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

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

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

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Avista Corporation	End of 2017/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules ___________________ of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and” firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

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.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

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

IDENTIFICATION

01 Exact Legal Name of Respondent Avista Corporation	02 Year/Period of Report End of 2017/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)* 1411 East Mission Avenue, Spokane, WA 99207	
05 Name of Contact Person Ryan L. Krasselt	06 Title of Contact Person VP, Controller, Prin. Acctg
07 Address of Contact Person *(Street, City, State, Zip Code)* 1411 East Mission Avenue, Spokane, WA 99207	

08 Telephone of Contact Person, *Including Area Code* (509) 495-2273	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 04/11/2018

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 Ryan L. Krasselt 02 Title VP, Controller, Prin. Acctg Officer	03 Signature Ryan L. Krasselt	04 Date Signed *(Mo, Da, Yr)* 04/11/2018

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.

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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.

R. Krasselt, Vice President, Controller, and Principal Accounting Officer
1411 E. Mission Avenue
Spokane, WA 99207

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.

State of Washington, Incorporated March 15, 1889

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.

Electric service in the states of Washington, Idaho, and Montana
Natural gas service in the states of Washington, Idaho, and 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
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

CONTROL OVER RESPONDENT

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Avista Capital, Inc.	Parent company to the	100	
2		Company's subsidiaries.		
3				
4	Avista Development, Inc.	Maintains an investment	100	Subsidiary of
5		portfolio of real estate and		Avista Capital
6		other investments.		
7				
8	Avista Energy, Inc.	Inactive	100	Subsidiary of
9				Avista Capital
10				
11	Pentzer Corporation	Parent company of Bay Area	100	Subsidiary of
12		Manufacturing and Pentzer		Avista Capital
13		Venture Holdings.		
14				
15	Pentzer Venture Holdings II, Inc.	Inactive	100	Subsidiary of
16				Pentzer Corporation
17				
18	Bay Area Manufacturing, Inc.	Holding Company	100	Subsidiary of
19				Pentzer Corporation
20				
21	Advanced Manufacturing and Development, Inc.	Performs custom sheet metal	89.20	Subsidiary of
22	dba Metalfx	manufacturing of electronic		Bay Area
23		enclosures, parts and systems		Manufacturing.
24		for the computer, telecom and		
25		medical industries. AM&D		
26		also has a wood products		
27		division.		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1				
2	Avista Capital II	An affiliated business trust	100	Affliate of
3		formed by the Company.		Avista Corp.
4		Issued Pref. Trust Securities		
5				
6	Avista Northwest Resources, LLC	Formed in 2009 to own	100	Subsidiary of
7		an interest in a venture		Avista Capital
8		fund investment		
9				
10	Steam Plant Square, LLC	Commercial office and retail	100	Subsidiary of
11		leasing.		Avista Development
12				
13	Courtyard Office Center, LLC	Commercial office and retail	100	Subsidiary of
14		leasing.		Avista Development
15				
16	Steam Plant Brew Pub, LLC	Restaurant operations	100	Subsidiary of Steam
17				Plant Square, LLC
18				
19	Salix, Inc.	Formed in 2014 to explore	100	Subsidiary of
20		markets that could be served		Avista Capital
21		with Liquefied Natural Gas		
22		mostly in Western N. America		
23				
24	Alaska Energy and Resources Company (AERC)	Parent company of Alaska	100	Subsidiary of
25		operations.		Avista Corp.
26				
27	Alaska Electric Light and Power Company	Utility operations based in	100	Subsidiary of

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1		the City and Borough of		AERC
2		Juneau, AK		
3				
4	AJT Mining Properties, Inc.	Inactive mining company	100	Subsidiary of
5		holding certain properties in		AERC
6		the City and Borough of		
7		Juneau, AK		
8				
9	Snettisham Electric Company	Holds certain rights to	100	Subsidiary of
10		purchase the Snettisham		AERC
11		Hydroelectric project in the		
12		City and Borough of		
13		Juneau, AK		
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	Chairman of the Board, President	S. L. Morris	816,923
2	and Chief Executive Officer		
3			
4	Senior Vice President, Chief Financial Officer,	M. T. Thies	418,952
5	and Treasurer		
6			
7	Sr Vice President, General Counsel, Chief Compliance	M. M. Durkin	362,923
8	Officer, and Corporate Secretary		
9			
10	Senior Vice President and Chief Human Resources Officer	K. S. Feltes	350,384
11			
12	Senior Vice President and Environmental	D. P. Vermillion	406,769
13	Compliance Officer, President of Avista Utilities		
14			
15	Senior Vice President, responsible for Energy	J. R. Thackston	312,554
16	Resources		
17			
18	Vice President, Controller, and	R. L. Krasselt	214,477
19	Principal Accounting Officer		
20			
21	Vice President, Chief Information Officer, and	J. M. Kensok	266,832
22	Chief Security Officer		
23			
24	Vice President and Chief Counsel for Regulatory	D. J. Meyer	280,453
25	and Governmental Affairs		
26			
27	Vice President, responsible for State and Federal	K. O. Norwood	229,000
28	Regulation (retired 11/01/2017)		
29			
30	Vice President, responsible for Customer Solutions	K. J. Christie	286,822
31	and Regulatory Affairs (effective 11/1/2017)		
32			
33	Vice President, responsible for Energy Deliver	H. L. Rosentrater	265,431
34			
35	Vice President and Chief Strategy Officer	E. D. Schlect	252,231
36			
37			
38			
39			
40			
41			
42			
43			
44			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Scott L. Morris**	1411 E. Mission Ave., Spokane, WA, 99202
2	(Chairman of the Board, President & CEO)	
3		
4	Erik J. Anderson	3720 Carillon Point, Kirkland, WA 98033
5		
6	Kristianne Blake***	P.O. Box 3727, Spokane, WA 99220-3727
7		
8	Donald C. Burke	16 Ivy Court, Langhorne, PA 19047
9		
10	John F. Kelly*** (Retired 05/11/2017)	851 Georgia Ave., Winter Park, FL 33143
11		
12	Heidi B. Stanley***	P.O. Box 2884, Spokane, WA 99220
13		
14	R. John Taylor***	111 Main Street, Lewiston, ID 83501
15		
16	Marc F. Racicot	28013 Swan Cove Dr., Big Fork, MT 59911
17		
18	Rebecca A. Klein	611 S. Congress Ave., Suite 125, Austin, TX 78704
19		
20	Janet D. Widmann	26 Sanford Ln., Lafayette, CA 94549
21		
22	Scott H. Maw	2401 Utah Ave. S., Suite 800, Seattle, WA 98134
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46		
47		
48		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

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

Does the respondent have formula rates?

[ ] Yes
[X] 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		
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		

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)?

[ ] Yes
[X] 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					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1				
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. None
2. None
3. On July 19, 2017, Avista Corp. entered into a definitive merger agreement to become an indirect, wholly-owned subsidiary of Hydro One Limited, Ontario's largest electricity transmission and distribution provider, based in Toronto. The proposed merger is subject to Avista Corp. shareholder approval and various regulatory approvals, and the merger is expected to close in the second half of 2018, upon receipt of such approvals. Reference is made to Note 3 of the Notes to Financial Statements for further information.
4. None
5. None
6. Reference is made to Notes 10 and 11 of the Notes to Financial Statements. In addition, the $90 million debt issuance referenced in Notes 10 and 11 was approved by regulatory commissions as follows: WUTC (Docket No. UE-151822 Order 01) IPUC (Case No. AVU-U-15-01 Order No. 33401) and the OPUC (Docket UF 4294 Order No. 15-305).
7. None
8. Average annual wage increases were 2.5% for non-exempt employees effective February 20, 2017. Average annual wage increases were 3.0% for exempt employees effective February 20, 2017. Officers received average increases of 4.7% effective February 20, 2017. Certain bargaining unit employees received increases of 3.0% effective March 26, 2017.
9. Reference is made to Note 15 of the Notes to Financial Statements.
10. None
11. Reserved
12. See page 123 of this report.
13. On May 11, 2017, John F. Kelly, lead director of the Avista Corp. Board of Directors retired from the Board, due to him reaching the mandatory retirement age of 72. Kristianne Blake was elected by the Board of Directors to replace Mr. Kelly as the lead director, effective at the conclusion of the annual shareholder meeting on May 11, 2017.

On November 1, 2017, Kelly Norwood, Vice President, State and Federal Regulation retired from the Company. Kevin Christie, currently Avista Corp.'s Vice President, Customer Solutions, will assume responsibility for the Company's rates and regulatory activities, while continuing his role in Customer Solutions. Effective January 1, 2018, Kevin Christie has been named Vice President, External Affairs and Chief Customer Officer.

On November 21, 2017, the Board of Directors of Avista Corp. named Dennis Vermillion as President of Avista Corp effective January 1, 2018. Prior to becoming President of Avista Corp., Mr. Vermillion, served as Avista Corp. Senior Vice President and Environmental Compliance Officer and President of Avista Utilities. Scott Morris, who was President of Avista Corp., will remain as Chairman of the Board and Chief Executive Officer.

Also on November 21, 2017, the Board of Directors of Avista Corp. increased the number of board members from 10 to 11 and elected Mr. Vermillion to fill the vacancy and serve as a director on the board, effective January 1, 2018.

Mr. Vermillion will stand for election to the board at the next annual meeting of shareholders on May 12, 2018. As an employee director, Mr. Vermillion will receive no compensation, consistent with the other employee directors of Avista Corp., as disclosed in Avista Corp.'s definitive Proxy Statement dated March 31, 2017.

Effective January 1, 2018, Bryan Cox, has been named Vice President Safety and HR Shared Services. Prior to being named as Vice President, Mr. Cox was Senior Director of HR Operations.

In addition, see item 3 above regarding the definitive merger agreement with Hydro One Limited, which will result in Hydro One Limited purchasing all of the issued and outstanding Avista Corp. common stock upon approval of the merger transaction.

14. Proprietary capital is not less than 30 percent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	5,650,433,358	5,304,257,392
3	Construction Work in Progress (107)	200-201	151,271,170	144,751,274
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,801,704,528	5,449,008,666
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,876,263,672	1,770,511,420
6	Net Utility Plant (Enter Total of line 4 less 5)		3,925,440,856	3,678,497,246
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		3,925,440,856	3,678,497,246
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		6,992,076	6,992,076
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		3,010,811	3,058,415
19	(Less) Accum. Prov. for Depr. and Amort. (122)		104,487	211,651
20	Investments in Associated Companies (123)		11,547,000	11,547,000
21	Investment in Subsidiary Companies (123.1)	224-225	161,131,682	161,804,156
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)		4,288,775	6,945,185
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		16,722,286	13,611,799
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		2,575,446	5,356,765
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		199,171,513	202,111,669
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		2,912,504	1,373,667
36	Special Deposits (132-134)		12,284,827	7,540,762
37	Working Fund (135)		1,149,696	1,138,883
38	Temporary Cash Investments (136)		50,305	22,854
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		174,683,071	172,903,052
41	Other Accounts Receivable (143)		5,614,311	4,163,026
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		5,170,026	4,961,486
43	Notes Receivable from Associated Companies (145)		11,659,191	0
44	Accounts Receivable from Assoc. Companies (146)		313,553	462,036
45	Fuel Stock (151)	227	3,958,296	3,566,367
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	38,180,423	37,423,657
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
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	0	-86
55	Gas Stored Underground - Current (164.1)		11,738,607	8,029,020
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		19,333,312	14,459,235
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		172,493	107,608
60	Rents Receivable (172)		2,101,931	1,429,562
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		138,513	537,127
63	Derivative Instrument Assets (175)		6,197,881	10,644,436
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		2,575,446	5,356,765
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)		282,743,442	253,482,955
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		10,945,098	11,690,512
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	621,273,693	622,464,411
73	Prelim. Survey and Investigation Charges (Electric) (183)		195,568	0
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		299	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		69,497	13,933
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	15,796,170	43,850,403
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)		11,879,551	13,699,992
82	Accumulated Deferred Income Taxes (190)	234	189,216,780	147,354,707
83	Unrecovered Purchased Gas Costs (191)		-37,474,157	-30,819,635
84	Total Deferred Debits (lines 69 through 83)		811,902,499	808,254,323
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,226,250,386	4,949,338,269

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Avista Corporation	(1) [x] An Original (2) [ ] A Resubmission	04/11/2018	end of 2017/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	1,109,643,921	1,052,578,756
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)		0	0
7	Other Paid-In Capital (208-211)	253	-10,696,711	-9,506,476
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	-34,500,271	-32,208,771
11	Retained Earnings (215, 215.1, 216)	118-119	604,413,488	582,156,946
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	56,139	-1,143,222
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)	-8,089,542	-7,567,509
16	Total Proprietary Capital (lines 2 through 15)		1,729,827,566	1,648,727,266
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,711,700,000	1,621,700,000
19	(Less) Reaquired Bonds (222)	256-257	83,700,000	83,700,000
20	Advances from Associated Companies (223)	256-257	51,547,000	51,547,000
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		159,900	168,783
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		786,481	960,522
24	Total Long-Term Debt (lines 18 through 23)		1,678,920,419	1,588,755,261
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	2,402,917
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		245,000	260,000
29	Accumulated Provision for Pensions and Benefits (228.3)		203,565,903	226,551,767
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		4,906,781	6,600,086
32	Long-Term Portion of Derivative Instrument Liabilities		10,456,971	41,994,092
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		17,481,829	15,514,534
35	Total Other Noncurrent Liabilities (lines 26 through 34)		236,656,484	293,323,396
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		105,000,000	120,000,000
38	Accounts Payable (232)		100,959,825	111,124,132
39	Notes Payable to Associated Companies (233)		0	5,634,684
40	Accounts Payable to Associated Companies (234)		22,197	37,625
41	Customer Deposits (235)		4,431,306	3,808,551
42	Taxes Accrued (236)	262-263	36,514,038	-16,431,293
43	Interest Accrued (237)		15,159,301	14,676,249
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
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	end of 2017/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,533,187	1,431,933
48	Miscellaneous Current and Accrued Liabilities (242)		59,386,964	58,068,093
49	Obligations Under Capital Leases-Current (243)		2,402,917	871,667
50	Derivative Instrument Liabilities (244)		53,752,463	55,076,777
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		10,456,971	41,994,092
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)		368,705,227	312,304,326
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,584,319	2,266,861
57	Accumulated Deferred Investment Tax Credits (255)	266-267	30,265,611	31,501,931
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	28,032,143	15,262,118
60	Other Regulatory Liabilities (254)	278	501,143,487	77,740,268
61	Unamortized Gain on Reaquired Debt (257)		1,707,433	1,836,970
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		481,835,128	731,162,121
64	Accum. Deferred Income Taxes-Other (283)		167,572,569	246,457,751
65	Total Deferred Credits (lines 56 through 64)		1,212,140,690	1,106,228,020
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		5,226,250,386	4,949,338,269

