	523,123	7,691,855	-
(3) Swan Falls Relicensing	4,494,488	189,908	4,304,580	272
(4) Software	17,327,222	5,961,479	19,363,826	-
(5) Shoshone Bannock ROW	2,596,400	287,899	2,308,501	96
(6) Boardman Retrofit Analysis	113,113	56,554	56,559	12
(7) FERC Compliance Costs	4,488,479	93,935	5,192,628	-
(8) Radio Frequency - Spectrum	-	44,656	3,530,819	474
Total	37,282,680	7,169,554	42,484,768	

(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 (Amoritzed over a 30 year license period; licenses expire July 31, 2034 and February 28, 2035).
(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 December 31, 2027).
(6) Boardman Retrofit Tech Analysis (Scheduled decommission date December 31, 2020).
(7) FERC License Compliance Costs (Termination date will be expiration date of the applicable FERC Licenses)
(8) Radio Frequency Spectrum (Amorized over a 40 year period beginning July 2019)

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.

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		4.40	R4.0	17.90
13	311.00	132,724	100.00	-9.00	3.09	S0.5	17.90
14	312.10	194,637	70.00	-5.00	3.46	S1.0	18.10
15	312.20	484,352	53.00	-8.00	4.90	R1.5	17.00
16	312.30	4,233	35.00	10.00	5.65	R3.0	13.50
17	314.00	151,989	45.00	-7.00	4.73	S0.5	16.50
18	315.00	57,780	60.00	-3.00	3.71	S1.5	16.80
19	316.00	12,127	35.00	2.00	4.64	S0.0	14.60
20	316.10	386	13.00	15.00	7.32	L2.0	5.40
21	316.40	253	13.00	15.00	1.46	L2.0	
22	316.50	1,163	13.00	15.00	5.56	L2.0	11.80
23	316.60	45			13.75		
24	316.70	401	21.00	15.00	0.37	S1.0	12.20
25	316.80	4,364	20.00	25.00	4.35	O1.0	17.80
26	316.90	14	35.00	15.00	2.43	S1.0	30.60
27	317.00	14,741					
28	Subtotal Steam	1,059,858					
29	331.00	208,164	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	258,829	120.00	-20.00	1.80	S1.5	31.20
32	332.30	5,472			1.15	Square	55.10
33	333.00	291,873	100.00	-10.00	1.92	R2.5	30.60
34	334.00	65,605	65.00	-10.00	2.82	R1.5	27.80
35	335.00	27,124	90.00	-5.00	2.18	R2.0	31.20
36	335.10	93	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	12,001	100.00		2.58	R3.0	22.70
40	Subtotal Hydro	889,023					
41	341.00	153,426			2.72	Square	32.80
42	342.00	10,438	50.00		2.81	S2.5	28.70
43	343.00	222,139	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	91,997	55.00		2.91	R2.0	29.30
47	346.00	6,645	35.00		3.24	R2.5	24.00
48	Subtotal Other	551,359					
49	350.20	34,942	100.00		0.89	R4.0	85.20
50	350.22	199	30.00		3.33		

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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	352.00	81,632	65.00	-33.00	1.88	R3.0	53.20
13	353.00	437,091	52.00	-10.00	1.97	S0.5	42.00
14	354.00	215,107	80.00	-10.00	1.07	R4.0	71.10
15	355.00	204,378	65.00	-80.00	2.64	R1.5	53.90
16	355.10	2,612	10.00		10.00		
17	356.00	240,483	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	1,216,834					
20	360.22	874	30.00		3.33		
21	361.00	47,761	70.00	-50.00	2.17	R3.0	54.40
22	362.00	269,468	55.00	-6.00	1.85	R1.5	42.90
23	364.00	273,345	58.00	-50.00	2.17	R1.5	44.10
24	364.10	10,172	12.00		8.34		
25	365.00	144,333	49.00	-30.00	2.65	R1.0	34.40
26	366.00	54,244	65.00	-25.00	1.89	R2.5	49.10
27	367.00	291,640	50.00	-11.00	1.90	R1.5	39.40
28	368.00	614,853	42.00	-7.00	2.17	R0.5	34.80
29	369.00	63,190	55.00	-40.00	1.58	R1.5	43.40
30	370.00	17,938	30.00	-5.00	2.05	O1.0	25.70
31	370.10	79,953	18.00	-5.00	5.39	R1.5	14.00
32	371.20	3,196	21.00	-5.00	2.88	R1.0	14.70
33	373.20	4,658	40.00	-30.00	1.73	R1.0	29.00
34	374.00						
35	Subtotal Distribution	1,875,625					
36	390.11	33,681	90.00	-3.00	2.08	S1.0	33.20
37	390.12	99,310	55.00	-3.00	2.11	R2.0	38.80
38	391.10	14,194	20.00		4.00	Square	12.30
39	391.20	25,344	5.00		20.00	Square	2.70
40	391.21	5,523	8.00		12.50	Square	3.50
41	392.10	873	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	27,743	13.00	15.00	6.20	L2.0	8.50
44	392.50	1,774	13.00	15.00	6.34	L2.0	8.90
45	392.60	45,490	21.00	15.00	3.95	S1.0	14.00
46	392.70	10,004	21.00	15.00	4.16	S1.0	12.30
47	392.90	6,589	35.00	15.00	2.24	S1.0	24.30
48	393.00	3,535	25.00		4.00	Square	17.40
49	394.00	11,670	20.00		5.00	Square	12.40
50	395.00	14,896	20.00		5.00	Square	10.60

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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	21,937	20.00	25.00	2.97	O1.0	16.70
13	397.10	2,446	15.00		6.67	Square	4.70
14	397.20	24,435	15.00		6.67	Square	8.10
15	397.30	4,285	15.00		6.67	Square	9.70
16	397.40	19,974	15.00		6.02	Square	13.10
17	398.00	7,637	15.00		6.67	Square	8.60
18	Subtotal General	385,903					
19	Total Plant	5,978,602					
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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	04/14/2020	End of 2019/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	4,326,406		4,326,406	
3					
4	General Regulatory Expenses and				
5	Various other Dockets		112,711	112,711	
6					
7	Oregon Hydro - Fees Amortization	158,501		158,501	
8					
9	Regulatory Commission Expenses - Idaho				
10	Rate Case - Misc expenses		63,470	63,470	27,719
11					
12	Regulatory Commission Expenses - Oregon				
13	Rate Case - Misc expenses		87,303	87,303	
14	General Regulatory		552,003	552,003	
15	Other OPUC expenses		20,495	20,495	
16					
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19					
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45					
46	TOTAL	4,484,907	835,982	5,320,889	27,719

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	4,326,406					2
							3
							4
Electric	928	112,711					5
							6
Electric	928	158,501					7
							8
							9
Electric	928	7,503	50,870	928203	55,967	22,622	10
							11
							12
Electric	928	87,303					13
Electric	928	552,003					14
Electric	928	20,495					15
							16
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		5,264,922	50,870		55,967	22,622	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	04/14/2020	End of 2019/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 2019.	
3		
4		
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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	04/14/2020	End of 2019/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	21,828,625		
4	Transmission	6,865,279		
5	Regional Market			
6	Distribution	17,754,666		
7	Customer Accounts	9,194,898		
8	Customer Service and Informational	4,937,487		
9	Sales			
10	Administrative and General	79,638,723		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	140,219,678		
12	Maintenance			
13	Production	4,424,027		
14	Transmission	3,147,207		
15	Regional Market			
16	Distribution	7,735,580		
17	Administrative and General	966,334		
18	TOTAL Maintenance (Total of lines 13 thru 17)	16,273,148		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	26,252,652		
21	Transmission (Enter Total of lines 4 and 14)	10,012,486		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	25,490,246		
24	Customer Accounts (Transcribe from line 7)	9,194,898		
25	Customer Service and Informational (Transcribe from line 8)	4,937,487		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	80,605,057		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	156,492,826		156,492,826
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			

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)	156,492,826		156,492,826
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	4,951,538		4,951,538
79	Other Clearing Accounts	3,800,752		3,800,752
80	Construction Work in Progress	64,149,359		64,149,359
81	Other Work in Progress	3,759,926		3,759,926
82	Other Acounts	5,182,165		5,182,165
83	Indirect Loading		46,764,986	46,764,986
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	81,843,740	46,764,986	81,843,740
96	TOTAL SALARIES AND WAGES	238,336,566	46,764,986	238,336,566

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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	04/14/2020	End of 2019/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			256,948			
2	Reactive Supply and Voltage			14,306			
3	Regulation and Frequency Response				3,295,910	KW	322,835
4	Energy Imbalance						
5	Operating Reserve - Spinning			2,755	4,310,917	KW	422,254
6	Operating Reserve - Supplement			2,310	4,310,917	KW	422,254
7	Other						
8	Total (Lines 1 thru 7)			276,319	11,917,744		1,167,343

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

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	3,283	22	900	1,579	235	973		496	
2	February	3,429	22	800	1,511	245	973		700	
3	March	3,150	5	900	629	223	973		1,325	
4	Total for Quarter 1				3,719	703	2,919		2,521	
5	April	2,782	26	800	525	198	973		1,086	
6	May	3,543	13	2000	1,480	298	973		792	
7	June	4,138	18	1900	2,565	352	973		248	
8	Total for Quarter 2				4,570	848	2,919		2,126	
9	July	4,478	12	1600	3,111	377	973		17	
10	August	4,067	15	1600	2,567	346	973		181	
11	September	4,326	5	1600	2,895	340	973		118	
12	Total for Quarter 3				8,573	1,063	2,919		316	
13	October	3,331	31	800	1,768	260	973		330	
14	November	3,269	1	900	1,781	240	973		275	
15	December	3,387	18	800	1,759	262	973		393	
16	Total for Quarter 4				5,308	762	2,919		998	
17	Total Year to Date/Year				22,170	3,376	11,676		5,961	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	14,536,714
3	Steam	3,012,385			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	8,293,793			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,850,922
7	Other	2,114,102			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	13,420,280	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	5,194,040	27	Total Energy Losses	1,146,823
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	18,534,459
12	Received	59,640			
13	Delivered	148,478			
14	Net Exchanges (Line 12 minus line 13)	-88,838			
15	Transmission For Other (Wheeling)				
16	Received	7,886,493			
17	Delivered	7,877,516			
18	Net Transmission for Other (Line 16 minus line 17)	8,977			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	18,534,459			

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

Page 329 Column I differs from page 401 by 8,977 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	04/14/2020	End of 2019/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	1,437,804	121,613	2,195	2	0900
30	February	1,582,242	375,283	2,225	7	0800
31	March	1,667,258	508,715	2,037	1	0800
32	April	1,574,313	524,562	1,781	30	0800
33	May	1,527,689	328,670	2,306	14	1700
34	June	1,665,859	189,081	2,818	17	1800
35	July	1,849,708	94,069	3,242	22	2000
36	August	1,767,923	88,582	3,201	5	2000
37	September	1,505,714	271,753	3,074	5	1800
38	October	1,265,938	121,792	2,226	30	0900
39	November	1,270,702	109,256	2,059	1	0900
40	December	1,419,309	117,546	2,256	17	0800
41	TOTAL	18,534,459	2,850,922			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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)	704			59		
7	Plant Hours Connected to Load	8760			5694		
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	2242910000			255121000		
13	Cost of Plant: Land and Land Rights	509671			106610		
14	Structures and Improvements	72850542			12628296		
15	Equipment Costs	647656399			64097916		
16	Asset Retirement Costs	9783428			5046008		
17	Total Cost	730800040			81878830		
18	Cost per KW of Installed Capacity (line 17/5) Including	948.4751			1275.3712		
19	Production Expenses: Oper, Supv, & Engr	181861			431898		
20	Fuel	74980977			6702539		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	5699367			983727		
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	6888420			982144		
27	Rents	224649			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	92916			46252		
30	Maintenance of Structures	0			35851		
31	Maintenance of Boiler (or reactor) Plant	6848631			120817		
32	Maintenance of Electric Plant	2400660			996116		
33	Maintenance of Misc Steam (or Nuclear) Plant	5919586			47821		
34	Total Production Expenses	103237067			10347165		
35	Expenses per Net KWh	0.0460			0.0406		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	1267922	5834	0	149646	935	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9343	140000	0	8608	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	55.864	97.044	0.000	42.405	87.902	0.000
41	Average Cost of Fuel per Unit Burned	58.638	78.749	0.000	44.084	95.384	0.000
42	Average Cost of Fuel Burned per Million BTU	3.138	13.393	0.000	2.577	16.356	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.033	0.000	0.000	0.026	0.000	0.000
44	Average BTU per KWh Net Generation	10578.000	0.000	0.000	10055.000	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	04/14/2020	End of 2019/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
		256			242			180	6
		3821			2076			2277	7
		0			261			164	8
		0			0			0	9
		0			0			0	10
		0			6			4	11
		514354000			294755000			317878000	12
		1106140			402745			0	13
		47245540			6031153			1783440	14
		199989898			105040745			54056780	15
		-88540			0			0	16
		248253038			111474643			55840220	17
		875.6721			411.4974			323.1494	18
		919380			149645			7798	19
		23573460			7379352			7377286	20
		0			0			0	21
		4100136			0			0	22
		0			0			0	23
		0			0			0	24
		1894278			559417			352628	25
		1324479			157792			46458	26
		0			0			0	27
		0			0			0	28
		0			0			0	29
		259350			76139			72394	30
		3562719			59119			13408	31
		681687			472835			248235	32
		57463			0			0	33
		36372952			8854299			8118207	34
		0.0707			0.0300			0.0255	35
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
282645	10257	0	3089460	0	0	3301141	0	0	38
9874	138778	0	1027	0	0	1027	0	0	39
47.571	97.372	0.000	2.389	0.000	0.000	2.235	0.000	0.000	40
79.791	97.406	0.000	2.389	0.000	0.000	2.235	0.000	0.000	41
4.041	16.711	0.000	2.880	0.000	0.000	2.690	0.000	0.000	42
0.046	0.000	0.000	0.025	0.000	0.000	0.023	0.000	0.000	43
10986.000	0.000	0.000	10764.000	0.000	0.000	10665.000	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	04/14/2020	End of 2019/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	5549			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	1501436000			0		
13	Cost of Plant: Land and Land Rights	2287261			0		
14	Structures and Improvements	145599781			0		
15	Equipment Costs	237868208			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	385755250			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	1211.3526			0		
19	Production Expenses: Oper, Supv, & Engr	511963			0		
20	Fuel	36851107			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	3483300			0		
26	Misc Steam (or Nuclear) Power Expenses	284538			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	59465			0		
31	Maintenance of Boiler (or reactor) Plant	65093			0		
32	Maintenance of Electric Plant	2119679			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	43375145			0		
35	Expenses per Net KWh	0.0289			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	11716727	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	3145.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3145.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.860	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.025	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	8014.000	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	04/14/2020	End of 2019/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)	92.34	75.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	107	72
7	Plant Hours Connect to Load	5,860	8,760
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	110	76
10	(b) Under the Most Adverse Oper Conditions	0	1
11	Average Number of Employees	4	4
12	Net Generation, Exclusive of Plant Use - Kwh	382,537,000	388,381,000
13	Cost of Plant		
14	Land and Land Rights	875,319	768,366
15	Structures and Improvements	12,090,205	1,757,779
16	Reservoirs, Dams, and Waterways	4,293,075	9,087,082
17	Equipment Costs	33,222,412	21,479,331
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	51,320,287	33,579,035
21	Cost per KW of Installed Capacity (line 20 / 5)	555.7753	447.7205
22	Production Expenses		
23	Operation Supervision and Engineering	248,887	760,110
24	Water for Power	1,808,422	593,062
25	Hydraulic Expenses	173,773	865,455
26	Electric Expenses	85,676	87,528
27	Misc Hydraulic Power Generation Expenses	364,413	619,267
28	Rents	191	4,898
29	Maintenance Supervision and Engineering	15,279	8,458
30	Maintenance of Structures	105,053	37,974
31	Maintenance of Reservoirs, Dams, and Waterways	334	10,561
32	Maintenance of Electric Plant	435,257	128,177
33	Maintenance of Misc Hydraulic Plant	131,683	195,459
34	Total Production Expenses (total 23 thru 33)	3,368,968	3,310,949
35	Expenses per net KWh	0.0088	0.0085

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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
553	12	212	6
8,760	8,753	8,760	7
			8
747	15	221	9
220	1	202	10
8	2	6	11
2,538,737,000	36,596,000	1,093,024,000	12
			13
18,400,296	82,142	1,212,767	14
40,104,551	7,328,252	14,865,098	15
67,642,337	3,145,631	31,502,551	16
114,707,578	13,486,621	22,357,195	17
1,459,263	122,668	585,876	18
0	0	0	19
242,314,025	24,165,314	70,523,487	20
371.3056	1,945.6775	371.1762	21
			22
612,510	198,222	421,957	23
371,020	165,548	222,404	24
1,171,215	465,060	720,689	25
457,772	109,654	247,867	26
660,352	305,163	442,509	27
120,989	75	19,837	28
18,551	6,646	13,102	29
29,283	3,426	47,267	30
40,181	17	17,211	31
382,274	190,453	140,422	32
414,552	116,442	402,739	33
4,278,699	1,560,706	2,696,004	34
0.0017	0.0426	0.0025	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	04/14/2020	End of 2019/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)	350	8
7	Plant Hours Connect to Load	8,728	8,755
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	2,213,314,000	148,512,000
13	Cost of Plant		
14	Land and Land Rights	2,113,754	205,376
15	Structures and Improvements	3,163,455	3,954,760
16	Reservoirs, Dams, and Waterways	53,958,676	7,356,921
17	Equipment Costs	22,638,014	16,736,415
18	Roads, Railroads, and Bridges	969,681	1,507,442
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	82,843,580	29,760,914
21	Cost per KW of Installed Capacity (line 20 / 5)	211.6056	1,367.0608
22	Production Expenses		
23	Operation Supervision and Engineering	348,267	165,453
24	Water for Power	221,174	721,716
25	Hydraulic Expenses	684,405	218,957
26	Electric Expenses	238,272	41,188
27	Misc Hydraulic Power Generation Expenses	504,401	141,872
28	Rents	32,997	0
29	Maintenance Supervision and Engineering	13,230	6,639
30	Maintenance of Structures	2,820	8,021
31	Maintenance of Reservoirs, Dams, and Waterways	87,681	29,880
32	Maintenance of Electric Plant	173,271	132,792
33	Maintenance of Misc Hydraulic Plant	354,014	121,453
34	Total Production Expenses (total 23 thru 33)	2,660,532	1,587,971
35	Expenses per net KWh	0.0012	0.0107

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	24	52	6
8,760	8,435	7,221	7
			8
91	24	53	9
84	14	50	10
5	4	2	11
495,712,000	134,329,000	147,630,000	12
			13
5,725,987	309,957	255,499	14
9,951,925	27,504,527	11,184,280	15
11,994,588	15,989,465	9,024,933	16
14,731,841	32,153,972	22,495,770	17
1,602,868	835,946	1,917,603	18
0	0	0	19
44,007,209	76,793,867	44,878,085	20
531.4880	2,826.4213	848.3570	21
			22
665,822	520,704	502,739	23
485,607	380,244	204,012	24
1,117,340	880,936	241,674	25
80,227	94,387	62,638	26
526,453	428,681	227,047	27
52,900	8,197	4,348	28
10,509	7,442	6,061	29
92,547	54,669	40,865	30
56,951	23,732	70,221	31
174,117	126,919	63,387	32
138,806	122,146	92,211	33
3,401,279	2,648,057	1,515,203	34
0.0069	0.0197	0.0103	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	04/14/2020	End of 2019/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	8,755	4,667
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	216,643,000	22,003,000
13	Cost of Plant		
14	Land and Land Rights	202,399	313,328
15	Structures and Improvements	3,142,130	7,714,668
16	Reservoirs, Dams, and Waterways	8,931,630	14,891,705
17	Equipment Costs	9,436,352	5,668,957
18	Roads, Railroads, and Bridges	29,359	115,108
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	21,741,870	28,703,766
21	Cost per KW of Installed Capacity (line 20 / 5)	630.1991	2,495.9797
22	Production Expenses		
23	Operation Supervision and Engineering	188,626	281,200
24	Water for Power	147,883	199,624
25	Hydraulic Expenses	309,391	193,011
26	Electric Expenses	136,797	72,827
27	Misc Hydraulic Power Generation Expenses	237,314	464,358
28	Rents	14	207
29	Maintenance Supervision and Engineering	10,457	2,406
30	Maintenance of Structures	52,805	30,326
31	Maintenance of Reservoirs, Dams, and Waterways	69,679	6,002
32	Maintenance of Electric Plant	214,342	30,915
33	Maintenance of Misc Hydraulic Plant	123,307	38,639
34	Total Production Expenses (total 23 thru 33)	1,490,615	1,319,515
35	Expenses per net KWh	0.0069	0.0600

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	53	60	6
0	8,753	6,159	7
			8
0	64	61	9
0	60	1	10
0	5	2	11
0	244,930,000	157,221,000	12
			13
114,368	424,428	138,100	14
50,643,369	3,521,218	10,663,927	15
13,556,785	7,769,895	17,767,002	16
2,671,666	17,765,359	29,317,474	17
142,581	88,693	501,877	18
0	0	0	19
67,128,769	29,569,593	58,388,380	20
0.0000	492.8266	982.1426	21
			22
0	496,863	302,649	23
0	252,469	807,609	24
6,795,573	452,438	296,710	25
0	206,329	58,675	26
134	428,554	355,334	27
0	4,196	3,878	28
0	5,684	4,379	29
0	81,339	25,069	30
0	26,657	4,320	31
0	44,604	83,438	32
274,264	97,491	79,873	33
7,069,971	2,096,624	2,021,934	34
0.0000	0.0086	0.0129	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	04/14/2020	End of 2019/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	2.5	17,272	3,565,864
3	Thousand Springs	1912	6.80	7.9	56,953	11,663,284
4						
5						
6	Internal Combustion:					
7	Salmon Diesel	1967	5.00	5.5	33	884,134
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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	04/14/2020	End of 2019/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	157,869		76,773			2
1,715,189	221,466		303,810			3
						4
						5
						6
176,827				Diesel		7
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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	04/14/2020	End of 2019/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	53.07		1
6	Hemingway	Midpoint	500.00	500.00	S Tower	47.76		1
7								
8	Jim Bridger	Goshen	345.00	345.00	S Tower	66.15		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	60.93		1
12	Populus	Kinport	345.00	345.00	S Tower	7.42		1
13	Jim Bridger	Populus	345.00	345.00	S Tower	61.10		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	4,768.60	11.02	211

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	16,048,838	16,305,219					1
2X1780 ACSR		446,708	446,708					2
1272 ACSR								3
1272 ACSR								4
3X1272 ACSR		18,865,237	18,865,237					5
3X1272 ACSR		17,078,077	17,078,077					6
								7
1272 ACSR	483,309	5,322,933	5,806,242					8
795 ACSR	571,979	11,257,170	11,829,149					9
1272 ACSR	344,220	4,397,073	4,741,293					10
1272 ACSR		9,535,579	9,535,579					11
1272 ACSR								12
1272 ACSR		9,261,147	9,261,147					13
1272 ACSR								14
2X1272 ACSR		585,453	585,453					15
715.5 ACSR	283,143	14,254,068	14,537,211					16
715.5 ACSR	64,851	14,921,607	14,986,458					17
715.5 ACSR	51,448	224,249	275,697					18
								19
795 ACSR	62,218	7,074,370	7,136,588					20
715.5 ACSR	9,145	999,238	1,008,383					21
1272 ACSR	108,301	3,459,620	3,567,921					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	20,742,897	22,419,735					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	7,833,438	9,581,640					29
715.5 ACSR								30
1272 ACSR	3,062,812	6,579,377	9,642,189					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
	35,480,823	662,969,892	698,450,715	7,525,410	950,539	3,934,696	12,410,645	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	04/14/2020	End of 2019/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	Bennett Mtn PP	Rattlesnake TS	230.00	230.00	SP Steel	4.39		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	31.67		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	108.67		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	10.38		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	4,768.60	11.02	211

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	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		6,611,933	6,611,933					10
715.5 ACSR	385,287	14,854,803	15,240,090					11
715.5 ACSR								12
795 ACSR	53,068	4,876,884	4,929,952					13
795 ACSR								14
VARIOUS	289,923	9,199,454	9,489,377					15
1272 ACSR	14,810	1,466,088	1,480,898					16
715.5 ACSR	227,814	18,194,010	18,421,824					17
VARIOUS								18
1272 ACSR	87,468	3,933,180	4,020,648					19
1272 ACSR	171,081	4,267,754	4,438,835					20
1272 ACSR	44,687	1,492,885	1,537,572					21
954 ACSR	184,805	6,411,734	6,596,539					22
715.5 ACSR	247,846	8,140,906	8,388,752					23
1272 ACSR	84,014	1,927,018	2,011,032					24
1272 ACSR	3,068	536,019	539,087					25
715.5 ACSR								26
1272 ACSR	7,248	427,228	434,476					27
								28
250 COPPER	375,576	3,072,644	3,448,220					29
715.5 ACSR	88,204	2,597,887	2,686,091					30
397.5 ACSR								31
397.5 ACSR		798,075	798,075					32
250 COPPER	116,873	1,320,142	1,437,015					33
250 COPPER	76,969	596,614	673,583					34
								35
	35,480,823	662,969,892	698,450,715	7,525,410	950,539	3,934,696	12,410,645	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	04/14/2020	End of 2019/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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (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	Skyway Tap		138.00	138.00	S P Steel	0.89		2
6	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	54.36		1
7	Upper Salmon	Cliff	138.00	138.00	H Wood	30.81		1
8	Eastgate	Russet	138.00	138.00	S P Wood	2.06		1
9	Brady	Fremont	138.00	138.00	S Tower	1.01		2
10	Brady	Fremont	138.00	138.00	H Wood	24.38		2
11	Brady	Fremont	138.00	138.00	S P Wood	24.33		2
12	King	Lower Malad	138.00	138.00	H Wood	84.73		2
13	Emmett Jct	Payette	138.00	138.00	H Wood	66.46		2
14	Mountain Home AFB Tap		138.00	138.00	H Wood	6.20		1
15	Ontario	Quartz	138.00	138.00	H Wood	73.20		1
16	King	American Falls PP	138.00	138.00	S Tower	0.91		2
17	King	American Falls PP	138.00	138.00	H Wood	142.16		1
18	King	American Falls PP	138.00	138.00	S P Wood	3.71		1
19	Duffin	Clawson	138.00	138.00	H Wood	6.19		1
20	American Falls	Brady Tie	138.00	138.00	H Wood	0.33		1
21	Upper Salmon A-B	King	138.00	138.00	H Wood	5.66		1
22	Upper Salmon B	Wells	138.00	138.00	H Wood	125.54		1
23	King	Wood River	138.00	138.00	H Wood	73.72		1
24	Toponis	Pocket	138.00	138.00	S P Wood	9.80		1
25	Boise Bench	Grove	138.00	138.00	S P Wood	10.37		2
26	Quartz	John Day	138.00	138.00	H Wood	67.30		1
27	Sinker Creek Tap		138.00	138.00	H Wood	2.79		1
28	Mora	Cloverdale	138.00	138.00	H Wood	2.51		1
29	Mora	Cloverdale	138.00	138.00	S P Wood	22.26		1
30	Mora	Cloverdale	138.00	138.00	S P Steel	0.96		2
31	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
32	Fossil Gulch Tap		138.00	138.00	H Wood	1.81		1
33	Wood River	Midpoint	138.00	138.00	H Wood	53.08		2
34	Wood River	Midpoint	138.00	138.00	S P Wood	16.69		2
35	Oxbow	McCall	138.00	138.00	H Wood	37.15		1
36					TOTAL	4,768.60	11.02	211

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
250 COPPER	26,507	385,066	411,573					1
250 COPPER								2
715.5 ACSR	21,327	249,232	270,559					3
795 AAC	1,798,312	5,965,067	7,763,379					4
1272 ACSR								5
795 ACSR	78,078	5,041,254	5,119,332					6
795 ACSR	43,568	2,995,670	3,039,238					7
795 AAC	270,823	561,561	832,384					8
VARIOUS	564,932	4,710,312	5,275,244					9
VARIOUS								10
VARIOUS								11
VARIOUS	76,823	3,744,888	3,821,711					12
VARIOUS	55,521	4,664,256	4,719,777					13
397.5 ACSR	5,086	81,843	86,929					14
VARIOUS	34,428	6,921,520	6,955,948					15
715.5 ACSR	216,919	11,229,578	11,446,497					16
715.5 ACSR								17
715.5 ACSR								18
4\0	4,191	475,664	479,855					19
954 ACSR		96,921	96,921					20
250 COPPER	2,741	753,925	756,666					21
VARIOUS	28,490	4,905,542	4,934,032					22
VARIOUS	186,198	24,631,195	24,817,393					23
397.5 ACSR								24
VARIOUS	225,602	1,646,308	1,871,910					25
397.5 ACSR	96,582	2,780,313	2,876,895					26
VARIOUS	11,083	133,347	144,430					27
715.5 ACSR	3,123,380	9,938,822	13,062,202					28
VARIOUS								29
795AAC								30
1272 ACSR								31
250 COPPER	450	190,553	191,003					32
397.5 ACSR	349,712	8,586,650	8,936,362					33
397.5 ACSR								34
397.5 ACSR	141,534	2,745,214	2,886,748					35
	35,480,823	662,969,892	698,450,715	7,525,410	950,539	3,934,696	12,410,645	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS

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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	Oxbow	McCall	138.00	138.00	S P Wood	2.32		1
2	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.49		2
3	Hunt	Milner	138.00	138.00	S P Wood	19.42		1
4	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.49		1
5	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.46		2
6	Pingree	Haven	138.00	138.00	S P Wood	11.72		1
7	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.20		2
8	Twin Falls	Russett	138.00	138.00	S P Wood	1.71		1
9	Blackfoot	Aiken	46.00	138.00	S P Wood	6.22		2
10	Peterson	Tendoy	69.00	138.00	H Wood	57.03		1
11	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	6.36		1
12	Kimberly Tap	Kimberly	138.00	138.00	S P Steel	1.84		2
13	Boise Bench	Mora	138.00	138.00	H Wood	13.10		2
14	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.51		1
15	Gary Lane	Eagle	138.00	138.00	S P Wood	6.65		1
16	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	9.25	2.98	1
17	Boise Bench	Butler	138.00	138.00	S P Wood	0.14	4.02	1
18	Eagle	Star	138.00	138.00	S P Wood	6.75		1
19	Star	Lansing	138.00	138.00	S P Steel	5.50		1
20	Karcher Sub	Zilog Tap	138.00	138.00	S P Steel	3.50		1
21	Zilog	Can Ada	138.00	138.00	S P Steel	1.50		1
22	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.42	4.02	1
23	Victory Jct	Victory	138.00	138.00	S P Steel	1.89		1
24	Butler	Wye	138.00	138.00	S P Steel	2.94		1
25	Horseflat	Starkey	138.00	138.00	H Wood	33.97		1
26	Starkey	Mccall	138.00	138.00	S P Steel	2.23		2
27	Starkey	Mccall	138.00	138.00	H Wood	3.80		1
28	Starkey	Mccall	138.00	138.00	S P Steel	1.50		1
29	Starkey	Mccall	138.00	138.00	S P Wood	17.61		1
30	Chestnut	Happy Valley	138.00	138.00	S P Steel	2.78		1
31	Garnet	Ward		138.00				
32	McCall	Lake Fork	138.00	138.00	S P Wood	8.89		1
33	McCall	Lake Fork	138.00	138.00	S Steel	2.90		1
34	Caldwell	Willis	138.00	138.00	S P Steel	1.30		1
35	Caldwell	Willis	138.00	138.00	S P Steel	3.62		1
36					TOTAL	4,768.60	11.02	211

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TRANSMISSION LINE STATISTICS (Continued)

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(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
397.5 ACSR								1
715.5 ACSR	211,131	1,454,879	1,666,010					2
715.5 ACSR	3,324	1,549,290	1,552,614					3
397.5 ACSR	14,927	717,475	732,402					4
715.5 ACSR	13,734	1,072,294	1,086,028					5
397.5 ACSR	18,223	1,299,173	1,317,396					6
VARIOUS	66,286	3,212,160	3,278,446					7
715.5 ACSR	16,790	213,033	229,823					8
715.5 ACSR	13,616	584,098	597,714					9
397.5 ACSR	395,696	3,593,395	3,989,091					10
715.5 ACSR	343,955	2,195,624	2,539,579					11
795 ACSR								12
715.5 ACSR	14,697	736,552	751,249					13
795 AAC		50,319	50,319					14
795 AAC	308,141	2,169,334	2,477,475					15
1272 ACSR	935,810	3,749,932	4,685,742					16
1272 ACSR	34,687	838,605	873,292					17
715.5 ACSR	619,128	6,678,554	7,297,682					18
795 AAC								19
795 AAC	43,911	672,648	716,559					20
795 AAC								21
1272 ACSR	140,412	2,577,075	2,717,487					22
1272 ACSR								23
795 ACSR	134,471	1,405,436	1,539,907					24
715.5 ACSR	2,473,833	19,006,561	21,480,394					25
715.5 ACSR								26
715.5 ACSR								27
715.5 ACSR								28
715.5 ACSR								29
1272 ACSR	78,579	2,219,508	2,298,087					30
	40,580		40,580					31
715.5 ACSR	331,539	4,682,879	5,014,418					32
715.5 ACSR								33
1272 ACSR	827,220	5,879,563	6,706,783					34
795 ACSR								35
	35,480,823	662,969,892	698,450,715	7,525,410	950,539	3,934,696	12,410,645	36

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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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Caldwell	Willis	138.00	138.00	S P Wood	0.87		1
2	Willis	Lansing	138.00	138.00	Verious	3.23		2
3	Valivue Tap		138.00	138.00	S P Steel	0.79		2
4	Bowmont	Happy Valley	138.00	138.00	S P Steel	8.65		1
5	Antelope	Scoville	138.00	138.00	H Wood	0.12		1
6	American Falls	Wheelon	138.00	138.00	H Wood	1.05		1
7	Kinport	Don #1	138.00	138.00	S Tower	1.27		2
8	Donn	HOKU	138.00	138.00	S P Steel	2.69		1
9	HOKU	Alamed	138.00	138.00	S P Steel	0.22		2
10	HOKU	Alamed	138.00	138.00	S P Steel	0.23		2
11	HOKU	Alamed	138.00	138.00	S P Steel	2.85		1
12	Eldridge tap		138.00	138.00	S P Steel	0.85		1
13	Rockland Jct	Rockland Wind Farm	138.00	138.00	S P Steel	5.18		1
14	King	Justice	138.00	138.00	S P Wood	0.07		1
15	NorthView Tap		138.00	138.00	S P Wood	6.17		1
16	Twin Falls PP Tap		138.00	138.00	H Wood	0.99		1
17	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.37		1
18	Lower Salmon	King Tie	138.00	138.00	H Wood	0.11		1
19	C J Strike	Strike Jct	138.00	138.00	S Tower	4.30		2
20	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	23.42		1
21	Strike Jct	Bowmont		138.00	H Wood	0.05		1
22	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
23	Strike Jct	Bowmont	138.00	138.00	H Wood	67.87		1
24	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.48		2
25	Bliss	King	138.00	138.00	H Wood	10.51		1
26	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.30		1
27	Swan Falls Tap		138.00	138.00	H Wood	0.95		1
28								
29								
30								
31	Hines	BPA (Harney)	115.00	115.00	H Wood	3.35		1
32								
33								
34	69 Kv Lines		69.00	69.00	H Wood	205.81		1
35	69 Kv Lines		69.00	69.00	S P Wood	878.80		1
36					TOTAL	4,768.60	11.02	211

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 ACSR								1
795 ACSR								2
795 ACSR		351,497	351,497					3
1272 ACSR	691,728	6,045,286	6,737,014					4
397.5 ACSR		94,004	94,004					5
250 COPPER		105,684	105,684					6
715.5 ACSR	1,174	273,275	274,449					7
1272 ACSR	320,323	2,188,419	2,508,742					8
1272 ACSR								9
795 ACSR								10
795 ACSR								11
795 ACSR								12
795 ACSR		-16,973	-16,973					13
1590 ACSR		60,659	60,659					14
715.5 ACSR	105,933	4,125,054	4,230,987					15
250 COPPER	58	63,264	63,322					16
715.5 ACSR		176,736	176,736					17
397.5 ACSR		4,406	4,406					18
715.5 ACSR	1,074	636,545	637,619					19
397.5 ACSR	6,332	2,566,179	2,572,511					20
715.5 ACSR	86,651	4,816,329	4,902,980					21
715.5 ACSR								22
715.5 ACSR								23
715.5 ACSR	7	287,676	287,683					24
715.5 ACSR	5,620	1,733,914	1,739,534					25
715.5 ACSR	14,968	183,606	198,574					26
397.5 ACSR	17,207	261,512	278,719					27
								28
								29
								30
397.5 ACSR	1,978	68,812	70,790					31
								32
								33
VARIOUS	1,815,538	89,169,178	90,984,716					34
VARIOUS								35
	35,480,823	662,969,892	698,450,715	7,525,410	950,539	3,934,696	12,410,645	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	04/14/2020	End of 2019/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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1								
2								
3	46 Kv Lines		46.00	46.00	S P Wood	377.97		1
4								
5	Total all lines					4,768.60	11.02	211
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
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21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	4,768.60	11.02	211

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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.
								1
								2
VARIOUS	196,503	21,147,803	21,344,306					3
				7,525,410	950,539	3,934,696	12,410,645	4
	35,480,823	662,969,892	698,450,715	7,525,410	950,539	3,934,696	12,410,645	5
								6
								7
								8
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								27
								28
								29
								30
								31
								32
								33
								34
								35
	35,480,823	662,969,892	698,450,715	7,525,410	950,539	3,934,696	12,410,645	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.: 5 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.: 6 Column: b

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Eldridge tap	Eldridge	0.85	steel LD	13.60	1	2
2	Skyway tap	Skyway	0.89	steel LD	18.70	2	2
3	Willis	Lansing	3.23	various	18.89	2	2
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
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39							
40							
41							
42							
43							
44	TOTAL		4.97		51.19	5	6

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

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

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
795	Tern	TVS-DC	138	1,035,167	539,141	733,394		2,307,702	1
1272	Bittern	TVS-DC	138	320,133	1,203,491	972,003		2,495,627	2
795	Tern	TAS & TVS	138	554,989	2,024,088	1,714,257		4,293,334	3
									4
									5
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									41
									42
									43
				1,910,289	3,766,720	3,419,654		9,096,663	44

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FOOTNOTE DATA

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

Estimated amounts are reported

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

Estimated amounts are reported

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

Estimated amounts are reported

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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	Brady	distribution	46.00	7.20	
37	Brownlee - attended	transmission	230.00	13.80	
38	Bruneau Bridge	distribution	138.00	35.00	
39	Bruneau Bridge	distribution	138.00	36.20	
40	Buckhorn	distribution	69.00	35.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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
		2				36
752	5	1				37
30	1					38
45	1					39
37	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	04/14/2020	End of 2019/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 Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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
30	1					3
90	2					4
28	1					5
225	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	04/14/2020	End of 2019/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	Eldredge	distribution	138.00	13.09	
18	Elkhorn	distribution	138.00	12.47	
19	Elkhorn	distribution	138.00	13.00	
20	Elmore	distribution	138.00	35.00	
21	Elmore	transmission	138.00	69.00	12.50
22	Elmore	transmission	138.00	69.00	12.98
23	Emmett	distribution	138.00		
24	Emmett	transmission	138.00	69.00	12.47
25	Falls	distribution	46.00	13.00	
26	Filer	distribution	46.00	13.00	
27	Flat Top	distribution	46.00	13.00	
28	Flying H	distribution	69.00	2.40	
29	Fort Hall	distribution	46.00	13.00	
30	Fossil Gulch	distribution	138.00	35.00	
31	Fremont	transmission	138.00	46.00	12.50
32	Gary	distribution	138.00	13.09	
33	Gary	distribution	138.00	13.00	
34	Gem	distribution	69.00	13.00	
35	Gem	distribution	69.00		
36	Glenns Ferry	distribution	138.00	13.00	
37	Gooding Rural	distribution	46.00	13.00	
38	Golden Valley	distribution	69.00	13.00	
39	Goshen	transmission	345.00	161.00	69.00
40	Gowen Substation	distribution	138.00	35.00	

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.
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
45	1					17
11	1					18
11	1					19
28	1					20
25	1					21
20	1					22
45	1					23
47	1					24
28	2					25
14	1					26
17	2					27
20	2					28
14	1	1				29
28	1					30
67	3	1				31
37	1					32
28	1					33
14	1	2				34
14	1					35
11	1					36
20	2					37
14	1	1				38
908	4					39
45	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	04/14/2020	End of 2019/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	Grindstone	distribution	35.00	2.40	
3	Grove	distribution	138.00	13.09	
4	Grove	distribution	138.00	13.00	
5	Hagerman	distribution	46.00	13.00	
6	Hagerman	distribution	69.00	13.00	
7	Hailey	distribution	138.00	13.00	
8	Happy Valley	distribution	138.00	13.09	
9	Haven	distribution	138.00	35.00	
10	Haven	transmission	138.00	46.00	
11	Hemingway	transmission	500.00	230.00	34.50
12	Hewlett Packard	distribution	138.00	13.00	
13	Hidden Springs	distribution	138.00	13.00	
14	Highland	distribution	138.00	13.00	
15	Hill	distribution	138.00	13.00	
16	Hillsdale	distribution	138.00		
17	Homedale	distribution	69.00	13.00	
18	Horse Flat	transmission	230.00	138.00	13.80
19	Horseshoe Bend	distribution	35.00		
20	Horseshoe Bend	distribution	69.00	36.20	
21	Horseshoe Bend	distribution	69.00	25.00	
22	Huston	distribution	69.00	13.00	
23	Hulen	distribution	46.00	13.00	
24	Hunt	transmission	230.00	138.00	13.80
25	Hydra	distribution	138.00	36.20	
26	Island	distribution	69.00	13.00	
27	Jefferson	transmission	161.00		
28	Jerome	distribution	138.00	13.00	
29	Jerome	distribution	138.00	13.09	
30	Julion Clawson	distribution	138.00	35.00	
31	Joplin	distribution	138.00	13.00	
32	Joplin	distribution	138.00	36.20	
33	Justice	transmission	230.00	138.00	13.80
34	Karcher	distribution	138.00	13.00	
35	Kenyon	distribution	69.00	13.00	
36	Ketchum	distribution	138.00	13.00	
37	Kimberly	distribution	138.00	13.09	
38	Kinport	transmission	161.00	46.00	13.20
39	Kinport	transmission	230.00	138.00	12.47
40	Kinport	transmission	230.00	138.00	13.80

