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IDAHO PUBLIC
UTILITIES COMMISSION

IDAHO POWER
An IDACORP Company

LISA D. NORDSTROM
Lead Counsel
lnordstrom@idahopower.com

IPC-E

May 1, 2020

ELECTRONIC FILING

Ms. Diane Hanian, Secretary
Idaho Public Utilities Commission
PO Box 83720
Boise, ID 83720-0074

Re: Idaho Power Company's 2019 Annual FERC Form 1 Report

Dear Ms. Hanian:

Pursuant to Idaho Code § 61-405, and Order No. 34622, attached for electronic filing are Idaho Power Company's FERC Form 1 report and Idaho supplement for the year ending December 31, 2019. One bound and one unbound copy are being sent U.S. Mail as previously requested by the Idaho Public Utilities Commission. 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

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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
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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

FERC FORM No.1/3-Q (REV. 02-04)

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* (208) 388-2761	09 This Report Is (1) ☒ An Original (2) ☐ A Resubmission	10 Date of Report *(Mo, Da, Yr)* 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 Ken Petersen 02 Title Vice President, Controller & CAO	03 Signature Ken Petersen	04 Date Signed *(Mo, Da, Yr)* 04/14/2020

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".

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".

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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	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

GENERAL INFORMATION

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

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

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

Idaho, June 30, 1989

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

Not Applicable

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

Class of Utility Service	State
Electric	Idaho
Electric	Oregon

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

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

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

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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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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		

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DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1		
2	Judith A. Johansen	10446 E. Palo Brea Dr., Scottsdale, Arizona 85262
3		
4	Christine King, Comp. Committee Chair,***	8527 East Old Field Rd
5		Scottsdale, Arizona 85266
6		
7	Thomas E. Carlile	2719 North Woodview place, Boise Idaho 83702
8		
9	Darrel T. Anderson President & CEO, ** ***	Idaho Power Company, 1221 W. Idaho Street,
10		P.O. Box 70, Boise, Idaho 83707-0070
11		
12	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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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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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 Annual	
3				Informational Filing	
4				under ER09-1641-000	
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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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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 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

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

Name of Respondent	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) (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

Name of Respondent	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

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		

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

Name of Respondent	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 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)

Name of Respondent	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

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)

Name of Respondent	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

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)		

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

IDAHO POWER COMPANY
NOTES TO 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.

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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	As of December 31, 2019			Total as of December 31,	
	Remaining Amortization Period	Earning a Return[1]	Not Earning a Return	2019	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 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.
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.

<u>Industrial Customers</u>: 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.

<u>Irrigation Customers</u>: 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.

<u>Provision for Sharing</u>: 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):

		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.

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

Name of Respondent	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)

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 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) (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

Name of Respondent	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)

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			
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
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46				
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

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 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		

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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 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

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
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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	

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

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 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

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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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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
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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					

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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						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	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			
7				
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CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT AS REACQUIRED STOCK (Account 217)		HELD BY RESPONDENT IN SINKING AND OTHER FUNDS		Line No.
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		
8		
9		
10	Explanation of Changes during the year:	
11		
12		
13		
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21		
22	TOTAL	2,096,925

Name of Respondent	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

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

Name of Respondent	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)	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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32			
33	TOTAL	2,021,445,000	33,876,373

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

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
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						12
						13
						14
						15
						16
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						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		
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36		
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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

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						
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37						
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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
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						40
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							
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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
			17
			18
			19
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	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						
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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

Name of Respondent	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 - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
	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

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)

FOOTNOTE DATA

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						
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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 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)

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 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	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**

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**	

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

Name of Respondent	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) (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.
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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 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)

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	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**

Name of Respondent	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) (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.
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**	

Name of Respondent	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: 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

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

Name of Respondent	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)
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

Name of Respondent	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)
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 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)	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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	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	

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	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					

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.
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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	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	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					

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)	
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)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Lateral 10 Ventures	LU	-	N/A	N/A	N/A
2	Lemhi Hydro Power Co.- Schaffner	LU	-	N/A	N/A	N/A
3	Lime Wind	LU		N/A	N/A	N/A
4	Little Mac Power Co./Cedar Draw	LU	-	N/A	N/A	N/A
5	Little Wood River Irrigation District	LU	-	N/A	N/A	N/A
6	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					

Name of Respondent	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)	
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:

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

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

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

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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	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.
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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)	
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.
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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	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					

Name of Respondent	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)	
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)	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 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
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.

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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	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.
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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 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:

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

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

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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.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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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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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					

Name of Respondent	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)	
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 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)	
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					

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		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)	
1,650				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	

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					

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			

Name of Respondent	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 (Substation 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 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	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			

Name of Respondent	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	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**	

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			

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		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**	

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp 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	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	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**	

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Morgan Stanley Capital Group Inc.	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 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	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**	

Name of Respondent	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	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 MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
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 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	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 MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
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 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 Classifi-cation (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 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 Classifi-cation (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**	

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	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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
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**	

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**	

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.
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REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	8,504		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**	

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.
	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**	

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**	

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**	

Name of Respondent	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.
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11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	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 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.
	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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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	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	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 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 Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	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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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 2019/Q4

FOOTNOTE DATA

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	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 (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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Name of Respondent	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 (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					
20							
21							
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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					
17					
18					
19					
20					
21					
22					
23					
24					
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43					
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45					
46	TOTAL	4,484,907	835,982	5,320,889	27,719

Name of Respondent	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 (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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							45
		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)	Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
					3
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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.

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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	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 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)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	3,012,385
4	Nuclear	
5	Hydro-Conventional	8,293,793
6	Hydro-Pumped Storage	
7	Other	2,114,102
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	13,420,280
10	Purchases	5,194,040
11	Power Exchanges:	
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

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	14,536,714
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,850,922
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	1,146,823
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Borah	Midpoint	345.00	500.00	S Tower	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

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)	
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		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	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

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)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 ACSR	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 Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	14.07		2
2	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	0.12		2
3	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.13		2
4	Nampa	Caldwell	138.00	138.00	S P Wood	9.59		2
5	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 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.
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	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.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	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

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

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	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

Name of Respondent	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

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Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	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

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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1								
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								
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17								
18								
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22								
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24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
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)

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
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								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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	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							
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9							
10							
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12							
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41							
42							
43							
44	TOTAL		4.97		51.19	5	6

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
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
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				1,910,289	3,766,720	3,419,654		9,096,663	44

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

Estimated amounts are reported

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

Estimated amounts are reported

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 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	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	

Name of Respondent	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.
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

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.
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 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	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	

Name of Respondent	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.
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				

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	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					
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 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	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					
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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

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
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						19
						20
						21
						22
						23
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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	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

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				
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