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	1,464,122,332	1,476,215,123		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	820,637,125	858,140,856		
5	Maintenance Expenses (402)	320-323	71,114,817	68,632,689		
6	Depreciation Expense (403)	336-337	137,234,038	130,221,417		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	263,254			
8	Amort. & Depl. of Utility Plant (404-405)	336-337	30,487,581	26,554,225		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	99,047	99,047		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		4,471,025	2,541,927		
13	(Less) Regulatory Credits (407.4)		8,041,294	1,790,145		
14	Taxes Other Than Income Taxes (408.1)	262-263	103,234,021	96,218,096		
15	Income Taxes - Federal (409.1)	262-263	22,710,789	-37,366,331		
16	- Other (409.1)	262-263	540,802	379,481		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	61,887,452	102,646,826		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	1,719,631	1,622,706		
19	Investment Tax Credit Adj. - Net (411.4)	266	-401,676	18,862,745		
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)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		795,991			
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,243,313,341	1,263,518,127		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		220,808,991	212,696,996		

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
989,932,258	1,004,897,624	474,190,074	471,317,499			2
						3
496,458,475	523,294,682	324,178,650	334,846,174			4
56,154,163	53,468,423	14,960,654	15,164,266			5
106,657,139	101,769,331	30,576,899	28,452,086			6
263,254						7
22,965,702	20,106,387	7,521,879	6,447,838			8
99,047	99,047					9
						10
						11
4,261,715	2,573,428	209,310	-31,501			12
7,669,732	1,781,713	371,562	8,432			13
77,630,348	74,172,165	25,603,673	22,045,931			14
12,447,375	-34,063,947	10,263,414	-3,302,384			15
-14,769	365,911	555,571	13,570			16
46,542,613	79,435,289	15,344,839	23,211,537			17
1,507,061	1,397,052	212,570	225,654			18
-381,612	18,887,909	-20,064	-25,164			19
						20
						21
						22
						23
795,991						24
814,702,648	836,929,860	428,610,693	426,588,267			25
175,229,610	167,967,764	45,579,381	44,729,232			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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)		220,808,991	212,696,996		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		9,648,685	11,653,482		
35	Nonoperating Rental Income (418)		-24,801	-939		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	2,517,761	6,288,876		
37	Interest and Dividend Income (419)		4,001,578	2,719,465		
38	Allowance for Other Funds Used During Construction (419.1)		6,441,370	7,298,983		
39	Miscellaneous Nonoperating Income (421)					
40	Gain on Disposition of Property (421.1)		19,733	240,298		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		3,306,956	4,893,201		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		-17,500			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		3,205,496	2,837,164		
46	Life Insurance (426.2)		2,967,371	2,589,159		
47	Penalties (426.3)		18,562	-64,096		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,663,123	1,788,417		
49	Other Deductions (426.5)		17,741,930	1,915,238		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		25,578,982	9,065,882		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	175,689	192,113		
53	Income Taxes-Federal (409.2)	262-263	-12,536,584	-10,041,967		
54	Income Taxes-Other (409.2)	262-263	-738,539	-834,874		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	7,571,606	1,585,996		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	440,920	322,781		
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)		-5,968,748	-9,421,513		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-16,303,278	5,248,832		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		82,342,603	74,527,233		
63	Amort. of Debt Disc. and Expense (428)		321,206	458,080		
64	Amortization of Loss on Reaquired Debt (428.1)		2,854,749	2,941,399		
65	(Less) Amort. of Premium on Debt-Credit (429)		8,883	8,883		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		677,027	766,389		
68	Other Interest Expense (431)		5,657,334	4,386,030		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		3,254,457	2,352,527		
70	Net Interest Charges (Total of lines 62 thru 69)		88,589,579	80,717,721		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		115,916,134	137,228,107		
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)		115,916,134	137,228,107		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		558,287,446	517,393,545
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Repurchases from common stock			
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		113,398,373	130,939,231
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess Earnings under Section 10 of the Federal Power Act		-8,262,625	(4,441,571)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-8,262,625	(4,441,571)
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			-92,460,231	(87,154,238)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-92,460,231	(87,154,238)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		1,318,400	1,550,479
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		572,281,363	558,287,446
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39	Excess Earnings under Sec 10 of the Federal Power Act		32,132,125	23,869,500
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		32,132,125	23,869,500
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		32,132,125	23,869,500
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		604,413,488	582,156,946
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-1,143,221	(5,881,618)
50	Equity in Earnings for Year (Credit) (Account 418.1)		2,517,761	6,288,876
51	(Less) Dividends Received (Debit)			
52			-1,318,401	(1,550,479)
53	Balance-End of Year (Total lines 49 thru 52)		56,139	(1,143,221)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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)	115,916,134	137,228,107
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	165,534,842	155,162,338
5	Amortization of Deferred Power and Natural Gas Costs	11,740,556	16,834,990
6	Amortization of Debt Expense	3,167,072	3,390,597
7	Amortization of Investment in Exchange Power	2,450,031	2,450,031
8	Deferred Income Taxes (Net)	67,298,507	102,361,230
9	Investment Tax Credit Adjustment (Net)	-401,676	18,862,744
10	Net (Increase) Decrease in Receivables	-8,257,764	-16,916,930
11	Net (Increase) Decrease in Inventory	-4,858,369	980,885
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	49,034,221	-26,152,468
14	Net (Increase) Decrease in Other Regulatory Assets	2,355,616	-38,029,474
15	Net Increase (Decrease) in Other Regulatory Liabilities	-7,591,159	2,936,022
16	(Less) Allowance for Other Funds Used During Construction	6,441,370	7,298,983
17	(Less) Undistributed Earnings from Subsidiary Companies	2,517,761	6,288,876
18	Other (provide details in footnote):	-16,170,168	36,012,182
19	Allowance for Doubtful Accounts	5,235,000	6,000,000
20	Changes in Other Non-Current Assets and Liabilities	25,628,277	4,190,684
21	Cash Paid for Settlement of Interest Rate Swaps	-11,301,842	-53,966,197
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	390,820,147	337,756,882
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-406,201,555	-390,690,230
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		
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-406,201,555	-390,690,230
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	313,974	1,288,524
38	Federal and State Grant Payments Received		512,000
39	Investments in and Advances to Assoc. and Subsidiary Companies	-17,160,819	-16,517,110
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	Restricted Cash	-277	-25,425
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):		
54	Changes in Other Property and Investments	-2,125,513	-8,915,799
55	Dividends Received from Subsidiaries	2,000,000	2,000,000
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-423,174,190	-412,348,040
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	90,000,000	245,000,000
62	Preferred Stock		
63	Common Stock	56,380,425	66,952,672
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		15,000,000
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	146,380,425	326,952,672
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-871,667	-160,871,667
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-3,551,786	-3,072,433
77	Debt Issuance Costs	-565,597	-1,698,045
78	Net Decrease in Short-Term Debt (c)	-15,000,000	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-92,460,231	-87,154,241
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	33,931,144	74,156,286
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	1,577,101	-434,872
87			
88	Cash and Cash Equivalents at Beginning of Period	2,535,404	2,970,276
89			
90	Cash and Cash Equivalents at End of period	4,112,505	2,535,404

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

Power and natural gas deferrals	1,889,235
Change in special deposits	(22,393,510)
Change in other current assets	(5,212,716)
Non-cash stock compensation	7,359,327
Cash received from settlement of interest rate swaps	2,478,520
Preliminary survey and investigation costs	(195,867)
Gain on sale of property and equipment	(37,232)
Other	(57,925)

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

Power and natural gas deferrals	1,408,987
Change in special deposits	10,712,388
Change in other current assets	(3,635,861)
Non-cash stock compensation	7,890,705
Amortization of Spokane Energy contract	14,694,374
Change in Coyote Springs 2 O&M LTSA	4,705,259
Preliminary survey and investigation costs	467,080
Gain on sale of property and equipment	(240,297)
Other	9,547

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

Payment of minimum tax withholdings for share-based payment awards	(3,551,786)

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

Payment of minimum tax withholdings for share-based payment awards	(3,072,433)

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.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corp. (the Company) is primarily an electric and natural gas utility with certain other business ventures. Avista Corp. provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Corp. also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Corp. has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Corp. also supplies electricity to a small number of customers in Montana, most of whom are employees who operate Avista Corp.'s Noxon Rapids generating facility.

Alaska Electric and Resources Company (AERC) is a wholly-owned subsidiary of Avista Corp. The primary subsidiary of AERC is Alaska Electric Light and Power (AEL&P), which comprises Avista Corp.'s regulated utility operations in Alaska.

Avista Capital, a wholly-owned non-regulated subsidiary of Avista Corp., is the parent company of all of the subsidiary companies except AERC (and its subsidiaries).

On July 19, 2017, Avista Corp. entered into an Agreement and Plan of Merger (Merger Agreement) to become a wholly-owned subsidiary of Hydro One Limited (Hydro One). Consummation of the pending acquisition is subject to a number of approvals and the satisfaction or waiver of other specified conditions. The transaction is expected to close in the second half of 2018. See Note 3 for additional information.

Basis of Reporting

The financial statements include the assets, liabilities, revenues and expenses of the Company and have been prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its 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 (GAAP). As required by the FERC, the Company accounts for its investment in majority-owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues, and expenses of these subsidiaries, as required by GAAP. The accompanying financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants. In addition, under the requirements of the FERC, there are differences from GAAP in the presentation of (1) current portion of long-term debt (2) assets and liabilities for cost of removal of assets, (3) assets held for sale, (4) regulatory assets and liabilities, (5) deferred income taxes associated with accounts other than utility property, plant and equipment, (6) comprehensive income, (7) unamortized debt issuance costs and (8) operating revenues and resource costs associated with settled energy contracts that are "booked out" (not physically delivered).

Use of Estimates

The preparation of the financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported for 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. Significant estimates include:

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,
- contingent liabilities,
- goodwill impairment testing for goodwill held at subsidiaries,
- recoverability of regulatory assets, and

- unbilled revenues.

Changes in these estimates and assumptions are considered reasonably possible and may have a material effect on the financial statements and thus actual results could differ from the amounts reported and disclosed herein.

System of Accounts

The accounting records of the Company's utility operations are maintained in accordance with the uniform system of accounts prescribed by the FERC and adopted by the state regulatory commissions in Washington, Idaho, Montana and Oregon.

Regulation

The Company is subject to state regulation in Washington, Idaho, Montana and Oregon. The Company is also subject to federal regulation primarily by the FERC, as well as various other federal agencies with regulatory oversight of particular aspects of its operations.

Utility Revenues

Operating revenues related to the sale of energy are recorded when service is rendered or energy is delivered to customers. The determination of the energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, the amount of energy delivered to customers since the date of the last meter reading is estimated and the corresponding unbilled revenue is estimated and recorded. Our estimate of unbilled revenue is based on:

- the number of customers,
- current rates,
- meter reading dates,
- actual native load for electricity,
- actual throughput for natural gas, and
- electric line losses and natural gas system losses.

Any difference between actual and estimated revenue is automatically corrected in the following month when the actual meter reading and customer billing occurs.

Accounts receivable includes unbilled energy revenues of the following amounts as of December 31 (dollars in thousands):

	2017	2016
Unbilled accounts receivable	$ 65,801	$ 69,544

Depreciation

For utility operations, depreciation expense is estimated by a method of depreciation accounting utilizing composite rates for utility plant. Such rates are designed to provide for retirements of properties at the expiration of their service lives. For utility operations, the ratio of depreciation provisions to average depreciable property was as follows for the years ended December 31:

	2017	2016
Ratio of depreciation to average depreciable property	3.12%	3.11%

The average service lives for the following broad categories of utility plant in service are (in years):

	Avista Corp.
Electric thermal/other production	41
Hydroelectric production	78
Electric transmission	57
Electric distribution	35
Natural gas distribution property	42
Other shorter-lived general plant	10

Taxes Other Than Income Taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on income. These taxes are generally based on revenues or the value of property. Utility- related taxes collected from customers (primarily state excise taxes and city utility taxes) are recorded as operating revenue and expense. Taxes other than income taxes consisted of the following items for the years ended December 31 (dollars in thousands):

	2017	2016
Utility-related taxes	$ 61,715	$ 56,286
Property taxes	40,074	38,505
Other taxes	1,621	1,619
Total	$ 103,410	$ 96,410

Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. As prescribed by regulatory authorities, AFUDC is capitalized as a part of the cost of utility plant. The debt component of AFUDC is credited against total interest expense in the Statements of Income in the line item “capitalized interest.” The equity component of AFUDC is included in the Statement of Income in the line item “other income-net.” The Company is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a reasonable return thereon, through its inclusion in rate base and the provision for depreciation after the related utility plant is placed in service. Cash inflow related to AFUDC does not occur until the related utility plant is placed in service and included in rate base. The effective AFUDC rate was the following for the years ended December 31:

	2017	2016
Effective AFUDC rate	7.29%	7.29%

Income Taxes

Deferred income tax assets represent future income tax deductions the Company expects to utilize in future tax returns to reduce taxable income. Deferred income tax liabilities represent future taxable income the Company expects to recognize in future tax returns. Deferred tax assets and liabilities arise when there are temporary differences resulting from differing treatment of items for tax and accounting purposes. A deferred income tax asset or liability is determined based on the enacted tax rates that will be in effect when the temporary differences between the financial statement carrying amounts and tax basis of existing assets and liabilities are expected to be reported in the Company’s income tax returns. The deferred income tax expense for the period is equal to the net change in the deferred income tax asset and liability accounts from the beginning to the end of the period. The effect on deferred income taxes from a change in tax rates is recognized in income in the period that includes the enactment date unless a regulatory order specifies deferral of the effect of the change in tax rates over a longer period of time. The Company establishes a valuation allowance when it is more likely than not that all, or a portion, of a deferred tax asset will not be realized. Deferred income tax liabilities and regulatory assets are established for income tax benefits flowed through to customers.

The Company's largest deferred income tax item is the difference between the book and tax basis of utility plant. This item results from the temporary difference on depreciation expense. In early tax years, this item is recorded as a deferred income tax liability that will eventually reverse and become subject to income tax in later tax years.

See Note 8 for discussion of the Tax Cuts and Jobs Act (TCJA) and its impacts on the Company's financial statements during 2017, as well as a tabular presentation of all the Company's deferred tax assets and liabilities.

The Company did not incur any penalties on income tax positions in 2017 or 2016. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as income deductions.

Stock-Based Compensation

The Company currently issues three types of stock-based compensation awards - restricted shares, market-based awards and performance-based awards. Historically, these stock compensation awards have not been material to the Company's overall financial results. Compensation cost relating to share-based payment transactions is recognized in the Company’s financial statements based on the fair value of the equity or liability instruments issued and recorded over the requisite service period.

The Company recorded stock-based compensation expense (included in other operating expenses) and income tax benefits in the Statements of Income of the following amounts for the years ended December 31 (dollars in thousands):

	2017	2016
Stock-based compensation expense	$ 7,359	$ 7,891
Income tax benefits (1)	2,576	2,762
Excess tax benefits on settled share-based employee payments (2)	2,348	1,597

(1) Income tax benefits were calculated using a 35 percent income tax rate; however, as of December 31, 2017, due to the TCJA enactment, deferred tax assets associated with stock compensation were revalued to 21 percent. Beginning on January 1, 2018 income tax benefits will be calculated using the new 21 percent tax rate.