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
7	1					2
90	2					3
45	1					4
14	1					5
6	1					6
37	1					7
30	1					8
20	1					9
47	1					10
1000	3	1				11
37	1					12
11	1					13
30	1					14
73	2					15
45	1					16
34	2					17
100	1					18
7	1					19
22	1					20
7	1					21
14	1					22
14	1					23
336	3					24
90	2					25
20	1					26
						27
37	1					28
37	1					29
56	2					30
28	1					31
45	1					32
300	1					33
20	1					34
25	2					35
75	2					36
45	1					37
		7				38
300	1					39
300	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	04/14/2020	End of 2019/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	Kinport	transmission	345.00	230.00	13.80
2	Kramer	distribution	138.00	35.00	
3	Kramer	distribution	138.00	36.20	
4	Kuna	distribution	138.00	13.09	
5	Lake	distribution	69.00	13.00	
6	Lake Fork	distribution	138.00	36.20	
7	Lake Fork	transmission	138.00	69.00	12.50
8	Lamb	distribution	138.00	13.00	
9	Langley Gulch- attended	transmission	230.00	138.00	13.80
10	Langley Gulch- attended	transmission	230.00		
11	Langley Gulch- attended	transmission	230.00	150.00	
12	Lansing	distribution	138.00	13.09	
13	Lincoln	distribution	138.00	13.09	
14	Linden	distribution	138.00	13.00	
15	Locust	distribution	138.00	36.20	
16	Locust	transmission	230.00	138.00	13.80
17	Lower Malad - attended	transmission	138.00	7.20	
18	Lower Salmon - attended	transmission	138.00	13.80	
19	Map Rock	distribution	69.00	13.09	
20	McCall	distribution	138.00	13.09	
21	McCall	distribution	138.00	36.20	
22	Melba	distribution	69.00	13.00	
23	Meridian	distribution	138.00	13.00	
24	Micron	distribution	138.00	13.09	
25	Micron	distribution	138.00	13.00	
26	Midpoint	transmission	230.00	138.00	13.80
27	Midpoint	transmission	345.00	230.00	13.80
28	Midpoint	transmission	500.00	345.00	
29	Midrose	distribution	138.00	13.09	
30	Milner	transmission	138.00	69.00	12.47
31	Milner	distribution	69.00	46.00	6.90
32	Milner	distribution	138.00	35.00	
33	Milner PP - attended	transmission	138.00	13.80	
34	Moonstone	distribution	138.00	35.00	
35	Mora	distribution	138.00	13.09	
36	Mora	distribution	138.00	36.20	
37	Moreland	distribution	46.00	13.00	
38	Mountain Home	distribution	69.00	13.00	
39	Mountain Home Air Force Base	distribution	69.00	13.00	
40	Mountain Home Air Force Base	distribution	138.00	13.00	

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.
1000	3	1				1
20	1					2
30	1					3
45	1					4
14	1					5
30	1					6
20	1					7
30	1					8
636	2					9
410	2					10
		1				11
45	1					12
14	1					13
58	2					14
134	3					15
600	2					16
16	1					17
70	4					18
14	1					19
22	1					20
30	1					21
11	1					22
60	2					23
40	2					24
40	2					25
200	1					26
1400	2	1				27
1500	3	1				28
45	1					29
125	3	1				30
8	3	1				31
50	2					32
60	1					33
20	1					34
45	1					35
45	1					36
28	2					37
28	1					38
		1				39
34	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	04/14/2020	End of 2019/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	transmission	230.00	138.00	13.80
2	Nampa	distribution	138.00	13.00	
3	New Meadows	distribution	138.00	36.20	
4	New Plymouth	distribution	69.00	13.00	
5	Northview	distribution	138.00		
6	Notch Butte	distribution	138.00	13.09	
7	Orchard	distribution	69.00	36.20	
8	Orchard	distribution	69.00		
9	Parma	distribution	69.00	13.00	
10	Parma	distribution	69.00	35.00	
11	Paul	distribution	138.00	35.00	
12	Paul	distribution	138.00	36.20	
13	Payette	distribution	138.00		
14	Pingree	transmission	138.00	46.00	12.50
15	Pingree	distribution	138.00	35.00	
16	Pleasant Valley	distribution	138.00	35.00	
17	Pleasant Valley	distribution	138.00	36.20	
18	Pocatello	distribution	46.00	13.00	
19	Pocket	distribution	138.00	36.20	
20	Poleline	distribution	138.00	13.09	
21	Populus	transmission	345.00		
22	Portneuf	distribution	138.00	35.00	
23	Portneuf	distribution	46.00	35.00	
24	Rockford	distribution	46.00	13.00	
25	Russett	distribution	138.00	13.00	
26	Sailor Creek	distribution	138.00	2.40	
27	Sailor Creek	distribution	138.00	35.00	
28	Salmon	distribution	69.00	13.00	
29	Salmon	distribution	69.00	34.50	12.47
30	Salmon	distribution	69.00	7.20	
31	Shoshone	distribution	46.00	13.09	
32	Shoshone	distribution	46.00	7.20	
33	Shoshone Falls - attended	transmission	46.00	4.16	
34	Shoshone Falls - attended	transmission	46.00	6.60	
35	Silver	distribution	138.00	35.00	
36	Simplot	distribution	138.00	13.00	
37	Sinker Creek	distribution	138.00	35.00	
38	Siphon	distribution	138.00	35.00	
39	Skyway	distribution	138.00	13.09	
40	South Park	distribution	46.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
300	1					1
87	3					2
22	1					3
13	1					4
45	1					5
14	1					6
8	1					7
33	1					8
14	1					9
22	1					10
30	1	1				11
45	1					12
45	1					13
67	3					14
34	2					15
30	1					16
45	1					17
60	2					18
45	1					19
30	1					20
						21
30	1					22
		1				23
25	2					24
30	1					25
21	2					26
28	1					27
14	1	4				28
10	3	1				29
		1				30
14	1					31
2	3					32
		1				33
14	1					34
20	1					35
53	2					36
20	1					37
55	2					38
45	1					39
14	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	04/14/2020	End of 2019/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	Spring Valley	distribution	138.00	12.47	
2	Star	distribution	138.00	13.09	
3	Starkey	transmission	138.00	69.00	12.47
4	State	distribution	69.00	13.00	
5	Sterling	distribution	46.00	13.00	
6	Stoddard	distribution	138.00	13.00	
7	Strike Power Plant - attended	transmission	138.00	13.80	
8	Sugar	distribution	138.00	35.00	
9	Swan Falls - attended	transmission	138.00	6.90	
10	Taber	distribution	46.00	13.00	
11	Tamarack	distribution	138.00	2.40	
12	Ten Mile	distribution	138.00	13.09	
13	Terry	distribution	138.00	13.09	
14	Terry	distribution	138.00	13.00	
15	Thousand Springs - attended	transmission	46.00	7.20	
16	Three Mile Knoll	transmission	345.00		
17	Toponis	distribution	138.00	33.00	
18	Twin Falls	distribution	138.00	13.09	
19	Twin Falls	transmission	138.00	46.00	12.98
20	Twin Falls PP - attended	transmission	138.00	7.20	
21	Twin Falls PP - attended	transmission	138.00	13.20	
22	Tyhee	distribution	46.00	13.00	
23	Upper Malad - attended	transmission	45.00	7.20	
24	Upper Salmon- attended	transmission	138.00	7.20	
25	Ustick	distribution	138.00	13.00	
26	Vallivue	distribution	138.00	13.09	
27	Victory	distribution	138.00	13.00	
28	Victory	distribution	138.00	13.09	
29	Ware	distribution	69.00	13.00	
30	Weiser	distribution	69.00	13.00	
31	Weiser	transmission	138.00	69.00	12.47
32	Wilder	distribution	69.00	13.00	
33	Willis	distribution	138.00	13.09	
34	Willow Creek	distribution	138.00	13.00	
35	Wye	distribution	138.00	13.00	
36	Wye	distribution	138.00	13.09	
37	Zilog	distribution	138.00	13.09	
38					
39					
40	The above are all State of Idaho				

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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.
11	1					1
30	1					2
30	1					3
58	2					4
11	2					5
28	1					6
104	3					7
28	2					8
34	1					9
6	1					10
11	1					11
90	2					12
20	1					13
50	2					14
8	1					15
						16
30	1					17
82	2					18
50	2					19
13	1					20
72	1					21
14	1					22
8	1					23
42	4					24
77	2					25
30	1					26
45	1					27
30	1					28
20	1	1				29
28	2	1				30
42	1					31
14	1					32
30	1					33
11	1					34
60	2					35
37	1					36
45	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) 04/14/2020	Year/Period of Report End of 2019/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	Montana:				
3	Mill Creek	transmission	230.00		
4	Peterson	transmission	230.00	69.00	13.20
5					
6	Nevada:				
7	Valmy - attended	transmission	345.00	18.00	
8	Wells	transmission	138.00	69.00	13.00
9					
10	Oregon:				
11	Adrian	distribution	69.00	13.00	
12	Boardman - attended	transmission	500.00	24.00	
13	Boardman - attended	transmission	230.00	7.20	
14	Boardman - attended	transmission	24.00	7.20	
15	Burns	transmission	500.00		
16	Cairo	distribution	69.00	13.00	
17	Hells Canyon - attended	transmission	230.00	13.80	
18	Hells Canyon - attended	distribution	69.00	0.50	
19	Hines	transmission	138.00	115.00	12.47
20	Hurricane	transmission	230.00		
21	Jacobson Gulch	distribution	69.00	2.40	
22	Malheur Butte	distribution	69.00	34.50	
23	Nyssa	distribution	69.00	13.00	
24	Ontario	distribution	138.00	13.00	
25	Ontario	transmission	138.00	69.00	12.47
26	Ontario	transmission	230.00	138.00	13.80
27	Ontario	transmission	138.00	69.00	12.98
28	Ontario	transmission	138.00	69.00	13.09
29	Ontario	transmission	138.00	69.00	12.50
30	Ore-Ida	distribution	69.00	13.00	
31	Oxbow - attended	transmission	138.00	69.00	13.00
32	Oxbow - attended	transmission	230.00	13.80	
33	Oxbow - attended	transmission	230.00	138.00	13.80
34	Quartz	transmission	138.00	69.00	12.50
35	Quartz	transmission	230.00	138.00	12.98
36	Quartz	transmission	138.00	69.00	12.98
37	Summer Lake	transmission	500.00		
38	Vale	distribution	69.00	13.00	
39					
40	Washington:				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/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
						3
30	3	1				4
						5
						6
315	1					7
25	3	1				8
						9
						10
11	1					11
685	3					12
55	1					13
55	1					14
						15
20	1					16
560	3					17
1	1					18
50	1					19
						20
11	1					21
11	3	1				22
28	2					23
67	2	1				24
47	1					25
400	2					26
93	2					27
		1				28
		1				29
28	1					30
13	3	1				31
274	2					32
100	1					33
25	1					34
167	3	1				35
20	1					36
						37
14	1					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	04/14/2020	End of 2019/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	Walla Walla	transmission	230.00		
2					
3	Wyoming:				
4	Jim Bridger - attended	transmission	345.00	22.00	34.50
5					
6					
7					
8					
9					
10	Transformers-distribution substations under 10,000				
11	KVA 61 unattended.				
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	04/14/2020	End of 2019/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
						3
2244	4					4
						5
						6
						7
						8
						9
						10
214						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.: 39 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.: 11 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.: 27 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: 426.4 Line No.: 1 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.: 28 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.: 21 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.: 16 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.: 3 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.: 7 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.: 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

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.: 15 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.: 20 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.: 37 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: 426.8 Line No.: 1 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.: 4 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 Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/14/2020	Year/Period of Report End of 2019/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	535,231
22			922000	30,432
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
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35				
36				
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38				
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40				
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	$ 61,353,717	$ 63,835,278
3	Operating Expenses			
4	Operation Expenses (401)..	8-11	36,125,371	36,138,421
5	Maintenance Expenses (402)..	8-11	3,298,438	3,497,859
6	Depreciation Expense (403)..	12	6,726,936	6,543,263
7	Amort. & Depl. of Utility Plant (404-405)...	12	297,422	287,950
8	Amort. of Utility Plant Acq. Adj. (406)..	12	621	616
9	Amort. of Property Losses, Unrecovered Plant and Regulatory.......... Study Costs (407-411)	12	(11,768)	(6,355)
10	Accretion Expense (411)...	12	9,990	10,126
11	Amort. of Conversion Expenses (407)..	12		
12	Taxes Other Than Income Taxes (408.1)...	13	2,353,520	2,380,283
13	Regulatory Debits/Credits..	14	237,316	219,223
14	Income Taxes - Federal (409.1)...	14	774,286	1,023,370
15	- Other (409.1)..	15	(188,777)	(947)
16	Provision for Deferred Inc. Taxes (410.1)...	16-23	1,057,995	1,840,748
17	(Less) Provision for Deferred Income Taxes - Cr.(411.1).................	16-23	(625,387)	(2,070,083)
18	Investment Tax Credit Adj. - Net (411.4)..	24	83,862	224,387
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)............		50,139,824	50,088,861
22	Net Utility Operating Income (Total of line 2 less 20)......................		$ 11,213,893	$ 13,746,417

ELECTRIC OPERATING REVENUES (Account 400) - STATE OF OREGON

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If previous year (columns (c), (e) and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.
4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regula used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (Se Account 442 of the Uniform System of Accounts. Exp 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..........	$ 17,082,540	$ 17,959,995	180,120	176,846	13,543	13,435	2
3	(442) Commercial and Industrial Sales							3
4	Small (or Commercial) (See Instr. 4) (1)........	18,588,524	20,244,849	215,027	222,754	5,675	5,578	4
5	Large (or Industrial) (See Instr. 4) (2)........	16,171,754	17,383,277	268,720	278,020	7	7	5
6	(444) Public Street and Highway Lighting........	148,007	136,613	904	912	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........	51,990,825*	55,724,734*	664,771 **	678,531	19,259	19,054	10
11	(447) Sales for Resale - Opportunity Non-Firm........	4,619,029	3,665,888	129,219	132,620			11
12	TOTAL Sales of Electricity........	56,609,854	59,390,623	793,990	811,152	19,259	19,054	12
13	(Less) (449.1) Provision for Rate Refunds........	-	564,308					13
14	TOTAL Revenue Net of Provision for Refunds....	56,609,854	58,826,314					
15	Other Operating Revenues							
16	(450) Forfeited Discounts........							
17	(451) Miscellaneous Service Revenues........	82,658	86,216					
18	(453) Sales of Water and Water Power........							
19	(454) Rent from Electric Property........	784,607	772,357					
20	(455) Interdepartmental Rents........							
21	(456) Other Electric Revenues........	3,876,597	4,150,391					
22								
23								
24								
25	TOTAL Other Operating Revenues........	4,743,862	5,008,964					
26	TOTAL Electric Operating Revenues........	$ 61,353,717	$ 63,835,278					

* Includes -$274,794 unbilled revenues.

** Includes -3,626 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 revenu account subheading.
3. Where the same customers are served under more than or 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	181,205	$ 17,799,864	13,542	13,381	9.82
3	03 - Residential-Mastered Metered					
4	05 - Residential - TOD	14	1,207	1		
5	15 - Dusk to Dawn customer Lighting	183	51,079			27.91
6	**Residential - Billed**	**181,402**	**17,852,150**	**13,543**	**13,395**	**9.84**
7	Residential - Unbilled	(1,282)	(184,323)			14.38
8	Bridger Depr & Boardman Decomm		(585,287)			
9	**Total 440**	**180,120**	**17,082,540**	**13,543**	**13,300**	**9.48**
10						
11	442 - Commercial and Industrial Sales:					
12	07 - General Service	19,007	2,055,863	2,587	7,347	10.82
13	09P - General Service	14,693	1,071,810	5	2,938,600	7.29
14	09S - General Service	114,747	9,321,662	911		
15	09T - General Service	3,200	207,778	1		
16	15 - Dusk to dawn customer lighting	249	56,940			22.87
17	19P - Uniform rate contracts	164,823	10,729,430	6	27,470,500	6.51
18	19S - Uniform rate contracts					
19	19T - Uniform rate contracts	105,493	6,439,578	1		
20	24S - Irrigation and soil drainage pump	63,872	6,448,488	2,169	29,448	10.10
21	40 - General Service	5	394	2	2,500	7.88
22	**Commercial & Industrial - Billed**	**486,089**	**36,331,943**	**5,682**	**85,549**	**7.47**
23	Commercial & Industrial - Unbilled	(2,342)	(90,472)			3.86
24	Bridger Depr & Boardman Decomm		(1,481,194)			
25	**Total 442**	**483,747**	**34,760,277**	**5,682**	**85,137**	**7.19**
26						
27						
28	444 - Public Street and Highway Lighting:					
29	40 - General Service					
30	41 - Municipal street lighting	883	146,489	26	33,962	16.59
31	42 - Municipal traffic control signal light	23	2,249	8	2,875	9.78
32	**Public Street & Highway lighting billed**	**906**	**148,738**	**34**	**26,647**	**16.42**
33	Public St & Highway lighting-unbilled	(2)	1			
34	Bridger Depr & Boardman Decomm		(731)			
35	**Total 444**	**904**	**148,008**	**34**	**26,588**	**16.37**
36						
37						
38						
39						
40						
41	Total Billed	668,397	52,265,619	19,259	34,706	7.82
42	Total Unbilled Rev. (See Instr. 6)	(3,626)	(274,794)			
43	TOTAL	664,771	51,990,825	19,259	34,706	7.82

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
				51,990,825		$ 51,990,825	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
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							23
							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	$ 136,673
22			
23	"	Transformer Rentals - Dist	671
24			
25	"	Line Rentals	-
26			
27	"	Cogeneration	75,125
28			
29	"	Pole Attachments	125,643
30			
31	"	Facilities Charges	410,518
32			
33	"	Other Rentals	32,845
34			
35	"	Water Lease	3,132
36			
37	"		
38	Total Account 454		$ 784,607

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	$ 82,658
7		
8	Account 456	
9		
10	Transmission for Others - Network	$ 439,882
11	Transmission - Point-to-Point and Other	1,371,784
12	Photovoltaic Station Service	-
13	DSM Rider Funds	2,057,892
14	Sierra Pacific Usage Charge	6,543
15	Antelope	-
16	Miscellaneous	496
17		
18		
19		
20	Total Account 456	$ 3,876,597
21		
22		
23		

Line No.	ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON If the amount for previous year is not derived from previously reported figures, explain in footnotes. Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	(1) POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$ 63,418	$ 49,422
5	(501) Fuel	4,770,805	5,350,133
6	(502) Steam Expenses	488,753	459,077
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	85,859	86,531
10	(506) Miscellaneous Steam Power Expenses	380,350	374,651
11	(507) Rents	9,293	10,289
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	5,798,477	6,330,103
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	5,757	8,747
16	(511) Maintenance of Structures	12,211	14,332
17	(512) Maintenance of Boiler Plant	477,374	502,354
18	(513) Maintenance of Electric Plant	184,858	210,489
19	(514) Maintenance of Miscellaneous Steam Plant	249,217	292,965
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	929,415	1,028,886
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	6,727,892	7,358,990
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 and 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	240,678	232,824
45	(536) Water for Power	274,093	374,215
46	(537) Hydraulic Expenses	607,944	631,122
47	(538) Electric Expenses	86,594	79,531
48	(539) Miscellaneous Hydraulic Power Generation Expenses	239,851	229,724
49	(540) Rents	10,454	10,119
50	TOTAL Operation (Enter Total of lines 44 thru 49)	1,459,613	1,557,534

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	$ 5,562	$ 3,836
54	(542) Maintenance of Structures	26,728	30,560
55	(543) Maintenance of Reservoirs, Dams, and Waterways	26,208	13,641
56	(544) Maintenance of Electric Plant	100,920	129,790
57	(545) Maintenance of Miscellaneous Hydraulic Plant	115,999	109,385
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	275,417	287,212
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	1,735,030	1,844,746
61	Operation		
62	(546) Operation Supervision and Engineering	27,770	26,617
63	(547) Fuel	2,339,472	818,514
64	(548) Generation Expenses	188,605	195,283
65	(549) Miscellaneous Other Power Generation Expenses	26,210	57,691
66	(550) Rents	-	-
67	TOTAL Operation (Enter Total of lines 62 thru 66)	2,582,057	1,098,105
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	-	2
70	(552) Maintenance of Structures	8,604	8,830
71	(553) Maintenance of Generating and Electric Plant	11,498	5,476
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	117,507	108,323
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	137,609	122,632
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	2,719,665	1,220,736
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	12,703,753	13,322,069
77	(556) System Control and Load Dispatching	205	219
78	(557) Other Expenses	75,552	110,667
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	12,779,510	13,432,954
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	23,962,098	23,857,426
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	131,108	136,354
84	(561) Load Dispatching	227,376	218,479
85	(562) Station Expenses	116,701	117,315
86	(563) Overhead Line Expenses	37,149	36,119
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	128,943	166,823
89	(566) Miscellaneous Transmission Expenses	-	623
90	(567) Rents	163,045	111,382
91	TOTAL Operation (Enter Total of lines 83 thru 90)	804,322	787,094
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	(1,699)	29,264
94	(569) Maintenance of Structures	50,772	43,939
95	(570) Maintenance of Station Equipment	66,969	70,714
96	(571) Maintenance of Overhead Lines	41,080	34,203
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	19	-
99	(575) Regional Market Expense - EIM	25,329	16,918
100	TOTAL Maintenance (Enter Total of lines 93 thru 98)	182,471	195,038
101	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	986,793	982,132
102	Operation		
103	(580) Operation Supervision and Engineering	184,260	193,558

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	$ 175,472	$ 165,089
106	(582) Station Expenses	61,287	65,091
107	(583) Overhead Line Expenses	303,163	287,179
108	(584) Underground Line Expenses	50,339	47,960
109	(585) Street Lighting and Signal System Expenses	2,827	7,260
110	(586) Meter Expenses	145,688	154,207
111	(587) Customer Installations Expenses	91,893	96,819
112	(588) Miscellaneous Distribution Expenses	188,754	210,092
113	(589) Rents	13,980	51,200
114	TOTAL Operation (Enter Total of lines 103 thru 113)	1,217,662	1,278,456
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	(11,532)	25,729
117	(591) Maintenance of Structures	2,535	(45)
118	(592) Maintenance of Station Equipment	158,604	186,320
119	(593) Maintenance of Overhead Lines	1,253,837	1,282,401
120	(594) Maintenance of Underground Lines	10,081	9,951
121	(595) Maintenance of Line Transformers	1,980	1,729
122	(596) Maintenance of Street Lighting and Signal Systems	11,955	27,103
123	(597) Maintenance of Meters	30,131	30,750
124	(598) Maintenance of Miscellaneous Distribution Plant	14,840	16,109
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	1,472,430	1,580,045
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	2,690,092	2,858,501
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	55,305	67,121
130	(902) Meter Reading Expenses	457,376	460,859
131	(903) Customer Records and Collection Expenses	448,590	479,938
132	(904) Uncollectible Accounts	172,510	225,836
133	(905) Miscellaneous Customer Accounts Expenses	7	(0)
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	1,133,788	1,233,754
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	38,148	42,418
138	(908) Customer Assistance Expenses	2,288,174	2,245,519
139	(909) Informational and Instructional Expenses	5,623	11,752
140	(910) Miscellaneous Customer Service and Informational Expenses	30,030	33,092
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	2,361,975	2,332,781
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	4,180,468	4,175,683
152	(921) Office Supplies and Expenses	681,934	695,269
153	(922) Administrative Expenses Transferred-Credit	(1,542,705)	(1,373,571)

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	$ 438,833	$ 364,038
156	(924) Property Insurance	141,162	123,912
157	(925) Injuries and Damages	248,936	264,068
158	(926) Employee Pensions and Benefits	2,809,072	2,742,526
159	(927) Franchise Requirements	-	-
160	(928) Regulatory Commission Expenses	858,962	897,860
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	2,176	28,383
163	(930.2) Miscellaneous General Expenses	169,129	169,472
164	(931) Rents	-	-
165	TOTAL Operation (Enter Total of lines 151 thru 164)	7,987,967	8,087,641
166	Maintenance		
167	(935) Maintenance of General Plant	301,097	284,046
168	TOTAL Administrative and General Expenses (Enter Total of lines 165 thru 167)	8,289,064	8,371,687
169	TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 80, 100, 126, 134, 141, 148, and 168)	$ 39,423,809	$ 39,636,280

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	$ 5,798,477	$ 929,415	$ 6,727,892
173	Nuclear power			
174	Hydraulic - Conventional	1,459,613	275,417	1,735,030
175	Hydraulic - Pumped Storage			
176	Other power	2,582,057	137,609	2,719,665
	Other Power Supply Expenses	12,779,510	-	12,779,510
177	Total Power Production Expenses	22,619,657	1,342,441	23,962,098
178	Transmission Expenses	804,322	182,471	986,793
179	Distribution Expenses	1,217,662	1,472,430	2,690,092
180	Customer Accounts Expenses	1,133,788	-	1,133,788
181	Customer Service and Informational Expenses	2,361,975	-	2,361,975
182	Sales Expenses	-	-	-
183	Administrative and General Expenses	7,987,967	301,097	8,289,064
184	Total Electric Operation and Maintenance Expenses	$ 36,125,371	$ 3,298,438	$ 39,423,809

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..	$ -	$ 297,422		$ 297,422
2	Steam Production Plant...	1,986,274	-		1,986,274
3	Nuclear Production Plant...				-
4	Hydraulic Production Plant - Conventional................	699,450	-		699,450
5	Hydraulic Production Plant - Pumped Storage..........				
6	Other Production Plant..	664,815	-		664,815
7	Transmission Plant...	945,697	-		945,697
8	Distribution Plant..	1,774,379	-		1,774,379
9	General Plant...	644,707	-		644,707
10	Depreciation on Disallowed Costs............................	(12,402)	-		(12,402)
11	Boardman ARO Depreciation....................................	24,017			24,017
12	ARO Accretion	9,990			9,990
13	TOTAL.................................	$ 6,736,926	$ 297,422		$ 7,034,347

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			$ 621.21
Account 411			
411.6			$ -
411.7			-
411.8 - Green Tags and Emissions			(11,768)
			$ (11,147)

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

	KIND OF TAX	Amount
1	Federal Taxes:	
2	FICA	$ 761,742
3	FUTA	4,281
4	Less: Payroll Deduction and Loading	(777,354)
5	State Taxes:	
6	Ad Valorem	1,161,316
7	Licenses - Hydro Projects	171
8	Regulatory Commission Fees	263,573
9	Franchise Taxes	851,644
10	State Unemployment Taxes	11,331
11	Hydro Generation KWH Tax	76,816
12	Canada Sales Tax	0
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23	TOTAL (Must agree with page 1, line 12.)	2,353,520

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	$ 61,353,717
2	Operations and Maintenance Expenses	39,423,809
3	Taxes Other Than Income	2,353,520
4	Regulatory Debits/Credits	237,316
5	State Income (Excise) Tax	(194,322)
6	Interest	4,059,848
7	Federal Income Tax Depreciation	6,726,936
8	Other Line items to Derive Taxable Income	9,990
9	Amortization of Limited-Term Plant	286,275
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24	Federal Tax Net Income	$ 8,450,346
25		
26		
27	Show Computation of Tax:	
28		
29	Federal Income Tax @ 21%	$ 1,774,573
30	FIN 48 Adjustment	(638,155)
31	Prior Years' Tax Adjustment	(91,599)
32	Total Federal Income Tax Before Other Adjustments	1,044,818
33		
34	Other Tax Adjustments	
35	Allowance for AFUDC	$ 1,573,016
36	Income Tax Adjustments	(2,861,267)
37	Federal Tax on Other Tax Adj @ 21%	(270,533)
38		
39	Total Federal Income Tax	$ 774,286

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	$ 61,353,717
2	Operations and Maintenance Expenses	39,423,809
3	Taxes Other Than Income	2,353,520
4	Regulatory Debits/Credits	237,316
5	Interest	4,059,848
6	State Income (Excise) Tax Depreciation	6,726,936
7		
8	Other Line Items to Derive Taxable Income	
9	Amortization of Limited-Term Plant	286,275
	ARO Accretion Expense	9,990
10	Income Tax Adjustments	3,191,098
11	Allowance for AFUDC	(1,573,016)
12	IERCO Taxable Income	(1,121,862)
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	$ 7,759,802
15		
16		
17		
18		
19	Show Computation of Tax:	
20		
21	State Taxes	(194,322)
22	Add: FIN 48 Adjustment	-
23	Prior Period Adjustment	5,545
24		
25		
26	Total Oregon State Tax	$ (188,777)

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. In the space provided:
(a) identfy, by amount and classification, significant items for which deferred taxes are being provided.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Electric			
2	Emission Allowances	$	$ -	$ -
3	Advances for Construction		0	(7,470)
4	Other Operating (See Note 1)		226,285	298,628
5				
6	Non-Operating			
7				
8				
9	Total Electric	$	$ 226,285	$ 291,159
10	Gas	$	$	$
11				
12				
13	Other			
14	Total Gas	$	$	$
15	Other Non-Electric	$	$	$
16	Total (Account 190)	$	$ 226,285	$ 291,159
17	Classification of TOTALS			
18	Federal Income Tax	$	$	$
19	State Income Tax	$	$	$
20	Local Income Tax	$	$	$
	Note 1:			
	Rate Case Disallowance		3,172	0
	Executive Deferred Compensation		4	0
	Executive Deferred Compensation Long-Term		0	0
	SFAS 112 - Post Retirement Benefits		0	(4,399)
	Non-VEBA Pension and Benefits		3,725	0
	FAS 123R - Stock Based Compensation		26	(1,244)
	Provision for Rate Refunds		0	(14,552)
	Revenue Sharing		53,782	0
	Stock Based Comp - Reserve		17,898	0
	Incentive Reserve - Deferred Only		1,792	0
	Tax Reform Regulatory Stipulation		0	(103,868)
	Valmy Union Pacific Contract		0	0
	Deferred Idaho ITC		293,677	0
	VEBA - Post Retiree Benefits		15,842	(4,978)
	Bridger Revenue Deferral		0	(6,398)
	AFUDC Hells Canyon Relicensing		14,552	(176,839)
	Reg Liability		0	0
	Reg Asset		0	0
	Unrealized Gain/Loss on Investment		(4)	(1)
	USBR-American Falls O&M Costs Settlement		374	0
	Oregon Pension Expense		0	(14,943)
	Incentive Deferral - Profit Sharing not in rates		4,087	(4,786)
	OR Reconnect Fees Adv.		0	(32)
	Asset Retirement Obligation (ARO)		0	(8,559)
	Deferred GBC Federal		(182,642)	639,227
	Retention Pay Accrual		0	0
	Total	$	$ 226,285	$ 298,628

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Continued)

(b) indicate insignificant amounts under OTHER.
3. Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited (Account 410.2)	Amounts Credited (Account 411.2)	Debits		Credits			
		Acct. No.	Amount	Acct. No.	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
$	$		$		$	$	2
							3
							4
							5
0	(21,693)						6
							7
							8
$ 0	$ (21,693)		$		$	$	9
$	$		$		$	$	10
							11
							12
							13
$	$		$		$	$	14
$ -			$		$	$	15
$ 0	$ (21,693)		$		$	$	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					
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Debits		Credits		Balance at End of Year (k)	Line No.
		Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)		
							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		$ 188,632	$ (745,267)
3	Gas			
4	Other (Define)			
5	TOTAL (Enter Total of lines 2 thru 4)		188,632	(745,267)
6	Other (Specify)			
7	FERC Jurisdictional Deferral			
8	Non-Utility Property			
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)		$ 188,632	$ (745,267)
10	Classification of TOTAL			
11	Federal Income Tax			
12	State Income Tax			
13	Local Income Tax			

Line 2:			
Depr Federal Adj		197,605	(568,611)
Intangible Asset - Labor Deductions		23,825	-
N Valmy Partnership Capitalized Items		0	-
CIAC as Taxable Income		0	(169,881)
FERC Juris-S Georgia-Acct 282 Def only		0	-
Engineering Fees		0	(6,775)
Software Costs		(32,799)	-
Total		188,632	(745,267)

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.
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
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)		643,078	(171,279)
3				
4	Total Electric......		643,078	(171,279)
5				
6				
7	Other (See Note 2)......			
8				
9				
10	Total (Account 283) (Enter Total of lines 4 - 9)....		$ 643,078	$ (171,279)
11	Classification of Total:			
12	Federal Income Tax......			
13	State Income Tax......			
14	Local Income Tax......			
	Note 1:			
	Oregon PCAM......		15	0
	Langley Revenue Accrual......		1,345	0
	PCA		0	0
	Conservation Programs......		441	0
	Oregon Excess Power Supply Costs......		0	0
	OATT Revenue Deficiency		0	0
	Emission Allowances......		0	0
	Fixed Cost Adjustment (FCA)......		0	(113,737)
	OPUC Grid West Loans......		0	0
	Intervenor Funding Orders......		110	0
	Bonus Deferral......		0	0
	Prepaid Credit Facility......		0	0
	EIM Deferral......		30	0
	REC Sales......		28,822	(35,972)
	Pension Expense......		284,399	0
	Valmy Settlement Adjust......		19,722	0
	Valmy Depreciation Adjust......		289,687	(4,201)
	Bennett Mtn Maintenance Deferral......		0	0
	Custom Efficiency Incentive Payment......		0	0
	LIDAR Surveys Deferral......		0	(467)
	Reg Asset......		0	0
	Siemens LTP Contract......		716	0
	Siemens OR DRB Interest Reserve......		0	(350)
	Boardman Decommission......		0	(13,604)
	Boardman Removal......		112	0
	PS&I Costs......		0	(1,428)
	Gain/Loss on Reacquired Debt......		17,597	0
	Prepaid Credit Facility......		0	(1,519)
	Royalty Income......		83	0
	Total......		643,078	(171,279)
	Note 2:			
	Advance Coal Royalties......			
	Unrealized Gain/Loss from Rabbi Trust......			
	Oregon Non-Operating Property Tax Adj......			
	Unrealized Gain/Loss from tax......			
	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					
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Debits Acct. No. (g)	Debits Amount (h)	Credits Acct. No. (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
0	0						2
							3
-	-		-		-		4
							5
							6
0	(1,730)						7
							8
							9
$ 0	$ (1,730)		$ -		$ -		10
							11
							12
							13
							14

0	0
0	0
0	(11)
0	0
0	(1,719)
0	(1,730)

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	$ 343,914	411.4	$ (260,052)			
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).......................................	$ 550,025,267	$ 550,025,267				
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).........................	$ 550,025,267	$ 550,025,267				
9	Leased to Others...						
10	Held for Future Use..	$ 89,977	$ 89,977				
11	Construction Work in Progress..................................	$ 54,353,112	$ 54,353,112				
12	Acquisition Adjustments...	100,845	$ 100,845				
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)....	$ 604,569,201	$ 604,569,201				
14	Accum. Prov. for Depr., Amort., & Depl......................	NOT AVAILABLE					
15	Net Utility Plant (Enter Total of line 13 less 14)………	$ 604,569,201	$ 604,569,201				
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 and						
27	Held for Future Use						
28	Depreciation..						
29	Amortization..						
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)..						
31	Abandonment of Leases (Natural Gas)........................						
32	Amort. of Plant Acquisition Adj....................................						
33	TOTAL Accumulated Provisions (Should agree with 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	247,823				488,846	(302)	3
4	(303) Miscellaneous Intangible Plant...		223,405				223,405	(303)	4
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)....................	242,253	471,228	0	0	0	713,481		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..	12,626,048	2,248				12,628,296	(311)	9
10	(312) Boiler Plant Equipment..	43,861,187	37,255				43,898,442	(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...	4,650,600					4,650,600	(315)	13
14	(316) Misc. Power Plant Equipment..	1,976,010	3,243				1,979,253	(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)..........	81,836,084	42,746	0	0	0	81,878,829		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..	11,320,290	18,046				11,338,336	(330)	27
28	(331) Structures and Improvements..	28,763,226	2,096,067	(282,312)			30,576,980	(331)	28
29	(332) Reservoirs, Dams, and Waterways..	92,295,672	23,728				92,319,399	(332)	29
30	(333) Water Wheels, Turbines, and Generators................................	27,005,885	616,532	(62,496)			27,559,921	(333)	30
31	(334) Accessory Electric Equipment...	12,750,291	1,469				12,751,760	(334)	31
32	(335) Misc. Power Plant Equipment..	6,092,191	263,081	(244,757)			6,110,515	(335)	32
33	(336) Roads, Railroads, and Bridges..	2,328,429	494				2,328,923	(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)....	180,555,983	3,019,416	(589,566)		0	182,985,833		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)	262,392,067	3,062,161	(589,566)	0	0	264,864,663		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights	4,877,532	$ 26,274	0			4,903,807	(350)	48
49	(352) Structures and Improvements	7,460,234	499,360	(1,172)			7,958,422	(352)	49
50	(353) Station Equipment	48,158,644	1,165,661	(939,802)			48,384,504	(353)	50
51	(354) Towers and Fixtures	27,109,646	176,503	14			27,286,163	(354)	51
52	(355) Poles and Fixtures	35,721,668	2,427,685	(107,224)			38,042,129	(355)	52
53	(356) Overhead Conductors and Devices	29,852,845	864,474	(93,762)			30,623,557	(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)	153,229,136	5,159,958	(1,141,945)	0	0	157,247,149		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights	196,155					196,155	(360)	60
61	(361) Structures and Improvements	1,651,398	23,432				1,674,830	(361)	61
62	(362) Station Equipment	11,094,413	(234,840)	(35,637)			10,823,936	(362)	62
63	(363) Storage Battery Equipment	0	0				0	(363)	63
64	(364) Poles, Towers, and Fixtures	21,037,917	1,368,507	(181,399)			22,225,025	(364)	64
65	(365) Overhead Conductors and Devices	9,338,059	216,851	(106,245)			9,448,665	(365)	65
66	(366) Underground Conduit	730,930	22,231	(6,314)			746,847	(366)	66
67	(367) Underground Conductors and Devices	3,909,411	158,792	(15,934)			4,052,268	(367)	67
68	(368) Line Transformers	52,618,998	2,242,807	(68,486)			54,793,320	(368)	68
69	(369) Services	2,856,606	2,995	(12,115)			2,847,485	(369)	69
70	(370) Meters	8,357,478	475,995	(109,809)			8,723,665	(370)	70
71	(371) Installations on Customer Premises	234,993	7,280	(3,854)			238,419	(371)	71
72	(372) Leased Property on Customer Premises	0					0	(372)	72
73	(373) Street Lighting and Signal Systems	211,044	3,310	(968)			213,386	(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)	112,237,401	4,287,361	(540,761)	0	0	115,984,001		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	544,421		(800)			543,621	(390)	78
79	(391) Office Furniture and Equipment	0					0	(391)	79
80	(392) Transportation Equipment	3,288,793	861,848	(61,427)			4,089,214	(392)	80
81	(393) Stores Equipment	0					0	(393)	81
82	(394) Tools, Shop and Garage Equipment	0					0	(394)	82
83	(395) Laboratory Equipment	23,962					23,962	(395)	83
84	(396) Power Operated Equipment	2,199,321	213,763	21,139			2,434,223	(396)	84
85	(397) Communication Equipment	4,097,140	44,670	(30,243)			4,111,567	(397)	85
86	(398) Miscellaneous Equipment	5,144					5,144	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86)	10,167,024	1,120,281	(71,331)	0	0	11,215,973		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)	10,167,024	1,120,281	(71,331)	0	0	11,215,973		91
92	TOTAL (Accounts 101 and 106)	538,267,881	14,100,989	(2,343,603)	0	0	550,025,267		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	538,267,881	14,100,989	(2,343,603)	-	-	550,025,267		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 colu (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				
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)........	$ 254,266,642	$ 254,266,642				
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)........	254,266,642	254,266,642				
9	Leased to Others........						
10	Held for Future Use........	$ 133,945	133,945				
11	Construction Work in Progress........						
12	Acquisition Adjustments........						
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)........	254,400,587	254,400,587				
14	Accum. Prov. for Depr., Amort., & Depl........	$ 99,891,725	99,891,725				
15	Net Utility Plant (Enter Total of line 13 less 14)........	$ 154,508,862	$ 154,508,862				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service						
18	Depreciation........	$ 98,736,821	$ 98,736,821				
19	Rights……………………..		0				
20	Amort. of Underground Storage Land and Land Rights........						
21	Amort. of Other Utility Plant........	$ 1,154,903	1,154,903				
22	TOTAL In Service (Enter total of lines 18 thru 21)........	99,891,725	99,891,725				
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).....	$ 99,891,725	$ 99,891,725				

ELECTRIC PLANT IN SERVICE

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

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

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

ELECTRIC PLANT IN SERVICE (Continued)