(2) Beginning in 2016, excess tax benefits associated with the settlement of share-based employee payments are recognized in the Statements of Income due to the adoption of Accounting Standards Update (ASU) 2016-09, effective January 1, 2016. See Note 2 for further discussion.

Restricted share awards vest in equal thirds each year over a three-year period and are payable in Avista Corp. common stock at the end of each year if the service condition is met. In addition to the service condition, the Company must meet a return on equity target in order for the Chief Executive Officer's restricted shares to vest. Restricted stock is valued at the close of market of the Company’s common stock on the grant date.

Total Shareholder Return (TSR) awards are market-based awards and Cumulative Earnings Per Share (CEPS) awards are performance awards. CEPS awards were first granted in 2014. Both types of awards vest after a period of three years and are payable in cash or Avista Corp. common stock at the end of the three-year period. The method of settlement is at the discretion of the Company and historically the Company has settled these awards through issuance of Avista Corp. common stock and intends to continue this practice. Both types of awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific market or performance conditions. Based on the level of attainment of the market or performance conditions, the amount of cash paid or common stock issued will range from 0 to 200 percent of the initial awards granted. Dividend equivalent rights are accumulated and paid out only on shares that eventually vest and have met the market and performance conditions.

For both the TSR awards and the CEPS awards, the Company accounts for them as equity awards and compensation cost for these awards is recognized over the requisite service period, provided that the requisite service period is rendered. For TSR awards, if the market condition is not met at the end of the three-year service period, there will be no change in the cumulative amount of compensation cost recognized, since the awards are still considered vested even though the market metric was not met. For CEPS awards, at the end of the three-year service period, if the internal performance metric of cumulative earnings per share is not met, all compensation cost for these awards is reversed as these awards are not considered vested.

The fair value of each TSR award is estimated on the date of grant using a statistical model that incorporates the probability of meeting the market targets based on historical returns relative to a peer group. The estimated fair value of the equity component of CEPS awards was estimated on the date of grant as the share price of Avista Corp. common stock on the date of grant, less the net present value of the estimated dividends over the three-year period.

The following table summarizes the number of grants, vested and unvested shares, earned shares (based on market metrics), and other pertinent information related to the Company's stock compensation awards for the years ended December 31:

	2017	2016
Restricted Shares		
Shares granted during the year	57,746	58,610
Shares vested during the year	(57,473)	(52,385)
Unvested shares at end of year	106,053	109,806
Unrecognized compensation expense at end of year (in thousands)	$ 1,853	$ 1,853
TSR Awards		
TSR shares granted during the year	114,390	116,435
TSR shares vested during the year	(107,649)	(111,665)
TSR shares earned based on market metrics	158,262	132,887
Unvested TSR shares at end of year	218,507	222,228
Unrecognized compensation expense (in thousands)	$ 2,849	$ 3,409
CEPS Awards		
CEPS shares granted during the year	57,223	57,521
CEPS shares vested during the year	(53,862)	(55,835)
CEPS shares earned based on market metrics	41,502	90,460
Unvested CEPS shares at end of year	108,581	110,452
Unrecognized compensation expense (in thousands)	$ 1,856	$ 1,671

Outstanding TSR and CEPS share awards include a dividend component that is paid in cash. This component of the share grants is accounted for as a liability award. These liability awards are revalued on a quarterly basis taking into account the number of awards outstanding, historical dividend rate, the change in the value of the Company’s common stock relative to an external benchmark (TSR awards only) and the amount of CEPS earned to date compared to estimated CEPS over the performance period (CEPS awards only). Over the life of these awards, the cumulative amount of compensation expense recognized will match the actual cash paid. As of December 31, 2017 and 2016, the Company had recognized cumulative compensation expense and a liability of $1.5 million, respectively, related to the dividend component on the outstanding and unvested share grants.

Cash and Cash Equivalents

For the purposes of the Statements of Cash Flows, the Company considers all temporary investments with a maturity of three months or less when purchased to be cash equivalents.

Allowance for Doubtful Accounts

The Company maintains an allowance for doubtful accounts to provide for estimated and potential losses on accounts receivable. The Company determines the allowance for utility and other customer accounts receivable based on historical write-offs as compared to accounts receivable and operating revenues. Additionally, the Company establishes specific allowances for certain individual accounts.

Utility Plant in Service

The cost of additions to utility plant in service, including AFUDC and replacements of units of property and improvements, is capitalized. The cost of depreciable units of property retired plus the cost of removal less salvage is charged to accumulated depreciation.

Asset Retirement Obligations (ARO)

The Company records the fair value of a liability for an ARO in the period in which it is incurred. When the liability is initially recorded, the associated costs of the ARO are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. In addition, if there are changes in the estimated timing or estimated costs of the AROs, adjustments are recorded during the period new information becomes available as an increase or decrease to the liability, with the offset recorded to the related long-lived asset. Upon retirement of the asset, the Company either settles the ARO for its recorded amount or recognizes a regulatory asset or liability for the difference, which will be surcharged/refunded to customers through the ratemaking process. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and AROs recorded since asset retirement costs are recovered through rates charged to customers (see Note 6 for further discussion of the Company's AROs).

Goodwill

Goodwill arising from acquisitions represents the future economic benefit arising from other assets acquired in a business combination that are not individually identified and separately recognized. The Company evaluates goodwill for impairment using a qualitative analysis (Step 0) for AEL&P and a combination of discounted cash flow models and a market approach for the other subsidiaries on at least an annual basis or more frequently if impairment indicators arise. The Company completed its annual evaluation of goodwill for potential impairment as of November 30, 2017 and determined that goodwill was not impaired at that time. While, the Company does not have any goodwill amounts recorded on its FERC balance sheets, it does have goodwill at its subsidiaries and the amounts for goodwill are reflected in the investment in subsidiary companies.

The following amounts were recorded as goodwill at the subsidiary companies and reflected through the investment in subsidiary companies on the FERC balance sheets (dollars in thousands):

	AEL&P	Other	Accumulated Impairment Losses	Total
Balance as of the December 31, 2016	$ 52,426	$ 12,979	$ (7,733)	$ 57,672
Balance as of the December 31, 2017	52,426	12,979	(7,733)	57,672

Accumulated impairment losses are attributable to the other businesses.

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the Balance Sheets measured at estimated fair value.

The Washington Utilities and Transportation Commission (WUTC) and the Idaho Public Utilities Commission (IPUC) issued accounting orders authorizing Avista Corp. to offset energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of delivery. Realized benefits and costs result in adjustments to retail rates through Purchased Gas Adjustments (PGA), the Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rates cases. The resulting regulatory assets have been concluded to be probable of recovery through future rates.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as derivative assets or liabilities at estimated fair value with an offsetting regulatory asset or liability. Contracts that are not considered derivatives are accounted for on the accrual basis until they are settled or realized unless there is a decline in the fair value of the contract that is determined to be other-than-temporary.

For interest rate swap derivatives, Avista Corp. records all mark-to-market gains and losses in each accounting period as assets and liabilities, as well as offsetting regulatory assets and liabilities, such that there is no income statement impact. The interest rate swap derivatives are risk management tools similar to energy commodity derivatives. Upon settlement of interest rate swap derivatives, the regulatory asset or liability is amortized as a component of interest expense over the term of the associated debt. The Company records an offset of interest rate swap derivative assets and liabilities with regulatory assets and liabilities, based on the prior practice of the commissions to provide recovery through the ratemaking process. See Note 16 for additional discussion regarding interest rate swaps in the Company's 2017 Washington general rate cases.

As of December 31, 2017, the Company has multiple master netting agreements with a variety of entities that allow for cross-commodity netting of derivative agreements with the same counterparty (i.e. power derivatives can be netted with natural gas derivatives). In addition, some master netting agreements allow for the netting of commodity derivatives and interest rate swap derivatives for the same counterparty. The Company does not have any agreements which allow for cross-affiliate netting among multiple affiliated legal entities. The Company nets all derivative instruments when allowed by the agreement for presentation in the Balance Sheets.

Fair Value Measurements

Fair value represents the price that would be received when selling an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Energy commodity derivative assets and liabilities, deferred compensation assets, as well as derivatives related to interest rate swap derivatives and foreign currency exchange derivatives, are reported at estimated fair value on the Balance Sheets. See Note 13 for the Company’s fair value disclosures.

Regulatory Deferred Charges and Credits

The Company prepares its financial statements in accordance with regulatory accounting practices because:

- rates for regulated services are established by or subject to approval by independent third-party regulators,
- the regulated rates are designed to recover the cost of providing the regulated services, and
- in view of demand for the regulated services and the level of competition, it is reasonable to assume that rates can be charged to and collected from customers at levels that will recover costs.

Regulatory accounting practices require that certain costs and/or obligations (such as incurred power and natural gas costs not currently included in rates, but expected to be recovered or refunded in the future), are reflected as deferred charges or credits on the Balance Sheets. These costs and/or obligations are not reflected in the Statements of Income until the period during which matching revenues are recognized. The Company also has decoupling revenue deferrals. Decoupling revenue deferrals are recognized in the Statements of Income during the period they occur (i.e. during the period of revenue shortfall or excess due to fluctuations in customer usage), subject to certain limitations, and a regulatory asset/liability is established which will be surcharged or rebated to customers in future periods. GAAP requires that for any alternative regulatory revenue program, like decoupling, the revenue must be expected to be collected from customers within 24 months of the deferral to qualify for recognition in the current period Statement of Income. Any amounts included in the Company's decoupling program that are not expected to be collected from customers within 24 months are not recorded in the financial statements until the period in which revenue recognition criteria are met. This could ultimately result in decoupling revenue that arose during the current year being recognized in a future period.

If at some point in the future the Company determines that it no longer meets the criteria for continued application of regulatory accounting practices for all or a portion of its regulated operations, the Company could be:

- required to write off its regulatory assets, and
- precluded from the future deferral of costs or decoupled revenues not recovered through rates at the time such amounts are incurred, even if the Company expected to recover these amounts from customers in the future.

Unamortized Debt Expense

Unamortized debt expense includes debt issuance costs that are amortized over the life of the related debt.

Unamortized Gain/Loss on Reacquired Debt

For the Company’s Washington regulatory jurisdiction and for any debt repurchases beginning in 2007 in all jurisdictions, premiums or discounts paid to repurchase debt are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these amounts are amortized over the life of the new debt. In the Company’s other regulatory jurisdictions, premiums or discounts paid to repurchase debt prior to 2007 are amortized over the average remaining maturity of outstanding debt when no new debt was issued in connection with the debt repurchase. The premiums and discounts are recovered or returned to customers through retail rates as a component of interest expense.

Appropriated Retained Earnings

In accordance with the hydroelectric licensing requirements of section 10(d) of the Federal Power Act (FPA), the Company maintains an appropriated retained earnings account for any earnings in excess of the specified rate of return on the Company's investment in the licenses for its various hydroelectric projects. Per section 10(d) of the FPA, the Company must maintain these excess earnings in an appropriated retained earnings account until the termination of the licensing agreements or apply them to reduce the net investment in the licenses of the hydroelectric projects at the discretion of the FERC. The Company calculates the earnings in excess of the specified rate of return on an annual basis, usually during the second quarter.

The appropriated retained earnings amounts included in retained earnings were as follows as of December 31 (dollars in thousands):

	2017	2016
Appropriated retained earnings	$ 32,132	$ 23,869

Operating Leases

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from 1 to 45 years. Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year were not material as of December 31, 2017.

Equity in Earnings (Losses) of Subsidiaries

The Company records all the earnings (losses) from its subsidiaries under the equity method. The Company had the following equity in earnings (losses) of its subsidiaries for the years ended December 31 (dollars in thousands):

	2017	2016
Avista Capital	$ (6,942)	$ (1,434)
AERC	9,460	7,723
Total equity in earnings of subsidiary companies	$ 2,518	$ 6,289

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2017 up to February 20, 2018, the date that Avista Corp.'s GAAP financial statements were issued and has updated such evaluation for disclosure purposes through the date of this report. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses loss contingencies that do not meet these conditions for accrual, if there is a reasonable possibility that a material loss may be incurred. As of December 31, 2017, the Company has not recorded any significant amounts related to unresolved contingencies. See Note 15 for further discussion of the Company's commitments and contingencies.

Transmission Utility Plant Write-Off (Immaterial Correction of an Error from Prior Years)

During the fourth quarter of 2017, the Company performed a detailed analysis of its capital overhead accounts associated with transmission system planning for the four-year period of January 1, 2014 through December 31, 2017. Based on this review, it was determined that a portion of transmission system planning costs capitalized as part of utility plant over that time period should have been recorded to operating expense (FERC account 561.5). The items that should have been recorded as operating expenses related to general transmission system planning not associated with specific projects and preliminary studies and designs of transmission systems. As a result, during 2017, the Company recorded an immaterial correction of an error from prior years which reduced utility plant transmission assets by $1.9 million and increased operating expenses by $1.9 million. Of the total correction amount recorded in 2017, between $0.6 million to $0.7 million related to each of 2014, 2015 and 2016.

NOTE 2. NEW ACCOUNTING STANDARDS

ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)"

In May 2014, the Financial Accounting and Standards Board (FASB) issued ASU No. 2014-09, which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. The core principle of the revenue model is that an entity should identify the various performance obligations in a contract, allocate the transaction price among the performance obligations and recognize revenue when (or as) the entity satisfies each performance obligation. This ASU is effective for periods beginning after December 15, 2017.

The Company will adopt this standard on January 1, 2018 using a modified retrospective method, which requires a cumulative adjustment to opening retained earnings, as opposed to a full retrospective application. The Company has not identified any cumulative adjustments.

Since the majority of Avista Corp.'s revenue is from rate-regulated sales of electricity and natural gas to retail customers and revenue is recognized as energy is delivered to these customers, the Company will not have a significant change in operating revenues or net income due to the application of this standard. The Company reviewed and analyzed certain contracts with customers (most of which are related to wholesale sales of power and natural gas) and did not identify any significant differences in revenue recognition between current GAAP and ASU No. 2014-09.

During the implementation process, the Company worked through several issues, the most significant of which are as follows:

Contributions in Aid of Construction (CIAC) – There was the potential that CIAC could be recognized as revenue upon the adoption of ASU No. 2014-09. Implementation guidance indicates that CIAC will continue to be accounted for as an offset to utility plant in service.

Utility-Related Taxes Collected from Customers – There were questions on the presentation of utility-related taxes collected from customers (primarily state excise taxes and city utility taxes) on a gross basis. Under GAAP, the Company has been allowed to record these utility-related taxes on a gross basis in revenue when billed to customers with an offset included in taxes other than income taxes in operating expenses. The Company evaluated whether this gross presentation is appropriate under ASU 2014-09 and determined that for Avista Corp., the current presentation will not change.

Renewable Energy Credits (REC) - Utility industry implementation guidance indicates that revenue associated with the sale of self-generated RECs will be recognized at the time of generation and sale of the credits as opposed to when the RECs are certified in the Western Renewable Energy Generation Information System, which generally occurs during a period subsequent to the sale. This represents a change from the Company's prior practice, which has been to defer revenue recognition until the time of certification. Revenue associated with the sale of RECs is not material to the financial statements and almost all of the Company's REC revenue is deferred for future rebate to retail customers. As such, the change in the timing of revenue recognition will have an insignificant impact to revenue and net income.

The Company is monitoring utility industry implementation guidance to determine if there will be further industry consensus regarding accounting and presentation issues.

In addition to the issues described above, the Company will also have significant changes to its revenue-related footnote disclosures, including the bifurcation of wholesale revenue into derivative and non-derivative sales. The Company continues to evaluate what information would be most useful for users of the financial statements, including information already provided elsewhere in the document outside the footnote disclosures. These additional disclosures will most likely include the disaggregation of revenues by type of service, source of revenue or customer class. Also, the Company will have enhanced disclosures regarding its revenue recognition policies and elections. The Company does not expect any material presentation changes to the base financial statements, and only expects changes to its footnote disclosures.

ASU No. 2016-02 "Leases (Topic 842)"

In February 2016, the FASB issued ASU No. 2016-02. This ASU introduces a new lessee model that requires most leases to be capitalized and shown on the balance sheet with corresponding lease assets and liabilities. The standard also aligns certain of the underlying principles of the new lessor model with those in Topic 606, the FASB's new revenue recognition standard. Furthermore, this ASU addresses other issues that arise under the current lease model; for example, eliminating the required use of bright-line tests in current GAAP for determining lease classification (operating leases versus capital leases). This ASU also includes enhanced disclosures surrounding leases. This ASU is effective for periods beginning on or after December 15, 2018; however, early adoption is permitted. Under ASU 2016-02, upon adoption, the effects of this standard must be applied using a modified retrospective approach to the earliest period presented, which will likely require restatements of previously issued financial statements. The modified retrospective approach includes a number of optional practical expedients that entities may elect to apply. During 2018, a proposed ASU was issued by the FASB that provides a practical expedient that would allow companies to use an optional transition method, which would allow for a cumulative adjustment to retained earnings during the period of adoption and prior periods would not require restatement.

The Company evaluated ASU 2016-02 and determined that it will not early adopt this standard before its effective date in 2019.

The Company has formed a lease standard implementation team that is working through the implementation process. Based on work to-date, the implementation team has identified a complete population of existing and potential leases under the new standard and has completed its review of the agreements associated with this population. However, the team has not yet quantified the impact of recording these leases. In addition, the team is developing a process to identify any new potential leases that may be entered into between now and the standard implementation date in 2019.

The Company is monitoring utility industry implementation guidance as it relates to several unresolved issues to determine if there will be an industry consensus. The Company has not yet estimated the potential impact on its future financial condition, results of operations and cash flows.

ASU No. 2016-09 "Compensation—Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting"

In March 2016, the FASB issued ASU No. 2016-09. This ASU simplified several aspects of the accounting for employee share-based payment transactions including:

- allowing excess tax benefits or tax deficiencies to be recognized as income tax benefits or expenses in the Statements of Income rather than in Additional Paid in Capital (APIC),
- excess tax benefits no longer represent a financing cash inflow on the Statements of Cash Flows and instead will be included as an operating activity,
- requiring excess tax benefits and tax deficiencies to be excluded from the calculation of diluted earnings per share, whereas under previous accounting guidance, these amounts had to be estimated and included in the calculation,
- allowing forfeitures to be accounted for as they occur, instead of estimating forfeitures, and
- changing the statutory tax withholding requirements for share-based payments.

The Company early adopted this standard during the second quarter of 2016, with a retrospective effective date of January 1, 2016. The adoption of this standard resulted in a recognized income tax benefit of $1.6 million in 2016 associated with excess tax benefits on settled share-based employee payments.

ASU No. 2017-07 "Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost"

In March 2017, the FASB issued ASU No. 2017-07, which amends the income statement presentation of the components of net periodic benefit cost for an entity's defined benefit pension and other postretirement plans. Under current GAAP, net benefit cost consists of several components that reflect different aspects of an employer's financial arrangements as well as the cost of benefits earned by employees. These components are aggregated and reported net in the financial statements. ASU No. 2017-07 requires entities to (1) disaggregate the current service-cost component from the other components of net benefit cost (other components) and present it with other current compensation costs for related employees in the income statement and (2) present the other components elsewhere in the income statement and outside of income from operations.

In addition, only the service-cost component of net benefit cost is eligible for capitalization (e.g., as part of utility plant). This is a change from current practice, under which entities capitalize the aggregate net benefit cost to utility plant when applicable, in accordance with FERC accounting guidance. Avista Corp. is a rate-regulated entity and all components of net periodic benefit cost are currently recovered from customers as a component of utility plant and, under the new ASU, these costs will continue to be recovered from customers in the same manner over the depreciable lives of utility plant. As all such costs are expected to continue to be recoverable, the components that are no longer eligible to be recorded as a component of utility plant for GAAP will be recorded as regulatory assets.

This ASU is effective for periods beginning after December 15, 2017 and early adoption is permitted. Upon adoption, entities must use a retrospective transition method to adopt the requirement for separate presentation in the income statement and a prospective transition method to adopt the requirement to limit the capitalization of net periodic benefit costs to the service-cost component. The Company did not early adopt this standard and does not expect a material impact on its future financial condition, results of operations or cash flows upon adoption of this standard.

ASU 2018-02 "Income Statement-Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income"

In February 2018, the FASB issued ASU 2018-02, which amends the guidance for reporting comprehensive income. The ASU allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the enactment of the TCJA. This ASU is effective for periods beginning after December 15, 2018 and early adoption is permitted. Upon adoption, the requirements of the ASU must be applied either in the period of adoption or retrospectively to each period (or periods) in which the effect of the change in the U.S. federal corporate income tax rate in the TCJA is recognized. The Company did not early adopt this standard as of December 31, 2017 and does not expect a material impact on its future financial condition, results of operations or cash flows upon adoption of this standard.

NOTE 3. PENDING ACQUISITION BY HYDRO ONE

On July 19, 2017, Avista Corp. entered into a Merger Agreement, by and among Hydro One, Olympus Holding Corp., a wholly owned subsidiary of Hydro One (US parent), and Olympus Corp., a wholly owned subsidiary of US parent (Merger Sub). Subject to the terms and conditions of the Merger Agreement, Merger Sub will be merged with and into Avista Corp., with Avista Corp. surviving as an indirect, wholly-owned subsidiary of Hydro One. Hydro One, based in Toronto, is Ontario's largest electricity transmission and distribution provider.

At the effective time of the acquisition, each share of Avista Corp. common stock issued and outstanding, other than shares of Avista Corp. common stock that are owned by Hydro One, US Parent (as defined in the Merger Agreement) or Merger Sub or any of their respective subsidiaries, will be converted automatically into the right to receive an amount in cash equal to $53, without interest.

Closing Conditions, Required Approvals

Consummation of the acquisition is subject to the satisfaction or waiver, if permissible under applicable law, of specified closing conditions, including, but not limited to, (i) the approval of the acquisition by the holders of a majority of the outstanding shares of Avista Corp. Common Stock, (ii) the receipt of regulatory approvals required to consummate the acquisition, including approval from the FERC, the Committee on Foreign Investment in the United States (CFIUS), the Federal Communications Commission (FCC), the WUTC, IPUC, Public Service Commission of the State of Montana (MPSC), Oregon Public Utilities Commission (OPUC), and the Regulatory Commission of Alaska (RCA), and (iii) meeting the requirements of the Hart-Scott-Rodino Antitrust Improvements Act of 1976 (HSR Act), as amended. Under the HSR Act and the rules and regulations promulgated thereunder, the acquisition may not be completed until notification and report forms have been filed with the U.S. Department of Justice (DOJ) and the Federal Trade Commission (FTC) and the applicable waiting period has expired or been terminated. Hydro One and the Company each intend to file the required HSR notification and report forms with the DOJ and the FTC.

The transaction is expected to close in the second half of 2018 subject to remaining referenced approvals and the satisfaction or waiver of other specified conditions.

Approvals Requested

On September 14, 2017, Avista Corp. and Hydro One filed applications for approval of the acquisition with the FERC, the WUTC, the IPUC, the OPUC and the MPSC, requesting approval of the transaction on or before August 14, 2018. However, the OPUC has set a procedural schedule with an end date no later than September 14, 2018. On November 21, 2017, applications for approval of the acquisition were filed with the RCA, with a statutory deadline of May 20, 2018.

Washington Settlement

On March 27, 2018, Avista Corp. and Hydro One filed an all-parties, all-issues settlement agreement in the merger proceeding before the WUTC recommending approval of the acquisition of the Company by Hydro One. This represents a full settlement that all parties, including the WUTC Staff, have agreed results in a net benefit to the Company's Washington customers and should be accepted by the WUTC.

The settlement includes financial and non-financial commitments by the Company. No costs associated with the transaction will be recovered from Avista Corp. or Hydro One customers. The Company's initial September 2017 applications for state regulatory approval of the transaction proposed a rate credit of approximately $32 million over a 10-year period across Washington, Oregon and Idaho. This amounted to an allocation of an approximately $20 million rate credit in Washington. The settlement, if approved, would result in the allocation to Washington of a rate credit of approximately $31 million over a 5-year period. In the settlement, Hydro One and Avista Corp. have also agreed to a number of other financial commitments, including providing funding for low income participation in new renewable energy and replacing certain manufactured homes. If the settlement is approved, the Company's financial commitments in Washington would total approximately $44 million, including the rate credits. While negotiations with parties in Idaho, Oregon, Montana and Alaska are still underway and will be resolved on a state-by-state basis, if the financial commitments in each other state bore the same ratio to the Company’s base revenue in such state as the financial commitments in Washington bear to the Washington revenue, the total amount of financial commitments would be approximately $74 million, which includes an additional $1 million proposed rate credit in Alaska.

The settlement in principle also provides for the use of a portion of Avista Corp.’s excess deferred federal income taxes for the purpose of accelerating the depreciation schedule for Colstrip Units 3 and 4 to reflect a remaining useful life of those units through December 31, 2027. In addition, included in the financial commitments described above is funding toward a Colstrip community transition fund which is intended to help the Colstrip community transition from coal-fired generation in the event of a future closure. The settlement in principle does not reflect any agreement with respect to the ultimate closure of Units 3 and 4 as that decision would be made in conjunction with the other owners of Colstrip.

The settlement agreement is subject to WUTC approval. The WUTC Staff’s recommendation that the WUTC approve the settlement agreement is not binding on the WUTC itself.

In addition to Hydro One, Avista Corp. and WUTC Staff, the parties to the merger proceeding include the Public Counsel Unit of the Washington Office of Attorney General, The Energy Project, Northwest Energy Coalition, Renewable Northwest, Natural Resources Defense Council, Sierra Club and the Washington and Northern Idaho District Council of Laborers, the Northwest Industrial Gas Users and the Industrial Customers of Northwest Utilities.

Alaska Settlement

On April 3, 2018, Avista Corp. and Hydro One submitted a settlement agreement in the merger proceeding before the RCA recommending approval of the acquisition of the Company by Hydro One. The settlement agreement is with the City and Borough of Juneau, the only intervenor in the case. Avista Corp. serves customers in Juneau, Alaska through its subsidiary utility, AEL&P.

The settlement agreement includes specific commitments that preserve the ownership structure and current operations of AEL&P, ensure customer rates will not be impacted by the transaction, enhance community giving and provide a $1 million rate credit over five years for AEL&P's customers. This rate credit would begin at the close of the transaction.

The settlement also provides that any transfer of the Snettisham Hydroelectric Project will not occur without RCA approval and a determination that such transfer would be in the public interest, formalizes AEL&P's interconnection process and outlines a process for a biennial AEL&P system and planning presentation.

The settlement agreement is subject to RCA review and approval. The parties have requested a decision from the RCA within 30 days of filing the settlement agreement.

On February 9, 2018, Hydro One and the Company filed a draft joint voluntary notice of the acquisition with CFIUS pursuant to Section 721 of Title VII of the Defense Production Act of 1950, as amended, 50 U.S.C. § 4565 (Section 721) and its implementing regulations.

Approvals Received

On November 21, 2017, Avista Corp. shareholders approved the acquisition in a special meeting of shareholders. Also, on January 16, 2018 the FERC approved the acquisition.

Other Pending Required Approvals

The Company intends to file for the required approvals with the FCC pursuant to Section 310 of the Communications Act of 1934, as amended, over the transfer of control of FCC licenses that would result from the acquisition.

Other Information Related to the Acquisition

The Merger Agreement also contains customary representations, warranties and covenants of Avista Corp., Hydro One, US Parent and Merger Sub. These covenants include, among others, an obligation on behalf of Avista Corp. to operate its business in the ordinary course until the acquisition is consummated, subject to certain exceptions. In addition, the parties are required to use reasonable best efforts to obtain any required regulatory approvals.

Avista Corp. has made certain additional customary covenants, including, among others, and subject to certain exceptions, a customary non-solicitation covenant prohibiting Avista Corp. from soliciting, providing non-public information or entering into discussions or negotiations concerning proposals relating to alternative business combination transactions, except as and to the extent permitted under the Merger Agreement with respect to an unsolicited written Takeover Proposal (as defined in the Merger Agreement) made prior to the approval of the acquisition by Avista Corp.'s shareholders if, among other things, Avista Corp.'s board of directors determines in good faith that such Takeover Proposal is or could be reasonably expected to lead to a Superior Proposal (as defined in the Merger Agreement) and that failure to take such actions would reasonably be expected to be inconsistent with its fiduciary duties under applicable law. No such Takeover Proposals have been received.

The Merger Agreement may be terminated by Avista Corp. and Hydro One by mutual consent and by either Avista Corp. or Hydro One under certain circumstances, including if the acquisition is not consummated by September 30, 2018 (subject to an extension of up to six months by either party if all of the conditions to closing, other than the conditions related to obtaining required regulatory approvals, the absence of a law or injunction preventing the consummation of the acquisition and the absence of a Burdensome Condition (as defined in the Merger Agreement) in any required regulatory approval, have been satisfied). The Merger Agreement also provides for certain additional termination rights for each of Avista Corp. and Hydro One. Upon termination of the Merger Agreement under certain specified circumstances, including (i) termination by Avista Corp. in order to enter into a definitive agreement with respect to a Superior Proposal, or (ii) termination by Hydro One following a withdrawal by Avista Corp.'s board or directors of its recommendation of the Merger Agreement, Avista Corp. will be required to pay Hydro One the Company Termination Fee of $103.0

million. Avista Corp. will also be required to pay Hydro One the Company Termination Fee in the event Avista Corp. signs or consummates any specified alternative transaction within twelve months following the termination of the Merger Agreement under certain circumstances. In addition, if the Merger Agreement is terminated under certain circumstances due to the failure to obtain required regulatory approvals, the imposition of a Burdensome Condition with respect to a required regulatory approval, or the breach by Hydro One, US Parent or Merger Sub of their obligations in respect of obtaining regulatory approvals, Hydro One will be required to pay Avista Corp. a termination fee of $103.0 million.