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. INTANGIBLE PLANT								1
2	(301) Organization	$ 237					$ 237	(301)	2
3	(302) Franchises and Consents	1,373,953					1,418,070	(302)	3
4	(303) Miscellaneous Intangible Plant	1,205,083					1,499,272	(303)	4
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	$ 2,579,272					$ 2,917,579		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)	$ 48,837,938					$ 43,275,330		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	$ 36,918,319					$ 38,094,668		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)..	$ 22,527,567					$ 22,918,457		45
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45	108,283,824					104,288,455		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights...	1,596,484					1,613,639	(350)	48
49	(352) Structures and Improvements..	3,323,896					3,377,304	(352)	49
50	(353) Station Equipment...	18,120,988					18,111,995	(353)	50
51	(354) Towers and Fixtures..	8,669,034					8,897,831	(354)	51
52	(355) Poles and Fixtures...	8,039,075					8,594,510	(355)	52
53	(356) Overhead Conductors and Devices.......................................	9,587,616					9,971,689	(356)	53
54	(357) Underground Conduit..							(357)	54
55	(358) Underground Conductors and Devices..................................							(358)	55
56	(359) Roads and Trails...	16,007					16,143	(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)........	$ 49,353,100					$ 50,583,111		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights...	171,256					170,732	(360)	60
61	(361) Structures and Improvements..	1,734,201					1,758,384	(361)	61
62	(362) Station Equipment...	10,573,321					10,314,966	(362)	62
63	(363) Storage Battery Equipment..	0					0	(363)	63
64	(364) Poles, Towers, and Fixtures...	21,037,917					22,225,025	(364)	64
65	(365) Overhead Conductors and Devices.......................................	9,338,058					9,448,665	(365)	65
66	(366) Underground Conduit..	730,930					746,847	(366)	66
67	(367) Underground Conductors and Devices..................................	3,909,411					4,052,268	(367)	67
68	(368) Line Transformers...	22,276,657					23,818,734	(368)	68
69	(369) Services..	2,856,606					2,847,485	(369)	69
70	(370) Meters...	3,148,688					3,239,520	(370)	70
71	(371) Installations on Customer Premises......................................	234,993					238,419	(371)	71

ELECTRIC PLANT IN SERVICE	ELECTRIC PLANT IN SERVICE (Continued)
(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.) 1. Report below the original cost of electric plant in service according to prescribed accounts. 2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.	3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts. 4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
72	(372) Leased Property on Customer Premises...............................							(372)	72
73	(373) Street Lighting and Signal Systems.......................................	211,044					213,386	(373)	73
74	(374) Asset Retirement Costs for Distribution Plant.......................							(374)	74
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)...........	$ 76,223,082					$ 79,074,431		75
76	5. GENERAL PLANT								76
77	(389) Land and Land Rights...	736,606					740,695	(389)	77
78	(390) Structures and Improvements..	5,293,817					5,532,073	(390)	78
79	(391) Office Furniture and Equipment..	2,013,699					1,874,390	(391)	79
80	(392) Transportation Equipment...	3,855,228					4,036,426	(392)	80
81	(393) Stores Equipment..	125,501					147,061	(393)	81
82	(394) Tools, Shop, and Garage Equipment....................................	460,592					485,454	(394)	82
83	(395) Laboratory Equipment...	568,889					619,649	(395)	83
84	(396) Power Operated Equipment..	798,494					912,536	(396)	84
85	(397) Communication Equipment...	2,155,794					2,127,346	(397)	85
86	(398) Miscellaneous Equipment..	306,232					317,684	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86)...............................	16,314,854					16,793,314		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).........	16,314,854					16,793,314		90
91	TOTAL (Accounts 101 and 106)..	252,754,132					253,656,889		91
92	(102) Electric Plant Purchased **...								92
93	(Less) (102) Electric Plant Sold **..								93
94	Asset Retirement Obligations (ARO)...	586,502					609,752		94
95	TOTAL Electric Plant in Service..	$ 253,340,634					$ 254,266,642		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	6,726,936	6,726,936		
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)	6,726,936	6,726,936		
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)	$ 6,726,936	$ 6,726,936		

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	$ 24,028,078	$ 24,028,078		
19	Nuclear Production				
20	Hydraulic Production - Conventional	18,481,064	18,481,064		
21	Hydraulic Production - Pumped Storage				
22	Other Production	5,002,996	5,002,996		
23	Transmission	15,414,525	15,414,525		
24	Distribution	30,175,506	30,175,506		
25	General	4,954,101	4,954,101		
26	FAS 143 Adj &/or Disallowed Cost	x 680,549	680,549		
27	TOTAL (Enter Total of lines 18 thru 26)	$ 98,736,821	$ 98,736,821		

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)..	$ 2,222,004	$ 2,603,828	
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)..	727,368	746,422	
8	Transmission Plant (Estimated)...	387,177	321,193	
9	Distribution Plant (Estimated)..	1,155,187	1,156,293	
10	Assigned to - Other..	(31,682)	38,294	
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)..........	2,238,048	2,262,203	
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)...........................	59,513	100,688	
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)............	$ 4,519,565	$ 4,966,719	

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	91.57	Wednesday	2	9 A.M	60 Min. Int	57,612
34	February	96.40	Thursday	7	8 A.M.	" " "	52,689
35	March	100.45	Friday	1	8 A.M.	" " "	55,745
36	April	84.82	Tuesday	30	8 A.M.	" " "	50,908
37	May	98.00	Tuesday	14	5 P.M.	" " "	54,976
38	June	113.05	Monday	17	6 P.M.	" " "	63,954
39	July	115.16	Monday	22	8 P.M.	" " "	74,693
40	August	102.12	Tuesday	6	6 P.M.	" " "	72,291
41	September	118.08	Thursday	5	6 P.M.	" " "	52,854
42	October	105.59	Wednesday	30	9 A.M.	" " "	57,109
43	November	106.01	Friday	1	9 A.M.	" " "	60,649
44	December	112.58	Tuesday	17	8 A.M.	" " "	63,714
45	TOTAL	1,243.83					717,194

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	$ 550,939	$ 25,636	$ 525,303
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	1,601,473	74,518	1,526,955
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	127,162	5,917	121,245
10	of items so grouped is shown)			
11				
12				
13	Directors' fees and expenses (see detail on page 39)	884,921	41,176	843,745
14				
15	Memberships and contributions (see detail on page 39)	470,293	21,883	448,410
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37				
38				
39	**TOTAL**	$ 3,634,788	$ 169,129	$ 3,465,659

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	$ 88,061	4,098	83,963
4	Christine King-Fees and expenses	99,764	4,642	95,122
5	Dennis Johnson - Fees and expenses	91,400	4,253	87,147
6	Judith Johansen-Fees and expenses	89,106	4,146	84,960
7	Richard Dahl - Fees and expenses	164,238	7,642	156,596
8	Richard Navarro - Fees and expenses	98,105	4,565	93,540
9	Robert A Tinstman Fees and expenses	64,466	3,000	61,466
10	Ronald Jibson - Fees and expenses	82,038	3,817	78,221
11	Thomas Carlile - Fees and expenses	81,454	3,790	77,664
12	Director Travel and Lodging	26,289	1,223	25,066
13	SUBTOTAL	884,921	41,176	843,745
14				
15	Other Expenses >$5,000:			
16	Bank of New York	$ 7,096	330	6,766
17	Investis, Inc.	39,959	1,859	38,100
18	Moody's Analytics Inc.	37,570	1,748	35,822
19	Retirement Related Expense	23,629	1,099	22,530
20	Union Bank, N.A.	9,610	447	9,163
21	Miscellaneious <$5,000	9,298	433	8,865
22	SUBTOTAL	127,162	5,917	121,245
23	Miscellaneous General Management Expenses:			
24	Bloomberg Finance LP	24,467	1,138	23,329
25	Broadridge Financial Solutions	52,168	2,427	49,741
26	Deutsche Bank Trust Co.	30,000	1,396	28,604
27	D F King & Company Inc.	39,515	1,839	37,676
28	EQ Shareholder Services	127,392	5,928	121,464
29	Modern Networks IR, LLC	11,821	550	11,271
30	NASDAQ Corporate Solutions LLC	55,114	2,564	52,550
31	New York Stock Exchange I	66,980	3,117	63,863
32	OKAPI Partners, LLC	19,800	921	18,879
33	Payroll Related Expenses	177,200	8,245	168,955
34	PR Newswire	18,169	845	17,324
35	Rivel Research Group	15,840	737	15,103
36	Stock Based Compensation	934,704	43,492	891,212
37	Travel Expense-Stock Related	28,303	1,317	26,986
38	SUBTOTAL	1,601,473	74,518	1,526,957
39				
40	Memberships and Contributions:			
41	Associated Taxpayers of Idaho	26,000	1,210	24,790
42	Bannock Development Corp.	6,000	279	5,721
43	Boise Valley Economic Par	25,000	1,163	23,837
44	Business Plus Inc.	5,000	233	4,767
45	CEATI International Inc.	59,500	2,769	56,731
46	Chamber of Commerce	52,900	2,461	50,439
47	Chartwell Inc.	50,388	2,345	48,043
48	Esource	15,729	732	14,997
49	IBISWorld Inc.	8,500	396	8,104
50	Idaho Association of Commerce	16,500	768	15,732
51	National Hydropower Association	93,280	4,340	88,940
52	North American Energy Standard	7,500	349	7,151
53	Oregon State University	15,000	698	14,302
54	Pacific NW Utilities	51,958	2,418	49,540
55	Southern Idaho Economic Development	5,000	233	4,767
56	Misc Memberships under $5,000	32,038	1,491	30,547
57	SUBTOTAL	470,293	21,883	448,410
58				
59				
60	**TOTAL**	$ 3,083,849	$ 137,577	$ 2,946,272

OFFICERS

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

2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and date change in incumbency was made.

3. Utilities which are required to file similar data with the Securities and Exchange Commission, may substitute a copy of item 4 of Regulation S-K identified as

Line No.	Title (a)	Name of Officer (b)	Salary for year Total	Salary for year Oregon
1				
2	Chief Executive Officer, Idaho Power Company (1).....................	Darrel T Anderson	$ 900,000	$ 41,878
3	President & CEO, Idaho Power Company (2)			
4				
5	President, Idaho Power Company (3)...	Lisa Grow	590,000	$ 27,453
6	Senior Vice President, COO (2)			
7				
8	Senior Vice President, CFO and Treasurer …….........................	Steven R. Keen	463,000	$ 21,544
9				
10	Senior Vice President & General Counsel...................................	Brian Buckham	385,000	17,914
11				
12	Senior Vice President & Chief Operating Officer (3)....................	Adam Richins	350,000	16,286
13	VP, Customer Operations & Bus. Development (2)			
14				
15	Senior Vice President, Public Affiars..	Jeffrey Malmen	320,000	14,890
16				
17	VP, T&D Engineering & Contstruction, and CSO (2)..................	Vern Porter	315,000	14,657
18	Vice President, Idaho Power Company (1 & 4)			
19				
20	Vice President, Power Supply..	Tessia Park	305,000	14,192
21				
22	Vice President, Corporate Controller & CAO...............................	Ken Petersen	275,000	12,796
23				
24	Vice President, Coporate Services & CIO (5)..............................	Jeff Glenn	270,000	12,563
25				
26	Vice President, Regulatory Affairs..	Tim Tatum	230,000	10,702
27				
28	Vice President, Human Resources (3)...	Sarah E. Griffin	210,000	9,771
29				
30	Vice President, Customer Operations & CSO (3)........................	Bo Hanchey	200,000	9,306
31				
32	Corporate Secretary..	Patrick Harrington	220,000	10,237
33				
34	Vice President, Corporate Services & Communications (3)........	Debra H. Leithauser	217,000	10,097
35				
36	Vice President, T&D Engineering & Contstruction (3).................	Ryan N. Adelman	190,000	8,841
37				
38				
39	(1) Title change effective 10/01/19			
40	(2) Vacated position 10/01/19			
41	(3) Appointed to position 10/01/19			
42	(4) Retirement effective 12/31/19, salary shows YTD wages			
43	(5) Retirement effective 10/01/19, salary shows YTD wages			

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
APG SIGNATURE EVENTS	426.400	5,000
BIETER FOR MAYOR	"	1,000
BOISE METRO CHAMBER	"	1,100
BRANDON WOOLF FOR STATE CONTRO	"	1,000
CADDY MCKEOWN FOR REPRESENTATI	"	500
CANYON COUNTY REPUBLICANS	"	500
CHAMBER OF COMMERCE, BOIS	"	1,150
CHUCK WINDER FOR STATE SENATE	"	1,000
CITIZENS TO ELECT CARL WILSON	"	1,000
COMMITTEE TO ELECT BETSY JOHNS	"	500
COMMITTEE TO ELECT DANIEL BONH	"	1,000
COMMITTEE TO ELECT JOHN LIVELY	"	500
COMMITTEE TO ELECT PAM MARSH	"	1,000
COMMITTEE TO RE-ELECT GREG SMI	"	1,000
FRIENDS OF BILL HANSELL	"	500
FRIENDS OF DAVID BROCK SMITH	"	1,000
FRIENDS OF DENYC BOLES	"	500
FRIENDS OF HERMAN BAERTSCHIGER	"	1,000
FRIENDS OF JANEEN SOLLMAN	"	500
FRIENDS OF KARIN POWER	"	1,500
FRIENDS OF MARK HASS	"	2,000
FRIENDS OF MICHAEL DEMBROW	"	1,000
FRIENDS OF SHELLY BOSHART DAVI	"	1,000
GRANT BURGOYNE FOR STATE SENAT	"	500
GREG BARRETO FOR HD 58	"	1,000
HOUSE REPUBLICAN CAUCUS	"	1,000
IDAHO DEMOCRATIC LEGISLATIVE C	"	250
IDAHO ENVIRONMENTAL FORUM	"	516
IDAHO LEGISLATIVE ADVISOR	"	500
IDAHO MINING ASSOCIATION	"	1,300
IDAHO PROSPERITY FUND	"	13,500
IDAHO REALTORS	"	2,000
IDAHO STATE SOCIETY	"	15,018
IDAHO VICTORY FUND PAC	"	5,000
IDAHO WATER USERS ASSOCIA	"	1,100
JACK ZIKA FOR STATE REPRESENTA	"	500
KATE BROWN FOR GOVERNOR	"	2,500
KATHLEEN TAYLOR FOR OREGON	"	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
KELLY ANTHON FOR STATE SENATE	426.400	1,000
KEN HELM FOR HD 34	"	500
LANCE CLOW FOR STATE REPRESENT	"	250
LINDA WRIGHT HARTGEN FOR STATE	"	500
LYNN FINDLEY FOR STATE REPRESE	"	500
MARTY WILDE FOR OREGON	"	500
MEGAN BLANKSMA FOR STATE REPRE	"	500
PAUL AMADOR FOR STATE REPRESEN	"	500
PETER COURTNEY FOR STATE SENAT	"	1,000
PORTLAND GENERAL ELECTRIC	"	409
SCOTT BEDKE FOR STATE REPRESEN	"	1,000
SENATE REPUBLICAN CAUCUS	"	1,000
SENATE REPUBLICAN PAC	"	1,000
TEAM BARBARA SMITH WARNER	"	1,000
WERNER RESCHKE FOR OREGON	"	500
	"	
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	"	
	"	
Total Political Contributions		**$ 80,593**

EXPENDITURES TO ANY PERSON OR ORGANIZATION HAVING AN AFFILIATED INTEREST FOR SERVICES, ETC.

INSTRUCTIONS: Report all expenditures to any person or organization having an affiliated interest for service, advice, auditing, associating, sponsoring, engineering, managing, operating, financial, legal or other services. See Oregon Revised Statute 757.015 for definition of “affiliated interest.” Give reference if such expenditures have in the past been approved by the Commission. Describe the services received and the account or accounts charged. Report whole dollars only.

Description	Account Charged	Total Amount	Amount Assigned to Oregon
Idaho Power does not have any expenditures to its affiliated companies			

INSTRUCTIONS: List all donations made by the utility during the year and the accounts charged (Items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name city and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

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

Description	Account Number	Total Amount	Amount Assigned to Oregon
IDACORP	426101	58,621	None
IDACORP EMPLOYEES	"	161,379	"
TOTAL MATCHING EMPLOYEE COMMUNITY SERVICE FUND	**426101**	**220,000**	
AMERICAN HEART ASSOCIATION	426101	7,500	None
ANDERSON,DARREL T	"	8,500	"
BOISE RESCUE MISSION	"	2,500	"
CANYON COUNTY FESTIVAL	"	4,292	"
CHILDREN'S HOME SOCIETY OF ID	"	1,250	"
FESTIVAL OF TREES	"	1,525	"
GIRL SCOUTS OF SILVER SAGE COU	"	5,000	"
IDAHO FOODBANK	"	2,750	"
IDAHO RONALD MCDONALD HOUSE	"	2,500	"
INTERFAITH SANCTUARY HOMELESS	"	1,500	"
LIFE'S KITCHEN	"	1,500	"
LION'S CLUB OF HALFWAY	"	1,000	"
NATIONAL FEDERATION OF THE BLI	"	1,000	"
ST ALPHONSUS FESTIVAL OF TREES	"	5,000	"
ST LUKES HEALTH FOUNDATION	"	9,500	"
WEST,KRISTA J	"	1,000	"
WESTERN IDAHO TRAINING CO, INC	"	1,000	"
WYAKIN WARRIOR FOUNDATION	"	2,500	"
ZBOROWSKI, DE	"	2,500	"
Misc Health & Human Services - 50 Organizations <$1,000	"	18,332	"
TOTAL HEALTH & HUMAN SERVICES	**426102**	**80,649**	
BIG BROTHERS BIG SISTERS	426103	1,250	None
BOGUS BASIN RECREATIONAL ASSOC	"	20,000	"
BOISE PHILHARMONIC ASSOCIATION	"	3,000	"
BOYS & GIRLS CLUB OF ADA CO	"	2,750	"
BOYS AND GIRLS CLUB OF MAGIC V	"	5,000	"
CHAMBER OF COMMERCE	"	20,441	"

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
COMMUNITY FORESTRY TRUST ACCOU	426103	7,000	None
FRIENDS OF ZOO BOISE	"	2,500	"
GARDEN CITY LIBRARY FOUNDATION	"	1,500	"
HERSHEL WOODY WILLIAMS	"	2,000	"
HOME PARTNERSHIP FOUNDATION	"	2,500	"
IDAHO BOTANICAL GARDEN	"	3,000	"
IDAHO COMMISSION FOR HISPANIC	"	2,000	"
IDAHO COMMUNITY FOUNDATION	"	5,000	"
IDAHO ECONOMIC DEVELOPMENT	"	4,000	"
IDAHO HORSE RESCUE	"	1,000	"
IDAHO HUMANE SOCIETY	"	2,500	"
IDAHO LAW FOUNDATION INC	"	2,500	"
IDAHO NONPROFIT CENTER	"	2,500	"
IDAHO PATRIOT THUNDER RIDE	"	1,000	"
IDAHO SALMON AND STEELHEAD DAY	"	2,500	"
JAIALDI	"	5,000	"
LAND TRUST OF THE TREASURE VAL	"	1,000	"
LIA FOUNDATION	"	1,000	"
LUPO,MARK J	"	1,269	"
MAGIC VALLEY ARTS COUNCIL	"	2,100	"
MCPAWS REGIONAL ANIMAL SHELTER	"	1,500	"
MERIDIAN, CITY OF	"	1,500	"
NAMPA, CITY OF	"	1,000	"
NEIGHBORWORKS	"	4,500	"
OLMSTEAD,DANIEL H	"	2,772	"
OXBOW FACILITIES USAGE	"	1,963	"
PEREGRINE FUND INC, THE	"	5,000	"
PERRYMAN,JACOB D	"	3,053	"
PORTNEUF GREENWAY FOUNDATION	"	1,000	"
PORTNEUF VALLEY PAINTFEST	"	1,000	"

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
ROGERSON COMMUNITY CENTER	426103	1,000	None
RONK,MEGAN A	"	2,764	"
ROTARY CLUB	"	1,000	"
SERVE IDAHO	"	1,000	"
SIMPLOT GAMES	"	2,500	"
SOUTHERN IDAHO RESOURCE,	"	1,000	"
SOUTHERN IDAHO TOURISM	"	2,000	"
STATE FINANCIAL OFFICERS FOUND	"	5,000	"
STUTZMAN,SHARON E	"	1,327	"
TREASURE VALLEY NAACP	"	1,500	"
TWIN FALLS SENIOR CENTER	"	1,000	"
WASSMUTH CENTER FOR HUMAN RIGH	"	1,250	"
WOMEN'S & CHILDREN'S ALLIANCE	"	5,000	"
Misc Civic & Community Services - 114 Organizations < $1,000	"	34,546	"
TOTAL CIVIC & COMMUNITY	**426103**	**188,485**	
BASQUE MUSEUM AND CULTURAL CEN	426104	2,500	"
BOISE ART MUSEUM	"	3,000	"
BOISE CONTEMPORARY THEATER INC	"	2,000	"
BOISE MUSIC WEEK	"	1,000	"
IDAHO SHAKESPEARE FESTIVAL	"	3,500	"
LOG CABIN LITERARY CENTER	"	2,500	"
WARHAWK AIR MUSEUM	"	2000	"
Misc Culture & Arts - 17 Organizations <$1,000	426104	8,013	"
TOTAL CULTURE & ARTS	**426104**	**24,513**	
Misc Volunteer Involvement Programs- 47 Organizations <$1,000	426106	5,300	None
TOTAL VOLUNTEER INVOLVEMENT PROGRAM	**426106**	**5,300**	
Salvation Army	426107	41,892	None
TOTAL PROJECT SHARE	**426107**	**41,892**	
IDAHO CHAPTER AMERICAN	426108	1,000	None
Misc Environment & Conservation - 10 Organizations <$1,000	426108	4,834	"

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
TOTAL ENVIROMENT & CONSERVATION	**426108**	**5,834**	
UNIVERSITY OF IDAHO FOUNDATION	426109	2,500	"
BOISE STATE UNIVERSITY	"	3,000	"
IDAHO GOVERNERS CUP	"	17,500	"
NAVAL HISTORICAL FOUNDATION	426109	75,000	"
TOTAL NON-PROGRAM	**426109**	**98,000**	"
BAKER COUNTY FAIR - HALFWAY	426110	1,373	None
BOISE PUBLIC SCHOOLS	"	3,000	"
BOISE STATE UNIVERSITY ACCOUNT	"	1,000	"
BOISE STATE UNIVERSITY COLLEGE	"	2,500	"
CHAMBER OF COMMERCE - TWIN FAL	"	1,000	"
COLLEGE OF IDAHO	"	3,500	"
COLLEGE OF SOUTHERN IDAHO	"	3,500	"
COLLEGE OF WESTERN IDAHO	"	3,500	"
COLLEGE OF WESTERN IDAHO FOUND	"	1,500	"
DISCOVERY CENTER OF IDAHO	"	2,500	"
FIRE NUGGETS INC	"	1,000	"
IDAHO STATE UNIVERSITY	"	3,000	"
IDAHO STEM ACTION CENTER	"	1,500	"
JUNIOR ACHIEVEMENT OF IDAHO	"	2,500	"
LEARNING LAB	"	1,500	"
NORTHWEST NAZARENE UNIVERSITY	"	3,500	"
ONECARD CORRECTIONS	"	1,034	"
SOCIETY OF WOMEN ENGINEERS	"	3,000	"
SP CUSTOM-LUMINAID	"	1,486	"
TREASURE VALLEY COMMUNITY COLL	"	3,500	"
WESTERN IDAHO MIDDLE SCHOOL SC	"	1,000	"
Misc Education Programs - 25 Organizations <$1,000	426110	5,800	"
TOTAL EDUCATION	**426110**	**52,194**	"
BOISE STATE UNIVERSITY	426111	4000	None

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
BRIGHAM YOUNG UNIVERSITY	426111	7,000	None
BRIGHAM YOUNG UNIVERSITY - HAW	"	2,000	"
BRIGHAM YOUNG UNIVERSITY CES A	"	6,000	"
COLLEGE OF IDAHO	"	4,000	"
COLLEGE OF SOUTHERN IDAHO	"	(1,000)	"
COLORADO CHRISTIAN UNIVERSITY	"	2,000	"
COLORADO STATE UNIVERSITY	"	2,000	"
GONZAGA UNIVERSITY	"	2,000	"
IDAHO STATE UNIVERSITY	"	1,000	"
NORTHWEST NAZARENE UNIVERSITY	"	2,000	"
TREASURE VALLEY COMMUNITY COLL	"	6,000	"
UNIVERSITY OF IDAHO	"	12,000	"
UNIVERSITY OF UTAH	"	4,000	"
WASHINGTON STATE UNIVERSITY	"	2,000	"
TOTAL SCHOLARSHIP PROGRAMS	**426111**	**55,000**	"
BOISE STATE UNIVERSITY	426112	1,500	None
BRIGHAM YOUNG UNIVERSITY	"	1,250	"
COLLEGE OF IDAHO	"	2,300	"
COLLEGE OF WESTERN IDAHO FOUND	"	1,000	"
IDAHO STATE UNIVERSITY	"	2,565	"
NORTHWEST NAZARENE UNIVERSITY	"	2,000	"
UNIVERSITY OF IDAHO FOUNDATION	"	8,600	"
Misc Higher Education Match - 5 Organizations <$1,000	"	675	"
TOTAL HIGHER EDUCATION MATCH	**426112**	**19,890**	
EEI	426120	15,000	None
TOTAL COMM & TRADE MEMBERSHIPS	**426120**	**15,000**	
MOUNTAIN HOME, CITY OF	426121	1,170	"
SNAKE RIVER ECONOMIC DEVELOPME	"	3,000	"
TWIN FALLS, CITY OF	"	1,500	"
Misc Economic Development - 10 Organizations <$1000	"	6,272	"

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
TOTAL ECONOMIC DEVELOPMENT	**426121**	**11,942**	
Chamber of Commerce	426130	1,200	None
Misc Non-Cash Contributions - 29 Organizations <$1,000	"	4,690	"
TOTAL NON-CASH CONTRIBUTIONS	**426130**	**5,890**	
UNIVERSITY OF IDAHO	426150	10,000	None
BOISE STATE UNIVERSITY	"	20,000	"
TOTAL DONATIONS - IDACORP	**426150**	**30,000**	"
TOTAL CONTRIBUTIONS ACCOUNT 426.1		**854,587**	

DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES
AND CHARGED TO OREGON OPERATING ACCOUNTS

1. Report for each service rendered (including materials furnished incidental to the service which are impracticable of separation) by recipient and in total the aggregate of all payments made during the year where the aggregate of all such payments to a recipient was $25,000 or more including fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payments for services or as donations (except rents for property, taxes, utility services, traffic settlements, amounts paid for general services and licenses, accurals paid to trustees of pension and other employee benefit funds, and amounts paid for construction or maintenance of plant to persons other than affiliates) to any one corporation, institution, association, firm, partnership, committee, or person (not an employee of the respondent). Indicate by an asterisk in column (c) each item that includes payments for materials furnished incidental to the service performed. Payments to a recipient by two or more companies within a single system under a cost sharing or other joint arrangement shall be considered a single item for reporting in this schedule and shall be shown in the report of the principal company in the joint arrangement (as measured by gross operating revenues) with references thereto in the reports of the other system companies in the joint arrangement.
2. If more convenient, this schedule may be filled out for a group of companies considered as one system and shown only in the report of the principal company in the system, with references thereto in the reports of the other companies.

	Name of Recipient (a)	Nature of Service (b)	Amount of Payment Allocated to Oregon (c)
1	AGREE TECHNOLOGIES AND SOLUTIO	Energy Efficiency Services	$ 1,556
2	ALLPHIN, RANDY C	Consulting Services	2,048
3	ANDERSEN SCHWARTZMAN WOODARD	Legal Services	15,148
4	BAKER BOTTS LLP	Legal Services	1,559
5	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	60,377.05
6	CGI TECHNOLOGIES AND SOLUTIONS	IT Services	17,984
7	CLEAREDGE PARTNERS INC	Training Consultants	3,490
8	COMPUNET, INC	IT Services	2,263
9	DAVIS WRIGHT TREMAINE LLP	Legal Services	29,607
10	DNV GL ENERGY INSIGHTS USA, IN	Energy Efficiency Services	2,057
11	EQ SHAREOWNER SERVICES	Management Services	5,928
12	EVERGREEN CONSULTING GROUP, LL	Management Services	18,472
13	GIVENS PURSLEY LLP	Legal Services	3,016
14	HOLLAND & HART LLP	Legal Services	18,519
15	HONEYWELL INTERNATIONAL INC	Management Services	1,565
16	ICEBERG NETWORKS CORPORATION	IT Services	2,006
17	INFORMATICA, CORP	Data Services	1,881
18	INTELLITECT	Management Services	2,173
19	ITRON, INC.	IT Services	2,504
20	JCMB TECHNOLOGY	IT Services	1,452
21	J M ROCHE AND ASSOCIATES	Communication Services	5,520
22	JENSEN HUGHES	Engineering Services	1,331
23	KW ENGINEERING INC	Engineering Services	2,536
24	MCDOWELL RACKNER & GIBSON PC	Legal Services	32,803
25	MEDIANT COMMUNICATIONS INC	Communication Services	1,461
26	MICROSOFT CORP	IT Services	9,294
27	MORROW & FISCHER PLLC	Legal Services	1,738
28	NAVIGANT CONSULTING INC	Management Services	2,209.01
29	NETSKOPE PROFESSIONALS	Training Consultants	1,430
30	NIELSEN GROUP INC, THE	IT Services	7,453
31	PARSONS BEHLE & LATIMER	Legal Services	1,485
32	PERKINS COIE LLP	Legal Services	35,816
33	PLANNEDSCAPE	IT Services	1,303
34	QUALITY COMMUNICATIONS INC	Communication Services	2,416
35	QUINTEL-MC INC	IT Services	115,015
36	REED HARRIS ENVIRONMENTAL LTD	Environmental Services	2,078
37	RESOURCE DATA, INC	IT Services	24,444
38	RM ENERGY CONSULTING	Management Services	13,444
39	STOEL RIVES LLP	Legal Services	1,166
40	TETRA TECH MA INC	IT Services	1,442
41	TRINOOR LLC	HR Consulting	2,305
42	U S GEOLOGICAL SURVEY	Environmental Services	8,088
43	UNIVERSITY OF IDAHO	Management Services	19,200
44	VAN NESS FELDMAN	Legal Services	30,816
45	ZASIO ENTERPRISES INC	Management Services	3,443
	TOTAL		$ 521,843

2019

SUSTAINABLE GROWTH

Annual Report

IDACORP®

2019 ANNUAL REVIEW

Cascade Spillway, Cascade, Idaho

Content

Highlights

Dollar Amounts in Thousands, Except Per-share Amounts

	2019	2018	% CHANGE
Total Operating Revenues	$1,346,383	$1,370,752	-1.78
Net Income	$232,854	$226,801	2.67
Earnings Per Diluted Common Share	$4.61	$4.49	2.67
Dividends Declared Per Common Share	$2.56	$2.40	6.67
Total Assets	$6,641,201	$6,382,754	4.05
Number of Employees (full-time)	1,985	1,981	0.02

As we look back on 2019, we are struck by the unique position our company occupies within the energy industry.

During a time when utilities are faced with challenges and uncertainty, IDACORP continues to thrive. Thanks to sustained customer growth, effective cost management and the hard work of our dedicated employees, IDACORP just delivered its 12th consecutive year of earnings growth. This is an incredible achievement. To our knowledge, it is an unprecedented feat among investor-owned utilities in the recent past.

In addition to sustained financial growth, IDACORP's principal operating subsidiary, Idaho Power, continues to perform as an industry leader on multiple fronts. In 2019, Idaho Power enjoyed record-setting metrics in employee safety and customer satisfaction, along with outstanding reliability numbers. We also announced an exciting new goal — to power our customers with 100% clean energy by 2045. Idaho Power embarks on this goal without any mandate from a government entity, which makes it virtually unprecedented among our peers. But we think it's the right thing to do, and we believe we can achieve a clean energy future while working to sustain the fair prices and excellent reliability our customers expect.

To understand our sustained success, we can look to our past. For more than a century, Idaho Power has provided reliable, affordable, clean energy to its customers. Our work in recent years has built on that foundation and established our company as a clean energy leader. Carbon emissions have decreased 46% since 2005. In 2013, coal provided 38.8% of our energy — it has decreased every year since, down to 16.3% in 2019. Meanwhile, our hydropower facilities on the Snake River and its tributaries help us generate clean energy that helps both the environment and our customers' energy prices.

Financial stewardship is another hallmark of our 100-year history. In 2019, IDACORP officers and board members joined us in ringing the New York Stock Exchange (NYSE) Closing Bell® as we celebrated 75 years on the NYSE. At that time, fewer than 85 companies had been listed on the NYSE for 75 or more consecutive years — another noteworthy achievement for our company and employees. This success and our continued growth would not be possible without wise financial management across our enterprise.

How will we work to sustain this success? By continuing to lead and innovate with creative solutions, including the new transmission lines that will create clean-energy pipelines across the West. By continuing to put our customers first as we power their lives with a product we can all be proud of. And by embracing advancing technology and the incredible growth happening within our service area. We are fortunate to do business in our nation's fastest-growing state, and the energy we provide plays a vital role in powering a thriving, diverse economy in the communities we call home.

These and many other notable accomplishments are further detailed in this *2019 Annual Report*. We thank our nearly 2,000 employees for their incredible work this past year. On their behalf, we also thank you for your continued support of IDACORP.

Darrel T. Anderson
President & Chief Executive Officer, IDACORP

Lisa Grow
President, Idaho Power

Richard J. Dahl
Chairperson of the Board

Overview

IDACORP enjoyed another record-setting year in 2019. The company achieved its 12th consecutive year of growth in earnings per share — an achievement we believe is unprecedented among investor-owned utilities in the United States — while net income increased by more than $6 million compared to 2018.

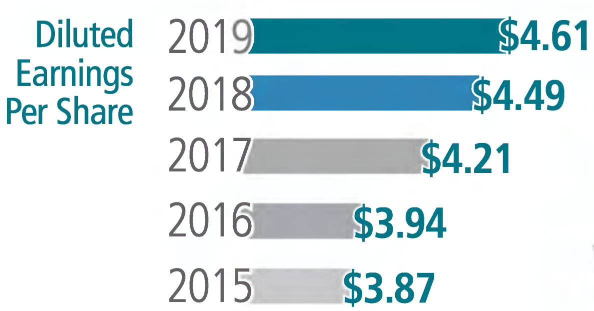
IDACORP's principal operating subsidiary, Idaho Power, continued to benefit from strong customer growth and effective cost management. Coupled with good performance across its other subsidiaries, IDACORP was able to achieve earnings growth while again preserving the full $45 million of tax credits available for future earnings support under Idaho's regulatory stipulation.

In addition to financial success, Idaho Power set records across several important metrics. Safety is a key value for our company, and 2019 saw the best employee safety results Idaho Power has ever recorded. Residential and business customer satisfaction scores also reached an all-time high, while our reliability numbers were just slightly behind the record performance achieved in 2018.

Idaho Power also launched an exciting goal of providing 100% clean energy by 2045. The company's *Clean Today, Cleaner Tomorrow®* plan builds on its long history as a clean-energy leader. With nearly half of our energy today coming from clean hydropower, and with a plan to move away from coal-fired generation already in motion as we exited North Valmy unit 1 in 2019, we believe we can achieve this goal while continuing to provide reliable energy at some of the lowest prices in the nation.

Earnings Guidance

We ended 2019 with earnings of $4.61 per diluted share, and on February 20, we initiated earnings guidance for the full year 2020 in the range of $4.45 to $4.65 per diluted share.



Downtown Boise

Clean Energy Goal

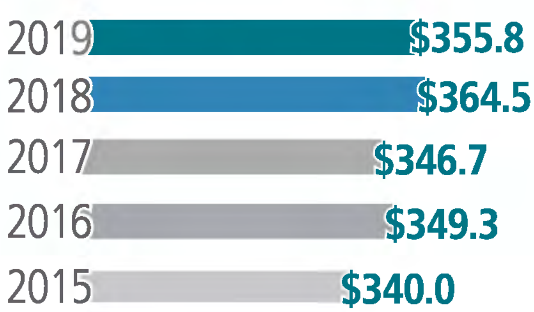
In March 2019, Idaho Power unveiled its goal to provide 100% clean energy by 2045. The *Clean Today, Cleaner Tomorrow®* plan will strive to build on the company's 100-year history of providing reliable service and clean energy at some of the lowest prices in the nation.

Idaho Power is one of the first publicly owned energy companies to set a clean-energy goal without a government mandate. Today, nearly half of Idaho Power's energy comes from hydropower, while the company also purchases energy from clean sources like wind, solar and small hydropower facilities. To achieve the goal, the company plans to continue its path away from coal-fired generation and invest in storage and additional clean generation sources — including a recently approved contract to buy 120 megawatts (MW) of energy from a new solar project in southern Idaho.

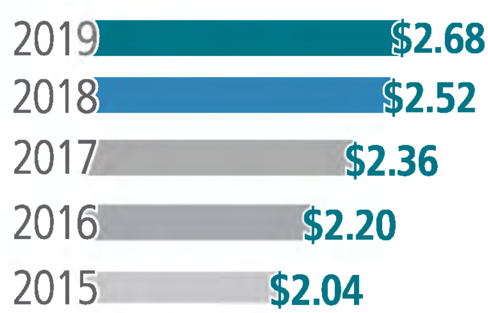
Dividend Growth

In 2019, IDACORP's quarterly common stock dividend increased from $0.63 per share to $0.67 per share. In November, the company announced a new policy that provides for a target long-term dividend payout ratio between 60 and 70% of sustainable IDACORP earnings. It is the first change to the dividend policy since 2011, when the long-term payout ratio was increased to between 50 and 60% of sustainable earnings. In determining future dividend actions, IDACORP's Board of Directors will continue to consider factors, such as current and projected capital requirements, the company's liquidity position and earnings, the competitiveness of the dividend yield, business cycles, credit rating impacts, legal requirements, long-term sustainability and other factors.

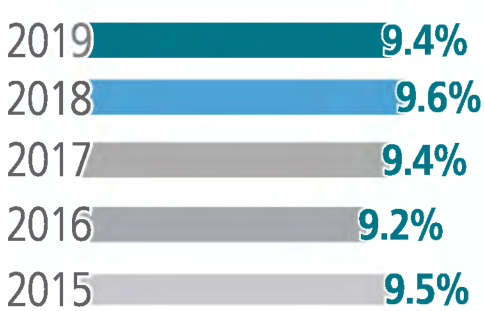
Operations & Maintenance Expenses in millions



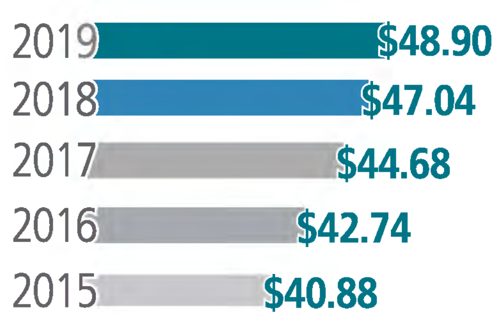
Annualized Year-End Dividend Per Share



Return on Year-End Equity



Book Value Per Share

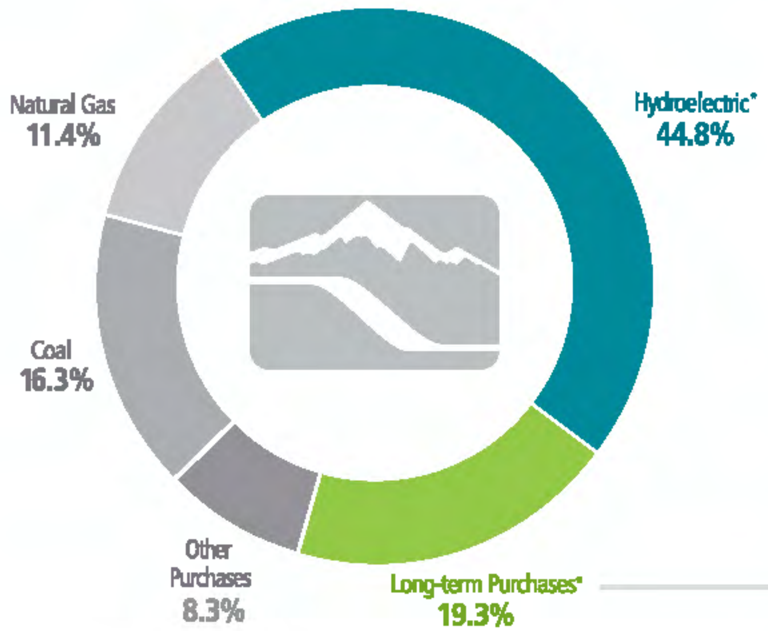


17 HYDROELECTRIC PROJECTS

Clean Energy Mix

Idaho Power's clean energy mix relies heavily on hydropower produced by our 17 projects on the Snake River and its tributaries. Hydropower once again accounted for the largest portion (44.8%) of our energy mix in 2019, while purchased power made up 27.6%. The remainder came from coal, which declined for the sixth consecutive year to 16.3%, and natural gas, which increased slightly to 11.4%.

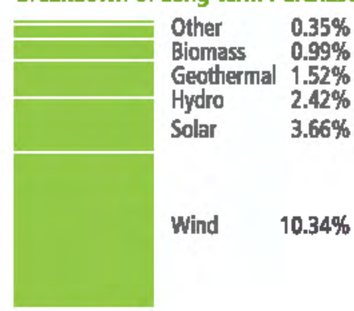
2019 Energy Mix



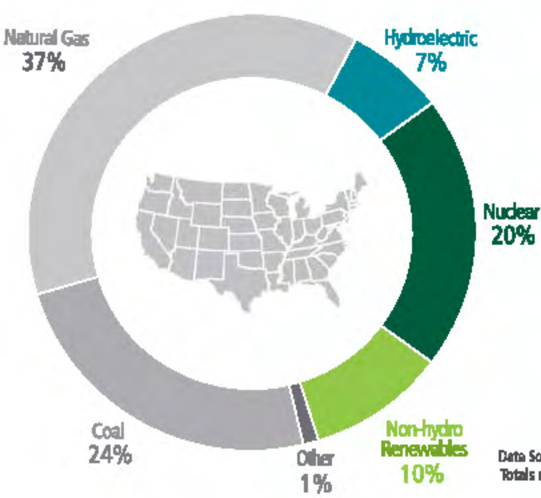
*About the sale of renewable energy credits:

Idaho Power sells the Renewable Energy Credits (REC) associated with our renewable energy purchases on Long-term Purchases and a small portion of our hydro generation to offset power supply costs and keep customer prices as low as possible. The buyer of the REC claims the renewable attributes of that energy; therefore, Idaho Power does not represent that this resource mix represents the energy delivered to our customers.