The Company is incurring significant acquisition costs associated with the pending Hydro One acquisition consisting primarily of consulting, banking fees, legal fees and employee time and are not being passed through to customers. In addition, a significant portion of these costs are not deductible for income tax purposes.

See Note 15 for discussion of shareholder lawsuits filed against the Company, the Company's directors, Hydro One, Olympus Holding Corp., and Olympus Corp. in relation to the Merger Agreement and the proposed acquisition.

NOTE 4. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Corp. utilizes derivative instruments, such as forwards, futures, swap derivatives and options in order to manage the various risks relating to these commodity price exposures. Avista Corp. has an energy resources risk policy and control procedures to manage these risks.

As part of Avista Corp.'s resource procurement and management operations in the electric business, the Company engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Corp.'s load obligations and the use of these resources to capture available economic value through wholesale market transactions. These include sales and purchases of electric capacity and energy, fuel for electric generation, and derivative contracts related to capacity, energy and fuel. Such transactions are part of the process of matching resources with load obligations and hedging a portion of the related financial risks. These transactions range from terms of intra-hour up to multiple years.

As part of its resource procurement and management of its natural gas business, Avista Corp. makes continuing projections of its natural gas loads and assesses available natural gas resources including natural gas storage availability. Natural gas resource planning typically includes peak requirements, low and average monthly requirements and delivery constraints from natural gas supply locations to Avista Corp.'s distribution system. However, daily variations in natural gas demand can be significantly different than monthly demand projections. On the basis of these projections, Avista Corp. plans and executes a series of transactions to hedge a portion of its projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend as much as four natural gas operating years (November through October) into the future. Avista Corp. also leaves a significant portion of its natural gas supply requirements unhedged for purchase in short-term and spot markets.

Avista Corp. plans for sufficient natural gas delivery capacity to serve its retail customers for a theoretical peak day event. Avista Corp. generally has more pipeline and storage capacity than what is needed during periods other than a peak day. Avista Corp. optimizes its natural gas resources by using market opportunities to generate economic value that helps mitigate fixed costs. Avista Corp. also optimizes its natural gas storage capacity by purchasing and storing natural gas when prices are traditionally lower, typically in the summer, and withdrawing during higher priced months, typically during the winter. However, if market conditions and prices indicate that Avista Corp. should buy or sell natural gas during other times in the year, Avista Corp. engages in optimization transactions to capture value in the marketplace. Natural gas optimization activities include, but are not limited to, wholesale market sales of surplus natural gas supplies, purchases and sales of natural gas to optimize use of pipeline and storage capacity, and participation in the transportation capacity release market.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2017 that are expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
2018	426	763	10,572	107,580	213	1,739	3,643	67,375
2019	235	737	610	61,073	94	1,420	1,345	35,438
2020	—	—	910	16,590	—	589	1,430	915
2021	—	—	—	—	—	—	1,049	—
2022	—	—	—	—	—	—	—	—
Thereafter	—	—	—	—	—	—	—	—

The following table presents the underlying energy commodity derivative volumes as of December 31, 2016 that were expected to be delivered in each respective year (in thousands of MWhs and mmBTUs):

	Purchases				Sales			
	Electric Derivatives		Gas Derivatives		Electric Derivatives		Gas Derivatives	
Year	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs	Physical (1) MWh	Financial (1) MWh	Physical (1) mmBTUs	Financial (1) mmBTUs
2017	510	907	15,475	110,380	316	1,552	4,165	73,110
2018	397	—	—	52,755	286	1,244	1,360	15,113
2019	235	—	610	29,475	158	982	1,345	4,020
2020	—	—	910	2,725	—	—	1,430	—
2021	—	—	—	—	—	—	1,060	—
Thereafter	—	—	—	—	—	—	—	—

(1) Physical transactions represent commodity transactions in which Avista Corp. will take or make delivery of either electricity or natural gas; financial transactions represent derivative instruments with delivery of cash in the amount of the benefit or cost but with no physical delivery of the commodity, such as futures, swap derivatives, options, or forward contracts.

The electric and natural gas derivative contracts above will be included in either power supply costs or natural gas supply costs during the period they are delivered and will be included in the various deferral and recovery mechanisms (ERM, PCA, and PGAs), or in the general rate case process, and are expected to be collected through retail rates from customers.

Foreign Currency Exchange Derivatives

A significant portion of Avista Corp.'s natural gas supply (including fuel for power generation) is obtained from Canadian sources. Most of those transactions are executed in U.S. dollars, which avoids foreign currency risk. A portion of Avista Corp.'s short-term natural gas transactions and long-term Canadian transportation contracts are committed based on Canadian currency prices and settled within 60 days with U.S. dollars. Avista Corp. hedges a portion of the foreign currency risk by purchasing Canadian currency exchange derivatives when such commodity transactions are initiated. The foreign currency exchange derivatives and the unhedged foreign currency risk have not had a material effect on Avista Corp.'s financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations are included with natural gas supply costs for ratemaking.

The following table summarizes the foreign currency exchange derivatives that Avista Corp. has outstanding as of December 31 (dollars in thousands):

	2017	2016
Number of contracts	18	21
Notional amount (in United States dollars)	$ 2,552	$ 2,819
Notional amount (in Canadian dollars)	3,241	3,754

Interest Rate Swap Derivatives

Avista Corp. is affected by fluctuating interest rates related to a portion of its existing debt, and future borrowing requirements. Avista Corp. hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swap derivatives and U.S. Treasury lock agreements. These interest rate swap derivatives and U.S. Treasury lock agreements are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

The following table summarizes the unsettled interest rate swap derivatives that Avista Corp. has outstanding as of the balance sheet date indicated below (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
December 31, 2017	14	275,000	2018
	6	70,000	2019
	3	30,000	2020
	1	15,000	2021
	5	60,000	2022
December 31, 2016	6	75,000	2017
	14	275,000	2018
	6	70,000	2019
	2	20,000	2020
	5	60,000	2022

During the third quarter 2017, in connection with the execution of a purchase agreement for $90.0 million of Avista Corp. first mortgage bonds issued in December 2017, Avista Corp. cash-settled five interest rate swap derivatives (notional aggregate amount of $60.0 million) and paid a total of $8.8 million. Upon settlement of interest rate swap derivatives, the cash payments made or received are recorded as a regulatory asset or liability and are subsequently amortized as a component of interest expense over the life of the associated debt. The settled interest rate swap derivatives are also included as a part of Avista Corp.'s cost of debt calculation for ratemaking purposes.

The fair value of outstanding interest rate swap derivatives can vary significantly from period to period depending on the total notional amount of swap derivatives outstanding and fluctuations in market interest rates compared to the interest rates fixed by the swaps. Avista Corp. is required to make cash payments to settle the interest rate swap derivatives when the fixed rates are higher than prevailing market rates at the date of settlement. Conversely, Avista Corp. receives cash to settle its interest rate swap derivatives when prevailing market rates at the time of settlement exceed the fixed swap rates.

Summary of Outstanding Derivative Instruments

The amounts recorded on the Balance Sheet as of December 31, 2017 and December 31, 2016 reflect the offsetting of derivative assets and liabilities where a legal right of offset exists.

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheet as of December 31, 2017 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) in Balance Sheet
Foreign currency exchange derivatives				
Derivative instrument assets current	$ 32	$ (1)	$ —	$ 31
Interest rate swap derivatives				
Derivative instrument assets current	2,597	(270)	—	2,327
Long-term portion of derivative assets	4,880	(2,304)	—	2,576
Derivative instrument liabilities current		(63,399)	28,952	(34,447)
Long-term portion of derivative liabilities		(7,540)	6,018	(1,522)
Energy commodity derivatives				
Derivative instrument assets current	1,386	(122)	—	1,264
Derivative instrument liabilities current	26,641	(52,895)	17,406	(8,848)
Long-term portion of derivative liabilities	15,970	(34,936)	10,032	(8,934)
Total derivative instruments recorded on the balance sheet	$ 51,506	$ (161,467)	$ 62,408	$ (47,553)

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheet as of December 31, 2016 (in thousands):

	Fair Value			
Derivative and Balance Sheet Location	Gross Asset	Gross Liability	Collateral Netting	Net Asset (Liability) in Balance Sheet
Foreign currency exchange derivatives				
Derivative instrument liabilities current	$ 5	$ (28)	$ —	$ (23)
Interest rate swap derivatives				
Derivative instrument assets current	3,393	—	—	3,393
Long-term portion of derivative assets	5,754	(397)	—	5,357
Derivative instrument liabilities current	—	(15,756)	9,731	(6,025)
Long-term portion of derivative liabilities	3,951	(57,825)	25,169	(28,705)
Energy commodity derivatives				
Derivative instrument assets current	18,682	(16,787)	—	1,895
Derivative instrument liabilities current	16,335	(29,598)	6,228	(7,035)

Long-term portion of derivative liabilities	13,071	(29,990)	3,630	(13,289)
Total derivative instruments recorded on the balance sheet	$ 61,191	$ (150,381)	$ 44,758	$ (44,432)

Exposure to Demands for Collateral

Avista Corp.'s derivative contracts often require collateral (in the form of cash or letters of credit) or other credit enhancements, or reductions or terminations of a portion of the contract through cash settlement. In the event of a downgrade in Avista Corp.'s credit ratings or changes in market prices, additional collateral may be required. In periods of price volatility, the level of exposure can change significantly. As a result, sudden and significant demands may be made against Avista Corp.'s credit facilities and cash. Avista Corp. actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements.

The following table presents Avista Corp.'s collateral outstanding related to its derivative instruments as of as of December 31 (in thousands):

	2017	2016
Energy commodity derivatives		
Cash collateral posted	$ 39,458	$ 17,134
Letters of credit outstanding	23,000	24,400
Balance sheet offsetting (cash collateral against net derivative positions)	27,438	9,858
Interest rate swap derivatives		
Cash collateral posted	34,970	34,900
Letters of credit outstanding	5,000	3,600
Balance sheet offsetting (cash collateral against net derivative positions)	34,970	34,900

Certain of Avista Corp.'s derivative instruments contain provisions that require the Company to maintain an "investment grade" credit rating from the major credit rating agencies. If Avista Corp.'s credit ratings 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 collateralization on derivative instruments in net liability positions.

The following table presents the aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position and the amount of additional collateral Avista Corp. could be required to post as of December 31 (in thousands):

	2017	2016
Energy commodity derivatives		
Liabilities with credit-risk-related contingent features	$ 1,336	$ 1,124
Additional collateral to post	1,336	1,046
Interest rate swap derivatives		
Liabilities with credit-risk-related contingent features	73,514	73,978
Additional collateral to post	18,770	21,100

NOTE 5. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in a twin-unit coal-fired generating facility, Colstrip, located in southeastern Montana, and provides financing for its ownership interest in the project. The Company's share of related fuel costs as well as operating expenses for plant in service are included in the corresponding accounts in the Statements of Income. The Company's share of utility plant in service for Colstrip and accumulated depreciation (inclusive of the ARO assets and accumulated amortization) were as follows as of December 31 (dollars in thousands):

	2017	2016
Utility plant in service	$ 379,970	$ 380,406
Accumulated depreciation	(255,604)	(249,359)

See Note 6 for further discussion of AROs.

NOTE 6. ASSET RETIREMENT OBLIGATIONS

The Company has recorded liabilities for future AROs to:

- restore coal ash containment ponds at Colstrip,
- cap a landfill at the Kettle Falls Plant,
- remove plant and restore the land at the Coyote Springs 2 site at the termination of the land lease, and
- dispose of PCBs in certain transformers.

Due to an inability to estimate a range of settlement dates, the Company cannot estimate a liability for the:

- removal and disposal of certain transmission and distribution assets, and
- abandonment and decommissioning of certain hydroelectric generation and natural gas storage facilities.

In 2015, the EPA issued a final rule regarding coal combustion residuals (CCR), also termed coal combustion byproducts or coal ash. Colstrip, of which Avista Corp. is a 15 percent owner of units 3 & 4, produces this byproduct. The rule established technical requirements for CCR landfills and surface impoundments under Subtitle D of the Resource Conservation and Recovery Act, the nation's primary law for regulating solid waste. The Company, in conjunction with the other Colstrip owners, developed a multi-year compliance plan to strategically address the CCR requirements and existing state obligations while maintaining operational stability. During 2015, the operator of Colstrip provided an initial cost estimate of the expected retirement costs associated with complying with the new CCR rule. Based on the initial assessments, Avista Corp. recorded an increase to its ARO of $12.5 million during 2015 with a corresponding increase in the cost basis of the utility plant. During 2016 and 2017, due to additional information and updated estimates, the ARO was adjusted during each of those years by minor amounts.

The actual asset retirement costs related to the CCR rule requirements may vary substantially from the estimates used to record the ARO due to the uncertainty and evolving nature of the compliance strategies that will be used and the availability of data used to estimate costs, such as the quantity of coal ash present at certain sites and the volume of fill that will be needed to cap and cover certain impoundments. Avista Corp. will coordinate with the plant operator and continue to gather additional data in future periods to make decisions about compliance strategies and the timing of closure activities. As additional information becomes available, Avista Corp. will update the ARO for these changes in estimates, which could be material. The Company expects to seek recovery of any increased costs related to complying with the CCR rule through customer rates.

The following table documents the changes in the Company's asset retirement obligation during the years ended December 31 (dollars in thousands):

	2017	2016
Asset retirement obligation at beginning of year	$ 15,515	$ 15,997

Liabilities incurred	1,171	430
Liabilities settled	—	(1,529)
Accretion expense	796	617
Asset retirement obligation at end of year	$ 17,482	$ 15,515

NOTE 7. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering the majority of all regular full-time employees at Avista Corp. that were hired prior to January 1, 2014. Individual benefits under this plan are based upon the employee's years of service, date of hire and average compensation as specified in the plan. Non-union employees hired on or after January 1, 2014 participate in a defined contribution 401(k) plan in lieu of a defined benefit pension plan. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $22.0 million in cash to the pension plan in 2017 and $12.0 million in 2016. The Company expects to contribute $22.0 million in cash to the pension plan in 2018.

The Company also has a SERP that provides additional pension benefits to certain executive officers and certain key employees of the Company. The SERP is intended to provide benefits to individuals whose benefits under the defined benefit pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans. The liability and expense for this plan are included as pension benefits in the tables included in this Note.

The Company expects that benefit payments under the pension plan and the SERP will total (dollars in thousands):

	2018	2019	2020	2021	2022	Total 2023-2027
Expected benefit payments	$ 36,916	$ 37,613	$ 38,610	$ 38,729	$ 38,837	$ 205,395

The expected long-term rate of return on plan assets is based on past performance and economic forecasts for the types of investments held by the plan. In selecting a discount rate, the Company considers yield rates for highly rated corporate bond portfolios with maturities similar to that of the expected term of pension benefits.

The Company provides certain health care and life insurance benefits for eligible retired employees that were hired prior to January 1, 2014. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The liability and expense of this plan are included as other postretirement benefits. Non-union employees hired on or after January 1, 2014, will have access to the retiree medical plan upon retirement; however, Avista Corp. will no longer provide a contribution toward their medical premium.

The Company has a Health Reimbursement Arrangement (HRA) to provide employees with tax-advantaged funds to pay for allowable medical expenses upon retirement. The amount earned by the employee is fixed on the retirement date based on the employee's years of service and the ending salary. The liability and expense of the HRA are included as other postretirement benefits.

The Company provides death benefits to beneficiaries of executive officers who die during their term of office or after retirement. Under the plan, an executive officer's designated beneficiary will receive a payment equal to twice the executive officer's annual base salary at the time of death (or if death occurs after retirement, a payment equal to twice the executive officer's total annual pension benefit). The liability and expense for this plan are included as other postretirement benefits.

The Company expects that benefit payments under other postretirement benefit plans will total (dollars in thousands):

	2018	2019	2020	2021	2022	Total 2023-2027
Expected benefit payments	$ 6,856	$ 7,064	$ 6,093	$ 6,223	$ 6,288	$ 32,265

The Company expects to contribute $6.9 million to other postretirement benefit plans in 2018, representing expected benefit payments to be paid during the year excluding the Medicare Part D subsidy. The Company uses a December 31 measurement date for its pension and other postretirement benefit plans.

The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2017 and 2016 and the components of net periodic benefit costs for the years ended December 31, 2017 and 2016 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2017	2016	2017	2016
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 666,472	$ 613,503	$ 136,453	$ 138,795
Service cost	20,406	18,302	3,220	3,205
Interest cost	27,898	27,544	5,490	6,110
Actuarial (gain)/loss	39,743	39,997	(6,020)	(3,648)
Plan change	3,158	—	—	—
Cumulative adjustment to reclassify liability	—	—	—	(1,042)
Benefits paid	(41,116)	(32,874)	(6,196)	(6,967)
Benefit obligation as of end of year	$ 716,561	$ 666,472	$ 132,947	$ 136,453
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 540,914	$ 517,234	$ 33,365	$ 30,868
Actual return on plan assets	82,476	43,212	4,588	2,497
Employer contributions	22,000	12,000	—	—
Benefits paid	(39,738)	(31,532)	—	—
Fair value of plan assets as of end of year	$ 605,652	$ 540,914	$ 37,953	$ 33,365
Funded status	$ (110,909)	$ (125,558)	$ (94,994)	$ (103,088)
Unrecognized net actuarial loss	157,883	178,783	68,280	81,979
Unrecognized prior service cost	3,179	23	(7,782)	(8,981)
Prepaid (accrued) benefit cost	50,153	53,248	(34,496)	(30,090)
Additional liability	(161,062)	(178,806)	(60,498)	(72,998)
Accrued benefit liability	$ (110,909)	$ (125,558)	$ (94,994)	$ (103,088)
Accumulated pension benefit obligation	$ 624,345	$ 583,498	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 60,354	$ 60,670
For fully eligible employees			$ 32,891	$ 34,429
For other participants			$ 39,702	$ 41,354
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost	$ 2,066	$ 15	$ (5,058)	$ (5,854)
Unrecognized net actuarial loss	102,624	116,209	44,382	53,303

Total	104,690	116,224	39,324	47,449
Less regulatory asset	(97,025)	(108,903)	(38,899)	(47,202)
Accumulated other comprehensive loss for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 7,665	$ 7,321	$ 425	$ 247

	Pension Benefits		Other Post-retirement Benefits	
	2017	2016	2017	2016
Weighted-average assumptions as of December 31:				
Discount rate for benefit obligation	3.71%	4.26%	3.72%	4.23%
Discount rate for annual expense	4.26%	4.57%	4.23%	4.57%
Expected long-term return on plan assets	5.87%	5.40%	5.69%	6.03%
Rate of compensation increase	4.69%	4.78%		
Medical cost trend pre-age 65 – initial			6.50%	7.00%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2023	2023
Medical cost trend post-age 65 – initial			6.50%	7.00%
Medical cost trend post-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2024	2024

	Pension Benefits		Other Post-retirement Benefits	
	2017	2016	2017	2016
Components of net periodic benefit cost:				
Service cost	$ 20,406	$ 18,302	$ 3,220	$ 3,205
Interest cost	27,898	27,544	5,490	6,110
Expected return on plan assets	(31,626)	(27,547))	(1,899)	(1,861
Amortization of prior service cost	2	2	(1,144)	(1,208
Net loss recognition	9,793	8,511	4,934	5,728
Net periodic benefit cost	$ 26,473	$ 26,812	$ 10,601	$ 11,974

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point increase in the assumed health care cost trend rate for each year would increase the accumulated postretirement benefit obligation as of December 31, 2017 by $6.6 million and the service and interest cost by $0.8 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease the accumulated postretirement benefit obligation as of December 31, 2017 by $5.2 million and the service and interest cost by $0.6 million.

Plan Assets

The Finance Committee of the Company's Board of Directors approves investment policies, objectives and strategies that seek an appropriate return for the pension plan and other postretirement benefit plans and reviews and approves changes to the investment and funding policies.

The Company has contracted with investment consultants who are responsible for monitoring the individual investment managers. The investment managers' performance and related individual fund performance is periodically reviewed by an internal benefits committee and by the Finance Committee to monitor compliance with investment policy objectives and strategies.

Pension plan assets are invested in mutual funds, trusts and partnerships that hold marketable debt and equity securities, real estate, absolute return and commodity funds. In seeking to obtain a return that aligns with the funded status of the pension plan, the investment consultant recommends allocation percentages by asset classes. These recommendations are reviewed by the internal benefits committee, which then recommends their adoption by the Finance Committee. The Finance Committee has established target investment allocation percentages by asset classes and also investment ranges for each asset class. The target investment allocation percentages are typically the midpoint of the established range. The target investment allocation percentages by asset classes are indicated in the table below:

	2017	2016
Equity securities	37%	37%
Debt securities	45%	45%
Real estate	8%	8%
Absolute return	10%	10%

The fair value of pension plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the reported last sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available or for which market prices do not represent the value at the time of pricing, the investment manager estimates fair value based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry).

Pension plan and other postretirement plan assets whose fair values are measured using net asset value (NAV) are excluded from the fair value hierarchy and are included as reconciling items in the tables below.

Investments in common/collective trust funds are presented at estimated fair value, which is determined based on the unit value of the fund. Unit value is determined by an independent trustee, which sponsors the fund, by dividing the fund's net assets by its units outstanding at the valuation date. The Company's investments in common/collective trusts have redemption limitations that permit quarterly redemptions following notice requirements of 45 to 60 days. The fair values of the closely held investments and partnership interests are based upon the allocated share of the fair value of the underlying net assets as well as the allocated share of the undistributed profits and losses, including realized and unrealized gains and losses. Most of the Company's investments in closely held investments and partnership interests have redemption limitations that range from bi-monthly to semi-annually following redemption notice requirements of 60 to 90 days. One investment in a partnership has a lock-up for redemption currently expiring in 2022 and is subject to extension.

The fair value of pension plan assets invested in real estate was determined by the investment manager based on three basic approaches:

- properties are externally appraised on an annual basis by independent appraisers, additional appraisals may be performed as warranted by specific asset or market conditions,
- property valuations are reviewed quarterly and adjusted as necessary, and
- loans are reflected at fair value.

The fair value of pension plan assets was determined as of December 31, 2017 and 2016.

The following table discloses by level within the fair value hierarchy (see Note 13 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2017 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 20,619	$ —	$ 20,619
Fixed income securities:				
U.S. government issues	—	20,305	—	20,305
Corporate issues	—	185,272	—	185,272
International issues	—	32,054	—	32,054
Municipal issues	—	20,201	—	20,201
Mutual funds:				
U.S. equity securities	127,742	—	—	127,742
International equity securities	40,755	—	—	40,755
Absolute return (1)	7,728	—	—	7,728
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	34,470
International equity securities	—	—	—	43,462
Partnership/closely held investments:				
Absolute return (1)	—	—	—	67,167
Private equity funds (2)	—	—	—	72
Real estate	—	—	—	5,805
Total	$ 176,225	$ 278,451	$ —	$ 605,652

The following table discloses by level within the fair value hierarchy (see Note 13 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2016 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 10,179	$ —	$ 10,179
Fixed income securities:				
U.S. government issues	—	30,919	—	30,919
Corporate issues	—	193,563	—	193,563
International issues	—	34,145	—	34,145
Municipal issues	—	18,888	—	18,888
Mutual funds:				
U.S. equity securities	120,856	—	—	120,856
International equity securities	30,025	—	—	30,025
Absolute return (1)	6,622	—	—	6,622

Plan assets measured at NAV (not subject to hierarchy disclosure)				
Common/collective trusts:				
Real estate	—	—	—	19,779
International equity securities	—	—	—	29,140
Partnership/closely held investments:				
Absolute return (1)	—	—	—	39,077
Private equity funds (2)	—	—	—	72
Real estate	—	—	—	7,649
Total	$ 157,503	$ 287,694	$ —	$ 540,914

(1) This category invests in multiple strategies to diversify risk and reduce volatility. The strategies include: (a) event driven, relative value, convertible, and fixed income arbitrage, (b) distressed investments, (c) long/short equity and fixed income, and (d) market neutral strategies.

(2) This category includes private equity funds that invest primarily in U.S. companies.

The fair value of other postretirement plan assets invested in debt and equity securities was based primarily on market prices. The fair value of investment securities traded on a national securities exchange is determined based on the last reported sales price; securities traded in the over-the-counter market are valued at the last reported bid price. Investment securities for which market prices are not readily available are fair-valued by the investment manager based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). The target asset allocation was 60 percent equity securities and 40 percent debt securities in both 2017 and 2016.

The fair value of other postretirement plan assets was determined as of December 31, 2017 and 2016.

The following table discloses by level within the fair value hierarchy (see Note 13 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2017 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Balanced index mutual funds (1)	$ 37,953	$ —	$ —	$ 37,953

The following table discloses by level within the fair value hierarchy (see Note 13 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2016 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 6	$ —	$ 6
Balanced index mutual funds (1)	33,359	—	—	33,359
Total	$ 33,359	$ 6	$ —	$ 33,365

(1) The balanced index fund for 2017 and 2016 is a single mutual fund that includes a percentage of U.S. equity and fixed income securities and International equity and fixed income securities.

401(k) Plans and Executive Deferral Plan

Avista Corp. has a salary deferral 401(k) plans that is a defined contribution plans and covers substantially all employees. Employees can make contributions to their respective accounts in the plans on a pre-tax basis up to the maximum amount permitted by law. The

Company matches a portion of the salary deferred by each participant according to the schedule in the respective plan.

Employer matching contributions were as follows for the years ended December 31 (dollars in thousands):

	2017	2016
Employer 401(k) matching contributions	$ 8,896	$ 8,555

The Company has an Executive Deferral Plan. This plan allows executive officers and other key employees the opportunity to defer until the earlier of their retirement, termination, disability or death, up to 75 percent of their base salary and/or up to 100 percent of their incentive payments. Deferred compensation funds are held by the Company in a Rabbi Trust.

There were deferred compensation assets and corresponding deferred compensation liabilities on the Balance Sheets of the following amounts as of December 31 (dollars in thousands):

	2017	2016
Deferred compensation assets and liabilities	$ 8,458	$ 7,679

NOTE 8. ACCOUNTING FOR INCOME TAXES

Federal Income Tax Law Changes

On December 22, 2017, the TCJA was signed into law. The legislation includes substantial changes to the taxation of individuals as well as U.S. businesses, multi-national enterprises, and other types of taxpayers. Highlights of provisions most relevant to Avista Corp. include:

- A permanent reduction in the statutory corporate tax rate from 35 percent to 21 percent, beginning with tax years after 2017;
- Statutory provisions requiring that excess deferred taxes associated with public utility property be normalized using the Average Rate Assumption Method (ARAM) for determining the timing of the return of excess deferred taxes to customers. Excess deferred taxes result from revaluing deferred tax assets and liabilities based on the newly enacted tax rate instead of the previous tax rate, which, for most rate-regulated utilities like Avista Corp., results in a net benefit to customers that will be deferred as a regulatory liability and passed through to customers over future periods;
- Repeal of the corporate alternative minimum tax (AMT);
- Bonus depreciation (expensing of capital investment on an accelerated basis) was removed as a deduction for property predominantly used in certain rate-regulated businesses (like Avista Corp.), but is still allowed for the Company's non-regulated businesses;
- The deduction for interest expense that is properly allocable to certain rate-regulated trade or businesses is still allowed under the new law, but the deduction is now limited for the Company's non-regulated businesses; and
- NOL carryback deductions were eliminated, but carryforward deductions are allowed indefinitely with some annual limitations versus the previous 20-year limitation.

The Company's analysis and interpretation of this legislation is complete as it relates to amounts recorded as of December 31, 2017 and based on its evaluation, the reduction of the U.S. corporate income tax rate required a revaluation of the Company's deferred income tax assets and liabilities (including the value of our net operating loss carryforwards) during the fourth quarter of 2017, the period in which the tax legislation was enacted. Because Avista Corp. is predominantly a rate-regulated entity, a large portion of the net effect of the legislation was recorded as a regulatory liability on the Balance Sheets and it will be returned to customers through the ratemaking process in future periods. The total net amount of the regulatory liability associated with the TCJA was $434.6 million as of December 31, 2017, which is made up of $334.4 million in excess deferred taxes and $100.2 million for the income tax gross-up of those excess deferred taxes (which, together with the excess deferred tax amount, reflects the revenue amounts to be refunded to customers through the regulatory process). The Company expects the Avista Corp. plant related amounts will be returned to customers over a period of approximately 36 years using the ARAM. The Company does not currently have an estimate for the amortization period for the regulatory liability attributable to non-plant excess deferred taxes items as the Company is waiting for additional implementation guidance from various regulatory agencies.

Because the Company has deferred income tax assets and liabilities related to its unregulated subsidiaries and certain utility expenses which are not being passed through to customers, the impact of the revaluation of the Company's deferred income tax assets and liabilities was recorded as a $7.5 million (net) discrete adjustment to income tax expense in the fourth quarter of 2017, specifically related to Avista Corp. In addition, there was a $2.7 million increase in expense at the other businesses, which is reflected in the equity in earnings of subsidiary companies in the Statements of Income.

Because most of the provisions of the TCJA are effective as of January 1, 2018 (including a reduction of the income tax rate to 21 percent), but the Company's customers' rates continue to have the 35 percent corporate tax rate built in from prior general rate cases, the Company filed Petitions in January 2018 with the WUTC and OPUC requesting orders authorizing the deferral of the accounting impact of the change in federal income tax expense caused by the enactment of the TCJA (the IPUC on its own ordered deferred accounting for all jurisdictional utilities in January 2018). The Company is requesting to defer the impact of the change in federal income tax expense beginning in January 2018 forward until all benefits are properly captured through the deferral and refunded to customers through tariffs to be reviewed and implemented in future rate proceedings. The IPUC has requested a report on the estimated overall benefit to customers related to the impacts of the TCJA by March 30, 2018. The WUTC issued a bench request in the Company's 2017 electric and natural gas general rate cases requesting such information by February 28, 2018.