Breakdown of Long-term Purchases



National Average



Data Source: U.S. Energy Information Administration
Totals may not equal 100% due to rounding.

Hells Canyon

Idaho Power continues to make progress toward renewing a long-term federal license for the three-dam Hells Canyon Complex, the company's largest generation resource. In May 2019, we reached a major milestone when the states of Idaho and Oregon certified the company's plan for meeting water-quality standards in the Snake River.

Under the plan, Idaho Power commits to a wide range of water-quality improvement measures, including projects to narrow and deepen key stretches of the Snake River to reduce water temperature and improve river function. Working with landowners, the company has begun planting thousands of native trees and shrubs along tributaries of the Snake River to provide shade, which is expected to lower stream temperatures. Additional steps include funding for pressurized sprinkler irrigation to reduce runoff from agricultural land; equipment to increase the oxygen in water released from Brownlee Dam; and spillway modifications to minimize dissolved gases. The company is also continuing its 10-year study of mercury levels in Brownlee and Hells Canyon reservoirs in coordination with the U.S. Geological Survey.

High-voltage Transmission Projects

We made solid progress on the Boardman to Hemingway project (B2H), in 2019. In May, the Oregon Department of Energy recommended approval of the 300-mile line. Shortly afterward, the Oregon Energy Facility Siting Council held public hearings on the project in each of the five eastern Oregon counties the line is planned to cross. The department is expected to release a proposed order — the next step in the permitting process — authorizing the transmission line in 2020. Construction is projected to begin in 2023, with the line in service in 2026 or later.

The Gateway West project is also progressing. Though Idaho Power doesn't have a schedule for building its portion of the line, PacifiCorp efforts to build early segments in Wyoming are under way. Idaho Power will continue to coordinate its involvement in Gateway West with PacifiCorp to meet customer and system needs.

Renewables & Jackpot Solar

Idaho Power's 100% clean energy goal relies partly on energy purchased from renewable generation sources including wind, solar, biomass, geothermal and small hydropower. Idaho Power has significant contracts to purchase power from Public Utility Regulatory Policies Act (PURPA) Qualifying Facilities as well as non-PURPA power purchase agreements — the largest currently on-line is the Elkhorn Valley wind project with a 101-MW nameplate capacity.

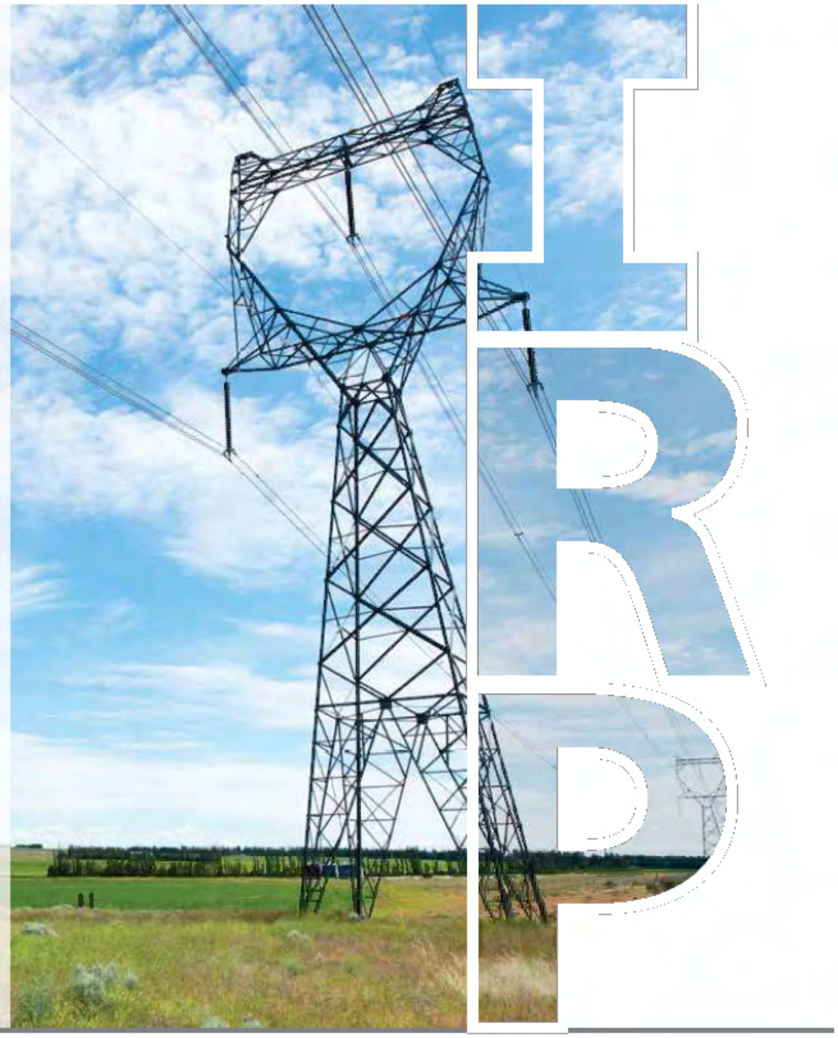
In 2019, Idaho Power entered a new contract to buy 120 MW of energy from Jackpot Solar, an Idaho company that plans to build a large solar-generation resource in southern Idaho. The clean energy will come at a price that is among the lowest in the nation for solar energy, starting at 2.175¢ per kW. Idaho Power's 20-year contract was approved by the Idaho Public Utilities Commission, and the project is expected to come on-line in 2022.

Boise Solar Project

2019 Integrated Resource Plan

Idaho Power plans for infrastructure that will support anticipated growth and allow the company to continue to produce reliable, affordable, clean energy for its customers. Every two years Idaho Power updates its Integrated Resource Plan (IRP), with the participation of the IRP Advisory Council.

Idaho Power submitted its initial 2019 IRP to the public utility commissions in Idaho and Oregon in June. We amended the plan in early 2020. The company's preferred energy mix calls for ending Idaho Power's participation in coal-fired operations that Idaho Power co-owns in 2030, including exiting five of seven coal-fired generating units by the end of 2026. Bringing the B2H transmission project on-line in 2026 or sometime thereafter will add to the company's available resources, which will be needed to serve an expected increase of approximately 10,900 customers each year during the next two decades. The company projects peak load — the period in the summer when demand is highest — will grow an average of 50 MW per year, and the energy needed for average load will increase more than 20 MW per year.



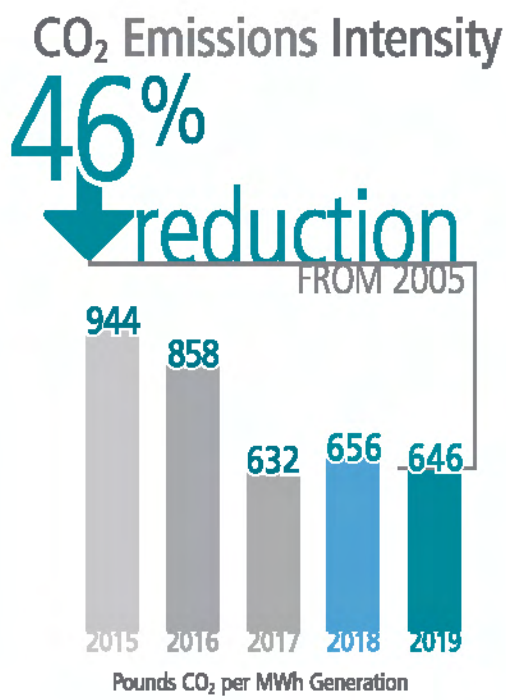
Path Away from Coal

Idaho Power remains on a path away from coal-fi red energy generation as it moves toward a 100% clean energy future. In 2019, as planned, the company ended its participation in unit 1 of the North Valmy plant in Nevada; we also have an agreement to exit unit 2 by 2025.

In addition to North Valmy, the Boardman plant in Oregon is scheduled to cease coal-fired operations in 2020. Idaho Power owns 10% of the 600 MW Boardman plant. In both cases, Idaho Power has state public utility commission support for a cost recovery framework to be applied through the end of the plants' useful life.

The third and final coal plant Idaho Power co-owns is Jim Bridger in Wyoming. The company owns one-third, while PacifiCorp owns two-thirds. We continue to explore options with PacifiCorp as we plan the appropriate end-of-life for the entire Jim Bridger plant.

Idaho Power's coal-fired generation has decreased for six consecutive years. As recently as 2013, coal was our largest energy source at 38.8%. Today, that number is 16.3%.



Social & Environmental Responsibility

Reducing coal-fired generation and committing to a clean energy future advance the path Idaho Power has been on for many years. The company continues to exceed its carbon-reduction goals, with 2019 absolute carbon dioxide (CO_2) emissions intensity levels at 646 pounds per MWh of generation — 46% below our baseline year of 2005. Our 100% clean energy goal and long-term resource planning will continue CO_2 reductions in the future.

Environmental stewardship remains a key initiative for Idaho Power. The company recently joined the Southern Idaho Water Quality Coalition, where we are working with cities, businesses, irrigators and other water users to find ways to improve the health of the Snake River. Other ongoing work includes energy efficiency programs, the Bayha and Rippee Island projects, efforts to protect birds of prey, and hatchery programs to boost populations of anadromous steelhead and Chinook salmon.

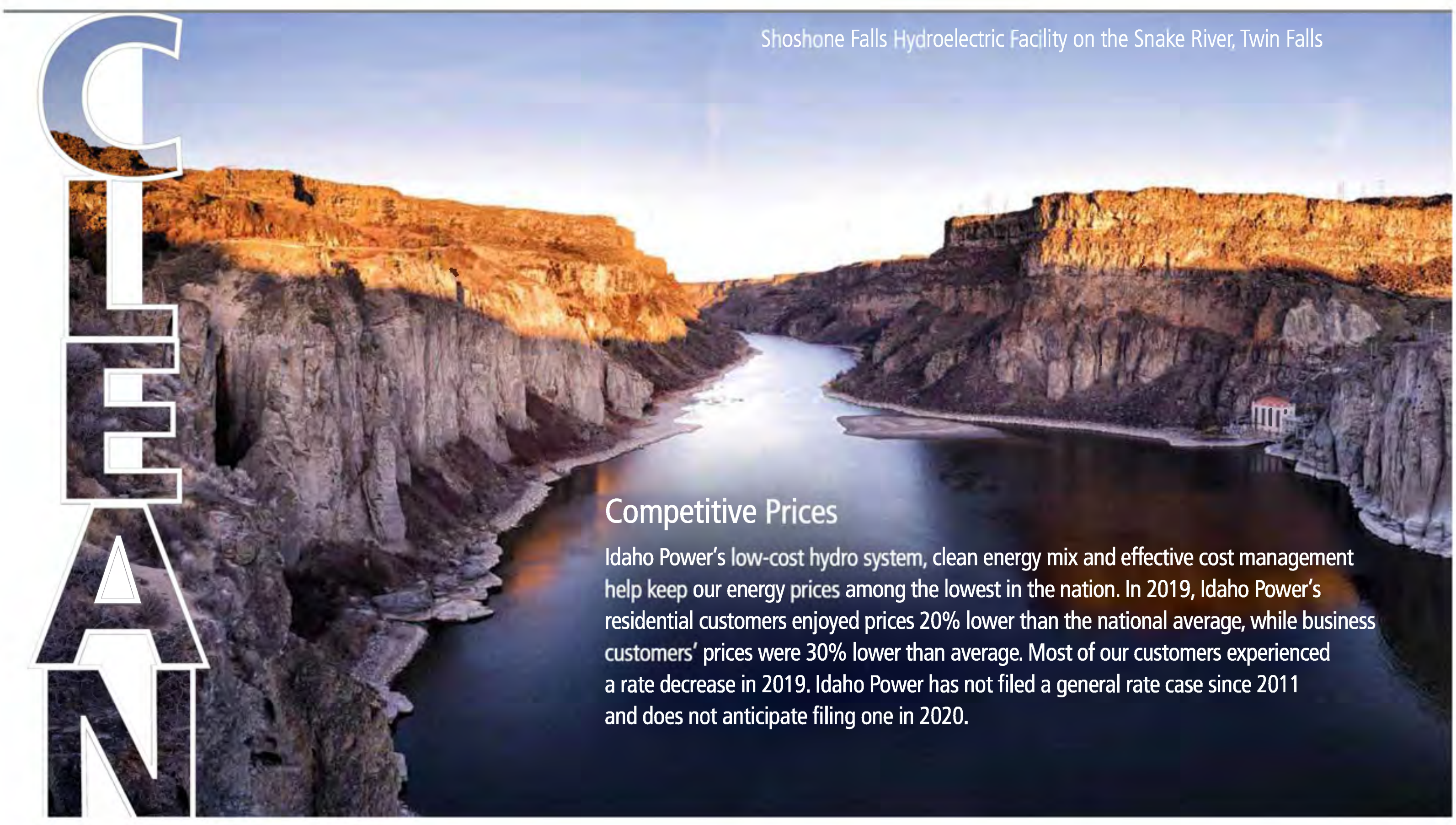
Idaho Power employees also continue to contribute as leaders in the communities we call home. Hundreds of employees spent thousands of hours volunteering and donated more than $1 million to charitable causes in 2019, funding scholarships, non-profit agencies and programs like the Salvation Army's Project Share, which helps our neighbors in need pay their energy bills during the winter months. Matching funds from IDACORP owners help maximize the impact of our corporate giving.

Price Decreases

Most Idaho customers experienced an overall price decrease for the second consecutive year in 2019, with business customers' rates going down by at least 5%. The biggest driver was the Power Cost Adjustment (PCA), an annual mechanism that adjusts rates based on power supply costs due to fuel, water supply, sales from surplus energy and other factors.

The 2019 PCA resulted in a rate decrease for all Idaho customers, as did a downward adjustment to the Energy Efficiency Rider. Those decreases were partially offset by a minor price increase related to Idaho Power's planned exit from the North Valmy coal-fired plant and an increase to the Fixed Cost Adjustment (FCA), an annual mechanism that adjusts prices based on energy use per customer for residential and small general service customers.

Overall, Idaho prices went down 7.1% for large power customers, 5.6% for large general service customers, 5.1% for irrigation customers and 0.7% for residential customers. Small general service customers experienced a 0.1% increase, and Oregon customers also had a slight price increase, mostly related to the planned exit from the North Valmy coal-fired plant.



Shoshone Falls Hydroelectric Facility on the Snake River, Twin Falls

Competitive Prices

Idaho Power's low-cost hydro system, clean energy mix and effective cost management help keep our energy prices among the lowest in the nation. In 2019, Idaho Power's residential customers enjoyed prices 20% lower than the national average, while business customers' prices were 30% lower than average. Most of our customers experienced a rate decrease in 2019. Idaho Power has not filed a general rate case since 2011 and does not anticipate filing one in 2020.

Customer Growth

Idaho Power's service area continues to experience substantial customer growth. Idaho remains the fastest-growing state in the nation, and Idaho Power's customer base grew 2.5% in 2019, including a 2.7% growth rate for our residential customer segment.

Unemployment in our service area was just 2.8% at the end of 2019, compared with 3.5% nationally. Idaho Power now has more than 570,000 customers, and we view the reliable, affordable, clean energy our company provides as a key driver for continuing to attract new customers to southern Idaho and eastern Oregon.

2.5%
CUSTOMER
GROWTH

Customer Satisfaction & Reliability

As the population within our service area continues to grow, Idaho Power is working hard to improve the customer experience and meet our customers' evolving needs. These efforts are making a difference — in 2019, we earned the highest residential and business customer satisfaction scores in company history, while overall customer satisfaction metrics ranked near the top of the list among our peer utilities.

Reliability also enjoyed another great year in 2019, as Idaho Power kept customers' lights on 99.972% of the time. Overall system reliability was the second-best in company history, trailing only 2018.

LIGHTS ON
99.972%
OF THE TIME

Effective Cost Management

While customer growth, favorable water conditions and a constructive regulatory environment have contributed to IDACORP's 12 consecutive years of earnings growth, effective cost management is an essential ingredient to our financial success. Thanks to prudent financial management by employees across our company, operations and maintenance expenses were down $8.7 million in 2019 compared to 2018. By using technological advancements, streamlined workflows and innovation, our nearly 2,000 employees continue to deliver outstanding results while staying within budgets.

Economic Development

The economy is thriving within Idaho Power's service area, and Moody's GDP forecast calls for sustained economic growth going forward.

Idaho Power experienced strong growth in its commercial and industrial sectors through a balanced mix of business attraction and expansion projects across the food processing, manufacturing, distribution and technology sectors. Of note is the new Amazon Fulfillment Center in Nampa, Idaho, which is scheduled to open in 2020. The 650,000-square-foot facility will create more than 1,000 jobs and generate significant economic opportunities in the region. Significant customer expansions included the FBI's new data center in Pocatello and Simplot Grower Solutions' new crop service facility in Aberdeen.

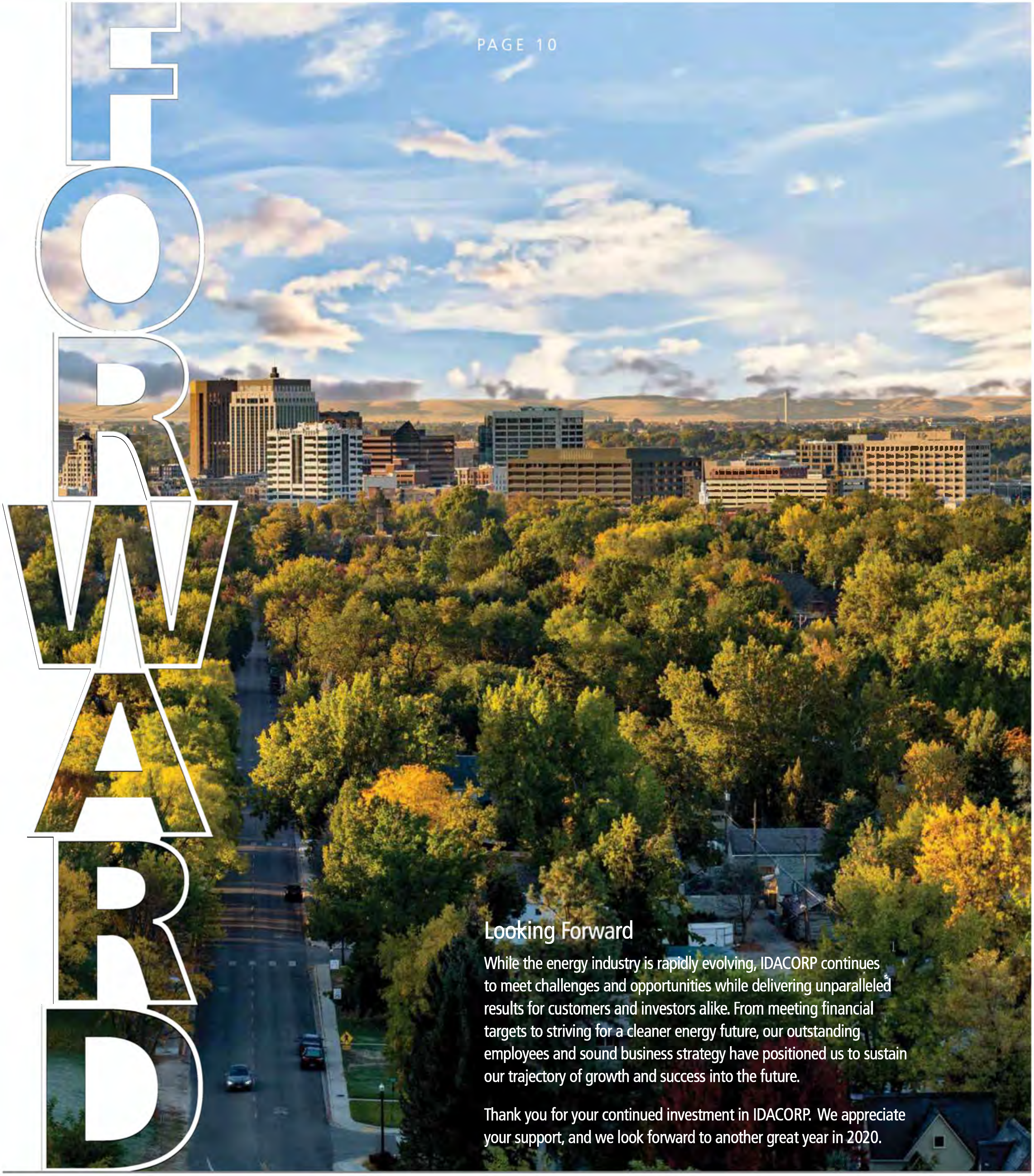
To provide enhanced support for economic development in the communities it serves, Idaho Power launched a series of new site mapping videos to promote premier industrial sites in addition to an "Energy Ready" site program designed to highlight areas with strong energy infrastructure.

Amazon Building, Nampa, Idaho

Tax Credit Preservation

Idaho Power did not use any additional accumulated deferred investment tax credits amortization in 2019. This again preserves the full $45 million of credits in the regulatory stipulation available for earnings support in future years, if needed. Idaho Power expects to continue practicing diligence in managing costs and growing revenues with the goal of preserving credits for future years.

$45 MILLION of CREDITS
AVAILABLE FOR FUTURE EARNINGS SUPPORT



Looking Forward

While the energy industry is rapidly evolving, IDACORP continues to meet challenges and opportunities while delivering unparalleled results for customers and investors alike. From meeting financial targets to striving for a cleaner energy future, our outstanding employees and sound business strategy have positioned us to sustain our trajectory of growth and success into the future.

Thank you for your continued investment in IDACORP. We appreciate your support, and we look forward to another great year in 2020.

BOARD OF DIRECTORS IDACORP & IDAHO POWER

Richard J. Dahl*
(2008) McCall, Idaho
Former Chairman of the Board and President and Chief Executive Officer of James Campbell Company, LLC; Director, Dine Brands Global, Inc.; Director, Hawaiian Electric Industries, Inc. and former Director Hawaii Electric Company; former President and Chief Operating Officer of Dole Food Company.

Darrel T. Anderson
(2013) Boise, Idaho
President and Chief Executive Officer of IDACORP, Inc. and Chief Executive Officer of Idaho Power.

Thomas E. Carlile
(2014) Boise, Idaho
Former Chief Executive Officer of Boise Cascade Company; Director of Boise Cascade 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.

Lisa A. Grow
(2020) Boise, Idaho
President of Idaho Power Company.

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.

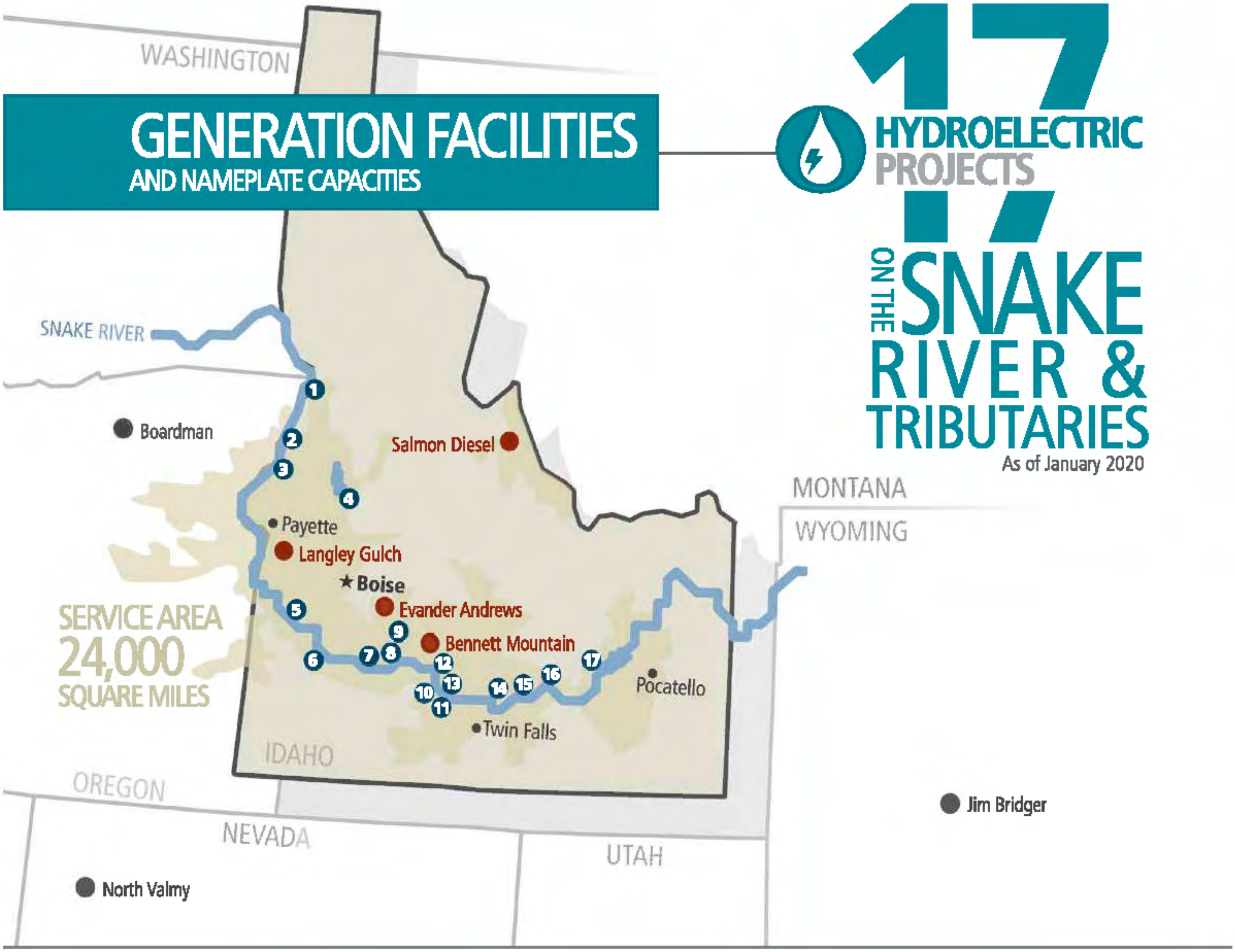
Average Tenure	7.2 years
Average Age	65 years
Independent	80 percent
Gender Diversity	40 percent

( ) year appointed or elected to the board
* Chairperson of the Board

GENERATION FACILITIES
AND NAMEPLATE CAPACITIES

17 HYDROELECTRIC PROJECTS ON THE SNAKE RIVER & TRIBUTARIES

As of January 2020



Hydroelectric Facilities

1	Hells Canyon	391,500 kW
2	Oxbow	190,000 kW
3	Brownlee	675,000 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	145,000 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

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

For the fiscal year ended December 31, 2019

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 Securities Exchange Act of 1934

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock, without par value	IDA	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Securities Exchange Act of 1934

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 ☒ No ☐ Idaho Power Company Yes ☐ No ☒

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 ☒ Idaho Power Company Yes ☐ No ☒

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	☒	No	☐	Idaho Power Company	Yes	☒	No	☐

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	☒	Idaho Power Company	Yes	☐	No	☒

Aggregate market value of voting and non-voting common stock held by non-affiliates (June 30, 2019):

IDACORP, Inc.: $ 5,017,481,695 Idaho Power Company: None

Number of shares of common stock outstanding as of February 14, 2020:
IDACORP, Inc.: 50,409,901
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 2020 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 2020 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:

2019 Annual Report	- IDACORP's and Idaho Power's Annual Report on Form 10-K for the year ended December 31, 2019	kWh	- Kilowatt-hour
ADITC	- Accumulated Deferred Investment Tax Credits	LTICP	- IDACORP 2000 Long-Term Incentive and Compensation Plan
AFUDC	- Allowance for Funds Used During Construction	MATS	- Mercury and Air Toxics Standards
AOCI	- Accumulated Other Comprehensive Income	MD&A	- Management's Discussion and Analysis of Financial Condition and Results of Operations
APCU	- Annual Power Cost Update	MMBtu	- Million British Thermal Units
ASU	- Accounting Standards Update	MW	- Megawatt
BCC	- Bridger Coal Company, a joint venture of IERCo	MWh	- Megawatt-hour
BLM	- U.S. Bureau of Land Management	NAAQS	- National Ambient Air Quality Standards
CAA	- Clean Air Act	NEPA	- National Environmental Policy Act
CO_2	- Carbon Dioxide	NMFS	- National Marine Fisheries Service
CWA	- Clean Water Act	NOAA Fisheries	- National Oceanic and Atmospheric Administration's National Marine Fisheries Service
EIS	- Environmental Impact Statement	NO_2	- Nitrogen Dioxide
EPA	- U.S. Environmental Protection Agency	NO_x	- Nitrogen Oxide
ESA	- Endangered Species Act	O&M	- Operations and Maintenance
FASB	- Financial Accounting Standards Board	OATT	- Open Access Transmission Tariff
FCA	- Idaho Fixed Cost Adjustment	OPUC	- Public Utility Commission of Oregon
FERC	- Federal Energy Regulatory Commission	PCA	- Idaho-jurisdiction Power Cost Adjustment
FPA	- Federal Power Act	PCAM	- Oregon Power Cost Adjustment Mechanism
GAAP	- Generally Accepted Accounting Principles	PEIS	- Programmatic Environmental Impact Statement
GHG	- Greenhouse Gas	PURPA	- Public Utility Regulatory Policies Act of 1978
HCC	- Hells Canyon Complex	REC	- Renewable Energy Certificate
IDACORP	- IDACORP, Inc., an Idaho Corporation	RH BART	- Regional haze - best available retrofit technology
Idaho Power	- Idaho Power Company, an Idaho Corporation	RPS	- Renewable Portfolio Standard
Idaho ROE	- Idaho-jurisdiction return on year-end equity	SEC	- U.S. Securities and Exchange Commission
Ida-West	- Ida-West Energy Company, a subsidiary of IDACORP, Inc.	SCR	- Selective catalytic reduction equipment
IERCo	- Idaho Energy Resources Co., a subsidiary of Idaho Power Company	SMSP	- Security Plan for Senior Management Employees
IFS	- IDACORP Financial Services, Inc., a subsidiary of IDACORP, Inc.	SO_2	- Sulfur Dioxide
IPUC	- Idaho Public Utilities Commission	USFWS	- U.S. Fish and Wildlife Service
IRP	- Integrated Resource Plan	Western EIM	- Energy imbalance market implemented in the western United States
IRS	- U.S. Internal Revenue Service	WDEQ	- Wyoming Department of Environmental Quality
Jim Bridger plant	Jim Bridger generating plant	WPSC	- Wyoming Public Service Commission
kW	- Kilowatt		

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;
- changes to or the elimination of Idaho Power's cost recovery mechanisms;
- 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;
- abnormal or severe weather conditions, including conditions and events associated with climate change, wildfires, drought, and other natural phenomena and natural disasters, which affect customer sales, hydropower generation levels, repair costs, service interruptions, 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, alternative energy sources, and other technologies that may affect Idaho Power's sale or delivery of electric power or introduce operational or cyber-security vulnerability to the power grid;
- acts or threats of terrorist incidents, other malicious acts, acts of war, cyber-attacks, 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 such events and related litigation or penalties;
- the expense and risks associated with capital expenditures for, and the permitting and construction of, utility infrastructure that Idaho Power may be unable or unwilling to complete or may not be deemed prudent by regulators;
- unusual or unanticipated changes in normal business operations, including unusual maintenance or repairs, or the failure to successfully implement new technology solutions;
- 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 hydropower 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, climate change, or a credit downgrade;
- 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;
- 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 company assets, operations, or reputation, subject Idaho Power 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 Idaho Power 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;

- 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;
- 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;
- 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 hydropower facilities;
- failure to comply with mandatory reliability and security requirements, which may result in penalties, reputational harm, and operational changes;
- 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 impacts of economic conditions, including inflation, interest rates, 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;
- 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;
- changes in the method for determining LIBOR and the potential replacement of LIBOR and the impact on interest rates for IDACORP's and Idaho Power's credit facilities;
- 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 assumptions underlying the coal mine reclamation obligations at Bridger Coal Company and related funding requirements;
- the ability to continue to pay dividends based on financial performance and in light of credit rating considerations, contractual covenants and restrictions, and regulatory limitations;
- Idaho Power's concentration in one industry and one region and the lack of diversification, regional economic condition and regional legislation and regulation;
- 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 third-party vendors, and the ability to adjust the labor cost structure when necessary; 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, 2019, IDACORP had 1,985 full-time employees, 1,976 of whom were employed by Idaho Power, and 8 part-time employees, 6 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 hydropower 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.

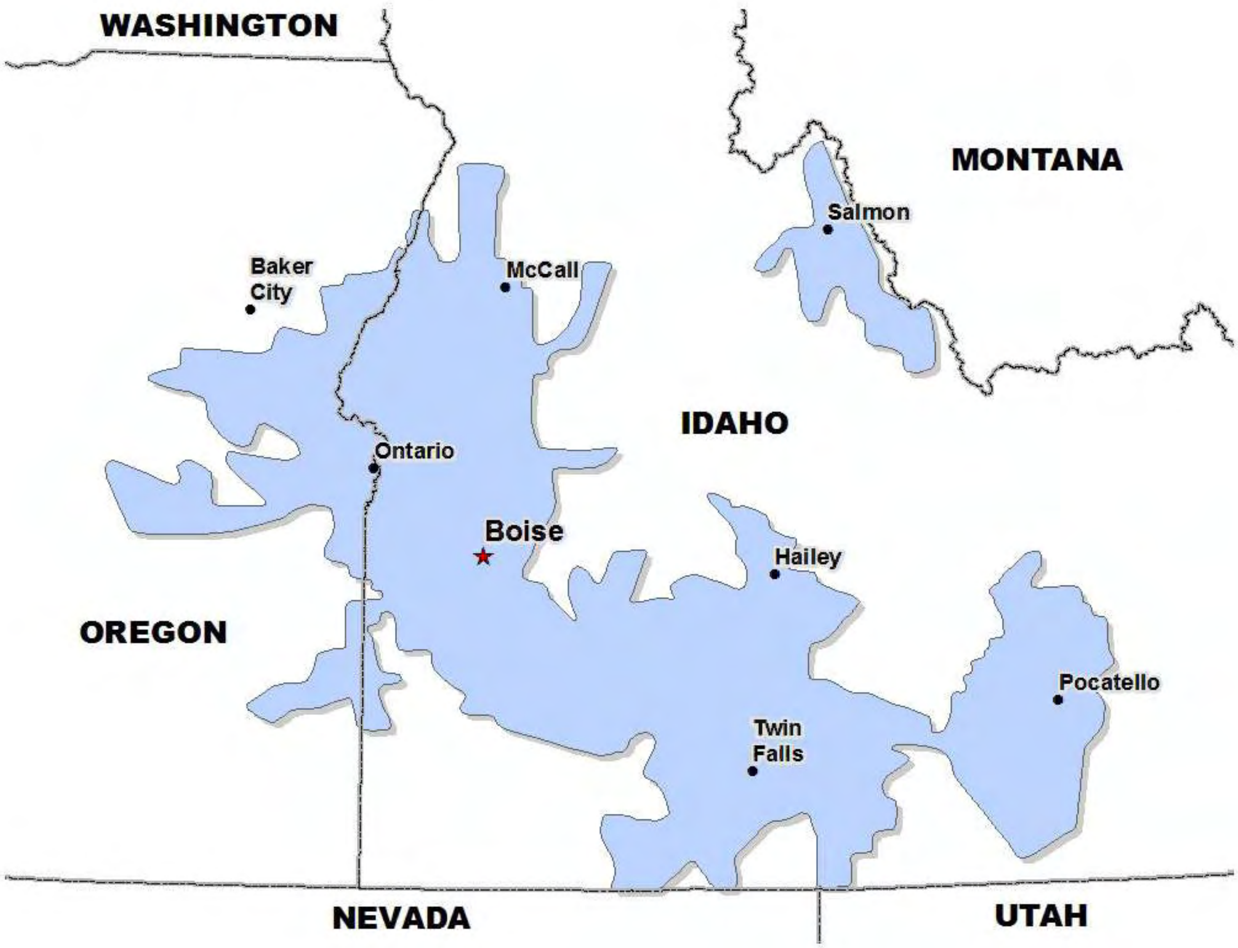
Available Information

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 IDACORP's and Idaho Power's Annual Report on Form 10-K for the year ended December 31, 2019 (2019 Annual Report).

UTILITY OPERATIONS

Background

Idaho Power provided electric utility service to approximately 572,000 retail customers in southern Idaho and eastern Oregon as of December 31, 2019. Approximately 477,000 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, government, and education. Idaho Power also provides irrigation customers with electric utility service to operate irrigation pumps during the agricultural growing season. 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 1.3 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, hydropower project relicensing, and system reliability, among other items.

Regulatory Accounting

Idaho Power meets the requirements under accounting principles generally accepted in the United States of America (GAAP) to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation, with the impacts of rate regulation reflected in its financial statements. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment; regulatory assets and liabilities; operating revenues; operation and maintenance expense; depreciation expense; and income tax expense. 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. Idaho Power recognizes such 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:

Cornerstones	Initiatives
Grow Financial Strength	- Pursue New Investment and Revenue Opportunities - Promote and Engage in Beneficial Electrification - Maintain Shareholder Confidence - Continue Focus on Productive Regulatory Outcomes
Improve the Core Business	- Evaluate and Control Expenditures and Continue Efficient Operations - Evaluate and Deploy Transformative Technology Solutions - Continue Progress on Key Transmission Projects - Continue Progress on Hydropower Relicensing Projects - Continue Development of Regional Markets
Enhance Idaho Power's Brand	- Enhance Idaho Power's Customers' Experience and Interactions - Communicate Progress Toward Environmental and Community Goals - Share Idaho Power's Story
Keep Employees Safe and Engaged	- Continue Idaho Power's Strong Focus on Safety - Facilitate Progress on Employee Engagement - Evolve Workforce Development Strategy and Programs

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

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 deferred or accrued under specific authorization from the IPUC or OPUC. 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. 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 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. Increases in FCA recovery may be capped at 3 percent of base revenue annually at the discretion of the IPUC, with any excess deferred for collection in a subsequent year. Idaho Power collects most of its energy efficiency program costs through energy efficiency riders on customer bills.

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 hydropower generation facilities are operated to optimize the water that is available by choosing when to run hydropower 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,		
	2019	2018	2017
Retail revenues (thousands of dollars):			
Residential (includes $35,587, $34,625 and $17,320, respectively, related to the FCA[1])	$ 526,966	$ 530,527	$ 552,333
Commercial (includes $1,336, $1,299, and $876, respectively, related to the FCA[1])	295,203	310,299	319,195
Industrial	181,372	190,130	195,124
Irrigation	135,850	158,001	150,030
Provision for sharing	—	(5,025)	—
Deferred revenue related to HCC relicensing AFUDC[2]	(8,780)	(8,780)	(10,706)
Total retail revenues	1,130,611	1,175,152	1,205,976
Wholesale energy sales	71,198	52,845	24,790
Transmission wheeling-related revenues	53,828	59,094	43,970
Energy efficiency program revenues	40,128	35,703	39,241
Other revenues	47,175	43,788	30,916
Total electric utility operating revenues	$ 1,342,940	$ 1,366,582	$ 1,344,893
Energy sales (thousands of Megawatt-hour (MWh)):			
Residential	5,273	5,135	5,355
Commercial	4,092	4,105	4,099
Industrial	3,412	3,371	3,346
Irrigation	1,760	1,976	1,771
Total retail energy sales	14,537	14,587	14,571
Wholesale energy sales	2,171	2,246	1,934
Bundled energy sales	680	617	202
Total energy	17,388	17,450	16,707

(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) The IPUC allows 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 hydropower, 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 hydropower 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 hydropower generation conditions increase production at Idaho Power's hydropower 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 to Idaho Power 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		
	2019	2018	2017	2019	2018	2017
	(thousands of MWh)					
Hydropower plants	8,294	8,682	8,900	62%	65%	65%
Coal-fired plants	3,012	3,274	3,284	22%	24%	24%
Natural gas-fired plants	2,114	1,408	1,504	16%	11%	11%
Total system generation	13,420	13,364	13,688	100%	100%	100%
Purchased power - cogeneration and small power production	2,983	3,045	2,800			
Purchased power - other	2,217	2,386	1,442			
Total purchased power	5,200	5,431	4,242			
Total power supply	18,620	18,795	17,930			

Hydropower Generation**:** Idaho Power operates 17 hydropower projects located on the Snake River and its tributaries. Together, these hydropower facilities provide a total nameplate capacity of 1,796 MW and annual generation of approximately 8.7 million MWh under median water conditions. The amount of water available for hydropower generation depends on several factors—the amount of snowpack in the mountains upstream of Idaho Power's hydropower 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 hydropower projects on the Snake River.

In 2019 and 2018, reservoir storage carryover from the previous year coupled with near-normal winter snowpack resulted in 8.3 million MWh and 8.7 million MWh of hydropower generation, respectively. In 2017, above normal winter and spring precipitation resulted in 8.9 million MWh of hydropower generation. During low water years, when stream flows into Idaho Power's hydropower projects are reduced, Idaho Power's hydropower generation is reduced, resulting in a greater reliance on other generation resources and wholesale power purchases. For 2020, Idaho Power estimates annual generation from its hydropower facilities will be between 6.5 million MWh and 8.5 million MWh.

Idaho Power obtains licenses for its hydropower projects from the FERC, similar to other utilities that operate nonfederal hydropower 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 hydropower 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 Hydropower Projects."

Idaho Power is subject to the provisions of the FPA as a "public utility" and as a "licensee" by virtue of its hydropower operations. As a licensee under Part I of the FPA, Idaho Power and its licensed hydropower 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. Idaho Power expects to meet 2020 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. Idaho Power has an established process approved by the IPUC and OPUC for recovery of non-fuel costs related to Idaho Power's plan to end its participation in coal-fired operations at the North Valmy plant. Idaho Power ended its participation in unit 1 of the North Valmy plant in December 2019, as planned, and plans to end its participation in unit 2 by December 31, 2025.

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 2020. As approved by the Oregon Environmental Quality Commission, Idaho Power plans to cease coal-fired operations at the Boardman power plant no later than December 31, 2020. Idaho Power has an established process approved by the IPUC and OPUC for recovery of non-fuel costs related to Idaho Power's plan to end its participation in coal-fired operations at the Boardman power plant.

***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, 2019, Idaho Power had approximately 12.6 million MMBtu of natural gas financially hedged for physical delivery, primarily for the operational dispatch of the Langley Gulch plant through July 2021. 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 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 2019 and 2018, Idaho Power purchased 1.6 million MWh and 1.8 million MWh of power through wholesale market purchases at an average cost of $21.95 per MWh and $28.82 per MWh, respectively. During both 2019 and 2018, Idaho Power sold 2.2 million MWh of power in wholesale market sales, with an average price of $32.80 per MWh and $23.53 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 hydropower 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.
- Jackpot Holdings LLC - a 20-year power purchase agreement to purchase the output from a planned 120-MW solar facility, with an expected in-service date in 2022. The agreement was approved by the IPUC in December 2019 and is, as of the date of this report, pending approval by the OPUC.

PURPA Qualifying Facility Energy Sales Agreements: Idaho Power purchases power from PURPA qualifying facilities as mandated by federal law. As of December 31, 2019, Idaho Power had contracts with on-line PURPA qualifying facilities with a total of 1,136 MW of nameplate generation capacity, with an additional 11 MW nameplate capacity of projects projected to be on-line by 2022. 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,		
	2019	**2018**	**2017**
PURPA contracts expense (in thousands)	$ 187,344	$ 189,722	$ 169,788
MWh purchased under PURPA contracts (in thousands)	2,983	3,045	2,800
Average cost per MWh from PURPA contracts	$ 62.80	$ 62.31	$ 60.64

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, subject to some exceptions such as adverse impacts on system reliability.
- 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 adjustment 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 using an avoided cost methodology based on 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 using an avoided cost methodology based on OPUC regulations.

Participation in Western Energy Imbalance Market: In April 2018, Idaho Power began participating in an energy imbalance market in the western United States (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.

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 project is a proposed 300-mile, high-voltage transmission line between a station near Boardman, Oregon and the Hemingway station near Boise, Idaho. The Gateway West project is a proposed 1,000-mile, high-voltage transmission lines 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 with the IPUC and OPUC in June 2019, which was amended in January 2020. The IRP seeks to forecast Idaho Power's loads and resources for a 20-year period, analyzes potential supply-side, demand-side, and transmission 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 supply-side, demand-side, and transmission resources; and
- involve the public in the planning process in a meaningful way.

During the time between IRP filings, the public and regulatory oversight of the activities identified in the IRP allows for discussion and adjustment of the IRP as warranted. Idaho Power makes periodic adjustments and corrections to the resource plan to reflect economic conditions, anticipated resource development, changes in technology, and regulatory requirements.

The load forecast assumptions Idaho Power used 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 Forecasted Annual Growth Rate		**20-Year Forecasted Annual Growth Rate**	
	Retail Sales (Billed MWh)	**Annual Peak (Peak Demand)**	**Retail Sales (Billed MWh)**	**Annual Peak (Peak Demand)**
2019 IRP	1.3%	1.4%	1.0%	1.2%
2017 IRP	1.1%	1.6%	0.9%	1.4%
2015 IRP	1.5%	1.8%	1.2%	1.5%

As noted above, on January 31, 2020, Idaho Power amended the originally filed 2019 IRP with additional information and modeling results. The updated 2019 IRP identified a preferred resource portfolio and action plan, which includes the completion of the Boardman-to-Hemingway transmission line in 2026, the end to Idaho Power's participation in coal-fired operations at the North Valmy plant units 1 and 2 in 2019 and 2025, respectively, the end to Idaho Power's participation in coal-fired operations at the Jim Bridger plant by 2030, including the exit from two of the four Jim Bridger plant units in 2022 and 2026, respectively, and the addition of a 120-MW solar resource in 2022. However, as noted in the 2019 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, the actual completion date of the Boardman-to-Hemingway transmission project, and the economics and logistics of plant retirements. These uncertainties, as well as others, will likely result in changes to the desirability of the preferred portfolio and adjustments to the timing and nature of anticipated and actual actions. As of the date of this report, proceedings relating to the amended 2019 IRP are pending at the IPUC and OPUC.

Energy Efficiency and Demand Response Programs: Idaho Power's energy efficiency and demand response portfolio is comprised of 27 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 programs 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
- participation in the Northwest Energy Efficiency Alliance, which supports market transformation efforts across the region.

In 2019, Idaho Power's energy efficiency programs reduced energy usage by approximately 205,000 MWh compared with 173,000 in 2018. For 2019, Idaho Power had a demand response available capacity of approximately 397 MW. In 2019, 2018, and 2017, Idaho Power expended approximately $49 million, $44 million, and $48 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 the companies' ESG and sustainability programs. IDACORP and Idaho Power publicly release annual sustainability reports and 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 2019 Annual Report. IDACORP's and Idaho Power's ESG initiatives include:

- establishing responsible management goals to related to the companies' impact on the environment, such as
    - the "Clean Today, Cleaner Tomorrow.®" goal to provide Idaho Power's customers with 100-percent clean energy by 2045,
    - 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,
    - continuing various environmental stewardship programs along the Snake River, including fish habitat preservation and restoration,
    - wildfire mitigation planning and actions, and
    - wildlife habitat, archaeological and cultural resource, and raptor protection stewardships.
- operational excellence in providing reliable, fair priced, and clean energy,
- engaging and empowering Idaho Power's workforce (including succession planning at all levels, employee development, 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.

Voluntary CO_2 Emissions Intensity Reduction Goal: Idaho Power is engaged in voluntary greenhouse gas (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. Through 2019, Idaho Power was beating its current $C0_2$ emissions intensity goal, with an average reduction of 29 percent since 2010.

Idaho Power's estimated historic CO_2 emissions intensity from its generation facilities is as follows (in lbs CO_2/MWh):

	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010
Cumulative Emissions Intensity 2010-2019	848	870	896	934	944	945	929	867	864	1,066
Annual Average Emissions Intensity	646	656	632	858	944	1,015	1,129	874	681	1,066

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 North 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 North Valmy plant in connection with Idaho Power's plan to end its participation in the operation of units 1 and 2. Idaho Power ended its participation in the operation of unit 1 in December 2019, as planned, and plans to end its participation in unit 2 by December 31, 2025. The plan to end Idaho Power's participation in operations of units 1 and 2 at the North 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.

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 co-owned coal-fired power plants, three natural gas combustion turbine power plants, and 17 hydropower 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):

	2020	2021-2022
Capital expenditures:		
License compliance and relicensing efforts at hydropower facilities	$ 30	$ 46
Investments in equipment and facilities at thermal plants	8	15
Total capital expenditures	$ 38	$ 61
Operating expenses:		
Operating costs for environmental facilities - hydropower	$ 21	$ 41
Operating costs for environmental facilities - thermal	11	22
Total operations and maintenance	$ 32	$ 63

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. At December 31, 2019, the unamortized amount of IFS’s portfolio was approximately $4 million ($126 million in gross tax credit investments, net of $122 million of accumulated amortization). IFS generated tax credits of $2.9 million in 2019 and $2.6 million in both 2018 and 2017. In 2019, 2018, and 2017, IFS received distributions related to fully-amortized affordable housing investments that reduced IDACORP's income tax expense by $3.2 million, $0.3 million, and $1.1 million, respectively.

IDA-WEST ENERGY COMPANY

Ida-West operates and has a 50 percent ownership interest in nine hydropower projects that have a total nameplate 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 hydropower projects at a cost of approximately $9 million in 2019 and $10 million in both 2018 and 2017.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

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.

RYAN N. ADELMAN, 45

- Vice President of Transmission & Distribution, Engineering and Construction, October 2019 - present
- Regional Manager for the Southeast Region of Idaho Power Company, January 2018 - October 2019
- Transmission & Distribution Projects Senior Manager of Idaho Power Company, January 2015 - December 2017

DARREL T. ANDERSON, 61

- Chief Executive Officer of Idaho Power Company, January 2014 - present
- President and Chief Executive Officer of IDACORP, Inc., May 2014 - present
- President and Chief Executive Officer of Idaho Power Company, January 2014 - September 2019
- Member of the Boards of Directors of IDACORP, Inc. and Idaho Power Company since September 2013

BRIAN R. BUCKHAM, 41

- 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

SARAH E. GRIFFIN, 50

- Vice President of Human Resources of Idaho Power Company, October 2019 - present
- Director of Human Resources of Idaho Power Company, May 2014 - October 2019

LISA A. GROW, 54

- President of Idaho Power Company, October 2019 - present
- Senior Vice President and Chief Operating Officer of Idaho Power Company, April 2016 - October 2019
- 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

JAMES BO D. HANCHEY, 44

- Vice President of Customer Operations and Chief Safety Officer of Idaho Power Company, October 2019 - present
- Customer Service Senior Manager of Idaho Power Company, February 2018 - October 2019
- Regional Manager of Southern Region of Idaho Power Company, May 2014 - February 2018

STEVEN R. KEEN, 59

- 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

JEFFREY L. MALMEN, 52

- 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, 58

- 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, 56

- Vice President, Controller and Chief Accounting Officer of IDACORP, Inc. and Idaho Power Company, January 2014 - present

ADAM RICHINS, 41

- Senior Vice President and Chief Operating Officer of Idaho Power Company, October 2019 - present
- Vice President of Customer Operations and Business Development of Idaho Power Company, March 2017 - October 2019
- General Manager of Customer Operations, Engineering and Construction, January 2014 - February 2017

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 should not be considered a complete list of potential risks that the companies may encounter. These risk factors 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, may be important to understanding any statement in this 2019 Annual Report or elsewhere and should be considered carefully when making any investment decisions relating to IDACORP or Idaho Power.

IDACORP's and Idaho Power's businesses regularly face risks, many of which may cause future results to be different than anticipated as of the date of this report. Below are certain important utility-specific regulatory, operational, legal and compliance, financial and investment, and general business risks. IDACORP's and Idaho Power's reactions to material future developments as well as the utility industry's reactions to those developments may also impact the Companies' future results.

Utility-Specific Regulatory Risks

Utility-specific regulatory risk includes the risks that federal, state, or local regulators may impose additional requirements and costs on Idaho Power and the utility industry, or require Idaho Power as a utility to make adverse changes to its business models, strategies, and practices.

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, changes in the long-term cost-effectiveness or changes to the operating conditions of Idaho Power's assets that could result in early retirements of utility facilities, 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. Compliance with state and federal regulatory standards may also limit Idaho Power's ability to operate profitably. 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," Part II - Item 7 - "Management's Discussion and Analysis of Financial Condition and

Results of Operations - Regulatory Matters," and Note 3 - "Regulatory Matters" to the consolidated financial statements of Part II - Item 8 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 hydropower 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.

Operational Risks

Operational risk relates to risks arising from the systems, assets, processes, people, and external factors that affect the operation of IDACORP's or Idaho Power's businesses.

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 1,039 kWh in 2010 to 936 kWh in 2019. 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.

Changes in weather conditions, severe weather, and the impacts of climate change can adversely affect IDACORP's and Idaho Power's operating results and cause them to fluctuate seasonally. 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 generate or 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 or mass outages, increasing costs and other operating and maintenance expenses, including emergency response planning and preparedness 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 hydropower plants.

Idaho Power's customers' energy needs vary with weather and to the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use due to weather changes may require Idaho Power to invest in generating assets and transmission and distribution infrastructure, while decreased energy use due to weather changes may result in decreased revenues. Extreme weather conditions creating high energy demand may raise wholesale electricity prices for power that Idaho Power purchases to serve customers, increasing the cost of energy Idaho Power provides to its customers, and at the same time can increase the revenues Idaho Power receives for wholesale market sales of excess generation during regional extreme weather events. Variations in hydropower 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 hydropower 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 repairing and replacing infrastructure or liability for personal injury, loss of life, and 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; including in the State of Oregon, to limit the severity and impact of climate change, such as imposing mandatory reductions in greenhouse gas emissions, which could increase Idaho Power’s power supply and compliance costs. If financial markets increasingly view climate change or greenhouse gas emissions as a financial or investment risk for electric utilities, it could negatively affect IDACORP's and Idaho Power's ability to access debt and equity capital markets on favorable terms. 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, alternative energy sources, 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. Advances in technology that reduce the costs of alternative methods of producing electric energy could result in loss of revenue and customers, and may require Idaho Power to make significant expenditure reductions to remain competitive. These changes in technology could also alter the channels through which customers buy or utilize energy, which could reduce Idaho Power's revenues or impact Idaho Power's expenses. A reduction in load, however, would not necessarily reduce Idaho Power's need for ongoing investments in its infrastructure to reliably serve its customers. 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. Idaho Power's electric transmission systems are part of an interconnected regional grid, and therefore, it faces the risk of causing or being subject to a blackout due to grid disturbances or disruptions on a neighboring interconnected system. 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. The breach of certain information technology systems could adversely affect IDACORP's and Idaho Power's ability to correctly record, process and report customer, business, and financial information. 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, human error, 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 or diminished customer confidence, 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.

Changes in capital expenditures for infrastructure and the risks associated with permitting and construction of utility infrastructure 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 high-voltage 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.

Factors contributing to lower hydropower 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 hydropower facilities. During 2018 and 2019, 65 percent and 62 percent, respectively, of Idaho Power's electric power from Idaho Power-owned generation was from hydropower facilities. Due to Idaho Power’s heavy reliance on hydropower 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 hydropower generation. When hydropower 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 hydropower 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.

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, regulations related to greenhouse gas emissions, 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 regulatory, 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's failure to provide service due to such disruptions may also result in fines, penalties, or cost disallowances through the regulatory process. Idaho Power may not be able to fully or timely recover these increased costs through rates, which may adversely affect IDACORP's and Idaho Power's financial condition and results of operations.

Idaho Power's generation, transmission, and distribution facilities are subject to numerous operational risks unique to it and its industry. Operating risks associated with Idaho Power's generation, transmission, and distribution facilities include equipment failures, volatility in fuel and transportation pricing, interruptions in fuel supplies, increased regulatory compliance costs, labor disputes 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 (both cyber and asset-based), 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 (including tort liability), 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, reputational harm, 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 hydropower 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, property damage, and environmental pollution, 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.

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. As of December 31, 2019, Idaho Power had federally-mandated contracts to purchase energy from 127 on-line projects with third parties. This increases the likelihood and frequency that Idaho Power will be required to reduce output from its lower-cost hydropower 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 revenue 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.

Legal and Compliance Risks

Legal and compliance risk relates to risks arising from government and regulatory action and from legal proceedings and compliance with applicable laws, rules, orders, regulations, policies, and procedures, including those related to financial reporting, environmental, health, and safety, and potential changes in legal requirements.

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. Although the United States has not adopted any international or federal greenhouse gas emissions reduction targets, many states and localities may continue to pursue climate policies in the absence of federal mandates. The state of Oregon, for instance, has been pursuing cap-and-trade legislation for greenhouse gas emissions. Idaho Power could also become subject to climate change lawsuits and an adverse outcome could require substantial expenditures and could possibly require payment of damages. Defense costs associated with such litigation can also be significant. Such payments or expenditures could affect results of operations, financial condition, or cash flows if such costs are not recovered through regulated rates. 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. These judgments may include estimates for potential outcomes regarding tax positions that may be subject to challenge by the taxing authorities. Disputes over interpretations of tax laws may be settled with the taxing authority in examination, upon appeal, or through litigation. In recent years, state regulatory mechanisms with income tax-related provisions (such as Idaho Power's May 2018 Idaho tax reform 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.

In response to state and federal regulatory requirements, judicial decisions and international accords, emissions of greenhouse gases including, most significantly CO_2 could be restricted in the future. If new emissions reduction rules were to become effective, they could result in significant additional compliance costs that would affect Idaho Power's future financial position, results of operations, and cash flows if such costs are not timely recovered through regulated rates. Moreover, the possibility exists that stricter laws, regulations, or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary.

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. For further discussion of environmental matters that may affect Idaho Power, see "Environmental Matters" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report.

Obligations imposed in connection with hydropower license renewals may require large capital expenditures, increase operating costs, reduce hydropower 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 hydropower 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 hydropower projects, which may be reflected in hydropower licenses, including for the Hells Canyon Complex. In addition, new interpretations of existing laws and regulations could be adopted or become applicable to hydropower facilities, which could further increase required expenditures for marine life recovery and endangered species protection and reduce the amount of hydropower generation available to meet Idaho Power's generation requirements. Idaho Power cannot predict the requirements that might be imposed during the relicensing process, the financial impact of those requirements, whether a new multi-year license will ultimately be issued, and whether the IPUC or OPUC will allow recovery through rates of the substantial costs incurred in connection with the licensing process and subsequent compliance. Imposition of onerous conditions in the relicensing process could result in Idaho Power incurring significant capital expenditures, increase operating costs (including power purchase costs), and reduce hydropower generation, which could negatively affect results of operations and financial condition.

Idaho Power could be subject to penalties, reputational harm, 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 $1.3 million per day per violation. As a utility with a large customer base, Idaho Power is subject to adverse publicity focused on the reliability of its services and the speed with which it is able to respond to electric outages caused by storm damage or other unanticipated events. Adverse publicity could harm the reputations of IDACORP and Idaho Power; may make state legislatures, utility commissions, and other regulatory authorities less likely to view the companies in a favorable light; and may cause Idaho Power to be subject to less favorable legislative and regulatory outcomes or increased regulatory oversight. The imposition of any of the foregoing 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.

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.

Financial and Investment Risks

Financial and investment risks relate to IDACORP's and Idaho Power's ability to meet financial obligations and mitigate exposure to market risks, including liquidity risks and the ability to raise capital and cost of funding, risks related to credit ratings, credit risk, liquidity, interest rates, and commodity prices.

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 on favorable terms. 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. Higher interest rates on short-term borrowings with variable interest rates could also have an adverse effect on IDACORP's and Idaho Power's operating results. Changes in interest rates may also impact the fair value of the debt securities in Idaho Power's pension funds, as well as Idaho Power's ability to earn a return on short-term investments of excess cash. 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. In addition, IDACORP's or Idaho Power's credit ratings may change as a result of the differing methodologies or change in the methodologies used by the various rating agencies. 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, limit the ability of IDACORP to declare and make dividends, 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 ability to pursue improvements or acquisitions (including generating capacity and transmission assets, which may be necessary for future growth), 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, as amended in November 2019, 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, provided that, an alternate benchmark rate selected by the administrative agent for the credit facilities and IDACORP and Idaho Power will apply during any period in which the LIBOR rate is unavailable or unascertainable. 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.

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. Idaho Power has additional indirect credit exposures to financial institutions in the form of letters of credit provided as security by power suppliers under various purchased power contracts and by vendors for infrastructure development projects. If any of the credit ratings of the letter of credit issuers were to drop below investment grade, the vendor or supplier would need to replace the security with an acceptable substitute, which may be impracticable and may expose Idaho Power to losses resulting from a vendor or supplier default. If the security were not replaced, the party could be in default under the contract and Idaho Power's remedies for default may be inadequate to fully compensate Idaho Power for its losses. 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. Idaho Power is a participant in the energy markets, including the Western EIM, and engages in direct and 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 counterparties may owe each other in the Western EIM and any such credit losses could be socialized to all Western EIM participants, including Idaho Power. A significant failure of a participant in the Western EIM to make payments when due on its obligations 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.

The performance of pension and postretirement benefit plan investments, increasing health care costs, 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. Idaho Power's self-insured costs of health care benefits for eligible employees and retirees have increased in recent years and Idaho Power believes these costs will continue to rise. As benefit costs continue to rise, there is no assurance that the IPUC and OPUC will continue to allow recovery.

The key actuarial assumptions that affect pension 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.

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.

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.

General Risks

General risks include other risks specific to IDACORP and Idaho Power that are not categorized above.

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, revenues, and collectability of revenues, as well as expenses, will be affected by regional 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 and the inability to hire qualified third-party vendors 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 2020 and in the near-term. At December 31, 2019, 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. Idaho Power does not have employment contracts with its officers or key employees and cannot guarantee that any member of its management or any key employee at the IDACORP parent or any subsidiary level will continue to serve in any capacity for any particular period of time. 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.

Idaho Power also hires third-party vendors to assist in performing a variety of ordinary business functions, such as power plant maintenance, data warehousing and management, software development and licensing, electric transmission and distribution operations, billing and metering processes, and vegetation management, among other things. In recent years, Idaho Power has experienced increased competition and rising prices for many forms of third-party vendor services. While Idaho Power does not rely entirely on third-party vendors for many of these business functions, the unavailability of such vendors could adversely affect the quality and cost of Idaho Power's electric service and negatively impact its results of operation.

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 the requirements 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 hydropower 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, 2019, the system also includes approximately 4,830 pole-miles of high-voltage transmission lines, 24 step-up transmission substations located at power plants, 21 transmission substations, 9 switching stations, 31 mixed-use transmission and distribution substations, 185 energized distribution substations (excluding mobile substations and dispatch centers), and approximately 27,968 pole-miles of distribution lines.

Idaho Power holds Federal Energy Regulatory Commission (FERC) licenses for all of its hydropower projects that are subject to federal licensing. Relicensing of Idaho Power's hydropower projects is discussed in Part II - Item 7 - MD&A – "Regulatory Matters – Relicensing of Hydropower Projects" in this report.

Idaho Power's hydropower projects and other owned and co-owned generating facilities and their nameplate capacities, as of the date of this report, are included in the table below.

Project	Nameplate Capacity (kW)[1]	License Expiration
Hydropower Projects:		
Properties Subject to Federal Licenses:		
Lower Salmon	60,000	2034
Bliss	75,000	2034
Upper Salmon	34,500	2034
Shoshone Falls	11,500	2040
CJ Strike	82,800	2034
Upper Malad - Lower Malad	21,770	2035
Brownlee - Oxbow - Hells Canyon (Hells Canyon Complex)	1,256,500	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 Hydropower:		
Clear Lakes - Thousand Springs	9,300	
Total Hydropower	1,795,645	
Steam and Other Generating Plants:		
Jim Bridger (coal-fired)[3]	770,501	
North Valmy Unit 2 (coal-fired)[3][4]	145,000	
Boardman (coal-fired)[3][5]	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	1,746,853	
Total Generation	3,542,498	

(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 agreement with NV Energy, Idaho Power's participation in coal-fired operations of North Valmy ended in December 2019 at unit 1 and is planned to end in 2025 at unit 2.

(5) 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 hydropower 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 14, 2020, there were 8,583 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.

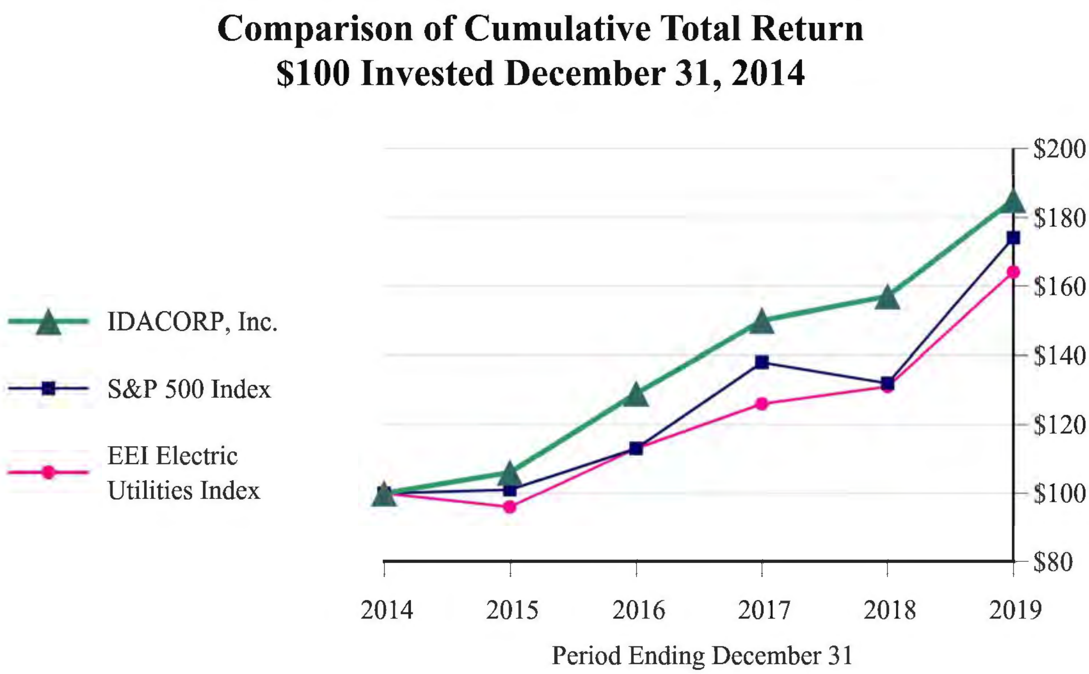
During the quarter ended December 31, 2019, IDACORP effected the following repurchases of common stock:

Period	(a) Total Number of Shares Purchased [1]	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 1, 2019 - October 31, 2019	—	$ —	—	—
November 1, 2019 - November 30, 2019	128	103.94	—	—
December 1, 2019 - December 31, 2019	244	106.80	—	—
Total	372	$ 105.82	—	—

(1) These shares were withheld for taxes upon vesting of restricted stock.

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, 2014, with beginning-of-period weighting of the peer group indices (based on market capitalization) and monthly compounding of returns.



Source: Bloomberg and EEI

	2014	2015	2016	2017	2018	2019
IDACORP	$ 100.00	$ 105.85	$ 128.94	$ 150.12	$ 156.97	$ 184.73
S&P 500	100.00	101.37	113.49	138.25	132.18	173.79
EEI Electric Utilities Index	100.00	96.10	112.86	126.08	130.71	164.42

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)

	2019	2018	2017	2016	2015
Operating revenues	$1,346,383	$1,370,752	$1,349,486	$1,262,020	$1,270,289
Operating income	298,326	296,922	315,545	283,582	297,048
Net income attributable to IDACORP, Inc.	232,854	226,801	212,419	198,288	194,679
Diluted earnings per share	4.61	4.49	4.21	3.94	3.87
Dividends declared per share	2.56	2.40	2.24	2.08	1.92
Financial Condition:					
Total assets	$6,641,201	$6,382,754	$6,045,405	$6,289,897	$6,023,314
Long-term debt (including current portion)	$1,836,659	$1,834,788	$1,746,123	$1,745,678	$1,726,474
Financial Statistics:					
Times interest charges earned:					
Before tax[(1)]	3.65	3.55	3.82	3.54	3.61
After tax[(2)]	3.40	3.36	3.30	3.15	3.12
Book value per share[(3)]	$ 48.90	$ 47.04	$ 44.68	$ 42.74	$ 40.88
Market-to-book ratio[(4)]	218%	198%	204%	188%	166%
Payout ratio[(5)]	56%	53%	53%	53%	50%
Return on year-end common equity[(6)]	9.4%	9.6%	9.4%	9.2%	9.5%

The financial statistics listed above are calculated in the following manner:

(1) 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.

(2) 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.

(3) "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.

(4) The closing price of IDACORP stock on the last day of the year divided by the book value per share, which is described in footnote (4) above.

(5) Dividends paid per common share divided by diluted earnings per share.

(6) "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. The discussion of IDACORP's and Idaho Power's general financial condition and results of operations for 2018 compared with 2017 can be found in their Annual Report on Form 10-K for the year ended December 31, 2018 (2018 Annual Report). See Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2018 Annual Report for further information on the companies' prior period results of operations. 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 hydropower 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 2019 include:

- IDACORP achieved net income growth for a twelfth consecutive year;
- IDACORP provided a 13 percent cumulative annual total shareholder return over the past three years, including share price appreciation and dividends paid;
- Idaho Power's customer count grew 2.5 percent in 2019;
- Idaho Power achieved its lowest ever recorded employee safety incident rate, which was significantly below the national average and the average of peer utilities of similar size;
- Idaho Power reached its highest ever recorded residential customer satisfaction score, the highest of any investor-owned utility in the nation, as rated by an independent third party;
- Idaho Power continued its strong performance in system reliability, slightly behind 2018's record reliability score;
- IDACORP increased its quarterly common stock dividend from $0.63 per share to $0.67 per share, as a part of a 123 percent increase in quarterly dividends approved over the last eight years;
- IDACORP adopted a new dividend policy that provides for a target long-term dividend payout ratio of between 60 percent and 70 percent of sustainable IDACORP earnings, an increase from the previous policy adopted in 2011 that targeted a dividend payout ratio of between 50 percent to 60 percent of sustainable earnings;
- Idaho Power reached an agreement with NV Energy, approved by the IPUC and OPUC, that facilitates the planned end of Idaho Power's participation in coal-fired operations at units 1 and 2 of its jointly-owned North Valmy coal-fired power plant in 2019 and 2025, respectively. As planned, Idaho Power ended its participation in unit 1 of the North Valmy plant in December 2019;
- Idaho Power announced its "Clean Today, Cleaner Tomorrow.®" goal to provide its customers with 100-percent clean energy by 2045; and
- Idaho Power beat its carbon dioxide (CO_2) emissions intensity goal, with an average reduction of 29 percent since 2010.

Summary of 2019 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, 2019, 2018, and 2017 (in thousands, except earnings per share amounts):

	Year Ended December 31,		
	2019	2018	2017
Idaho Power net income	$ 224,437	$ 222,334	$ 206,347
Net income attributable to IDACORP, Inc.	$ 232,854	$ 226,801	$ 212,419
Average outstanding shares – diluted (000's)	50,537	50,510	50,424
IDACORP, Inc. earnings per diluted share	$ 4.61	$ 4.49	$ 4.21

The table below provides a reconciliation of net income attributable to IDACORP for the year ended December 31, 2019, from the year ended December 31, 2018 (items are in millions and are before tax unless otherwise noted):

Net income attributable to IDACORP, Inc. - December 31, 2018		**$ 226.8**
Increase (decrease) in Idaho Power net income:		
Customer growth, net of associated power supply costs and power cost adjustment mechanisms	18.8	
Usage per retail customer, net of associated power supply costs and power cost adjustment mechanisms	(21.4)	
Idaho fixed cost adjustment (FCA) revenues	1.0	
Retail revenues per MWh, net of associated power supply costs and power cost adjustment mechanisms	(2.8)	
Transmission wheeling-related revenues	(5.3)	
Other operations and maintenance (O&M) expenses	8.7	
Other changes in operating revenues and expenses, net	(1.7)	
Prior year provision for sharing with customers	5.0	
Increase in Idaho Power operating income	2.3	
Non-operating income and expenses, net	9.9	
Income tax expense	(10.1)	
Total increase in Idaho Power net income		2.1
Other IDACORP changes (net of tax)		4.0
Net income attributable to IDACORP, Inc. - December 31, 2019		**$ 232.9**

IDACORP's net income increased $6.1 million for 2019 compared with 2018, primarily due to higher net income at Idaho Power and IFS.

Idaho Power's customer growth of 2.5 percent added $18.8 million to Idaho Power's operating income compared with 2018. Lower sales volumes on a per-customer basis decreased operating income by $21.4 million in 2019 compared with 2018, primarily due to lower irrigation sales. Greater precipitation and more moderate spring and summer temperatures in Idaho Power's service area led agricultural irrigation customers to use 12 percent less energy per customer to operate irrigation pumps during 2019 compared with 2018. To a lesser extent, sales volumes on a per-customer basis in 2019 were negatively affected by lower per-customer commercial and industrial sales.

The net decrease in retail revenues per MWh reduced operating income by $2.8 million in 2019 compared with 2018. As provided by the settlement stipulation approved by the IPUC in 2018 related to income tax reform, retail revenues per MWh in 2019 were reduced by $7.4 million of non-cash accruals for future amortization related to regulatory deferrals that would otherwise be a future liability of Idaho customers, compared with a $1.5 million revenue reduction in 2018. In 2018, a corresponding $4.0 million of non-cash accruals were recorded as other O&M expense for the amortization of specified deferrals. The decrease in retail revenues per MWh from these non-cash accruals was partially offset by changes in the customer sales mix, as volumes sold to residential customers in 2019 made up a greater portion of the customer sales mix compared with 2018. Residential customers generally pay a higher per-MWh rate than other customers.

During 2019, transmission wheeling-related revenues decreased $5.3 million compared with 2018. Idaho Power's open access transmission tariff (OATT) rates decreased 10 percent in October 2018 and 13 percent in October 2019. To a lesser extent, lower volumes also reduced transmission wheeling-related revenues.

Other O&M expenses were $8.7 million lower in 2019 compared with 2018, as Idaho Power's continued focus on managing other O&M expenses resulted in lower expenses across a number of areas. Lower bad debt expense reduced other O&M expenses by $1.1 million, due primarily to enhanced collection efforts and a strong economy. Also, other O&M expenses in 2018 included $4.0 million of non-cash amortization expense of regulatory deferrals pursuant to the settlement stipulation approved by the IPUC in 2018 related to income tax reform.

Based on its 2019 Idaho ROE, Idaho Power recorded no additional ADITC amortization or provision against current revenues for sharing of earnings with customers in 2019 under the Idaho regulatory settlement stipulation approved in October 2014. In 2018, Idaho Power recorded a $5.0 million provision against revenues for sharing of earnings with customers.

Non-operating income and expenses, net, increased $9.9 million in 2019 compared with 2018. As disclosed in Note 12 - "Benefit Plans" to the consolidated financial statements included in this report, a temporary deviation from an Idaho Power substantive postretirement plan resulted in a $4.2 million charge in 2018 that did not recur in 2019. Allowance for equity funds used during construction increased $2.8 million in 2019 as the average construction work in progress balance was higher throughout 2019 compared with 2018. Also, investment income from the Rabbi trust associated with Idaho Power's nonqualified defined benefit pension plans increased $2.2 million based on stronger asset returns in 2019 compared with 2018.

During 2018, Idaho Power recorded tax benefits for a $5.7 million remeasurement of deferred taxes resulting from income tax reform and $1.3 million for tax-deductible bond redemption costs incurred in 2018. There was no such remeasurement or bond redemption in 2019. These items, combined with higher pre-tax net income in 2019, resulted in higher income tax expense in 2019 compared with 2018. Amortization of vintage investment tax credits that became available in 2019 lowered income tax expense by $3.4 million, most of which is not expected to recur.

At IFS, a $3.0 million increase in distributions from the sale of low-income housing properties led to higher IFS net income in 2019 compared with 2018.

2020 Initiatives and Strategy

IDACORP’s strategy is focused on four areas: growing financial strength, improving Idaho Power's core business, enhancing Idaho Power’s brand, and keeping employees safe and engaged. IDACORP's board of directors has reviewed and affirmed IDACORP’s long-term strategy. In executing on these four strategic cornerstones, IDACORP seeks to balance the interests of shareowners, Idaho Power customers, employees, and other stakeholders. Idaho Power is committed to working for strong, sustainable financial results by continuing to provide safe, fair-priced, reliable service to its customers from diversified generation resources. 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 prices that Idaho Power is authorized to charge for its electric and transmission services are 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 prudently managing 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 its Idaho customers of Idaho-jurisdictional earnings in excess of 10.0 percent 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 2020, 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.

- ***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 and purchase power. In recent years, Idaho Power has seen growth in the number of customers in its service area. In 2019, Idaho Power's customer count grew by 2.5 percent. Idaho Power expects its number of customers to continue to increase in the foreseeable future. Employment in Idaho Power's service area grew by approximately 3.2 percent based on Idaho Department of Labor preliminary December 2019 data. Idaho Power continues to support State of Idaho-coordinated efforts to promote economic development with an emphasis on attracting industrial and commercial customers to its service area.

  In June 2019, Idaho Power released its 2019 Integrated Resource Plan (IRP), Idaho Power's long-term forecast of loads and resources, which was amended in January 2020. For more information on the 2019 IRP, including the load forecast assumptions Idaho Power used 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 hydropower facilities comprise over one-half of Idaho Power's nameplate generation capacity, precipitation levels impact the mix of Idaho Power's generation resources. When hydropower generation is reduced, Idaho Power must rely on more expensive generation sources and purchased power. When favorable hydropower generating conditions exist for Idaho Power, they also may exist for other Pacific Northwest hydropower facility operators, lowering regional wholesale market prices and impacting the revenue Idaho Power receives from wholesale energy sales. 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 depreciation 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 hydropower and thermal generation facilities also require continuing upgrades and equipment replacement, and the company is undertaking a significant relicensing effort for the Hells Canyon Complex (HCC), its largest hydropower 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 hydropower 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 hydropower generation resources, transmission capacity, energy market prices, and Idaho Power's hedging program for managing fuel costs. 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 to Idaho Power of fluctuations in power supply costs.

- ***Regulatory and Environmental Compliance Costs:*** Idaho Power is subject to extensive federal and state laws, policies, and regulations, as well as regulatory actions and audits by agencies and quasi-governmental agencies, including the FERC, 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, increase the cost of 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 its jointly-owned coal-fired generating plants.

- ***Water Management and Relicensing of the Hells Canyon Hydropower 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 hydropower projects. Also, Idaho Power is involved in renewing its long-term federal license for the HCC, its largest hydropower 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 2019 are compared with 2018.

The table below presents Idaho Power's energy sales and supply (in thousands of MWh) for the last two years.

	Year Ended December 31,	
	2019	**2018**
Retail energy sales	14,537	14,587
Wholesale energy sales	2,171	2,246
Bundled energy sales	680	617
Total energy sales	17,388	17,450
Hydropower generation	8,294	8,682
Coal generation	3,012	3,274
Natural gas and other generation	2,114	1,408
Total system generation	13,420	13,364
Purchased power	5,200	5,431
Line losses	(1,232)	(1,345)
Total energy supply	17,388	17,450

For purposes of illustration, Boise, Idaho, weather-related information for the last two years is presented in the table that follows.

	Year Ended December 31,		
	2019	**2018**	**Normal[(2)]**
Heating degree-days[(1)]	5,314	4,984	5,514
Cooling degree-days[(1)]	1,020	1,116	942
Precipitation (inches)	14.5	10.6	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 2019, retail sales volumes decreased less than 1 percent compared with the prior year. Greater precipitation and more moderate spring and summer temperatures in Idaho Power's service area led agricultural irrigation customers to use 12 percent less energy per customer to operate irrigation pumps during 2019. Customer growth partially offset the decrease in sales volumes per customer during 2019 compared with 2018, with the number of Idaho Power's customers growing by 2.5 percent.

Total system generation in 2019 was consistent with that of the prior year. An increase in natural gas generation more than offset decreases in hydropower and coal generation.

Wholesale energy sales volumes decreased 75 thousand MWh, or 3 percent, during 2019 compared with 2018, due primarily to a decrease in purchased power, both in market purchases and in purchases under PURPA contracts, resulting in decreased 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 two years.

	Year Ended December 31,	
	2019	**2018**
Retail revenues:		
Residential (includes $35,587 and $34,625, respectively, related to the FCA[1])	$ 526,966	$ 530,527
Commercial (includes $1,336 and $1,299, respectively, related to the FCA[1])	295,203	310,299
Industrial	181,372	190,130
Irrigation	135,850	158,001
Provision for sharing	—	(5,025)
Deferred revenue related to HCC relicensing AFUDC[2]	(8,780)	(8,780)
Total retail revenues	$ 1,130,611	$ 1,175,152
Volume of Sales (MWh)		
Residential	5,273	5,135
Commercial	4,092	4,105
Industrial	3,412	3,371
Irrigation	1,760	1,976
Total retail MWh sales	14,537	14,587
Number of retail customers at year-end		
Residential	477,404	464,670
Commercial	72,855	71,680
Industrial	131	120
Irrigation	21,387	21,175
Total customers	571,777	557,645

(1) The FCA mechanism is an alternative revenue program and does not represent revenue from contracts with customers.
(2) The IPUC allows 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.

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 two 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: Retail revenues decreased $44.5 million in 2019 compared with 2018. The primary factors affecting retail revenues during the period were the following:

- Rates: Customer rates, excluding collections of amounts related to the power cost adjustment mechanism, decreased retail revenues by $3.8 million in 2019 compared with 2018. The 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 reduced revenues in 2019 more significantly than in 2018. Customer rates also include the return to customers of amounts related to the PCA mechanism, which decreased revenues by $42.8 million in 2019 compared with 2018. The return to customers of amounts related to the PCA mechanism in rates does not have a significant effect on operating income as a corresponding amount is recorded as a reduction of expense in the same period it is returned through rates.

- Customers: Customer growth of 2.5 percent increased retail revenues by $27.0 million in 2019 compared with 2018.

- Usage: Lower usage (on a per customer basis), primarily by irrigation customers, decreased retail revenues by $30.9 million during 2019 compared with 2018. Greater precipitation and more moderate spring and summer temperatures in Idaho Power's service area led agricultural irrigation customers to use 12 percent less energy per customer to operate irrigation pumps during 2019. To a lesser extent, sales volumes on a per-customer basis were negatively affected by lower per-customer commercial and industrial sales.

- 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 2019 increased the amount of FCA revenue accrued by $1.0 million compared with 2018.

- Sharing: In 2019, Idaho Power recorded no provision against current revenue for sharing with customers, as its full-year return on year-end equity in the Idaho jurisdiction (Idaho ROE) was between 9.5 percent and 10.0 percent. In 2018, Idaho Power recorded a $5.0 million provision against current revenue for sharing with customers as Idaho ROE was above 10.0 percent. 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.