In March, 2018, FERC issued a show-cause order under the Federal Power Act directing the Company to propose revisions to transmission rates or show cause why such a change should not be required. The Company is evaluating its response and will respond to the order before the end of the second quarter, 2018.

Deferred Income Taxes

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes and tax credit carryforwards.

The realization of deferred income tax assets is dependent upon the ability to generate taxable income in future periods. The Company evaluated available evidence supporting the realization of its deferred income tax assets and determined it is more likely than not that deferred income tax assets will be realized.

As of December 31, 2017, the Company had $19.6 million of state tax credit carryforwards. Of the total amount, the Company believes that it is more likely than not that it will only be able to utilize $8.6 million of the state tax credits. As such, the Company has recorded a valuation allowance of $11.0 million against the state tax credit carryforwards and reflected the net amount of $8.6 million as an asset as of December 31, 2017. State tax credits expire from 2019 to 2028. The Company also has approximately $3.5 million of federal tax credit carryforwards and the Company believes that it is more likely than not all the federal credits will be utilized. The federal tax credits expire in 2036.

Status of Internal Revenue Service (IRS) Examinations

The Company and its eligible subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon, Montana and Alaska. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The IRS has completed its examination of all tax years through 2011 and all issues were resolved related to these years. The statute of limitations for the IRS to review the 2012 and 2013 tax years has expired, and the Company has received a notice of an IRS review in 2018 for tax years 2014 through 2016. The Company believes that any open tax years for federal or state income taxes will not result in adjustments that would be significant to the financial statements.

Regulatory Assets and Liabilities Associated with Income Taxes

The Company had regulatory assets and liabilities related to the probable recovery/refund of certain deferred income tax assets and liabilities through future customer rates as of December 31 (dollars in thousands):

	2017	2016
Regulatory assets for deferred income taxes	$ 90,315	$ 109,853
Regulatory liabilities for deferred income taxes	452,817	28,966

NOTE 9. ENERGY PURCHASE CONTRACTS

Avista Corp. has contracts for the purchase of fuel for thermal generation, natural gas for resale and various agreements for the purchase or exchange of electric energy with other entities. The remaining term of the contracts range from one month to twenty-five years.

Total expenses for power purchased, natural gas purchased, fuel for generation and other fuel costs, which are included in utility resource costs in the Statements of Income, were as follows for the years ended December 31 (dollars in thousands):

	2017	2016
Utility power resources	$ 380,523	$ 402,575

The following table details Avista Corp.'s future contractual commitments for power resources (including transmission contracts) and natural gas resources (including transportation contracts) (dollars in thousands):

	2018	2019	2020	2021	2022	Thereafter	Total
Power resources	$ 189,262	$ 185,610	$ 161,596	$ 149,125	$ 147,573	$ 916,255	$ 1,749,421
Natural gas resources	77,936	60,942	48,098	31,428	31,428	326,482	576,314
Total	$ 267,198	$ 246,552	$ 209,694	$ 180,553	$ 179,001	$ 1,242,737	$ 2,325,735

These energy purchase contracts were entered into as part of Avista Corp.'s obligation to serve its retail electric and natural gas customers' energy requirements, including contracts entered into for resource optimization. As a result, these costs are recovered either through base retail rates or adjustments to retail rates as part of the power and natural gas cost deferral and recovery mechanisms.

The above future contractual commitments for power resources include fixed contractual amounts related to the Company's contracts with certain Public Utility Districts (PUD) to purchase portions of the output of certain generating facilities. Although Avista Corp. has no investment in the PUD generating facilities, the fixed contracts obligate Avista Corp. to pay certain minimum amounts whether or not the facilities are operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in utility resource costs in the Statements of Income. The contractual amounts included above consist of Avista Corp.'s share of existing debt service cost and its proportionate share of the variable operating expenses of these projects. The minimum amounts payable under these contracts are based in part on the proportionate share of the debt service requirements of the PUD's revenue bonds for which the Company is indirectly responsible. The Company's total future debt service obligation associated with the revenue bonds outstanding at December 31, 2017 (principal and interest) was $63.5 million.

In addition, Avista Corp. has operating agreements, settlements and other contractual obligations related to its generating facilities and transmission and distribution services. The following table details future contractual commitments under these agreements (dollars in thousands):

	2018	2019	2020	2021	2022	Thereafter	Total
Contractual obligations	$ 32,205	$ 34,996	$ 33,961	$ 28,939	$ 33,925	$ 193,595	$ 357,621

NOTE 10. NOTES PAYABLE

Avista Corp.

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million that expires in April 2021. The committed line of credit is secured by non-transferable first mortgage bonds of Avista Corp. issued to the agent bank that would only become due and payable in the event, and then only to the extent, that Avista Corp. defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of “consolidated total debt” to “consolidated total capitalization” of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2017, the Company was in compliance with this covenant.

Balances outstanding and interest rates of borrowings (excluding letters of credit) under the Company’s revolving committed lines of credit were as follows as of December 31 (dollars in thousands):

	2017	2016
Balance outstanding at end of period	$ 105,000	$ 120,000
Letters of credit outstanding at end of period	$ 34,420	$ 34,353
Average interest rate at end of period	2.26%	1.50%

As of December 31, 2017 and 2016, the borrowings outstanding under Avista Corp.’s committed line of credit were classified as short-term borrowings on the Balance Sheet.

NOTE 11. BONDS

The following details long-term debt outstanding as of December 31 (dollars in thousands):

Maturity Year	Description	Interest Rate	2017	2016
2018	First Mortgage Bonds	5.95%	250,000	250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2020	First Mortgage Bonds	3.89%	52,000	52,000
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (1)	(1)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000

2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2044	First Mortgage Bonds	4.11%	60,000	60,000
2045	First Mortgage Bonds	4.37%	100,000	100,000
2047	First Mortgage Bonds	4.23%	80,000	80,000
2047	First Mortgage Bonds (2)	3.91%	90,000	—
2051	First Mortgage Bonds	3.54%	175,000	175,000
	Total secured bonds		1,711,700	1,621,700
	Secured Pollution Control Bonds held by Avista Corporation (2)		(83,700)	(83,700)
	Total long-term debt and capital leases		$ 1,628,000	$ 1,538,000

(1) In December 2010, $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due in 2032 and 2034, respectively, which had been held by Avista Corp. since 2008 and 2009, respectively, were refunded by new variable rate bond issues (Series 2010A and Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Balance Sheets.

(2) In December 2017, Avista Corp. issued and sold $90.0 million of 3.91 percent first mortgage bonds due in 2047 pursuant to a bond purchase agreement with institutional investors in the private placement market. The total net proceeds from the sale of the bonds were used to repay a portion of the borrowings outstanding under Avista Corp.'s $400.0 million committed line of credit. In connection with the execution of the bond purchase agreement, Avista Corp. cash-settled five interest rate swap derivatives (notional aggregate amount of $60.0 million) and paid a total of $8.8 million.

The following table details future long-term debt maturities including advances from associated companies (see Note 12) (dollars in thousands):

	2018	2019	2020	2021	2022	Thereafter	Total
Debt maturities	$ 272,500	$ 90,000	$ 52,000	$ —	$ 250,000	$ 1,015,047	$ 1,679,547

Substantially all of Avista Corp.'s owned properties are subject to the lien of its respective mortgage indentures. Under the Mortgage and Deed of Trust (Mortgage) securing its first mortgage bonds (including secured medium-term notes), Avista Corp. may issue additional first mortgage bonds under its specific mortgage in an aggregate principal amount equal to the sum of:

- 66-2/3 percent of the cost or fair value (whichever is lower) of property additions which have not previously been made the basis of any application under the Mortgage, or
- an equal principal amount of retired first mortgage bonds which have not previously been made the basis of any application under the Mortgage, or
- deposit of cash.

However, Avista Corp. may not issue any additional first mortgage bonds (with certain exceptions in the case of bonds issued on the basis of retired bonds) unless Avista Corp. has "net earnings" (as defined in the Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months that were at least twice the annual interest requirements on all mortgage securities at the time outstanding, including the first mortgage bonds to be issued, and on all indebtedness of prior rank. As of December 31, 2017, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.3 billion in aggregate principal amount of additional first mortgage bonds at Avista Corp.

NOTE 12. ADVANCES FROM ASSOCIATED COMPANIES

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly.

The distribution rates paid were as follows during the years ended December 31:

	2017	2016	2015
Low distribution rate	1.81%	1.29%	1.11%
High distribution rate	2.36%	1.81%	1.29%
Distribution rate at the end of the year	2.36%	1.81%	1.29%

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. These debt securities may be redeemed at the option of Avista Capital II at any time and mature on June 1, 2037. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

The Company owns 100 percent of Avista Capital II and has solely and unconditionally guaranteed the payment of distributions on, and redemption price and liquidation amount for, the Preferred Trust Securities to the extent that Avista Capital II has funds available for such payments from the respective debt securities. Upon maturity or prior redemption of such debt securities, the Preferred Trust Securities will be mandatorily redeemed.

NOTE 13. FAIR VALUE

The carrying values of cash and cash equivalents, special deposits, accounts and notes receivable, accounts payable and notes payable are reasonable estimates of their fair values. Bonds and advances from associated companies are reported at carrying value on the Balance Sheets.

The fair value hierarchy prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurements) and the lowest priority to fair values derived from unobservable inputs (Level 3 measurements).

The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities. Active markets are those in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1, but which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry-standard models that consider various assumptions, including quoted forward prices for commodities, time value, volatility factors, and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Level 3 – Pricing inputs include significant inputs that are generally unobservable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input 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 levels. The determination of the fair values incorporates various factors that not only include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and letters of credit), but also the impact of Avista Corp.'s nonperformance risk on its liabilities.

The following table sets forth the carrying value and estimated fair value of the Company's financial instruments not reported at estimated fair value on the Balance Sheets as of December 31 (dollars in thousands):

	2017		2016	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt (Level 2)	$ 951,000	$ 1,067,783	$ 951,000	$ 1,048,661
Long-term debt (Level 3)	677,000	713,147	587,000	583,073
Advances from associated companies (Level 3)	51,547	41,882	51,547	38,660

These estimates of fair value of long-term debt and long-term debt to affiliated trusts were primarily based on available market information, which generally consists of estimated market prices from third party brokers for debt with similar risk and terms. The price ranges obtained from the third party brokers consisted of par values of 81.25 to 130.03, where a par value of 100.00 represents the carrying value recorded on the Balance Sheets. Level 2 long-term debt represents publicly issued bonds with quoted market prices; however, due to their limited trading activity, they are classified as Level 2 because brokers must generate quotes and make estimates using comparable debt with similar risk and terms if there is no trading activity near a period end. Level 3 long-term debt consists of private placement bonds and debt to affiliated trusts, which typically have no secondary trading activity. Fair values in Level 3 are estimated based on market prices from third party brokers using secondary market quotes for debt with similar risk and terms to generate quotes for Avista Corp. bonds.

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Balance Sheets as of December 31, 2017 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2017					
Assets:					
Energy commodity derivatives	$ —	$ 43,814	$ —	$ (42,550)	$ 1,264
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	183	(183)	—
Foreign currency exchange derivatives	—	32	—	(1)	31
Interest rate swap derivatives	—	7,477	—	(2,574)	4,903
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities	1,638	—	—	—	1,638
Equity securities	6,631	—	—	—	6,631
Total	$ 8,269	$ 51,323	$ 183	$ (45,308)	$ 14,467
Liabilities:					
Energy commodity derivatives	$ —	$ 71,342	$ —	$ (69,988)	$ 1,354
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	3,347	(183)	3,164
Power exchange agreement	—	—	13,245	—	13,245
Power option agreement	—	—	19	—	19
Foreign currency exchange derivatives	—	1	—	(1)	—
Interest rate swap derivatives	—	73,513	—	(37,544)	35,969
Total	$ —	$ 144,856	$ 16,611	$ (107,716)	$ 53,751

The following table discloses by level within the fair value hierarchy the Company's assets and liabilities measured and reported on the Balance Sheets as of December 31, 2016 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2016					
Assets:					
Energy commodity derivatives	$ —	$ 47,994	$ —	$ (46,099)	$ 1,895
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	69	(69)	—
Power exchange agreement	—	—	25	(25)	—

Foreign currency exchange derivatives	—	5	—	(5)	—
Interest rate swap derivatives	—	13,098	—	(4,348)	8,750
Deferred compensation assets:					
Mutual Funds:					
Fixed income securities	1,789	—	—	—	1,789
Equity securities	5,481	—	—	—	5,481
Total	$ 7,270	$ 61,097	$ 94	$ (50,546)	$ 17,915
Liabilities:					
Energy commodity derivatives	$ —	$ 56,871	$ —	$ (55,957)	$ 914
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	5,954	(69)	5,885
Power exchange agreement	—	—	13,474	(25)	13,449
Power option agreement	—	—	76	—	76
Foreign currency exchange derivatives	—	28	—	(5)	23
Interest rate swap derivatives	—	73,978	—	(39,248)	34,730
Total	$ —	$ 130,877	$ 19,504	$ (95,304)	$ 55,077

(1) The Company is permitted to net derivative assets and derivative liabilities with the same counterparty when a legally enforceable master netting agreement exists. In addition, the Company nets derivative assets and derivative liabilities against any payables and receivables for cash collateral held or placed with these same counterparties.

The difference between the amount of derivative assets and liabilities disclosed in respective levels in the table above and the amount of derivative assets and liabilities disclosed on the Balance Sheets is due to netting arrangements with certain counterparties. See Note 4 for additional discussion of derivative netting.

To establish fair value for energy commodity derivatives, the Company uses quoted market prices and forward price curves to estimate the fair value of energy commodity derivative instruments included in Level 2. In particular, electric derivative valuations are performed using market quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange (NYMEX) pricing for similar instruments, adjusted for basin differences, using market quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

To establish fair values for interest rate swap derivatives, the Company uses forward market curves for interest rates for the term of the swaps and discounts the cash flows back to present value using an appropriate discount rate. The discount rate is calculated by third party brokers according to the terms of the swap derivatives and evaluated by the Company for reasonableness, with consideration given to the potential non-performance risk by the Company. Future cash flows of the interest rate swap derivatives are equal to the fixed interest rate in the swap compared to the floating market interest rate multiplied by the notional amount for each period.

To establish fair value for foreign currency derivatives, the Company uses forward market curves for Canadian dollars against the US dollar and multiplies the difference between the locked-in price and the market price by the notional amount of the derivative. Forward foreign currency market curves are provided by third party brokers. The Company's credit spread is factored into the locked-in price of the foreign exchange contracts.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.2 million as of December 31, 2017 and $0.4 million as of December 31, 2016.

Level 3 Fair Value

Under the power exchange agreement the Company purchases power at a price that is based on the average operating and maintenance (O&M) charges from three surrogate nuclear power plants around the country. To estimate the fair value of this agreement the Company estimates the difference between the purchase price based on the future O&M charges and forward prices for energy. The Company compares the Level 2 brokered quotes and forward price curves described above to an internally developed forward price which is based on the average O&M charges from the three surrogate nuclear power plants for the current year. Because the nuclear power plant O&M charges are only known for one year, all forward years are estimated assuming an annual escalation. In addition to the forward price being estimated using unobservable inputs, the Company also estimates the volumes of the transactions that will take place in the future based on historical average transaction volumes per delivery year (November to April). Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, a change in the current year O&M charges for the surrogate plants is accompanied by a directionally similar change in O&M charges in future years. There is generally not a correlation between external market prices and the O&M charges used to develop the internal forward price.