***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 two years (in thousands, except for MWh amounts).

	Year Ended December 31,	
	2019	**2018**
Wholesale energy revenues	$ 71,198	$ 52,845
Wholesale MWh sold	2,171	2,246
Wholesale energy revenues per MWh	$ 32.80	$ 23.53

In 2019, wholesale energy revenue increased by $18.4 million, or 35 percent, compared with 2018. Wholesale energy sales volumes decreased 3 percent in 2019 compared with 2018, but the average price of wholesale energy sales was 39 percent higher for 2019 compared with 2018. 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. During the first half of 2019, the pipeline was operating at reduced capacity, which contributed to continued elevated energy prices during that period.

Transmission Wheeling-Related Revenues: Revenue related to transmission wheeling decreased $5.3 million in 2019 compared with 2018. Idaho Power's OATT rates decreased 10 percent in October 2018 and 13 percent October 2019. To a lesser extent, lower volumes also reduced transmission wheeling-related revenues. Refer to "Regulatory Matters" in this MD&A for more information on Idaho Power's OATT rate.

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, 2019, Idaho Power's energy efficiency rider balances were a $0.3 million regulatory asset in the Idaho jurisdiction and a $1.2 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 two years (in thousands, except for MWh amounts).

	Year Ended December 31,	
	2019	**2018**
Expense		
PURPA contracts	$ 187,344	$ 189,722
Other purchased power (including wheeling)	97,922	104,092
Total purchased power expense	$ 285,266	$ 293,814
MWh purchased		
PURPA contracts	2,983	3,045
Other purchased power	2,217	2,386
Total MWh purchased	5,200	5,431
Cost per MWh from PURPA contracts	$ 62.80	$ 62.31
Cost per MWh from other sources	$ 44.17	$ 43.63
Weighted average - all sources	$ 54.86	$ 54.10

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 hydropower 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 expense decreased $8.5 million, or 3 percent, in 2019 compared with 2018, primarily due to a 7 percent decrease in the volume of other non-PURPA power purchases. Other non-PURPA purchased power volumes decreased as Idaho Power used its own generation to meet customer demand. These volume decreases were partially offset by increases in cost per MWh of power purchased from all sources.

Fuel Expense**:** The table below presents Idaho Power's fuel expenses and thermal generation for the last two years (in thousands, except per MWh amounts).

	Year Ended December 31,	
	2019	**2018**
Expense		
Coal	$ 105,257	$ 115,524
Natural gas(1)	51,615	17,674
Total fuel expense	$ 156,872	$ 133,198
MWh generated		
Coal	3,012	3,274
Natural gas(1)	2,114	1,408
Total MWh generated	5,126	4,682
Cost per MWh - Coal	$ 34.95	$ 35.29
Cost per MWh - Natural gas	$ 24.42	$ 12.55
Weighted average, all sources	$ 30.60	$ 28.45

(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 increased $23.7 million, or 18 percent, in 2019 compared with 2018, due to a 9 percent increase in thermal generation volume and higher average costs per MWh for natural gas. Higher gas generation was mostly due to economic-based decisions to use the Danskin and Bennett Mountain gas-fired power plants as baseload resources and to increase generation at the Langley Gulch plant in 2019 compared with 2018. In 2019, gains on financial gas hedges included in fuel expense were $8.7 million lower than in 2018, increasing average costs per MWh for natural gas. 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 financial gas hedges at the time of the rupture. Most of these realized hedging gains benefit customers through the power cost adjustment mechanisms described below.

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 hydropower 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 two years (in thousands).

	Year Ended December 31,	
	2019	2018
Power supply cost accrual	$ 49,234	$ 41,535
Amortization of prior year authorized balances	(47,187)	571
Total power cost adjustment expense	$ 2,047	$ 42,106

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 2019 and 2018, most of the difference is accrued. When actual power supply costs are higher than the amount forecasted in power cost adjustment rates, most of the difference is deferred. The amortization of the prior year's balances represents the offset to the amounts being collected or refunded in the current 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).

Idaho Power accrued $7.7 million more in power supply costs in 2019 compared with 2018 as actual net power supply costs were lower relative to forecasted costs. In addition, Idaho Power recorded $47.2 million of amortization of the prior-year authorized balances in 2019, compared with $0.6 million of amortization in 2018.

***Other Operations and Maintenance Expenses*:** Other O&M expenses decreased $8.7 million, or 2 percent, in 2019 compared with 2018, as Idaho Power's continued focus on managing other O&M expenses resulted in lower expenses across a number of areas. Lower bad debt expense reduced other O&M expenses by $1.1 million, due primarily to enhanced collection efforts and a strong economy. Also, other O&M expenses in 2018 included $4.0 million of non-cash amortization expense of regulatory deferrals pursuant to the settlement stipulation approved by the IPUC in 2018 related to income tax reform.

Income Taxes

IDACORP's and Idaho Power's 2019 income tax expense increased $7.1 million and $10.1 million, respectively, when compared with 2018. During 2018 Idaho Power recorded tax benefits for a $5.7 million remeasurement of deferred taxes resulting from income tax reform and $1.3 million for tax-deductible bond redemption costs incurred in 2018. There was no such remeasurement or bond redemption in 2019. Also, 2018 included a benefit from plant-related income tax return adjustments, which reduced Idaho Power income tax expense in 2018. These items, combined with greater 2019 net income, resulted in higher income tax expense in 2019 compared with 2018. Amortization of vintage investment tax credits that became available in 2019 lowered tax expense by $3.4 million, most of which is not expected to recur. Also, at IFS, a $3.0 million increase in distributions from the sale of low-income housing properties reduced income tax expense at IDACORP in 2019 compared with 2018.

For additional information relating to IDACORP's and Idaho Power's income taxes 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 hydropower and thermal generation facilities also require continuing upgrades and component replacement. On an accrual basis, Idaho Power's additions to electric plant, excluding AFUDC, were $295 million in 2019 and $274 million in 2018. Cash construction expenditures, excluding AFUDC and excluding net costs of removing assets from service, were $268 million in each of 2019 and 2018. Idaho Power expects these substantial capital expenditures to continue, with estimated total capital expenditures of more than $1.6 billion expected over the period from 2020 through 2024.

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 14, 2020, IDACORP's and Idaho Power's access to debt, equity, and credit arrangements included:

- their respective $100 million and $300 million revolving credit facilities;
- IDACORP's shelf registration statement filed with the U.S. Securities and Exchange Commission (SEC) on May 17, 2019, 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 17, 2019, which may be used for the issuance of first mortgage bonds and debt securities; $500 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 2020, the companies believe they will be able to meet capital requirements and fund corporate expenses during 2020 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.

IDACORP and Idaho Power seek to maintain capital structures of approximately 50 percent debt and 50 percent equity, maintaining this ratio influences IDACORP's and Idaho Power's debt and equity issuance decisions. As of December 31, 2019, IDACORP's and Idaho Power's capital structures, as calculated for purposes of applicable debt covenants, were as follows:

	IDACORP	Idaho Power
Debt	43%	45%
Equity	57%	55%

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 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 2019 were $367 million and $344 million, respectively, decreases of $125 million and $75 million for IDACORP and Idaho Power, respectively, when compared with 2018. Significant items that affected the companies' operating cash flows in 2019 relative to 2018 were as follows:

- a $6 million increase and $2 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 cost adjustment amounts accrued or deferred and refunded or collected under Idaho rate mechanisms, decreased operating cash inflows by $53 million;
- Idaho Power received $19 million of distributions from IERCo's investment in BCC for 2019, compared with $29 million in 2018; changes in distributions from year to year are primarily driven by changes in the timing of cash needs associated with BCC;
- changes in deferred taxes and in taxes accrued and receivable combined to increase cash flows by $7 million and $4 million at IDACORP and Idaho Power, respectively; and

- 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 decreased operating cash flows by $7 million and $5 million for IDACORP and Idaho Power, respectively;
  - the changes in other current assets decreased cash flows by $20 million, which was primarily due to the timing of purchases and consumption of coal at Idaho Power's jointly-owned coal-fired generating plants; and
  - timing of accounts payable payments decreased operating cash flows by $39 million for IDACORP and increased operating cash flows by $16 million for Idaho Power (the difference relates to the timing of estimated income tax payments from Idaho Power to IDACORP).

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 $279 million and $278 million in 2019 and 2018, 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 $2 million and $22 million in 2019 and 2018 from Boardman-to-Hemingway project joint permitting participants relating to a portion of these permitting 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 equity securities of $11 million in both 2019 and 2018. Idaho Power received $5 million of proceeds from the sales of equity securities in both 2019 and 2018.

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 2019 and 2018:

- in August 2019, Idaho Power purchased and remarketed two of its outstanding series of pollution control tax-exempt bonds, one in the aggregate principal amount of $49.8 million issued in 2003 by Humboldt County, Nevada and due in 2024, and the other in the aggregate principal amount of $116.3 million issued in 2006 by Sweetwater County, Wyoming and due in 2026. The bonds were remarketed with substantially the same terms, but with lower term interest rates. The term interest rate of the series due in 2024 decreased from 5.15 percent to 1.45 percent and the term interest rate of the series due in 2026 decreased from 5.25 percent to 1.70 percent. Idaho Power expects the lower interest rates to reduce interest expense by approximately $5.6 million annually for the next five years and $3.9 million annually thereafter for the final two years of the longer-lived bonds;
- in March 2018, Idaho Power issued $220 million in principal amount of 4.20% first mortgage bonds Series K, maturing March 1, 2048;
- in April 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;
- IDACORP and Idaho Power paid dividends of approximately $130 million and $121 million in 2019 and 2018, respectively.

Financing Programs and Available Liquidity

IDACORP Equity Programs: From time to time, IDACORP enters into sales agency agreements under which it offers and sells shares of its common stock through a third-party agent. The most recent sales agency agreement terminated in May 2016. IDACORP has no current plans to issue equity securities other than under its equity compensation plans during 2020, and as of the date of this report, IDACORP has not pursued the execution of a new sales agency agreement.

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 2019, Idaho Power received orders from the IPUC, OPUC, and WPSC authorizing the company 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, 2022, 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 all-in interest rate limit of seven percent.

In May 2019, Idaho Power filed a shelf registration statement with the SEC, which became effective upon filing for the offer and sale of an unspecified principal amount of its first mortgage bonds. The issuance of first mortgage bonds requires that Idaho Power meet interest coverage and security provisions set forth in the Idaho Power's Indenture of Mortgage and Deed of Trust dated as of October 1, 1937, as amended and supplemented from time to time (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, 2019, 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, 2019, Idaho Power could issue approximately $1.9 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions.

Pollution Control Tax-Exempt Bonds**:** In August 2019, Idaho Power purchased and remarketed two of its outstanding series of pollution control tax-exempt bonds, one in the aggregate principal amount of $49.8 million issued in 2003 by Humboldt County, Nevada and due in 2024, and the other in the aggregate principal amount of $116.3 million issued in 2006 by Sweetwater County, Wyoming and due in 2026. The bonds were remarketed with substantially the same terms, but with lower term interest rates. The term interest rate of the series due in 2024 decreased from 5.15 percent to 1.45 percent and the term interest rate of the series due in 2026 decreased from 5.25 percent to 1.70 percent. Idaho Power expects the lower interest rates to reduce interest expense by approximately $5.6 million annually for the next five years and $3.9 million annually thereafter for the final two years of the longer-lived bonds.

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 December 2019, IDACORP and Idaho Power entered into amendments to credit agreements for their $100 million and $300 million credit facilities, respectively. 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 one time and letters of credit not to exceed $50 million at any one 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 $50 million at any one time outstanding. 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 Market Index rate plus 1.0 percent, or (2) the LIBOR Market Index rate, plus, in each case, an applicable margin, provided that the federal funds rate and LIBOR Market Index rate will not be less than zero percent. An alternate benchmark rate selected by the administrative agent for the credit facilities and IDACORP and Idaho Power will apply during any period in which the LIBOR rate is unavailable or unascertainable. The applicable margin is based on IDACORP's or Idaho Power's, as applicable, senior unsecured long-term indebtedness credit rating, as set forth on a schedule to the credit agreements. The companies also pay a facility fee based on the respective company's credit rating for senior unsecured long-term debt securities. The credit facilities terminate on December 6, 2024, though IDACORP and Idaho Power may request up to two-one-year extensions of the credit agreements, subject to certain conditions.

Each facility contains a covenant requiring each company to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization equal to or less than 65 percent as of the end of each fiscal quarter. In determining the leverage ratio, “consolidated indebtedness” broadly includes all indebtedness of the respective borrower and its subsidiaries, including, in some instances, indebtedness evidenced by certain hybrid securities (as defined in the credit agreement). “Consolidated total capitalization" is calculated as the sum of all consolidated indebtedness, consolidated stockholders' equity of the borrower and its subsidiaries, and the aggregate value of outstanding hybrid securities. At December 31, 2019, the leverage ratios for IDACORP and Idaho Power were 43 percent and 45 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, 2019, 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 2020.

The events of default under both facilities include, without limitation, non-payment of principal, interest, or fees; materially false representations or warranties; breach of covenants; bankruptcy or insolvency events; condemnation of property; cross-default to certain other indebtedness; failure to pay certain judgments; change of control; failure of IDACORP to own free and clear of liens the voting stock of Idaho Power; the occurrence of specified events or the incurring of specified liabilities relating to benefit plans; and the incurring of certain environmental liabilities, subject, in certain instances, to cure periods.

Upon any event of default relating to the voluntary or involuntary bankruptcy of IDACORP or Idaho Power or the appointment of a receiver, the obligations of the lenders to make loans under the applicable facility and to issue letters of credit will automatically terminate and all unpaid obligations will become due and payable. Upon any other event of default, the lenders holding greater than 50 percent of the outstanding loans or greater than 50 percent of the aggregate commitments (required lenders) or the administrative agent with the consent of the required lenders may terminate or suspend the obligations of the lenders to make loans under the facility and to issue letters of credit under the facility and/or declare the obligations to be due and payable. During an event of default under the facilities, the lenders may, at their option, increase the applicable interest rates then in effect and the letter of credit fee by 2.0 percentage points per annum. A ratings downgrade would result in an increase in the cost of borrowing but would not result in a default or acceleration of the debt under the facilities. However, if Idaho Power's ratings are downgraded below investment grade, Idaho Power must extend or renew its authority for borrowings under its IPUC and OPUC regulatory orders.

Without additional approval from the IPUC, the OPUC, and the WPSC, the aggregate amount of short-term borrowings by Idaho Power at any one time outstanding may not exceed $450 million. Idaho Power has obtained approval of the state public utility commissions of Idaho, Oregon, and Wyoming for the issuance of short-term borrowings through December 2026.

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, 2019		December 31, 2018	
	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.

IDACORP and Idaho Power had no short term commercial paper outstanding during the years ended December 31, 2019 and 2018. At February 14, 2020, 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, 2019, Idaho Power had $1.4 million of 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, 2019, the amount of additional collateral that could be requested upon a downgrade to below investment grade is approximately $10.3 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

On an accrual basis, Idaho Power's additions to electric plant, excluding AFUDC, were $295 million in 2019. Idaho Power's cash construction expenditures, excluding AFUDC, were $268 million during the year ended December 31, 2019. The cash expenditure amount excludes net costs of removing assets from service. The table below presents Idaho Power's estimated accrual-basis additions to electric plant for 2020 through 2024 (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.

	2020	2021	2022-2024
Expected capital expenditures (excluding AFUDC)	$ 300-310	$ 305-315	$ 1,000-1,050

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 2020 through 2024 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-$125 million per year for construction and replacement of distribution lines and stations, including replacement of underground distribution cables;
- $15-$35 million per year for ongoing improvements and replacements at thermal plants;
- $60-$95 million per year for hydropower 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.

<u>Boardman-to-Hemingway Transmission Line</u>: The Boardman-to-Hemingway line, a proposed 300-mile, high-voltage transmission project between a substation near Boardman, Oregon, and the Hemingway substation 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 at least 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.

Approximately $106 million, including AFUDC, has been expended on the Boardman-to-Hemingway project through December 31, 2019. Pursuant to the terms of the joint funding arrangements, Idaho Power has received $72 million as of December 31, 2019, from project participants for their share of costs. As of the date of this report, no material co-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.

Idaho Power's share of the remaining permitting phase of the project (excluding AFUDC) is included in the capital requirements table above, which includes approximately $105 million of Idaho Power's share of estimated costs related to design and early construction, which are primarily included in the table in the period 2022-2024. 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, allocation of ownership interests, and cost estimates.

The permitting phase of the Boardman-to-Hemingway project is subject to federal review and approval by the U.S. Bureau of Land Management (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. In September 2019, the Department of the Navy issued its record of decision authorizing the project to cross approximately seven miles of Department of the Navy lands. In November 2019, third parties filed a lawsuit in the federal district court of Oregon, challenging the BLM and U.S. Forest Service records of decision for the Boardman-to-Hemingway project. On February 13, 2020, Idaho Power filed a motion to intervene in the legal proceeding. The litigation is in its initial phases and remains pending as of the date of this report.

In the separate Oregon state permitting process, the Oregon Department of Energy (ODOE) issued a Draft Proposed Order in May 2019 that recommends approval of the project to the state's Energy Facility Siting Council (EFSC). The ODOE is expected to issue a Proposed Order in the first half of 2020. Idaho Power currently expects the EFSC to issue a final order and site certificate in 2021. Given the status of ongoing permitting activities and the construction period, Idaho Power expects the in-service date for the transmission line will be in 2026 or some time thereafter.

<u>Gateway West Transmission Line</u>: Idaho Power and PacifiCorp are pursuing the joint development of the Gateway West project, a high-voltage transmission lines project between a substation located near Douglas, Wyoming, and the Hemingway substation 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 $41 million, including Idaho Power's AFUDC, for its share of the permitting phase of the project through December 31, 2019. 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 ongoing expenditures for 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. PacifiCorp is currently constructing a 140-mile segment of their portion of the project in Wyoming, scheduled to be completed by the end of 2020. 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 70 percent of Idaho Power's hydropower generating nameplate capacity and 35 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 April 2018, the IPUC issued an order approving 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.

Environmental Regulation Costs: Idaho Power anticipates that it will continue to incur significant expenditures for its hydropower relicensing efforts and could incur significant expenditures if required to install additional environmental controls at its Jim Bridger coal-fired plant. 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 2019, which was amended in January 2020. The 2019 IRP identified a preferred resource portfolio and action plan, which includes the completion of the Boardman-to-Hemingway transmission line in 2026, the end to Idaho Power's participation in coal-fired operations at the North Valmy plant units 1 and 2 in 2019 and 2025, respectively, the end to Idaho Power's participation in coal-fired operations at the Jim Bridger plant by 2030, with the exit from two of the four Jim Bridger plant units in 2022 and 2026, respectively, and the addition of a 120 megawatt (MW) solar resource in 2022. However, as noted in the 2019 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, the actual completion date of the Boardman-to-Hemingway transmission project, and the economics and logistics of plant retirements. These uncertainties, as well as others, likely will 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 2019 IRP is included in Part I, Item 1 - "Business - Resource Planning" in this report.

Potential Future Rate Base Additions

As noted previously in this MD&A, 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 depreciation 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. Idaho Power's current rate base of $2.7 billion was established in June 2012, when the IPUC issued an order approving the inclusion of the investment and associated costs of the Langley Gulch plant in rates. Through December 31, 2019, Idaho Power has placed $0.7 billion of property, plant, and equipment in service since June 2012, net of accumulated depreciation. These assets could be included in future rate base if Idaho Power were to file a general rate case, though Idaho Power has no plans to do so in 2020. Idaho Power expects to place in service an additional $0.7 billion of rate base-eligible projects over the next five years. Idaho Power expects it could also add up to an additional $1.3 billion to rate base over the next several years by completing projects currently in process with uncertain in-service dates or due to additional spending required by completion of the projects. These projects include HCC relicensing, additional capital expenditures to comply with the expected requirements of a new HCC license, post-relicensing water temperature mitigation efforts at HCC, the Boardman-to-Hemingway project either at or above Idaho Power's current ownership percentage in the project, and certain distribution system modernization projects.

Defined Benefit Pension Plan Contributions and Recovery

Idaho Power contributed $40 million to its defined benefit pension plan in each of 2019 and 2018. Idaho Power's minimum required contribution to be made during 2020 is estimated to be $14 million. Depending on market conditions and cash flow considerations, Idaho Power could contribute up to $40 million to the pension plan during 2020. 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 2020, Idaho Power expects continuing significant contribution obligations under the pension plan. Refer to 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, 2019 and 2018, Idaho Power's deferral balance associated with the Idaho jurisdiction was $173 million and $148 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. Additional information on the regulatory assets related to Idaho Power's pension and postretirement programs can be found in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

Contractual Obligations

The following table presents IDACORP's and Idaho Power's contractual cash obligations as of December 31, 2019, for the respective periods in which they are due:

	Payments Due by Period				
	Total	2020	2021-2022	2023-2024	Thereafter
	(millions of dollars)				
Long-term debt[1]	$ 1,856	$ 100	$ 75	$ 125	$ 1,556
Future interest payments[2]	1,441	79	150	144	1,068
Purchase obligations:					
Maintenance and service agreements[3]	148	48	30	14	56
FERC and other industry-related fees[3]	132	14	27	26	65
Cogeneration and small power production	4,010	242	500	529	2,739
Fuel supply agreements	192	56	44	17	75
Other[3][4]	48	3	8	7	30
Pension and postretirement benefit plans[5]	323	26	117	128	52
Other long-term liabilities - IDACORP only[3]	2	—	—	—	2
Total[6]	$ 8,152	$ 568	$ 951	$ 990	$ 5,643

(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, 2019.

(3) Approximately $48 million of the amounts in maintenance and service agreements, $131 million of the amounts in FERC and other industry-related fees, $27 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 2024 with any level of precision, and amounts through 2024 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.

(6) Asset retirement obligations of $28.2 million are not included in the table as the settlement of these liabilities cannot be determined with certainty, however we believe these liabilities will be settled in more than five years. For more information on asset retirement obligations, refer to Note 14 – "Asset Retirement Obligations (ARO)" to the consolidated financial statements included in this report.

In March 2019, Idaho Power signed a 20-year power purchase agreement to purchase the output from a planned 120-MW solar facility. The agreement was approved by the IPUC in December 2019 and is, as of the date of this report, pending approval by the OPUC. If approved, the agreement would increase contractual obligations by $136 million over the 20-year term. In October 2019, Idaho Power exercised its right under the power purchase agreement to negotiate during the fourth quarter of 2019 for the acquisition by Idaho Power or one of its affiliates of the planned 120-MW solar facility. Idaho Power and its affiliates did not ultimately reach an agreement to acquire ownership of the facility.

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 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. In 2019, IDACORP's board of directors increased the target long-term dividend payout ratio to between 60 percent and 70 percent of sustainable IDACORP earnings from the previous policy adopted in 2011, that targeted a dividend payout ratio of between 50 percent to 60 percent of sustainable earnings. 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 2019 and 2018, IDACORP's board of directors voted to increase the quarterly dividend to $0.67 per share and $0.63 per share of IDACORP common stock, respectively. IDACORP's dividends during 2019 were 55.5 percent of actual 2019 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 $58.3 million at December 31, 2019, representing IERCo's one-third share of BCC's total reclamation obligation of $175.0 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2019, the value of the reclamation trust fund totaled $139.5 million. During 2019, the reclamation trust fund made no 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.

In May 2019, the state of Wyoming enacted legislation that limits a mine operator's maximum amount of self-bonding. Idaho Power and the co-owners of BCC have until December 2020 to comply with the new regulations, which would reduce the portion of Idaho Power's guarantee of reclamation activities and obligations at BCC that Idaho Power is allowed to self-bond. As of the date of this report, Idaho Power believes the cost of any insurance, third-party assurance, or additional collateral that might be required for this guarantee due to the new law would be immaterial to the companies' consolidated financial statements.

REGULATORY MATTERS

Introduction

Idaho Power is under the jurisdiction (as to rates, service, accounting, and other general matters of utility operation) of the IPUC, the 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 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 OATT. Additionally, the FERC has jurisdiction over Idaho Power's sales of transmission capacity and wholesale electricity, hydropower project relicensing, and system reliability, among other items.

Idaho Power's development of regulatory filings takes into consideration short-term and long-term needs for rate relief and involves several factors that can affect the timing of these regulatory 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. In 2012, large single-issue rate cases for the Langley Gulch power plant resulted in the resetting of base rates in both Idaho and Oregon. 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. The IPUC and OPUC have also approved base rate changes in single-issue cases subsequent to 2014. Between general rate cases, Idaho Power relies upon customer growth, a fixed cost adjustment mechanism, power cost adjustment mechanisms, tariff riders, and other mechanisms to mitigate 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 2020.

Notable Retail Rate Changes in Idaho and Oregon

Included in the table that follows are notable regulatory developments during 2019 and 2018 that affected Idaho Power's results for the periods or that will likely affect future periods. Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report also provides a description of regulatory mechanism and associated orders of the IPUC and OPUC, and should be read in conjunction with the discussion of regulatory matters in this MD&A.

Description	Effective Date	Estimated Annualized Rate Impact (millions)[1]	
Oregon North Valmy plant Exit Framework Settlement Stipulation	1/1/2020	$	(3)
Idaho North Valmy plant Exit Framework Settlement Stipulation	6/1/2019		1
2019 Idaho PCA[2]	6/1/2019		(50)
2019 Idaho FCA	6/1/2019		19
May 2018 Idaho Tax Reform Settlement Stipulation - Idaho base rates	6/1/2018		(19)
May 2018 Idaho Tax Reform Settlement Stipulation - Idaho PCA[3]	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 North Valmy plant Accelerated Depreciation Settlement Stipulation	6/1/2018		2

(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) 2019 Idaho PCA rates include a $5.0 million credit to customers for sharing of 2018 earnings under the IPUC order approving the extension, with modifications, of the terms of the December 2011 Idaho settlement stipulation for the period from 2015 through 2019 (October 2014 Idaho Earnings Support and Sharing Settlement Stipulation) and a $2.7 million credit for income tax reform benefits related to Idaho Power's OATT rate under a May 2018 Idaho tax reform settlement stipulation as described below in this MD&A.

(3) 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 as described below in this MD&A.

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.

Other Notable Regulatory Matters

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 that allowed Idaho Power to, in certain circumstances, amortize additional accumulated deferred investment tax credits (ADITC) if Idaho Power's actual Idaho ROE was less than 9.5 percent, to help achieve a 9.5 percent Idaho ROE for the applicable year (October 2014 Idaho Earnings Support and Sharing Settlement Stipulation). Under the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation, when Idaho Power's actual calendar-year Idaho ROE exceeded 10.0 percent, Idaho Power was required to share a portion of its calendar-year Idaho-jurisdiction earnings with Idaho customers for the period from 2015 through 2019. The more specific terms and conditions of the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation are described in Note 3 - "Regulatory Matters - *Notable Idaho Regulatory Matters*" to the consolidated financial statements included in this report. The October 2014 Idaho Earning Support and Sharing Settlement Stipulation was modified and indefinitely extended, as described in "May 2018 Idaho Tax Reform Settlement Stipulation" of this MD&A.

In 2019, Idaho Power recorded no provision against current revenue for sharing with customers, as its full-year Idaho ROE was between 9.5 percent and 10.0 percent. In 2018, Idaho Power recorded a $5.0 million provision against current revenue for sharing with customers.

Idaho Power recorded the following amounts 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
2019	$ —	$ —	$ —
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.

May 2018 Idaho Tax Reform Settlement Stipulation: 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 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 was 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 decreased 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, with no defined end date. The May 2018 Idaho Tax Reform Settlement Stipulation does not impose a moratorium on Idaho Power filing a general rate case or other form of rate proceeding in Idaho during its term. IDACORP and Idaho Power believe that the terms allowing amortization of additional ADITC in the May 2018 Idaho Tax Reform Settlement Stipulation provide the companies with a greater degree of earnings stability than would be possible without the terms of the stipulation in effect. At December 31, 2019, the full $45 million of additional ADITC remained available for future use under the terms of the May 2018 Idaho Tax Reform Settlement Stipulation.

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. In December 2019, Idaho Power filed an application with the OPUC requesting approval of Idaho Power's quantification of $1.5 million in annualized Oregon jurisdictional benefits associated with federal and state income tax changes resulting from tax reform and adjusting customer rates to reflect this amount, effective June 1, 2020, until its next general rate case or other proceeding where the tax-related revenue requirement components are reflected in rates.

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.

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 North Valmy coal-fired power 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, and (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. 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 February 2019, Idaho Power reached an agreement with NV Energy that facilitates the planned end of Idaho Power's participation in coal-fired operations at units 1 and 2 of its jointly-owned North Valmy plant in 2019 and 2025, respectively. In May 2019, the IPUC issued an order approving the North Valmy plant exit agreement and allowing Idaho Power to recover through customer rates the $1.2 million incremental annual levelized revenue requirement associated with required North Valmy plant investments and other exit costs, effective June 1, 2019, through December 31, 2028. In December 2019, as planned, Idaho Power ended its participation in coal-fired operations of North Valmy plant unit 1 and removed approximately $160 million from both Utility plant in service and Accumulated provision for depreciation on the consolidated balance sheets at December 31, 2019.

In June 2017, the OPUC also approved a settlement stipulation allowing for (1) accelerated depreciation of North Valmy plant units 1 and 2 through December 31, 2025, (2) cost recovery of incremental North Valmy plant investments through May 31, 2017, and (3) forecasted North Valmy plant 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. In October 2019, the OPUC approved the North Valmy plant exit agreement and authorized Idaho Power to adjust customer rates in Oregon, effective January 1, 2020, to reflect a decrease in the annual levelized revenue requirement of $3.2 million, which mostly relates to the decrease in depreciation expense and other costs associated with the December 2019 end of Idaho Power's participation in coal-fired operations of North Valmy plant unit 1.

Customer-Owned Generation Filing: Customer-owned generation allows customers to install solar panels or other on-site energy-generating resources and connect them to Idaho Power's grid. If a customer requires more energy than its system generates, it utilizes energy supplied by Idaho Power's grid. If its system generates more energy than the customer uses, the energy goes back to the grid and Idaho Power applies a corresponding kWh credit to the customer's bill. In May 2018, the IPUC issued an order authorizing the creation of two new customer classes for residential and small commercial customers who install their own on-site generation, with no change to pricing or compensation. Since October 2018, Idaho Power has initiated two cases related to studying the costs and benefits of customer-owned generation on Idaho Power's system, and exploring whether, and to what extent, there should be modifications to the customer-owned generation pricing structure for residential and small general service customers (Residential and Small Commercial Case), and large commercial, industrial, and irrigation customers (Large Commercial, Industrial, and Irrigation Case). The IPUC issued orders in the Residential and Small Commercial Case during December 2019 and February 2020 directing Idaho Power to (1) complete additional studies related to the costs and benefits of customer generation before changes to the compensation structure are implemented, and (2) continue to allow customers with on-site generation prior to December 20, 2019, to be subject to the billing terms in place on that date until December 20, 2045. As of the date of this report, both the Residential and Small Commercial Case and Large Commercial, Industrial, and Irrigation Case are ongoing, and Idaho Power does not expect these cases to materially affect its financial condition or results of operations.

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 hydropower 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" in this MD&A 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 last year (in millions):

	Idaho	Oregon	Total
Balance at December 31, 2018	(42.1)	(0.2)	(42.3)
Current period net power supply costs accrued	(49.2)	—	(49.2)
Revenue sharing	(5.0)	—	(5.0)
Western EIM cost recovery to be collected through Idaho PCA	3.2	—	3.2
Prior amounts refunded through rates	51.4	0.1	51.5
SO_2 allowance and REC sales	(5.0)	(0.2)	(5.2)
Interest and other	(1.5)	—	(1.5)
Balance at December 31, 2019	$ (48.2)	$ (0.3)	$ (48.5)

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 actual financial and operational data Idaho Power files with the FERC and allows Idaho Power to recover costs for FERC-approved expenditures associated with its transmission system. In August 2019, Idaho Power filed its 2019 final transmission rate with the FERC, reflecting a transmission rate of $27.32 per kW-year, to be effective for the period from October 1, 2019, to September 30, 2020. 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 $107.0 million. The OATT rate in effect from October 1, 2018, to September 30, 2019, was $31.25 per kW-year based on a net annual transmission revenue requirement of $123.1 million. The decrease in the OATT rate is largely attributable to federal tax reform and increased short-term firm and non-firm transmission revenues in 2018, which serve 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 Hydropower Projects

Overview: Idaho Power, like other utilities that operate non-federal hydropower projects on qualified waterways, obtains licenses for its hydropower 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 hydropower 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. In April 2018, the IPUC approved a settlement stipulation signed by Idaho Power, the IPUC Staff, and a third-party intervenor and determined that $216.5 million in expenditures incurred for relicensing through December 31, 2015, were reasonably and prudently incurred, and therefore should be eligible for inclusion in customer rates at a later date. Relicensing costs of $326 million (including AFUDC) for the HCC, Idaho Power's largest hydropower complex and a major relicensing effort, were included in construction work in progress at December 31, 2019. 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, 2019, Idaho Power's regulatory liability for collection of AFUDC relating to the HCC was $152 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 hydropower generating plants.

Hells Canyon Complex: The HCC, located on the Snake River where it forms the border between Idaho and Oregon, provides approximately 70 percent of Idaho Power's hydropower generating nameplate capacity and 35 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 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 filed and withdrew its Section 401 certification applications with Oregon and Idaho on an annual basis while it was 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, provided that Idaho Power take no action that might 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 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 2019, the states of Idaho and Oregon, along with Idaho Power, reached a settlement pertaining to the CWA Section 401 certification that resolved the fish passage conflict between the parties. The settlement 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 Section 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 first 20 years of the new license term. In May 2019, Oregon and Idaho issued final CWA Section 401 certifications. These certifications have been submitted to the FERC as part of the relicensing process. In July 2019, three third-party lawsuits were filed against the Oregon Department of Environmental Quality in Oregon state court challenging the Oregon CWA Section 401 certification based on fish passage, water temperature, and mercury issues associated with the Snake River and HCC. Idaho Power has intervened in one of the third-party lawsuits and may intervene in the other two as well. No parties challenged the Idaho CWA Section 401 certification. On December 30, 2019, Idaho Power filed an Offer of Settlement with the FERC requesting specific language be included in the new HCC license based upon the settlement among Idaho, Oregon, and Idaho Power. The FERC has received several comments opposing the Offer of Settlement and its decision relating to the Offer of Settlement is pending as of the date of this report. Idaho Power continues to expect the FERC to issue an HCC license no earlier than 2022.

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 on measures to provide reasonable assurance that any discharges from the HCC will comply with applicable state water quality standards and associated measures identified in the final Section 401 certifications, and continues to cooperate with the USFWS, NMFS, and the FERC in an effort to address ESA concerns. Measures identified in the final Section 401 certifications included construction of aerated runners at the Brownlee project (part of the HCC), modification of spillways at the three dams in the HCC to address total dissolved gas issues, and upstream watershed improvements to address water temperatures during a small portion of the year. These and any other additional measures to satisfy relicensing requirements have added and will 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.

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, 2019, and 2018, Idaho Power's REC sales totaled $5.5 million and $2.9 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 hydropower and geothermal. The majority of these contracts are entered into as mandatory purchases under PURPA. As of December 31, 2019, Idaho Power had contracts to purchase energy from 129 on-line PURPA projects. An additional three contracts are with on-line non-PURPA projects, including the Elkhorn Valley wind project with a 101-MW nameplate capacity.

The following table sets forth, as of December 31, 2019, the resource type and nameplate capacity of Idaho Power's signed agreements for power purchases from PURPA and non-PURPA generating facilities. These agreements have original contract terms ranging from one to 35 years.

Resource Type	On-line megawatts (MW)	Under Contract but not yet On-line (MW)	Total Projects under Contract (MW)
PURPA:			
Wind	627	—	627
Solar	310	9	319
Hydropower	147	2	149
Other	52	—	52
Total PURPA	1,136	11	1,147
Non-PURPA:			
Wind	101	—	101
Geothermal	35	—	35
Solar	—	120	120
Total non-PURPA	136	120	256

The projects not yet on-line include one hydropower PURPA project and two solar PURPA projects that are scheduled to be on-line in 2020 and one solar PURPA project scheduled to be on-line in 2022. The non-PURPA solar project is scheduled to be on-line in 2022.

In September 2019, the FERC issued a Notice of Proposed Rulemaking that, if adopted, could affect how states determine PURPA project avoided cost rates for purchases of power generated from qualified facilities (QF), which facilities are eligible for QF status, whether and when certain QFs can enter into purchase agreements with utilities, and how parties can contest the eligibility of a generation facility seeking QF status. As of the date of this report, Idaho Power is unable to determine the impact of these potential changes on the company's future obligations for new PURPA power purchase contracts, as it would require further action by the state public utility commissions to implement many of the changes. 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 reduce the number of future PURPA generation projects, which could reduce purchased power costs for Idaho Power. Substantially all PURPA power purchase costs are recovered through base rates and Idaho Power's power cost adjustment mechanisms.

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 Affordable Clean Energy (ACE) rule and other Clean Air Act (CAA) requirements, 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 hydropower 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 North Valmy plant was also based primarily on the economics of operating the 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 2020 to 2022. Given the uncertainty of future environmental regulations and technological advances, Idaho Power is unable to predict its environmental-related expenditures beyond 2022, though they could be substantial. Furthermore, several executive orders issued since 2017 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. 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 hydropower 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 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. Furthermore, in August 2019, the USFWS and the NMFS issued a set of regulatory changes to some of the standards under which listings, delisting, and reclassifications, and critical habitat designations are made. 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 reduce the role of climate change models in listing decisions and the designations of critical habitat in areas where species are not present, which could also reduce Idaho Power's obligations for mitigation under the ESA related to various construction and relicensing projects.

The construction of generation, transmission, or distribution facilities and the relicensing of Idaho Power's hydropower 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 hydropower 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 hydropower 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 hydropower 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 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. 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. 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 2020 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.

The Washington ground squirrel inhabits various locations throughout two of the counties within the proposed routes for Boardman-to-Hemingway. It is not listed under the federal ESA, but it is considered endangered under Oregon law and the Boardman-to-Hemingway project will need to avoid ground squirrel colonies during construction. If colonies are found within the proposed site boundary during pre-construction surveys, re-siting the transmission would require additional permitting and would likely involve increased permitting costs and could further delay the in-service date of the project.

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 hydropower 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 hydropower dams on the lower Snake River, which Idaho Power expects will take place over a five-year period. In January 2020, the presidential administration's Council on Environmental Quality proposed rules to narrow federal agencies' NEPA obligations, which if adopted, may expedite projects and reduce the number of actions subject to NEPA review. None of Idaho Power's hydropower 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, personal property damage, personal injuries and loss of life, legal 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 hydropower 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 greenhouse gas (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 ended its participation in coal-fired operations at the North Valmy plant unit 1 in December 2019 and plans to end its participation in unit 2 in 2025, and plans 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/Affordable Clean Energy Rule: 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. In June 2019, the EPA released the ACE rule to replace the CPP under Section 111(d) of the CAA for existing electric utility generating units. The new rule provides states with new emissions guidelines that inform the state development of standards of performance to reduce CO_2 emissions from existing generation facilities and 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. States are required to submit their compliance plans to the EPA by July 2022. In August 2019, twenty-two states sued the EPA in federal appeals court to challenge the ACE rule.

Because the rule is premised on state implementation plans, the terms of which Idaho Power does not control, as of the date of this report Idaho Power is uncertain whether and to what extent the ACE rule may impact its operations in the near term. Idaho Power's preliminary review of the rule indicates that it may not have substantial impacts on Idaho Power's operation of existing thermal generation units due to its planned retirements and other planned upgrades at generating facilities.

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 emissions reporting system. The Climate Registry is a collaboration aimed at developing and managing a common GHG emissions 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. In December 2018, the EPA determined that it is not appropriate and necessary to regulate hazardous air pollutant emissions from power plants under Section 112 of the CAA. The emissions standards and other requirements of the MATS rule, however, remain in place. Idaho Power believes that as of the date of this report, its jointly-owned coal-fired plants are in compliance with the MATS rule, which does not significantly impact 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 emissions 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 one-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.

- *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 selective catalytic reduction (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. 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.

In February 2019, PacifiCorp submitted to the WDEQ an alternative regional haze compliance plan for the Jim Bridger plant that includes a reduced plant-wide monthly limit on emissions for NO_x and SO_2 and an annual total emissions cap of NO_x and SO_2 for units 1-4. If approved as proposed, the alternative plan would likely eliminate the requirement to install add-on NO_x controls at Jim Bridger units 1 and 2. If the compliance plan as proposed is not approved by WDEQ and finalized, Idaho Power will re-evaluate options with PacifiCorp to ensure it complies with EPA and WDEQ rules, but does not believe it would move forward with the installation of SCR equipment at units 1 and 2.

Clean Water Act Matters

Definition of "Waters of the United States" Under the CWA: In August 2015, the EPA and U.S. Army Corps of Engineers' (USACE) final rule defining the phrase "waters of the United States" (WOTUS) under the CWA became effective (WOTUS Rule). Idaho Power believes that the 2015 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. In January 2020, the EPA and USACE finalized the rule to repeal the WOTUS Rule and set new and more expansive standards for determining which waters are subject to the CWA, which substantially restored the definitions and guidance used prior to the WOTUS Rule.

Idaho Power believes the repeal rule and the WOTUS Rule will continue to be challenged in court, but expects that, even if the WOTUS Rule is reinstated in Idaho and should the revised definition take effect 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 hydropower plants, Idaho Power does not expect reinstatement would have a material impact on Idaho Power's operations or financial condition.

CWA Matters Related to Hydropower Relicensing: Idaho Power is also addressing CWA issues associated with the relicensing of its HCC. See "Relicensing of Hydropower 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 disclosures. 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 $1.4 billion of regulatory assets and $0.8 billion of regulatory liabilities at December 31, 2019. 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 plans 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, 2019, with maturities matching the projected cash outflows of the plans. Based on the results of this analysis, the discount rate used to calculate the 2020 pension expense will be decreased to 3.60 percent from the 4.55 percent rate used in 2019.

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 2020 pension expense will be decreased to 7.4 percent from the 7.5 percent used in 2019.

Gross net periodic pension and other postretirement benefit cost for these plans totaled $50.0 million and $51.2 million for the years ended December 31, 2019 and 2018, respectively, including amounts deferred as regulatory assets (see discussion below) and amounts allocated to capitalized labor. For 2020, gross pension and other postretirement benefit costs are expected to total approximately $54.9 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	
	2020	2019	2020	2019
	(millions of dollars)			
Effect of 0.5% rate increase on net periodic benefit cost	$ (8.7)	$ (7.0)	$ (4.0)	$ (3.5)
Effect of 0.5% rate decrease on net periodic benefit cost	9.7	7.8	4.0	3.4

Additionally, a 0.5 percent increase in the plans' discount rates would have resulted in a $97.1 million decrease in the combined benefit obligations of the plans as of December 31, 2019. A 0.5 percent decrease in the plans' discount rates would have resulted in an $110.0 million increase in the combined benefit obligations of the plans as of December 31, 2019.

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, 2019, a total of $173 million of expense was deferred as a regulatory asset. Idaho Power expects to defer approximately $26 million of expense in 2020. 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 2019 and 2018.

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 AND AUDITING PRONOUNCEMENTS

On June 1, 2017, the Public Company Accounting Oversight Board (PCAOB) issued Auditing Standard 3101, *The Auditor's Report on an Audit of Financial Statements When the Auditor Expresses an Unqualified Opinion* (AS 3101). AS 3101 includes a new requirement to describe critical audit matters arising from the audit of the current period's financial statements in the auditor's report. The requirements related to critical audit matters in AS 3101 were effective for audits of fiscal years ending on or after June 30, 2019, for large accelerated filers; and for fiscal years ending on or after December 15, 2020, for all other companies to which the requirements apply. Therefore, critical audit matters are included in the Report of Independent Registered Public Accounting Firm for IDACORP's consolidated financial statements as of and for the year ended December 31, 2019, and AS 3101 will be effective for Idaho Power as of and for the year ending December 31, 2020.

For a listing of other 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, 2019. 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, 2019, 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, 2019, both IDACORP and Idaho Power had $1.8 billion in fixed rate debt, with a fair market value of approximately $2.1 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 $262.2 million if market interest rates were to decline by one percentage point from their December 31, 2019, 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 and associated standards implementing the Risk Management Policy describe a collaborative process with customers and regulators via a committee called the Customer Advisory Group (CAG). The Risk Management Committee (RMC), comprised of selected Idaho Power officers and other senior managers, oversees the risk management program. The RMC is responsible for communicating the status of risk management activities to Idaho Power's Board of Directors and to the CAG, and Idaho Power’s Audit Committee is responsible for approving the Risk Management 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 Integrated Resource Plan. 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 Risk Management 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 Risk Management 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 Risk Management 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, 2019, Idaho Power had $1.4 million of 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, 2019, the amount of collateral that could be requested upon a downgrade to below investment grade was approximately $10.3 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,		
	2019	2018	2017
	(thousands of dollars except for per share amounts)		
Operating Revenues:			
Electric utility revenues	$ 1,342,940	$ 1,366,582	$ 1,344,893
Other	3,443	4,170	4,593
Total operating revenues	1,346,383	1,370,752	1,349,486
Operating Expenses:			
Electric utility:			
Purchased power	285,266	293,814	248,950
Fuel expense	156,872	133,198	145,829
Power cost adjustment	2,047	42,106	52,024
Other operations and maintenance	355,770	364,456	346,695
Energy efficiency programs	40,128	35,703	39,241
Depreciation	169,210	165,190	162,091
Taxes other than income taxes	34,044	34,792	34,089
Total electric utility expenses	1,043,337	1,069,259	1,028,919
Other	4,720	4,571	5,022
Total operating expenses	1,048,057	1,073,830	1,033,941
Operating Income	298,326	296,922	315,545
Allowance for Equity Funds Used During Construction	27,112	24,353	20,784
Earnings of Unconsolidated Equity-Method Investments	12,370	12,449	11,374
Other Income (Expense), Net	6,502	(2,867)	(2,109)
Interest Expense:			
Interest on long-term debt	82,457	84,408	81,198
Other interest	14,721	11,691	11,242
Allowance for borrowed funds used during construction	(10,703)	(10,151)	(8,694)
Total interest expense, net	86,475	85,948	83,746
Income Before Income Taxes	257,835	244,909	261,848
Income Tax Expense	24,507	17,386	48,660
Net Income	233,328	227,523	213,188
Adjustment for income attributable to noncontrolling interests	(474)	(722)	(769)
Net Income Attributable to IDACORP, Inc.	$ 232,854	$ 226,801	$ 212,419
Weighted Average Common Shares Outstanding - Basic (000's)	50,502	50,432	50,361
Weighted Average Common Shares Outstanding - Diluted (000's)	50,537	50,510	50,424
Earnings Per Share of Common Stock:			
Earnings Attributable to IDACORP, Inc. - Basic	$ 4.61	$ 4.50	$ 4.22
Earnings Attributable to IDACORP, Inc. - Diluted	$ 4.61	$ 4.49	$ 4.21

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2019	**2018**	**2017**
	(thousands of dollars)		
Net Income	$ 233,328	$ 227,523	$ 213,188
Other Comprehensive Income:			
Unfunded pension liability adjustment, net of tax of $(4,658), $2,815, and $(1,555)	(13,440)	8,120	(5,990)
Total Comprehensive Income	219,888	235,643	207,198
Comprehensive income attributable to noncontrolling interests	(474)	(722)	(769)
Comprehensive Income Attributable to IDACORP, Inc.	$ 219,414	$ 234,921	$ 206,429

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Balance Sheets

	December 31, 2019	December 31, 2018
	(in thousands)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 217,254	$ 267,492
Receivables:		
Customer (net of allowance of $1,401 and $1,725, respectively)	72,675	77,178
Other (net of allowance of $343 and $264, respectively)	18,789	7,476
Income taxes receivable	3,106	4,356
Accrued unbilled revenues	64,545	69,318
Materials and supplies (at average cost)	56,660	54,987
Fuel stock (at average cost)	57,448	47,979
Prepayments	17,638	16,492
Current regulatory assets	56,626	48,707
Other	405	3,655
Total current assets	565,146	597,640
Investments	98,218	101,178
Property, Plant and Equipment:		
Utility plant in service	6,113,567	6,103,856
Accumulated provision for depreciation	(2,155,783)	(2,210,781)
Utility plant in service - net	3,957,784	3,893,075
Construction work in progress	552,499	480,259
Utility plant held for future use	3,872	4,751
Other property, net of accumulated depreciation	17,299	17,650
Property, plant and equipment - net	4,531,454	4,395,735
Other Assets:		
Company-owned life insurance	58,922	59,852
Regulatory assets	1,326,433	1,165,467
Other	61,028	62,882
Total other assets	1,446,383	1,288,201
Total	$ 6,641,201	$ 6,382,754

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Balance Sheets

	December 31,	
	2019	**2018**
	(in thousands)	
Liabilities and Equity		
Current Liabilities:		
Current maturities of long-term debt	$ 100,000	$ —
Accounts payable	110,745	110,824
Taxes accrued	11,501	12,009
Interest accrued	20,999	23,622
Accrued compensation	52,550	55,121
Current regulatory liabilities	33,987	25,883
Advances from customers	28,452	20,037
Other	16,625	11,096
Total current liabilities	374,859	258,592
Other Liabilities:		
Deferred income taxes	746,231	699,878
Regulatory liabilities	748,198	738,994
Pension and other postretirement benefits	519,570	431,475
Other	45,131	43,216
Total other liabilities	2,059,130	1,913,563
Long-Term Debt	1,736,659	1,834,788
Commitments and Contingencies		
Equity:		
IDACORP, Inc. shareholders' equity:		
Common stock, no par value (120,000 shares authorized; shares issued 50,420)	868,307	863,593
Retained earnings	1,634,525	1,531,543
Accumulated other comprehensive loss	(36,284)	(22,844)
Treasury stock (22 and 27 shares at cost, respectively)	(1,920)	(1,932)
Total IDACORP, Inc. shareholders' equity	2,464,628	2,370,360
Noncontrolling interests	5,925	5,451
Total equity	2,470,553	2,375,811
Total	$ 6,641,201	$ 6,382,754

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2019	2018	2017
	(thousands of dollars)		
Operating Activities:			
Net income	$ 233,328	$ 227,523	$ 213,188
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	173,800	169,120	165,933
Deferred income taxes and investment tax credits	22,389	11,292	33,245
Changes in regulatory assets and liabilities	(4,310)	48,392	57,131
Pension and postretirement benefit plan expense	27,804	32,256	28,911
Contributions to pension and postretirement benefit plans	(48,525)	(45,899)	(46,589)
Earnings of equity-method investments	(12,370)	(12,449)	(11,374)
Distributions from equity-method investments	21,800	31,115	24,975
Allowance for equity funds used during construction	(27,112)	(24,353)	(20,784)
Gain on sale of investments and assets	(285)	(155)	(131)
Other non-cash adjustments to net income, net	8,325	9,152	8,454
Change in:			
Accounts receivable	(5,996)	729	1,045
Accounts payable and other accrued liabilities	(9,526)	29,666	(17,208)
Taxes accrued/receivable	742	4,725	4,361
Other current assets	(8,820)	12,707	2,814
Other current liabilities	(799)	6,848	1,017
Other assets	(4,375)	(7,488)	(8,734)
Other liabilities	555	(1,555)	(1,093)
Net cash provided by operating activities	366,625	491,626	435,161
Investing Activities:			
Additions to property, plant and equipment	(278,705)	(277,853)	(285,488)
Payments received from transmission project joint funding partners	2,442	21,587	6,074
Purchase of equity securities	(10,896)	(11,390)	(11,356)
Proceeds from sale of equity securities	5,080	5,007	4,989
Other	1,587	4,472	5,340
Net cash used in investing activities	(280,492)	(258,177)	(280,441)
Financing Activities:			
Issuance of long-term debt	166,100	220,000	—
Retirement of long-term debt	(166,100)	(130,000)	(1,064)
Dividends on common stock	(129,677)	(121,421)	(113,127)
Net change in short-term borrowings	—	—	(21,800)
Acquisition of treasury stock	(4,160)	(3,614)	(3,212)
Make-whole premium on retirement of long-term debt	—	(4,607)	—
Debt issuance costs and other	(2,534)	(2,964)	(348)
Net cash used in financing activities	(136,371)	(42,606)	(139,551)
Net (decrease) increase in cash and cash equivalents	(50,238)	190,843	15,169
Cash and cash equivalents at beginning of the year	267,492	76,649	61,480
Cash and cash equivalents at end of the year	$ 217,254	$ 267,492	$ 76,649
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Income taxes	$ 14,055	$ 5,272	$ 14,742
Interest (net of amount capitalized)	$ 85,260	$ 80,951	$ 80,004
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$ 38,815	$ 29,528	$ 33,220

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Equity

	Year Ended December 31,		
	2019	2018	2017
	(thousands of dollars)		
Common Stock:			
Balance at beginning of year	$ 863,593	$ 857,207	$ 851,833
Share-based compensation expense	8,788	9,362	7,384
Treasury shares issued	(4,172)	(3,068)	(2,069)
Other	98	92	59
Balance at end of year	868,307	863,593	857,207
Retained Earnings:			
Balance at beginning of year	1,531,543	1,426,528	1,323,198
Cumulative effect of change in accounting principle	—	—	4,092
Net income attributable to IDACORP, Inc.	232,854	226,801	212,419
Common stock dividends ($2.56, $2.40, and $2.24 per share, respectively)	(129,872)	(121,786)	(113,181)
Balance at end of year	1,634,525	1,531,543	1,426,528
Accumulated Other Comprehensive (Loss) Income:			
Balance at beginning of year	(22,844)	(30,964)	(20,882)
Cumulative effect of change in accounting principle	—	—	(4,092)
Unfunded pension liability adjustment (net of tax)	(13,440)	8,120	(5,990)
Balance at end of year	(36,284)	(22,844)	(30,964)
Treasury Stock:			
Balance at beginning of year	(1,932)	(1,386)	(243)
Issued	4,172	3,068	2,069
Acquired	(4,160)	(3,614)	(3,212)
Balance at end of year	(1,920)	(1,932)	(1,386)
Total IDACORP, Inc. shareholders' equity at end of year	2,464,628	2,370,360	2,251,385
Noncontrolling Interests:			
Balance at beginning of year	5,451	4,729	3,960
Net income attributable to noncontrolling interests	474	722	769
Balance at end of year	5,925	5,451	4,729
Total equity at end of year	$ 2,470,553	$ 2,375,811	$ 2,256,114

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Income

	Year Ended December 31,		
	2019	2018	2017
	(thousands of dollars)		
Operating Revenues	$ 1,342,940	$ 1,366,582	$ 1,344,893
Operating Expenses:			
Operation:			
Purchased power	285,266	293,814	248,950
Fuel expense	156,872	133,198	145,829
Power cost adjustment	2,047	42,106	52,024
Other operations and maintenance	355,770	364,456	346,695
Energy efficiency programs	40,128	35,703	39,241
Depreciation	169,210	165,190	162,091
Taxes other than income taxes	34,044	34,792	34,089
Total operating expenses	1,043,337	1,069,259	1,028,919
Income from Operations	299,603	297,323	315,974
Other Income (Expense):			
Allowance for equity funds used during construction	27,112	24,353	20,784
Earnings of unconsolidated equity-method investments	10,285	10,712	9,267
Other income (expense), net	2,266	(5,851)	(4,756)
Total other income	39,663	29,214	25,295
Interest Charges:			
Interest on long-term debt	82,457	84,408	81,198
Other interest	14,658	11,634	11,156
Allowance for borrowed funds used during construction	(10,703)	(10,151)	(8,694)
Total interest charges	86,412	85,891	83,660
Income Before Income Taxes	252,854	240,646	257,609
Income Tax Expense	28,417	18,312	51,262
Net Income	$ 224,437	$ 222,334	$ 206,347

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2019	2018	2017
	(thousands of dollars)		
Net Income	$ 224,437	$ 222,334	$ 206,347
Other Comprehensive Income:			
Unfunded pension liability adjustment, net of tax of $(4,658), $2,815, and $(1,555)	(13,440)	8,120	(5,990)
Total Comprehensive Income	$ 210,997	$ 230,454	$ 200,357

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31, 2019	December 31, 2018
	(in thousands)	
Assets		
Electric Plant:		
In service (at original cost)	$ 6,113,567	$ 6,103,856
Accumulated provision for depreciation	(2,155,783)	(2,210,781)
In service - net	3,957,784	3,893,075
Construction work in progress	552,499	480,259
Held for future use	3,872	4,751
Electric plant - net	4,514,155	4,378,085
Investments and Other Property	87,104	90,019
Current Assets:		
Cash and cash equivalents	98,950	165,460
Receivables:		
Customer (net of allowance of $1,401 and $1,725, respectively)	72,675	77,178
Other (net of allowance of $343 and $264, respectively)	17,107	7,206
Income taxes receivable	9,279	11,829
Accrued unbilled revenues	64,545	69,318
Materials and supplies (at average cost)	56,660	54,987
Fuel stock (at average cost)	57,448	47,979
Prepayments	17,520	16,374
Current regulatory assets	56,626	48,707
Other	405	3,655
Total current assets	451,215	502,693
Deferred Debits:		
Company-owned life insurance	58,922	59,852
Regulatory assets	1,326,433	1,165,467
Other	56,330	58,284
Total deferred debits	1,441,685	1,283,603
Total	$ 6,494,159	$ 6,254,400

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31,	
	2019	**2018**
	(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	1,503,805	1,409,245
Accumulated other comprehensive loss	(36,284)	(22,844)
Total common stock equity	2,275,559	2,194,439
Long-term debt	1,736,659	1,834,788
Total capitalization	4,012,218	4,029,227
Current Liabilities:		
Current maturities of long-term debt	100,000	—
Accounts payable	110,581	110,597
Accounts payable to affiliates	2,053	2,088
Taxes accrued	11,481	11,750
Interest accrued	20,999	23,622
Accrued compensation	52,267	54,910
Current regulatory liabilities	33,987	25,883
Advances from customers	28,452	20,037
Other	15,629	10,198
Total current liabilities	375,449	259,085
Deferred Credits:		
Deferred income taxes	794,402	753,239
Regulatory liabilities	748,198	738,994
Pension and other postretirement benefits	519,570	431,475
Other	44,322	42,380
Total deferred credits	2,106,492	1,966,088
Commitments and Contingencies		
Total	$ 6,494,159	$ 6,254,400

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2019	2018	2017
	(thousands of dollars)		
Operating Activities:			
Net income	$ 224,437	$ 222,334	$ 206,347
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	173,205	168,519	165,337
Deferred income taxes and investment tax credits	14,889	(2,272)	(10,875)
Changes in regulatory assets and liabilities	(4,310)	48,392	57,131
Pension and postretirement benefit plan expense	27,788	32,240	28,894
Contributions to pension and postretirement benefit plans	(48,509)	(45,883)	(46,573)
Earnings of equity-method investments	(10,285)	(10,712)	(9,267)
Distributions from equity-method investments	19,450	29,400	23,000
Allowance for equity funds used during construction	(27,112)	(24,353)	(20,784)
Gain on sale of investments and assets	(285)	(155)	(131)
Other non-cash adjustments to net income, net	(463)	(210)	1,069
Change in:			
Accounts receivable	(4,724)	633	(5,282)
Accounts payable	(9,463)	(25,532)	38,111
Taxes accrued/receivable	2,281	15,509	(3,601)
Other current assets	(8,821)	12,707	2,812
Other current liabilities	(870)	6,822	996
Other assets	(4,280)	(7,488)	(8,734)
Other liabilities	584	(1,476)	(967)
Net cash provided by operating activities	343,512	418,475	417,483
Investing Activities:			
Additions to utility plant	(278,707)	(277,823)	(285,471)
Payments received from transmission project joint funding partners	2,442	21,587	6,074
Purchase of equity securities	(10,896)	(11,390)	(11,356)
Proceeds from the sale of equity securities	5,080	5,007	4,989
Other	4,117	4,320	5,176
Net cash used in investing activities	(277,964)	(258,299)	(280,588)
Financing Activities:			
Issuance of long-term debt	166,100	220,000	—
Retirement of long-term debt	(166,100)	(130,000)	(1,064)
Dividends on common stock	(129,877)	(121,791)	(113,284)
Net change in short term borrowings	—	—	(21,800)
Make-whole premium on retirement of long-term debt	—	(4,607)	—
Debt issuance costs	(2,181)	(2,964)	(241)
Net cash used in financing activities	(132,058)	(39,362)	(136,389)
Net (decrease) increase in cash and cash equivalents	(66,510)	120,814	506
Cash and cash equivalents at beginning of the year	165,460	44,646	44,140
Cash and cash equivalents at end of the year	$ 98,950	$ 165,460	$ 44,646
Supplemental Disclosure of Cash Flow Information:			
Cash paid to IDACORP related to income taxes	$ 19,856	$ 63,914	$ 12,444
Cash paid for interest (net of amount capitalized)	$ 85,198	$ 80,894	$ 79,918
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$ 38,815	$ 29,528	$ 33,220

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	2019	2018	2017
	(thousands of dollars)		
Retained Earnings, Beginning of Year	$ 1,409,245	$ 1,308,702	$ 1,211,547
Net Income	224,437	222,334	206,347
Dividends on Common Stock	(129,877)	(121,791)	(113,284)
Cumulative Effect of Change in Accounting Principle	—	—	4,092
Retained Earnings, End of Year	$ 1,503,805	$ 1,409,245	$ 1,308,702

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 (Jim Bridger 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 hydropower 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, 2019, Marysville had approximately $18 million of assets, primarily a hydropower plant, and approximately $6 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 Idaho Power's investment in BCC was $40.7 million at December 31, 2019, and Idaho Power's maximum exposure to loss is the carrying value, any additional future contributions to BCC, and a $58.3 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 2019. 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 $3.7 million at December 31, 2019.

Ida-West's other investments in PURPA facilities, Idaho Power's investment in 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.

Idaho Power meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. IDACORP’s and Idaho Power’s financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment; regulatory assets and liabilities; operating revenues; operation and maintenance expense; depreciation expense; and income tax expense. 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, 2019 and 2018. 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 2.9 percent in 2019, 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 2019, 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 2019, 2018 and 2017.

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. Idaho Power recognizes 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.

Investment tax credits earned on regulated assets are deferred and amortized to income over the estimated service lives of the related properties.

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.

New and Recently Adopted Accounting Pronouncements

Recently Adopted Accounting Pronouncements

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842),* intended to improve financial reporting on 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. IDACORP and Idaho Power adopted ASU 2016-02 on January 1, 2019. The adoption did not have a material impact on their respective financial statements. Neither IDACORP nor Idaho Power has material agreements that meet the definition of a lease under ASU 2016-02.

Recent Accounting Pronouncements Not Yet Adopted

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments*, to provide financial statement users with more information about expected credit losses on financial instruments. The ASU revises the incurred loss impairment methodology to reflect current expected credit losses and requires consideration of a broader range of information to estimate credit losses. 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 finalizing the assessment of the financial impacts of adoption, but do not believe that the adoption of ASU 2016-13 will have a material impact on their respective financial statements.

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 recognition of such implementation costs with the accounting for costs incurred to implement an internal-use software solution. However, the balance sheet line item for presentation of capitalized implementation costs for a cloud arrangement that is a service contract should be the same as that for the prepayment of fees related to the same arrangement, while capitalized implementation costs for internal-use software solutions are often included in property, plant, and equipment as an intangible asset. 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 finalizing the assessment of the financial impacts of adoption, but do not believe the adoption of ASU 2018-15 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		
	2019	2018	2017	2019	2018	2017
	(thousands of dollars)					
Federal income tax expense at statutory rate	$ 54,046	$ 51,279	$ 91,378	$ 53,099	$ 50,536	$ 90,163
Change in taxes resulting from:						
AFUDC	(7,941)	(7,246)	(10,318)	(7,941)	(7,246)	(10,318)
Capitalized interest	976	928	1,513	976	928	1,513
Investment tax credits	(6,252)	(2,929)	(3,081)	(6,252)	(2,929)	(3,081)
Removal costs	(3,139)	(3,471)	(6,280)	(3,139)	(3,471)	(6,280)
Capitalized overhead costs	(7,140)	(6,720)	(11,200)	(7,140)	(6,720)	(11,200)
Capitalized repair costs	(18,480)	(17,850)	(28,700)	(18,480)	(17,850)	(28,700)
Bond redemption costs	—	(1,029)	—	—	(1,029)	—
Remeasurement of deferred taxes	—	(5,411)	1,690	—	(5,664)	1,970
State income taxes, net of federal benefit	8,627	8,512	8,153	8,401	8,532	8,108
Depreciation	14,641	13,110	18,953	14,641	13,110	18,953
Excess deferred income tax reversal	(6,181)	(7,289)	—	(6,181)	(7,289)	—
Income tax return adjustments	745	(5,076)	(3,710)	993	(4,968)	(3,601)
Affordable housing tax credits	(2,874)	(2,560)	(2,559)	—	—	—
Affordable housing investment distributions	(3,232)	(267)	(1,124)	—	—	—
Affordable housing investment amortization	1,825	1,519	1,271	—	—	—
Other, net	(1,114)	1,886	(7,326)	(560)	2,372	(6,265)
Total income tax expense	$ 24,507	$ 17,386	$ 48,660	$ 28,417	$ 18,312	$ 51,262
Effective tax rate	9.5%	7.1%	18.6%	11.2%	7.6%	19.9%

The items comprising income tax expense are as follows:

	IDACORP			Idaho Power		
	2019	2018	2017	2019	2018	2017
	(thousands of dollars)					
Income taxes current:						
Federal	$ 8,830	$ 5,390	$ 11,726	$ 25,338	$ 24,919	$ 51,575
State	4,865	3,328	5,418	(4,392)	(2,049)	10,562
Total	13,695	8,718	17,144	20,946	22,870	62,137
Income taxes deferred:						
Federal	9,486	1,649	24,018	(4,599)	(15,388)	(13,002)
State	1,159	30	(154)	10,054	5,425	(5,298)
Total	10,645	1,679	23,864	5,455	(9,963)	(18,300)
Investment tax credits:						
Deferred	8,268	8,334	10,506	8,268	8,334	10,506
Restored	(6,252)	(2,929)	(3,081)	(6,252)	(2,929)	(3,081)
Total	2,016	5,405	7,425	2,016	5,405	7,425
Affordable housing investments	(1,849)	1,584	227	—	—	—
Total income tax expense	$ 24,507	$ 17,386	$ 48,660	$ 28,417	$ 18,312	$ 51,262

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

	IDACORP		Idaho Power	
	2019	2018	2019	2018
	(thousands of dollars)			
Deferred tax assets:				
Regulatory liabilities	$ 96,599	$ 98,042	$ 96,599	$ 98,042
Deferred compensation	21,946	21,871	21,946	21,826
Deferred revenue	39,039	35,137	39,039	35,137
Tax credits	76,125	100,041	24,489	44,532
Partnership investments	7,911	4,200	4,912	1,086
Retirement benefits	114,124	91,867	114,124	91,867
Other	11,347	9,299	11,107	9,121
Total	367,091	360,457	312,216	301,611
Deferred tax liabilities:				
Property, plant and equipment	286,583	294,471	286,583	294,471
Regulatory assets	646,886	614,144	646,886	614,144
Partnership investments	3,565	3,875	—	—
Retirement benefits	132,764	108,440	132,764	108,440
Other	43,524	39,405	40,385	37,795
Total	1,113,322	1,060,335	1,106,618	1,054,850
Net deferred tax liabilities	$ 746,231	$ 699,878	$ 794,402	$ 753,239

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, 2019, IDACORP had \$36.7 million of general business credit carryforwards for federal income tax purposes and \$39.4 million of Idaho investment tax credit carryforward. The general business credit carryforward period expires from 2032 to 2039, and the Idaho investment tax credit expires from 2024 to 2033.

Uncertain Tax Positions

IDACORP and Idaho Power believe that they have no material income tax uncertainties for 2019 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 2019 for federal and 2016-2019 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 2019, the IRS completed its examination of IDACORP's 2018 tax year with no unresolved income tax issues.

Income Tax Reform

On December 22, 2017, the Tax Cuts and Jobs Act was signed into law, which significantly reformed 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 full 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. See Note 3 - "Regulatory Matters" for more information.

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, 2019 Earning a Return[(1)]	As of December 31, 2019 Not Earning a Return	Total as of December 31, 2019	Total as of December 31, 2018
Regulatory Assets:					
Income taxes[(2)]		$ —	$ 646,886	$ 646,886	$ 614,144
Unfunded postretirement benefits[(3)]		—	347,935	347,935	278,674
Pension expense deferrals[(4)]		150,350	22,287	172,637	147,836
Energy efficiency program costs[(5)]		1,465	—	1,465	1,398
Fixed cost adjustment[(6)]	2020-2021	35,208	18,808	54,016	42,503
North Valmy plant settlements[(6)]	2020-2028	107,525	—	107,525	77,512
Asset retirement obligations[(7)]		—	18,835	18,835	17,655
Long-term service agreement	2020-2043	15,412	10,178	25,590	26,748
Other	2020-2055	2,804	5,366	8,170	7,704
Total		$ 312,764	$ 1,070,295	$ 1,383,059	$ 1,214,174
Regulatory Liabilities:					
Income taxes[(8)]		$ —	$ 96,599	$ 96,599	$ 98,042
Depreciation-related excess deferred income taxes[(9)]		183,881	—	183,881	190,062
Removal costs[(7)]		—	185,685	185,685	183,798
Investment tax credits		—	94,806	94,806	92,790
Deferred revenue-AFUDC[(10)]		109,921	41,747	151,668	135,146
Energy efficiency program costs[(5)]		—	—	—	5,259
Power supply costs[(6)]	2020-2021	46,022	2,470	48,492	42,322
Settlement agreement sharing mechanism[(6)]		—	—	—	5,025
Tax reform accrual for future amortization[(11)]		—	9,139	9,139	—
Other		6,636	5,279	11,915	12,433
Total		$ 346,460	$ 435,725	$ 782,185	$ 764,877

(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) Idaho Power records a regulatory asset for the difference between net periodic pension cost and pension cost considered for rate-making purposes relating to Idaho Power's defined benefit pension plan. In its Idaho jurisdiction, Idaho Power's inclusion of pension costs for the establishment of retail rates is based upon contributions made to the pension plan. This regulatory asset account represents the difference between cumulative cash contributions and amounts collected in rates. Deferred costs are amortized into expense as the amounts are provided for in Idaho retail revenues.
(5) The energy efficiency asset includes the Oregon jurisdiction balance at December 31, 2019 and 2018. The Idaho jurisdiction balance was an asset at December 31, 2019, and a liability at December 31, 2018.
(6) This item is discussed in more detail in this Note 3 - "Regulatory Matters."
(7) Asset retirement obligations and removal costs are discussed in Note 14 - "Asset Retirement Obligations (ARO)."
(8) 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."
(9) In 2017, income tax reform reduced 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.
(10) 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.
(11) Represents amount accrued under the May 2018 Idaho Tax Reform Settlement Stipulation (described below) for the future amortization of existing or future unspecified regulatory deferrals that would otherwise be a future liability recoverable from Idaho customers.

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 Idaho Power (5 percent), with the exceptions of expenses associated with PURPA power purchases and demand response incentive payments, which are allocated 100 percent to customers; and
- a sales-based adjustment intended to ensure that power supply expense recovery resulting solely from sales changes does not distort the results of the mechanism.

The table below summarizes the three most recent Idaho-jurisdiction 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, 2019	$ (50.1)	The $50.1 million decrease includes a $5.0 million credit to customers for sharing of 2018 earnings under the IPUC order approving the extension, with modifications, of the terms of the December 2011 Idaho settlement stipulation for the period from 2015 through 2019 (October 2014 Idaho Earnings Support and Sharing Settlement Stipulation) and a $2.7 million credit for income tax reform benefits related to Idaho Power's OATT rate under a May 2018 Idaho tax reform settlement stipulation as described below in this Note 3 - Regulatory Matters.
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 as described below in this Note 3 - Regulatory Matters.
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. Oregon jurisdiction power supply cost changes under the APCU and PCAM during each of 2019, 2018, and 2017 did not have a material impact on the companies' financial statements.

Notable Idaho Base Rate Adjustments

Idaho base rates were most recently established through a general rate case in 2012, and adjusted in 2014, 2017, 2018, and 2019.

January 2012 and June 2014 Idaho Base Rate Adjustments: 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.

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.

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 - Idaho Regulatory Treatment" below.

In 2019 and 2017, Idaho Power recorded no provision against current revenue for sharing with customers, as its full-year return on year-end equity in the Idaho jurisdiction (Idaho ROE) for both years was between 9.5 percent and 10.0 percent. In 2018, Idaho Power recorded a $5.0 million provision against current revenue for sharing with customers as Idaho ROE was above 10.0 percent. Accordingly, at December 31, 2019, the full $45 million of additional ADITC remained available for future use under the terms of the May 2018 Idaho Tax Reform Settlement Stipulation described in "Income Tax Reform - Idaho Regulatory Treatment" below.

May 2018 Idaho Tax Reform Settlement Stipulation: 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 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 provided 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 was 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 decreased 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 became applicable 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 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.

The May 2018 Idaho Tax Reform Settlement Stipulation did not impose a moratorium on Idaho Power filing a general rate case or other form of rate proceeding in Idaho during its respective term.

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. 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, and (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. 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 February 2019, Idaho Power reached an agreement with NV Energy that facilitates the planned end of Idaho Power's participation in coal-fired operations at units 1 and 2 of its jointly-owned North

Valmy coal-fired power plant in 2019 and 2025, respectively. In May 2019, the IPUC issued an order approving the North Valmy plant agreement and allowing Idaho Power to recover through customer rates the $1.2 million incremental annual levelized revenue requirement associated with required North Valmy plant investments and other exit costs, effective June 1, 2019, through December 31, 2028. In December 2019, as planned, Idaho Power ended its participation in coal-fired operations of North Valmy plant unit 1.

Other Notable Idaho Regulatory Matters

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. The IPUC has discretion to cap the annual increase in the FCA recovery 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)
2018	June 1, 2019-May 31, 2020	$34.8
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.

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 Public Utility Commission of Oregon (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 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. In December 2019, Idaho Power filed an application with the OPUC requesting approval of Idaho Power's quantification of $1.5 million in annualized Oregon jurisdictional benefits associated with federal and state income tax changes resulting from tax reform and adjusting customer rates to reflect this amount, effective June 1, 2020, until its next general rate case or other proceeding where the tax-related revenue requirement components are reflected in rates.

In June 2017, the OPUC approved a settlement stipulation allowing for (1) accelerated depreciation of North Valmy plant units 1 and 2 through December 31, 2025, (2) cost recovery of incremental North Valmy plant investments through May 31, 2017, and (3) forecasted North Valmy plant 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. In October 2019, the OPUC approved the North Valmy plant agreement and authorized Idaho Power to adjust customer rates in Oregon, effective January 1, 2020, to reflect a decrease in the annual levelized revenue requirement of $3.2 million, which mostly relates to the decrease in depreciation expense and other costs associated with the December 2019 end of Idaho Power's participation in coal-fired operations of North Valmy plant unit 1.

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 actual financial and operational data Idaho Power files with the FERC and allows Idaho Power to recover costs for FERC-approved expenditures associated with its transmission system. 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, 2019 to September 30, 2020	$ 27.32
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 $107.0 million, which represents the OATT formulaic determination of Idaho Power's net cost of providing OATT-based transmission service.

4. REVENUES

IDACORP and Idaho Power adopted ASU 2014-09, *Revenue from Contracts with Customers (Topic 606),* using the modified retrospective method on January 1, 2018. 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,		
	2019	2018	2017
Electric utility operating revenues:			
Revenue from contracts with customers	$ 1,285,286	$ 1,312,112	$ 1,320,004
Alternative revenue programs and derivative revenues	57,654	54,470	24,889
Total electric utility operating revenues	$ 1,342,940	$ 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 (Topic 606)*. 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,		
	2019	2018	2017
Revenues from contracts with customers:			
Retail revenues:			
Residential (includes $35,587, $34,625 and $17,320, respectively, related to the FCA[1])	$ 526,966	$ 530,527	$ 552,333
Commercial (includes $1,336, $1,299, and $876, respectively, related to the FCA[1])	295,203	310,299	319,195
Industrial	181,372	190,130	195,124
Irrigation	135,850	158,001	150,030
Provision for sharing	—	(5,025)	—
Deferred revenue related to HCC relicensing AFUDC[2]	(8,780)	(8,780)	(10,706)
Total retail revenues	1,130,611	1,175,152	1,205,976
Less: FCA mechanism revenues[1]	(36,923)	(35,924)	(18,196)
Wholesale energy sales	71,198	52,845	24,790
Transmission wheeling-related revenues	53,828	59,094	43,970
Energy efficiency program revenues	40,128	35,703	39,241
Other revenues from contracts with customers	26,444	25,242	24,223
Total revenues from contracts with customers	$ 1,285,286	$ 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) The IPUC allows 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 $2.6 million, $3.6 million, and $4.7 million for 2019, 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 2019 Idaho ROE, Idaho Power recorded no provision against current revenues for sharing of earnings with customers for 2019. Idaho Power recorded $5.0 million of sharing of earnings with customers during 2018 and no provision was recorded during 2017. 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-Related 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-related revenues consist of a single performance obligation satisfied as capacity on Idaho Power’s transmission system is provided to the third party. Transmission wheeling-related 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, 2019, Idaho Power's energy efficiency rider balances were a $0.3 million regulatory asset in the Idaho jurisdiction and a $1.2 million regulatory asset in the Oregon jurisdiction.

Alternative Revenue Programs and Derivative 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 derivative revenues (in thousands):

	Year Ended December 31,		
	2019	**2018**	**2017**
Alternative revenue programs and derivative revenues:			
FCA mechanism revenues	$ 36,923	$ 35,924	$ 18,196
Derivative revenues	20,731	18,546	6,693
Total alternative revenue programs and derivative revenues	$ 57,654	$ 54,470	$ 24,889

IDACORP's Other Revenues

IDACORP's other revenues are primarily comprised of revenues from IDACORP's subsidiary, Ida-West. Ida-West operates small hydropower 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):

	2019	2018
First mortgage bonds:		
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	220,000
Total first mortgage bonds	1,665,000	1,665,000
Pollution control revenue bonds:		
1.45% Series due 2024(1)	49,800	49,800
1.70% 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	(18,686)	(20,557)
Total IDACORP and Idaho Power outstanding debt(2)	1,836,659	1,834,788
Current maturities of long-term debt	(100,000)	—
Total long-term debt	$ 1,736,659	$ 1,834,788

(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, 2019, to $1.831 billion. These two bonds were purchased and remarketed in August of 2019. See "Long-Term Debt Issuances, Maturities, and Redemptions" below.

(2) At December 31, 2019 and 2018, the overall effective cost rate of Idaho Power's outstanding debt was 4.50 percent and 4.83 percent, respectively.

At December 31, 2019, the maturities for the aggregate amount of IDACORP and Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

2020	2021	2022	2023	2024	Thereafter
$ 100,000	$ —	$ 75,000	$ 75,000	$ 49,800	$ 1,555,545

Long-Term Debt Issuances, Maturities, and Redemptions

In March 2018, Idaho Power issued $220.0 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, $130.0 million in principal amount of 4.50% first mortgage bonds, secured 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 from the March 2018 sale of first mortgage bonds, medium-term notes to effect the redemption.

In August 2019, Idaho Power purchased and remarketed two of its outstanding series of pollution control tax-exempt bonds, one in the aggregate principal amount of $49.8 million issued in 2003 by Humboldt County, Nevada and due in 2024, and the other in the aggregate principal amount of $116.3 million issued in 2006 by Sweetwater County, Wyoming and due in 2026. The bonds were remarketed with substantially the same terms, but with lower term interest rates. The term interest rate of the series due in 2024 decreased from 5.15 percent to 1.45 percent and the term interest rate of the series due in 2026 decreased from 5.25 percent to 1.70 percent.

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 2019, Idaho Power received orders from the IPUC, OPUC, and WPSC authorizing the company 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, 2022, 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.

In May 2019, Idaho Power filed a shelf registration statement with the SEC, which became effective upon filing, for the offer and sale of an unspecified principal amount of its first mortgage bonds. The issuance of first mortgage bonds requires that Idaho Power meet interest coverage and security provisions set forth in the Idaho Power's Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented from time to time (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.

As of the date of this report, Idaho Power has not entered into a selling agency agreement under the new shelf agreement. 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 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, 2019, 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, 2019 was limited to approximately $669 million under the Indenture.

6. NOTES PAYABLE

Credit Facilities

On December 6, 2019, IDACORP and Idaho Power entered into amendments to their outstanding Credit Agreements, which 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 $50 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 Market Index rate plus 1.0 percent, or (2) the LIBOR Market Index rate, plus, in each case, an applicable margin, provided that the federal funds rate and LIBOR rate will not be less than zero percent. An alternate benchmark rate selected by the administrative agent for the credit facilities and IDACORP and Idaho Power will apply during any period in which the LIBOR rate is unavailable or unascertainable. The applicable margin is based on IDACORP's or Idaho Power's, as applicable, senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreements. 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 December 6, 2024, the credit agreements grant IDACORP and Idaho Power the right to request up to two one-year extensions, subject to certain conditions.

At December 31, 2019, no loans were outstanding under either IDACORP's or Idaho Power's facilities. At December 31, 2019, Idaho Power had regulatory authority to incur up to $450 million in principal amount of short-term indebtedness at any one time outstanding. IDACORP’s and Idaho Power's short-term borrowings were zero at December 31, 2019, and December 31, 2018.

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, 2019:

	Shares issued			Shares reserved
	2019	**2018**	**2017**	**December 31, 2019**
Balance at beginning of year	50,420,017	50,420,017	50,420,017	
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)	—	—	—	1,356,729
Balance at end of year	50,420,017	50,420,017	50,420,017	

(1) During 2019, 2018, and 2017, IDACORP granted 70,419, 75,761, and 72,397 restricted stock unit awards, respectively, to employees and 9,594, 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, 2019, the leverage ratios for IDACORP and Idaho Power were 43 percent and 45 percent, respectively. Based on these restrictions, IDACORP's and Idaho Power's dividends were limited to $1.5 billion and $1.3 billion, respectively, at December 31, 2019. 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, 2019, 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, 2019, Idaho Power's common equity capital was 55 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, 2019, the maximum number of shares available under the LTICP was 613,394.

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, 2019	206,035	$ 81.31	204,859	$ 81.31
Shares/units granted	98,868	92.58	98,362	92.59
Shares/units forfeited	(4,640)	94.57	(4,640)	94.57
Shares/units vested	(97,353)	71.95	(96,761)	71.95
Nonvested shares/units at December 31, 2019	202,910	$ 90.99	201,820	$ 90.99

The total fair value of shares vested was $9.4 million in 2019, $8.3 million in 2018, and $7.5 million in 2017. At December 31, 2019, IDACORP had $7.9 million of total unrecognized compensation cost related to nonvested share-based compensation. Idaho Power's share of this amount was $7.8 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 2019, a total of 9,594 shares were awarded to directors at a grant date fair value of $98.41 per share. Directors elected to defer receipt of 3,198 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		
	2019	2018	2017	2019	2018	2017
Compensation cost	$ 8,788	$ 9,362	$ 7,384	$ 8,639	$ 9,276	$ 7,304
Income tax benefit(1)	2,262	2,410	2,887	2,224	2,388	2,856

(1) Due to tax reform, 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, 2019, 2018, and 2017 (in thousands, except for per share amounts):

	Year Ended December 31,		
	2019	2018	2017
Numerator:			
Net income attributable to IDACORP, Inc.	$ 232,854	$ 226,801	$ 212,419
Denominator:			
Weighted-average common shares outstanding - basic	50,502	50,432	50,361
Effect of dilutive securities	35	78	63
Weighted-average common shares outstanding - diluted	50,537	50,510	50,424
Basic earnings per share	$ 4.61	$ 4.50	$ 4.22
Diluted earnings per share	$ 4.61	$ 4.49	$ 4.21

10. COMMITMENTS

Purchase Obligations

At December 31, 2019, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2020	2021	2022	2023	2024	Thereafter
Cogeneration and power production	$ 241,835	$ 248,481	$ 251,964	$ 262,735	$ 266,061	$2,739,123
Fuel	55,693	36,069	8,389	8,379	8,371	75,074

As of December 31, 2019, Idaho Power had 1,136 MW nameplate capacity of PURPA-related projects on-line, with an additional 11 MW nameplate capacity of projects projected to be on-line by 2022. 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 $187 million in 2019, $190 million in 2018, and $170 million in 2017.

Also, in March 2019, Idaho Power signed a 20-year power purchase agreement to purchase the output from a planned 120-megawatt solar facility. The agreement was approved by the IPUC in December 2019 and is, as of the date of this report, pending approval by the OPUC. If approved, the agreement would increase contractual obligations by $136 million over the 20-year term.

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

	2020	2021	2022	2023	2024	Thereafter
Joint-operating agreement payments(1)	$ 2,678	$ 2,678	$ 2,678	$ 2,678	$ 2,678	$ 13,391
Easements and other payments	269	1,124	1,072	1,062	1,055	16,408
Maintenance and service agreements(1)	47,547	13,797	16,468	7,143	7,354	55,768
FERC and other industry-related fees(1)	14,178	13,874	13,056	13,056	13,056	65,278

(1) Approximately $27 million, $48 million, and $131 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 2019, 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 $58.3 million at December 31, 2019, representing IERCo's one-third share of BCC's total reclamation obligation of $175.0 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2019, the value of the reclamation trust fund was $139.5 million. During 2019, the reclamation trust fund made no 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.

In May 2019, the state of Wyoming enacted legislation that limits a mine operator's maximum amount of self-bonding. Idaho Power and the co-owners of BCC have until December 2020 to comply with the new regulations, which would reduce the portion of Idaho Power's guarantee of reclamation activities and obligations at BCC that Idaho Power is allowed to self-bond. As of the date of this report, Idaho Power believes the cost of any insurance, third-party assurance, or additional collateral that might be required for this guarantee due to the new law would be immaterial to the companies' consolidated financial statements.

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, 2019, 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, tax, 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 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.

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

	Pension Plan		SMSP	
	2019	2018	2019	2018
Change in projected benefit obligation:				
Benefit obligation at January 1	$ 951,857	$ 999,344	$ 102,318	$ 110,303
Service cost	34,061	37,836	(181)	(316)
Interest cost	42,312	38,833	4,575	4,248
Actuarial loss (gain)	147,784	(84,758)	17,888	(7,050)
Plan amendment	—	—	2,839	—
Benefits paid	(41,262)	(39,398)	(4,996)	(4,867)
Projected benefit obligation at December 31	1,134,752	951,857	122,443	102,318
Change in plan assets:				
Fair value at January 1	650,604	697,683	—	—
Actual return (loss) on plan assets	113,777	(47,681)	—	—
Employer contributions	40,000	40,000	—	—
Benefits paid	(41,262)	(39,398)	—	—
Fair value at December 31	763,119	650,604	—	—
Funded status at end of year	$ (371,633)	$ (301,253)	$ (122,443)	$ (102,318)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (5,911)	$ (5,158)
Noncurrent liabilities	(371,633)	(301,253)	(116,532)	(97,160)
Net amount recognized	$ (371,633)	$ (301,253)	$ (122,443)	$ (102,318)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 347,785	$ 278,720	$ 45,851	$ 30,496
Prior service cost	56	62	3,143	399
Subtotal	347,841	278,782	48,994	30,895
Less amount recorded as regulatory asset[1]	(347,841)	(278,782)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 48,994	$ 30,895
Accumulated benefit obligation	$ 958,586	$ 814,549	$ 109,966	$ 94,630

(1) Changes in the funded status of the pension plan that would be recorded in accumulated other comprehensive income for an unregulated entity are recorded as a regulatory asset for Idaho Power as Idaho Power believes it is probable that an amount equal to the regulatory asset will be collected through the setting of future rates.

The actuarial losses reflected in the benefit obligations for the pension and SMSP plans in 2019 are due primarily to decreases in the assumed discount rates of both plans from December 31, 2018, to December 31, 2019. The actuarial gains affecting the benefit obligations for the pension and SMSP plans in 2018 are due primarily to increases in the assumed discount rates from December 31, 2017, to December 31, 2018. For more information on discount rates, see "Plan Assumptions" below in this Note 12.

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 $97.6 million and $92.5 million at December 31, 2019 and 2018, 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		
	2019	2018	2017	2019	2018	2017
Service cost	$ 34,061	$ 37,836	$ 33,742	$ (181)	$ (316)	$ 759
Interest cost	42,312	38,833	38,957	4,575	4,248	4,315
Expected return on assets	(48,623)	(52,302)	(45,138)	—	—	—
Amortization of net loss	13,564	13,558	13,190	2,533	3,788	2,963
Amortization of prior service cost	6	6	28	96	98	127
Net periodic pension cost	41,320	37,931	40,779	7,023	7,818	8,164
Regulatory deferral of net periodic benefit cost(1)	(39,379)	(36,153)	(38,699)	—	—	—
Previously deferred pension cost recognized(1)	17,154	17,154	17,154	—	—	—
Net periodic benefit cost recognized for financial reporting(1)(2)	$ 19,095	$ 18,932	$ 19,234	$7,023	$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 $15.1 million, $15.2 million, and $16.2 million respectively, was recognized in "Other operations and maintenance" and $11.0 million, 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, 2019, 2018, and 2017.

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

	Pension Plan			SMSP		
	2019	2018	2017	2019	2018	2017
Actuarial (loss) gain during the year	$ (82,631)	$ (15,226)	$ (26,608)	$ (17,888)	$ 7,049	$ (10,635)
Plan amendment service cost	—	—	—	(2,839)	—	—
Reclassification adjustments for:						
Amortization of net loss	13,564	13,558	13,190	2,533	3,788	2,963
Amortization of prior service cost	6	6	28	96	98	127
Adjustment for deferred tax effects	17,776	428	1,744	4,658	(2,815)	1,555
Adjustment due to the effects of regulation	51,285	1,234	11,646	—	—	—
Other comprehensive (loss) income recognized related to pension benefit plans	$ —	$ —	$ —	$ (13,440)	$ 8,120	$ (5,990)

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

	2020	2021	2022	2023	2024	2025-2029
Pension Plan	$ 40,727	$ 42,674	$ 44,576	$ 46,670	$ 48,694	$ 273,700
SMSP	6,010	6,186	6,281	6,700	6,724	33,304

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 2019, 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. As of the date of this report, IDACORP's and Idaho Power's minimum required contribution to the pension plan is estimated to be $14 million during 2020. Depending on market conditions and cash flow considerations in 2020, Idaho Power could contribute up to $40 million to the pension plan during 2020 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):

	2019	2018
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 66,453	$ 70,051
Service cost	853	1,051
Interest cost	2,989	2,643
Actuarial loss (gain)	5,298	(2,688)
Benefits paid(1)	(4,564)	(4,604)
Plan amendments		—
Benefit obligation at December 31	71,029	66,453
Change in plan assets:		
Fair value of plan assets at January 1	33,391	38,294
Actual return (loss) on plan assets	7,269	(1,330)
Employer contributions(1)	3,529	1,031
Benefits paid(1)	(4,564)	(4,604)
Fair value of plan assets at December 31	39,625	33,391
Funded status at end of year (included in noncurrent liabilities)	$ (31,404)	$ (33,062)

(1) Contributions and benefits paid are each net of $3.3 million and $3.1 million of plan participant contributions for 2019 and 2018, respectively.

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

	2019	2018
Net loss	$ (81)	$ (330)
Prior service cost	174	222
Subtotal	93	(108)
Less amount recognized in regulatory assets	(93)	108
Net amount recognized in accumulated other comprehensive income	$ —	$ —

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

	2019	2018	2017
Service cost	$ 853	$ 1,051	$ 973
Interest cost	2,989	2,643	2,783
Expected return on plan assets	(2,220)	(2,467)	(2,307)
Immediate recognition of loss from temporary deviation(1)	—	4,216	—
Amortization of prior service cost	48	47	47
Net periodic postretirement benefit cost	$ 1,670	$ 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):

	2019	2018	2017
Actuarial loss during the year	$ (249)	$ (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	48	47	47
Adjustment for deferred tax effects	52	270	807
Adjustment due to the effects of regulation	149	(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):

	2020	2021	2022	2023	2024	2025-2028
Expected benefit payments	$ 5,552	$ 4,932	$ 4,750	$ 4,532	$ 4,289	$ 19,133

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	
	2019	2018	2019	2018	2019	2018
Discount rate	3.60%	4.55%	3.65%	4.60%	3.60%	4.60%
Rate of compensation increase(1)	4.37%	4.25%	4.75%	4.75%	—	—
Medical trend rate	—	—	—	—	6.7%	6.3%
Dental trend rate	—	—	—	—	4.0%	4.0%
Measurement date	12/31/2019	12/31/2018	12/31/2019	12/31/2018	12/31/2019	12/31/2018

(1) The 2019 rate of compensation increase assumption for the pension plan includes an inflation component of 2.40% plus a 1.97% 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 0.6% 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		
	2019	2018	2017	2019	2018	2017	2019	2018	2017
Discount rate	4.55%	3.95%	4.45%	4.60%	3.95%	4.45%	4.60%	3.95%	4.45%
Expected long-term rate of return on assets	7.50%	7.50%	7.50%	—	—	—	6.75%	6.75%	6.75%
Rate of compensation increase	4.37%	4.25%	4.17%	4.75%	4.75%	4.75%	—	—%	—%
Medical trend rate	—	—	—	—	—	—	6.7%	6.3%	6.8%
Dental trend rate	—	—	—	—	—	—	4.0%	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 6.7 percent in 2019 and is assumed to decrease to 5.9 percent in 2020, 5.2 percent in 2021, 5.1 percent in 2022 and to gradually decrease to 3.9 percent by 2091. 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.

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2019, for the pension asset portfolio by asset class is set forth below:

Asset Class	Target Allocation	Actual Allocation December 31, 2019
Debt securities	24%	23%
Equity securities	56%	59%
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. 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 30 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, 2019				
Cash and cash equivalents	$ 10,878	$ —	$ —	$ 10,878
Short-term bonds	21,628	—	—	21,628
Intermediate bonds	22,369	134,931	—	157,300
Long-term bonds	—	—	—	—
Equity Securities: Large-Cap	92,852	—	—	92,852
Equity Securities: Mid-Cap	81,663	—	—	81,663
Equity Securities: Small-Cap	67,075	—	—	67,075
Equity Securities: Micro-Cap	31,469	—	—	31,469
Equity Securities: International	13,817	—	—	13,817
Equity Securities: Emerging Markets	8,245	—	—	8,245
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Commingled Fund: Equity Securities: Global and International				114,975
Commingled Fund: Equity Securities: Emerging Markets				40,059
Commingled Fund: Commodities fund				34,793
Real estate				47,570
Private market investments				40,795
Total	$ 349,996	$ 134,931	$ —	$ 763,119
Postretirement plan assets(1)	$ 641	$ 38,984	$ —	$ 39,625

	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)				
Commingled Fund: Equity Securities: International				95,653
Commingled Fund: Equity Securities: Emerging Markets				29,757
Commingled Fund: Commodities fund				30,842
Real estate				39,846
Private market investments				35,041
Total	$ 290,962	$ 128,503	$ —	$ 650,604
Postretirement plan assets(1)	$ 758	$ 32,633	$ —	$ 33,391

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

For the years ended December 31, 2019 and 2018, 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 international and 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 open-end and closed-end 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 on the open-end funds 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. The closed-end funds are formed for a stated life of 7 to 9 years. 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.

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, $7.7 million, and $7.4 million in 2019, 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 both IDACORP's and Idaho Power's consolidated balance sheets at December 31, 2019, and 2018, 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, 2019 and 2018 (in thousands of dollars):

	2019		2018	
	Balance	**Avg Rate**	**Balance**	**Avg Rate**
Production	$ 2,535,938	3.19%	$ 2,654,201	3.10%
Transmission	1,220,703	1.89%	1,201,092	1.89%
Distribution	1,882,136	2.25%	1,792,284	2.24%
General and Other	474,790	6.17%	456,279	6.40%
Total in service	6,113,567	2.87%	6,103,856	2.84%
Accumulated provision for depreciation	(2,155,783)		(2,210,781)	
In service - net	$ 3,957,784		$ 3,893,075	

At December 31, 2019, Idaho Power's construction work in progress balance of $552.5 million included relicensing costs of $326.0 million for the HCC, Idaho Power's largest hydropower complex. In 2019, 2018, and 2017, Idaho Power had IPUC authorization to include in its Idaho jurisdiction rates $6.5 million annually ($8.8 million when grossed-up for the effect of income taxes in 2019 and 2018 and $10.7 million when grossed-up for the effect of income taxes in 2017 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, 2019, Idaho Power's regulatory liability for collection of AFUDC relating to the HCC was $151.7 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, 2019 (in thousands of dollars):

Name of Plant	Location	Utility Plant in Service	Construction Work in Progress	Accumulated Provision for Depreciation	Ownership %	MW(1)(2)
Jim Bridger units 1-4	Rock Springs, WY	$ 745,096	$ 4,622	$ 353,254	33	771
Boardman	Boardman, OR	82,501	12	78,411	10	64
North Valmy unit 2(2)	Winnemucca, NV	252,921	217	166,419	50	145

(1) Idaho Power's share of nameplate capacity.
(2) Idaho Power ended its participation in coal-fired operations at unit 1 of the North Valmy plant on December 31, 2019.

IERCo, Idaho Power's wholly-owned subsidiary, is a joint venturer in BCC. Idaho Power's coal purchases from the joint venture were $73.6 million in 2019, $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 $8.6 million in 2019, $9.7 million in 2018, and $9.8 million in 2017.

IDACORP's consolidated VIE, Marysville, owns a hydropower plant with a net book value of $14.7 million and $15.2 million at December 31, 2019 and 2018, 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 reclamation and removal costs at its jointly-owned coal-fired generation facilities.

Idaho Power also has additional AROs associated with its transmission system, hydropower 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, 2019 and 2018.

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

	2019	2018
Balance at beginning of year	$ 26,792	$ 26,415
Accretion expense	1,115	1,055
Revisions in estimated cash flows	365	(751)
Liability incurred	—	129
Liability settled	(81)	(56)
Balance at end of year	$ 28,191	$ 26,792

15. INVESTMENTS

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

	2019	2018
Idaho Power investments:		
Bridger Coal Company (equity method investment)	$ 40,713	$ 49,878
Exchange traded short-term bond funds and cash equivalents	42,648	36,471
Executive deferred compensation plan investments	90	17
Total Idaho Power investments	83,451	86,366
Investments in affordable housing (IDACORP Financial Services)	3,665	3,446
Ida-West joint ventures (equity method investments)	11,102	11,366
Total IDACORP investments	$ 98,218	$ 101,178

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):

	2019	2018	2017
Bridger Coal Company (Idaho Power)	$ 10,285	$ 10,712	$ 9,267
Ida-West joint ventures	2,085	1,737	2,107
Total	$ 12,370	$ 12,449	$ 11,374

Investments in Equity Securities

Investments in equity securities are reported at fair value. Any unrealized gains or losses on equity securities are included in income. Unrealized gains and losses on equity securities were immaterial at December 31, 2019 and December 31, 2018. The following table summarizes sales of equity securities (in thousands of dollars):

	2019	2018	2017
Proceeds from sales	$ 5,080	$ 5,007	$ 4,989
Gross realized gains from sales	—	—	—

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, 2019, 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] 2019	2018	2017
Financial swaps	Operating revenues	$ 904	$ 1,316	$ 902
Financial swaps	Purchased power	(2,183)	7,828	166
Financial swaps	Fuel expense	13,811	22,563	701
Financial swaps	Other operations and maintenance	—	118	(84)
Forward contracts	Operating revenues	285	41	55
Forward contracts	Purchased power	(270)	(54)	(69)
Forward contracts	Fuel expense	565	(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 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, 2019 and 2018 (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, 2019							
Current:							
Financial swaps	Other current assets	$ 2,426	$ (2,034)	$ 392	$ 2,034	$ (2,034)	$ —
Financial swaps	Other current liabilities	134	(134)	—	924	(134)	790
Forward contracts	Other current assets	13	—	13	—	—	—
Forward contracts	Other current liabilities	—	—	—	32	—	32
Long-term:							
Financial swaps	Other assets	3	(3)	—	27	(3)	24
Total		$ 2,576	$ (2,171)	$ 405	$ 3,017	$ (2,171)	$ 846
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

(1) Current asset derivative amounts offset include $45 thousand of collateral payable at December 31, 2018.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2019 and 2018 (in thousands of units):

		December 31,	
Commodity	Units	2019	2018
Electricity purchases	MWh	91	52
Electricity sales	MWh	138	39
Natural gas purchases	MMBtu	14,053	7,514
Natural gas sales	MMBtu	78	446

Credit Risk

At December 31, 2019, 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, 2019, was $3.0 million. Idaho Power posted $1.4 million cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2019, Idaho Power would have been required to pay or post collateral to its counterparties up to an additional $6.7 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 for derivative instruments 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, 2019 and 2018.

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, 2019 and 2018 (in thousands of dollars):

	December 31, 2019				December 31, 2018			
	Level 1	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets:								
Money market funds and commercial paper								
IDACORP[(1)]	$ 64,173	$ —	$ —	$ 64,173	$ 97,833	$ —	$ —	$ 97,833
Idaho Power	26,510	—	—	26,510	79,228	—	—	79,228
Derivatives	392	13	—	405	3,655	—	—	3,655
Equity securities	42,738	—	—	42,738	36,488	—	—	36,488
Liabilities:								
Derivatives	$ 814	$ 32	$ —	$ 846	$ 870	$ 104	$ —	$ 974

(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, 2019 and 2018, using available market information and appropriate valuation methodologies (in thousands).

	December 31, 2019		December 31, 2018	
	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 (including current portion)[(1)]	1,836,659	2,083,931	1,834,788	1,942,773
Idaho Power				
Liabilities:				
Long-term debt (including current portion)[(1)]	$ 1,836,659	$ 2,083,931	$ 1,834,788	$ 1,942,773

(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 hydropower 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 hydropower 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
2019				
Revenues	$ 1,342,940	$ 3,443	$ —	$ 1,346,383
Operating income	297,652	674	—	298,326
Other income, net	20,362	1	—	20,363
Interest income	10,968	3,052	(769)	13,251
Equity-method income	10,285	2,085	—	12,370
Interest expense	86,412	832	(769)	86,475
Income before income taxes	252,854	4,981	—	257,835
Income tax expense (benefit)	28,417	(3,910)	—	24,507
Income attributable to IDACORP, Inc.	224,437	8,417	—	232,854
Total assets	6,494,159	220,620	(73,578)	6,641,201
Expenditures for long-lived assets	278,707	(2)	—	278,705

	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
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

19. OTHER INCOME AND EXPENSE

The following table presents the components of IDACORP's other income (expense), net and Idaho Power's other income (expense), net (in thousands of dollars):

IDACORP	2019	2018	2017
Interest and dividend income, net	$ 8,181	$ 5,605	$ 3,872
Carrying charges on regulatory assets	5,494	4,075	2,310
Pension and postretirement non-service costs[1]	(10,976)	(15,781)	(11,194)
Income from life insurance investments	4,104	2,779	2,090
Other (expense) income	(301)	455	813
Total other income (expense), net	$ 6,502	$ (2,867)	$ (2,109)
Idaho Power			
Interest and dividend income, net	$ 5,898	$ 4,688	$ 3,787
Carrying charges on regulatory assets	5,494	4,075	2,310
Pension and postretirement non-service costs[1]	(10,976)	(15,781)	(11,194)
Income from life insurance investments	4,104	2,779	2,090
Other expense	(2,254)	(1,612)	(1,749)
Total other income (expense), net	$ 2,266	$ (5,851)	$ (4,756)

(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, 2019, 2018, and 2017 (in thousands of dollars). Items in parentheses indicate reductions to AOCI.

	Year Ended December 31,		
	2019	2018	2017
Defined benefit pension items			
Balance at beginning of period	$ (22,844)	$ (30,964)	$ (20,882)
Other comprehensive income before reclassifications	(15,392)	5,234	(7,872)
Amounts reclassified out of AOCI to net income	1,952	2,886	1,882
Net current-period other comprehensive income	(13,440)	8,120	(5,990)
Cumulative effect of change in accounting principle[1]	—	—	(4,092)
Balance at end of period	$ (36,284)	$ (22,844)	$ (30,964)

(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, 2019, 2018, and 2017 (in thousands of dollars). Items in parentheses indicate increases to net income.

	Amount Reclassified from AOCI		
	Year Ended December 31,		
	2019	2018	2017
Amortization of defined benefit pension items[(1)]			
Prior service cost	$ 96	$ 98	$ 127
Net loss	2,533	3,788	2,963
Total before tax	2,629	3,886	3,090
Tax benefit[(2)]	(677)	(1,000)	(1,208)
Net of tax	1,952	2,886	1,882
Total reclassification for the period	$ 1,952	$ 2,886	$ 1,882

(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 $0.8 million in 2019 and $0.7 million in both 2018 and 2017.

At December 31, 2019 and 2018, Idaho Power had a $1.9 million payable to IDACORP, which was included in its accounts payable to affiliates balance on its consolidated balance sheets. In 2019, Idaho Power paid IDACORP certain estimated income taxes that had been accrued at December 31, 2018.

Ida-West: Idaho Power purchases all of the power generated by four of Ida-West’s hydropower projects located in Idaho. Idaho Power paid Ida-West $8.6 million in 2019, $9.7 million in 2018, and $9.8 million in 2017 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, 2019 and 2018, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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 20, 2020, 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 audit 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.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Regulation of Utility Operations - Refer to Notes 1 and 3 to the financial statements

Critical Audit Matter Description

Idaho Power Company ("Idaho Power"), the principal operating subsidiary of the Company, is subject to rate regulation by the Federal Energy Regulatory Commission and the Idaho and Oregon Public Utility Commissions (the "Commissions"), which have jurisdiction with respect to the rates of electric distribution companies in Idaho and Oregon. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. Accounting for the economics of rate regulation impacts multiple financial statement line items and disclosures, such as property, plant, and equipment; regulatory assets and liabilities; operating revenues; operation and maintenance expense; depreciation expense; and income tax expense.

Idaho Power’s rates are subject to regulatory rate-setting processes. Regulatory decisions can have an impact on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. The Commissions’ regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the Commissions in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated it expects Idaho Power to recover costs from customers through regulated rates, there is a risk that the Commissions will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

Additionally, consistent with orders and directives of the Commissions, 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. Idaho Power recognizes 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.

We identified the impact of rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about impacted account balances and disclosures and the degree of subjectivity involved in assessing the impact of future regulatory orders on the financial statements. Management judgments include assessing the likelihood of (1) recovery in future rates of incurred costs and (2) a refund to customers for amounts collected prior to costs being incurred. Given that management’s accounting judgments are based on assumptions about the outcome of future decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate-setting process due to its inherent complexities.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the uncertainty of future decisions by the Commissions and the application of flow-through accounting for income taxes included the following, among others:

- We tested the effectiveness of management’s controls over the evaluation of the likelihood of (1) the recovery in future rates of costs incurred as property, plant, and equipment and deferred as regulatory assets, and (2) a refund or a future reduction in rates that should be reported as regulatory liabilities.

- We evaluated the Company’s disclosures related to the impacts of rate regulation, including the balances recorded and regulatory developments.

- We read relevant regulatory orders issued by the Commissions for Idaho Power and evaluated whether such orders were appropriately reflected in the Company's financial statements.

- For selected regulatory assets and liabilities, we evaluated whether management had determined such amounts in accordance with regulatory orders.

- With the assistance of income tax specialists, we evaluated whether management had appropriately identified the income tax timing differences eligible for flow-through accounting and recorded such differences as adjustments to income tax expense and regulatory assets.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 20, 2020

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, 2019 and 2018, 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, 2019, 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, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019, 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, 2019, 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 20, 2020, 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 audit 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 20, 2020

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 2019 and 2018 (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.				
2019				
Revenues	$ 350,319	$ 316,895	$ 386,320	$ 292,849
Operating income	58,119	71,780	114,156	54,271
Net income	42,637	53,400	90,218	47,073
Net income attributable to IDACORP, Inc.	42,686	53,156	89,876	47,136
Basic earnings per share	$ 0.85	$ 1.05	$ 1.78	$ 0.93
Diluted earnings per share	$ 0.84	$ 1.05	$ 1.78	$ 0.93
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
Idaho Power Company				
2019				
Revenues	$ 349,771	$ 315,774	$ 385,028	$ 292,367
Income from operations	58,734	71,749	113,924	55,196
Net income	41,584	51,176	87,979	43,698
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

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, 2019, 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, 2019. 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, 2019, 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, 2019 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, 2019.

February 20, 2020

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, 2019, 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, 2019, 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 as of and for the year ended December 31, 2019, of the Company and our report dated February 20, 2020, expressed an unqualified opinion on those financial statements.

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 20, 2020

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, 2019, 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, 2019. 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, 2019, 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, 2019 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, 2019.

February 20, 2020

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholder and the 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, 2019, 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, 2019, 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 as of and for the year ended December 31, 2019, of the Company and our report dated February 20, 2020, expressed an unqualified opinion on those financial statements.

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 20, 2020

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, 2019 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," "Delinquent Section 16(a) Reports," "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 2020 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 2020 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 2020 annual meeting of shareholders is hereby incorporated by reference. The table below includes information as of December 31, 2019, 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	232,550 (1)	$ — (2)	613,394 (3)
Equity compensation plans not approved by shareholders	—	$ —	—
Total	232,550	$ —	613,394

(1) Represents shares subject to outstanding time-based restricted stock units, performance-based restricted stock units (at target), and deferred director stock unit awards, all under the LTICP. Restricted stock unit awards and director deferred stock unit awards may be settled only for shares of common stock on a one-for-one basis.

(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) unvested performance-based restricted stock units (at target), (ii) unvested time-based restricted stock units, and (iii) deferred director stock unit awards, in all cases as of December 31, 2019.

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 2020 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 2020 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, 2019 and 2018:

	2019	2018
Audit fees	$ 1,515,701	$ 1,437,100
Audit-related fees(1)	3,927	29,550
Tax fees(2)	3,993	26,125
All other fees(3)	1,895	1,895
Total	$ 1,525,516	$ 1,494,670

(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 2019 and 2018, 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 IDACORP's and Idaho Power's Annual Report on Form 10-K for the year ended December 31, 2019 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	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
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	
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*					

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
	File number 2-14935, as Exhibit 4-N, Twelfth, May 15, 1959*					
	File number 2-18976, as Exhibit 4-O, Thirteenth, November 15, 1960*					
	File number 2-18977, as Exhibit 4-Q, Fourteenth, November 1, 1961*					
	File number 2-22988, as Exhibit 4-B-16, Fifteenth, September 15, 1964*					
	File number 2-24578, as Exhibit 4-B-17, Sixteenth, April 1, 1966*					
	File number 2-25479, as Exhibit 4-B-18, Seventeenth, October 1, 1966*					
	File number 2-45260, as Exhibit 2(c), Eighteenth, September 1, 1972*					
	File number 2-49854, as Exhibit 2(c), Nineteenth, January 15, 1974*					
	File number 2-51722, as Exhibit 2(c)(i), Twentieth, August 1, 1974*					
	File number 2-51722, as Exhibit 2(c)(ii), Twenty-first, October 15, 1974*					
	File number 2-57374, as Exhibit 2(c), Twenty-second, November 15, 1976*					
	File number 2-62035, as Exhibit 2(c), Twenty-third, August 15, 1978*					
	File number 33-34222, as Exhibit 4(d)(iii), Twenty-fourth, September 1, 1979*					
	File number 33-34222, as Exhibit 4(d)(iv), Twenty-fifth, November 1, 1981*					
	File number 33-34222, as Exhibit 4(d)(v), Twenty-sixth, May 1, 1982*					
	File number 33-34222, as Exhibit 4(d)(vi), Twenty-seventh, May 1, 1986*					
	File number 33-00440, as Exhibit 4(c)(iv), Twenty-eighth, June 30, 1989*					
	File number 33-34222, as Exhibit 4(d)(vii), Twenty-ninth, January 1, 1990*					
	File number 33-65720, as Exhibit 4(d)(iii), Thirtieth, January 1, 1991*					
	File number 33-65720, as Exhibit 4(d)(iv), Thirty-first, August 15, 1991*					
	File number 33-65720, as Exhibit 4(d)(v), Thirty-second, March 15, 1992*					
	File number 33-65720, as Exhibit 4(d)(vi), Thirty-third, April 1, 1993*					
	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 10.13)	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 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	
4.6	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	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
4.7	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	
4.8	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	
4.9	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	
4.10	Description of the Registrant's Securities					X
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	
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	First Amendment to Credit Agreement, dated December 6, 2019, 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 Bank, LTD., as documentation agents and LC Issuers; Wells Fargo Securities, LLC, and JPMorgan Chase 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	12/10/2019	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
10.11	First Amendment to Credit Agreement, dated December 6, 2019, 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 Bank, LTD., as documentation agents and LC Issuers; Wells Fargo Securities, LLC, and JPMorgan Chase 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	12/10/2019	
10.12	Loan Agreement, dated October 1, 2006, between Sweetwater County, Wyoming and Idaho Power Company	8-K	1-3198	10.1	10/10/2006	
10.13	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	
10.14[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	
10.15[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	
10.16[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	
10.17[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	
10.18[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	
10.19[1]	IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended November 21, 2019					X
10.20[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	
10.21[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	
10.22[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	
10.23[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	
10.24[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	
10.25[1]	IDACORP, Inc. and/or Idaho Power Company Executive Officers with Amended and Restated Change in Control Agreements chart, as of February 1, 2020					X
10.26[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	
10.27[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Unit Award Agreement (Time Vesting)	10-K	1-14465, 1-3198	10.30	2/21/2019	
10.28[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Unit Award Agreement (Performance with Total Shareholder Return Goal)	10-K	1-14465, 1-3198	10.31	2/21/2019	
10.29[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Unit Award Agreement (Performance with Cumulative Earnings Per Share Goal)	10-K	1-14465, 1-3198	10.32	2/21/2019	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
10.30[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	
10.31[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	
10.32[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	
10.33[1]	IDACORP, Inc. Executive Incentive Plan, as amended and restated November 14, 2018	10-K	1-14465, 1-3198	10.36	2/21/2019	
10.34[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	
10.35[1]	IDACORP, Inc. and Idaho Power Company Compensation for Non-Employee Directors of the Board of Directors, effective January 1, 2020					X
10.36[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	
10.37[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	
10.38[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	
10.39[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	
10.40[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	
10.41[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	
10.42[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	
10.43[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	
10.44[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	
10.45[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	
10.46[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	
10.47[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	
10.48[1]	Fourth Amendment to the Idaho Power Company Employee Savings Plan, executed October 24, 2019 and effective January 1, 2020	10-Q	1-14465, 1-3198	10.1	10/31/2019	
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
32.1	IDACORP, Inc. Section 1350 CEO certification					X
32.2	IDACORP, Inc. Section 1350 CFO certification					X

Exhibit No.	Exhibit Description	Incorporated by Reference				Included Herewith
		Form	File No.	Exhibit No.	Date	
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.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
104	Cover Page Interactive Data File (formatted as inline XBRL with applicable taxonomy extension information contained in Exhibits 101.)					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,		
	2019	2018	2017
	(thousands of dollars)		
Income:			
Equity in income of subsidiaries	$ 231,534	$ 226,567	$ 211,974
Investment income	2,214	865	26
Total income	233,748	227,432	212,000
Expenses:			
Operating expenses	816	668	708
Interest expense	831	713	294
Other expenses	30	—	30
Total expenses	1,677	1,381	1,032
Income Before Income Taxes	232,071	226,051	210,968
Income Tax Benefit	(783)	(750)	(1,451)
Net Income Attributable to IDACORP, Inc.	232,854	226,801	212,419
Other comprehensive (loss) income	(13,440)	8,120	(5,990)
Comprehensive Income Attributable to IDACORP, Inc.	$ 219,414	$ 234,921	$ 206,429

The accompanying note is an integral part of these statements.

IDACORP, INC.
CONDENSED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2019	2018	2017
	(thousands of dollars)		
Operating Activities:			
Net cash provided by operating activities	$ 112,745	$ 197,185	$ 113,849
Investing Activities:			
Net cash provided by investing activities	—	—	—
Financing Activities:			
Dividends on common stock	(129,682)	(121,421)	(113,127)
Decrease in short-term borrowings	—	—	—
Change in intercompany notes payable	37,588	(2,867)	17,097
Other	(4,410)	(3,614)	(3,321)
Net cash used in financing activities	(96,504)	(127,902)	(99,351)
Net increase in cash and cash equivalents	16,241	69,283	14,498
Cash and cash equivalents at beginning of year	98,900	29,617	15,119
Cash and cash equivalents at end of year	$ 115,141	$ 98,900	$ 29,617

The accompanying note is an integral part of these statements.

IDACORP, INC.
CONDENSED BALANCE SHEETS

	December 31,	
	2019	**2018**
Assets	**(thousands of dollars)**	
Current Assets:		
Cash and cash equivalents	$ 115,141	$ 98,900
Receivables	2,125	2,046
Other	98	98
Total current assets	117,364	101,044
Investment in subsidiaries	2,379,680	2,294,464
Other Assets:		
Deferred income taxes	45,864	17,593
Other	429	277
Total other assets	46,293	17,870
Total assets	$ 2,543,337	$ 2,413,378
Liabilities and Shareholders' Equity		
Current Liabilities:		
Taxes accrued	$ 5,622	$ 8,354
Other	996	899
Total current liabilities	6,618	9,253
Other Liabilities:		
Intercompany notes payable	71,285	32,929
Other	806	836
Total other liabilities	72,091	33,765
IDACORP, Inc. Shareholders' Equity	2,464,628	2,370,360
Total Liabilities and Shareholders' Equity	$ 2,543,337	$ 2,413,378

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 2019 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 $133 million, $124 million, and $116 million in 2019, 2018, and 2017, respectively.

IDACORP, INC. AND IDAHO POWER COMPANY
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2019, 2018, and 2017

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)				
2019:					
Reserve for uncollectible accounts	$ 1,989	$ 2,381	$ 227	$ 2,853	$ 1,744
Injuries and damages	1,877	390	—	519	1,748
2018:					
Reserve for uncollectible accounts	$ 2,193	$ 3,363	$ 392	$ 3,959	$ 1,989
Injuries and damages	1,469	855	—	447	1,877
2017:					
Reserve for uncollectible accounts	$ 1,132	$ 5,753	$ 324	$ 5,016	$ 2,193
Injuries and damages	1,792	687	—	1,010	1,469

(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.

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 20, 2020
Date

IDACORP, INC.

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/ Richard J. Dahl Richard J. Dahl	Chairman of the Board	February 20, 2020
/s/ Darrel T. Anderson Darrel T. Anderson President and Chief Executive Officer and Director	(Principal Executive Officer)	February 20, 2020
/s/ Steven R. Keen Steven R. Keen Senior Vice President, Chief Financial Officer, and Treasurer	(Principal Financial Officer)	February 20, 2020
/s/ Kenneth W. Petersen Kenneth W. Petersen Vice President, Controller, and Chief Accounting Officer	(Principal Accounting Officer)	February 20, 2020
/s/ Thomas Carlile Thomas Carlile	Director	February 20, 2020
/s/ Annette G. Elg Annette G. Elg	Director	February 20, 2020
/s/ Lisa A. Grow Lisa A. Grow	Director	February 20, 2020
/s/ Ronald W. Jibson Ronald W. Jibson	Director	February 20, 2020
/s/ Judith A. Johansen Judith A. Johansen	Director	February 20, 2020
/s/ Dennis L. Johnson Dennis L. Johnson	Director	February 20, 2020
/s/ Christine King Christine King	Director	February 20, 2020
/s/ Richard J. Navarro Richard J. Navarro	Director	February 20, 2020

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 20, 2020		Idaho Power Company
Date		
	By:	*/s/ Darrel T. Anderson*
		Darrel T. Anderson 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/ Richard J. Dahl Richard J. Dahl	Chairman of the Board	February 20, 2020
/s/ Darrel T. Anderson Darrel T. Anderson Chief Executive Officer and Director	(Principal Executive Officer)	February 20, 2020
/s/ Steven R. Keen Steven R. Keen Senior Vice President, Chief Financial Officer, and Treasurer	(Principal Financial Officer)	February 20, 2020
/s/ Kenneth W. Petersen Kenneth W. Petersen Vice President, Controller, and Chief Accounting Officer	(Principal Accounting Officer)	February 20, 2020
/s/ Thomas Carlile Thomas Carlile	Director	February 20, 2020
/s/ Annette G. Elg Annette G. Elg	Director	February 20, 2020
/s/ Lisa A. Grow Lisa A. Grow	Director	February 20, 2020
/s/ Ronald W. Jibson Ronald W. Jibson	Director	February 20, 2020
/s/ Judith A. Johansen Judith A. Johansen	Director	February 20, 2020
/s/ Dennis L. Johnson Dennis L. Johnson	Director	February 20, 2020
/s/ Christine King Christine King	Director	February 20, 2020
/s/ Richard J. Navarro Richard J. Navarro	Director	February 20, 2020

IDACORP Inc. & Idaho Power ( ) total years of service

Darrel T. Anderson **(24)**
President and Chief Executive Officer, IDACORP, Inc.
and Chief Executive Officer, Idaho Power

Brian Buckham **(9)**
Senior Vice President and General Counsel

Patrick A. Harrington **(34)**
Corporate Secretary

Steven R. Keen **(37)**
Senior Vice President and Chief Financial Officer

Jeffrey Malmen **(12)**
Senior Vice President of Public Affairs

Ken W. Petersen **(21)**
Vice President, Chief Accounting Officer
and Treasurer

Idaho Power

Ryan N. Adelman **(15)**
Vice President of Transmission & Distribution
Engineering and Construction

Sarah E. Griffin **(12)**
Vice President of Human Resources

Lisa A. Grow **(32)**
President

Bo Hanchey **(22)**
Vice President of Customer Operations and
Chief Safety Officer

Debra Leithauser **(2)**
Vice President of Corporate Services & Communications

Tessia Park **(22)**
Vice President of Power Supply

Adam J. Richins **(8)**
Senior Vice President and Chief Operating Officer

Tim E. Tatum **(24)**
Vice President of Regulatory Affairs

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 and Treasury
Phone: 208-388-2728
Email: jforsberg@idacorpinc.com

Shareowner Contact: Elizabeth Paynter
Phone: 1-800-635-5406, 208-388-5259, Fax: 208-388-6955
Email: epaynter@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

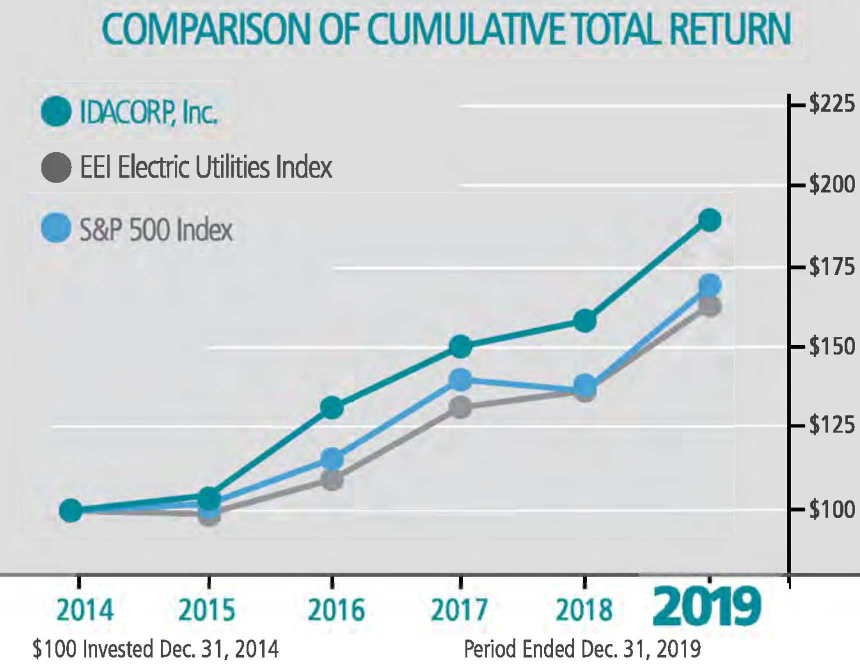
The IDACORP, Inc. and Idaho Power combined Form 10-K has been filed with the Securities and Exchange Commission. The Form 10-K and this Annual Report to Shareholders also are available on our website at idacorpinc.com. This report is prepared for the information of shareholders of the company and is not to be used by others in connection with any sale, offer for sale or solicitation of any offer to buy any securities.

2020 Annual Meeting

The 2020 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 21, 2020. Formal notice of the meeting will be mailed to shareholders on or about Tuesday, April 7, 2020.

IDACORP, Inc. (NYSE: IDA), Boise, Idaho-based and formed in 1998, is a holding company comprised 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. Idaho Power's goal of 100% clean energy by 2045 builds on its long history as a clean-energy leader providing reliable service at affordable prices. With 17 low-cost hydropower projects at the core of its diverse energy mix, Idaho Power's more than 570,000 residential, business, and agricultural customers pay among the nation's lowest prices for electricity. To learn more about IDACORP or Idaho Power, visit idacorpinc.com or idahopower.com.

TOTAL RETURN



SUSTAINABLE GROWTH

IDACORP

Clean today. **Cleaner tomorrow.**®
100% clean energy by 2045.

P.O. Box 70
Boise, ID 83707-0070
idacorpinc.com