For the power commodity option agreement, which expires in June 2019, the Company uses the Black-Scholes-Merton valuation model to estimate the fair value, and this model includes significant inputs not observable or corroborated in the market. These inputs include: 1) the strike price (which is an internally derived price based on a combination of generation plant heat rate factors, natural gas market pricing, delivery and other O&M charges) and 2) estimated delivery volumes. Significant increases or decreases in these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, changes in overall commodity market prices are accompanied by directionally similar changes in the strike price used in the calculation.

For the natural gas commodity exchange agreement, the Company uses the same Level 2 brokered quotes described above; however, the Company also estimates the purchase and sales volumes (within contractual limits) as well as the timing of those transactions. Changing the timing of volume estimates changes the timing of purchases and sales, impacting which brokered quote is used. Because the brokered quotes can vary significantly from period to period, the unobservable estimates of the timing and volume of transactions can have a significant impact on the calculated fair value. The Company currently estimates volumes and timing of transactions based on a most likely scenario using historical data. Historically, the timing and volume of transactions have not been highly correlated with market prices and market volatility.

The following table presents the quantitative information which was used to estimate the fair values of the Level 3 assets and liabilities above as of December 31, 2017 (dollars in thousands):

	Fair Value (Net) at December 31, 2017		Valuation Technique	Unobservable Input	Range
Power exchange agreement	$	(13,245)	Surrogate facility	O&M charges	$38.87-$45.20/MWh (1)
			pricing	Escalation factor	5% - 2018 to 2019
				Transaction volumes	256,663 - 396,984 MWhs
Power option agreement		(19)	Black-Scholes-	Strike price	$36.64/MWh - 2018

		Merton		$42.51/MWh - 2018
			Delivery volumes	94,221 - 190,339 MWhs
Natural gas exchange agreement	(3,164)	Internally derived weighted-average cost of gas	Forward purchase prices	$1.60 - $2.07/mmBTU
			Forward sales prices	$1.56 - $2.98/mmBTU
			Purchase volumes	115,000 - 310,000 mmBTUs
			Sales volumes	60,000 - 310,000 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2017 are $41.95 per MWh.

The valuation methods, significant inputs and resulting fair values described above were developed by the Company's management and are reviewed on at least a quarterly basis to ensure they provide a reasonable estimate of fair value each reporting period.

The following table presents activity for energy commodity derivative assets (liabilities) measured at fair value using significant unobservable inputs (Level 3) for the years ended December 31 (dollars in thousands):

	Natural Gas Exchange Agreement	Power Exchange Agreement	Power Option Agreement	Total
Year ended December 31, 2017:				
Balance as of January 1, 2017	$ (5,885)	$ (13,449)	$ (76)	$ (19,410)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	3,292	(7,674)	57	(4,325)
Settlements	(571)	7,878	—	7,307
Ending balance as of December 31, 2017 (2)	$ (3,164)	$ (13,245)	$ (19)	$ (16,428)
Year ended December 31, 2016:				
Balance as of January 1, 2016	$ (5,039)	$ (21,961)	$ (124)	$ (27,124)
Total gains or (losses) (realized/unrealized):				
Included in regulatory assets/liabilities (1)	259	400	48	707
Settlements	(1,105)	8,112	—	7,007
Ending balance as of December 31, 2016 (2)	$ (5,885)	$ (13,449)	$ (76)	$ (19,410)

(1) All gains and losses are included in other regulatory assets and liabilities. There were no gains and losses included in either net income or other comprehensive income during any of the periods presented in the table above.
(2) There were no purchases, issuances or transfers from other categories of any derivatives instruments during the periods presented in the table above.

NOTE 14. COMMON STOCK

The payment of dividends on common stock could be limited by:

- certain covenants applicable to preferred stock (when outstanding) contained in the Company's Restated Articles of Incorporation, as amended (currently there are no preferred shares outstanding),
- certain covenants applicable to the Company's outstanding long-term debt and committed line of credit agreements,

- the hydroelectric licensing requirements of section 10(d) of the FPA (see Note 1),
- certain requirements under the OPUC approval of the AERC acquisition in 2014. The OPUC's AERC acquisition order requires Avista Corp. to maintain a capital structure of no less than 40 percent common equity (inclusive of short-term debt). This limitation may be revised upon request by the Company with approval from the OPUC, and
- the Merger Agreement with Hydro One, which states Avista Corp. cannot (A) declare, authorize, set aside for payment or pay any dividend on, or make any other distribution in respect of, any shares of its capital stock, other than (1) dividends paid by any subsidiary of the Company to the Company or to any wholly owned subsidiary of the Company, (2) quarterly cash dividends with respect to the Company common stock not to exceed the 2017 annual per share dividend rate by more than $0.06 per year, with record dates and payment dates consistent with the Company's current dividend practice, or (3) a "stub period" dividend to holders of record of Company common stock as of immediately prior to the effective time of the merger equal to the product of (x) the number of days from the record date for payment of the last quarterly dividend paid by the Company prior to the effective time of the merger, multiplied by (y) a daily dividend rate determined by dividing the amount of the last quarterly dividend prior to the effective time of the merger by ninety-one or (B) adjust, split, combine, subdivide or reclassify any shares of its capital stock (see "Note 3" for additional information regarding the merger).

The Company declared the following dividends for the year ended December 31:

	2017	2016
Dividends paid per common share	$ 1.43	$ 1.37

Under the most restrictive of the dividend limitations discussed above, which are the requirements of the Merger Agreement with Hydro One, the amount available for dividends at December 31, 2017 was limited to $97.6 million (which is based on the number of shares outstanding as of December 31, 2017 and an annual dividend of $1.49 per share that was declared on February 2, 2018).

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2017 and 2016.

Equity Issuances

In March 2016, the Company entered into four separate sales agency agreements under which Avista Corp.'s sales agents may offer and sell up to 3.8 million new shares of Avista Corp.'s common stock, no par value, from time to time. The sales agency agreements expire on February 29, 2020. Through December 31, 2017, 2.7 million shares were issued under these agreements resulting in total net proceeds of $120.0 million ($54.7 million in 2017 and $65.3 million in 2016), leaving 1.1 million shares remaining to be issued.

NOTE 15. COMMITMENTS AND CONTINGENCIES

In the course of its business, the Company becomes involved in various claims, controversies, disputes and other contingent matters, including the items described in this Note. Some of these claims, controversies, disputes and other contingent matters involve litigation or other contested proceedings. For all such matters, the Company intends to vigorously protect and defend its interests and pursue its rights. However, no assurance can be given as to the ultimate outcome of any particular matter because litigation and other contested proceedings are inherently subject to numerous uncertainties. For matters that affect Avista Corp.'s operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the ratemaking process.

California Refund Proceeding

In February 2016, APX, a market maker in the California Refund Proceedings in whose markets Avista Energy participated in the summer of 2000, asserted that Avista Energy and its other customer/participants may be responsible for a share of the disgorgement penalty APX may be found to owe to Pacific Gas & Electric (PG&E), Southern California Edison, San Diego Gas & Electric, the California Attorney General (AG), the California Department of Water Resources (CERS), and the California Public Utilities Commission (together, the "California Parties"). The penalty arises as a result of the FERC's finding that APX committed violations in the California market in the summer of 2000. APX is making these assertions despite Avista Energy having been dismissed in FERC Opinion No. 536 from the on-going administrative proceeding at the FERC regarding potential wrongdoing in the California markets in the summer of 2000. APX has identified Avista Energy's share of APX's exposure to be as much as $16.0 million even though no wrongdoing allegations are specifically attributable to Avista Energy. Avista Energy believes its settlement with the California Parties in 2014 insulates it from any such liability and that as a dismissed party it cannot be drawn back into the litigation. Avista Energy intends to vigorously dispute APX's assertions of indirect liability, but cannot at this time predict the eventual outcome.

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels (referred to as "Total Dissolved Gas" or "TDG") in the Clark Fork River exceed state of Idaho and federal water quality numeric standards downstream of Cabinet Gorge particularly during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement (CFSA) as incorporated in Avista Corp.'s FERC license for the Clark Fork Project, Avista Corp. has worked in consultation with agencies, tribes and other stakeholders to address this issue. Under the terms of a gas supersaturation mitigation plan, Avista Corp. is reducing TDG by constructing spill crest modifications on spill gates at the dam. These modifications have been shown to be effective in reducing TDG downstream. TDG monitoring and analysis is ongoing. Under the terms of the mitigation plan, Avista Corp. will continue to work with stakeholders to determine the degree to which TDG abatement reduces future mitigation obligations. The Company has sought, and will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Fish Passage at Cabinet Gorge and Noxon Rapids

In 1999, the United States Fish and Wildlife Service (USFWS) listed bull trout as threatened under the Endangered Species Act. In 2010, the USFWS issued a revised designation of critical habitat for bull trout, which includes the lower Clark Fork River. The USFWS issued a final recovery plan in October 2015.

The CFSA describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company evaluated the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies led, in part, to the decision to move forward with development of permanent facilities, among other bull trout enhancement efforts. In 2017, parties to the CFSA reached an agreement regarding Avista Corp.'s obligations regarding fish passage and related issues. Avista Corp. filed this agreement, which amends the original Clark Fork Settlement Agreement, with the FERC. Avista Corp. has also initiated a license amendment and permitting efforts in support of construction of the permanent fishway at Cabinet Gorge. Construction is expected to begin in late 2018. The Company has sought, and will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to fish passage at Cabinet Gorge and Noxon Rapids.

Collective Bargaining Agreements

The Company's collective bargaining agreements with the IBEW represent approximately 45 percent of all of Avista Corp.'s employees. A three-year agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the Avista Corp.'s bargaining unit employees was approved in March 2016 and expires in March 2019.

A three-year agreement in Oregon, which covers approximately 50 employees will expire in March 2020.

There is a risk that if collective bargaining agreements expire and new agreements are not reached in each of our jurisdictions, employees could strike. Given the magnitude of employees that are covered by collective bargaining agreements, this could result in disruptions to our operations. However, the Company believes that the possibility of this occurring is remote.

Legal Proceedings Related to the Pending Acquisition by Hydro One

See Note 3 for information regarding the proposed acquisition of the Company by Hydro One.

In connection with the proposed acquisition, as of the date of this annual report, the three lawsuits that had been filed in the United States District Court for the Eastern District of Washington have been voluntarily dismissed by the plaintiffs. Those cases were captioned as follows:

- *Jenß v. Avista Corporation., et al.*, No. 2:17-cv-00333 (E.D. Wash.) (filed September 25, 2017);
- *Samuel v. Avista Corporation, et al.*, No. 2:17-cv-00334 (E.D. Wash.) (filed September 26, 2017); and
- *Sharpenter v. Avista Corporation., et al.*, No. 2:17-cv-00336 (E.D. Wash.) (filed September 26, 2017)

There remains one lawsuit that has been filed in the Superior Court for the State of Washington in and for Spokane County, captioned as follows:

- *Fink v. Morris, et al.,* No. 17203616-6 (filed September 15, 2017, amended complaint filed October 25, 2017).

This lawsuit was filed against Hydro One Limited, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch,, as well as all members of the Company's Board of Directors, namely Erik Anderson, Kristianne Blake, Donald Burke, Rebecca Klein, Scott Maw, Scott Morris, Marc Racicot, Heidi Stanley, John Taylor and Janet Widmann.

The complaint generally alleges that the members of the Board breached their fiduciary duties by, among other things, conducting an allegedly inadequate sale process and agreeing to the acquisition at a price that allegedly undervalues Avista Corporation, and that Hydro One Limited, Olympus Holding Corp., and Olympus Corp. aided and abetted those purported breaches of duty. The aiding and abetting claims were brought only against Hydro One Limited, Olympus Holding Corp. and Olympus Corp. The complaints seek various remedies, including monetary damages, including attorneys' fees and expenses. The complaint has been stayed by the court until the closing of the transaction at which time the plaintiff will have the option to file an amended complaint within 30 days of such closing. If the amended complaint is not filed within the 30 days the suit will be dismissed.

All defendants deny any wrongdoing in connection with the proposed acquisition and plan to vigorously defend against all pending claims; however, the Company cannot at this time predict the eventual outcome.

Other Contingencies

In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material impact on its financial condition, results of operations or cash flows. It is possible that a change could occur in the Company's estimates of the probability or amount of a liability being incurred. Such a change, should it occur, could be significant.

The Company routinely assesses, based on studies, expert analyses and legal reviews, its contingencies, obligations and commitments for remediation of contaminated sites, including assessments of ranges and probabilities of recoveries from other responsible parties who either have or have not agreed to a settlement as well as recoveries from insurance carriers. The Company's policy is to accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred. For matters that affect Avista Corp.'s operations, the Company seeks, to the extent appropriate, recovery of incurred costs through the ratemaking process.

The Company has potential liabilities under the Endangered Species Act for species of fish, plants and wildlife that have either already been added to the endangered species list, listed as "threatened" or petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company. However, the Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to these issues.

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. In addition, the company holds additional non-hydro water rights. The state of Montana is examining the status of all water right claims within state boundaries through a general adjudication. Claims within the Clark Fork River basin could adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The state of Idaho has initiated adjudication in northern Idaho, which will ultimately include the lower Clark Fork River, the Spokane River and the Coeur d'Alene basin. The Company is and will continue to be a participant in these and any other relevant adjudication processes. The complexity of such adjudications makes each unlikely to be concluded in the foreseeable future. As such, it is not possible for the Company to estimate the impact of any outcome at this time. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

NOTE 16. REGULATORY MATTERS

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge or liability on the Balance Sheets for future prudence review and recovery or rebate through retail rates. The power supply costs deferred include certain differences between actual net power supply costs incurred by Avista Corp. and the costs included in base retail rates. This difference in net power supply costs primarily results from changes in:

- short-term wholesale market prices and sales and purchase volumes,
- the level, availability and optimization of hydroelectric generation,
- the level and availability of thermal generation (including changes in fuel prices),
- retail loads, and
- sales of surplus transmission capacity.

In Washington, the ERM allows Avista Corp. to periodically increase or decrease electric rates with WUTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual power supply costs, net of wholesale sales and sales of fuel, and the amount included in base retail rates for Washington customers and defer these differences (over the $4.0 million deadband and sharing bands) for future surcharge or rebate to customers. For 2017, the Company recognized a pre-tax benefit of $4.6 million under the ERM in Washington compared to a benefit of $5.1 million for 2016. Total net deferred power costs under the ERM were a liability of $23.7 million as of December 31, 2017 and a liability of $21.3 million as of December 31, 2016. These deferred power cost balances represent amounts due to customers.

Avista Corp. has a PCA mechanism in Idaho that allows it to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, Avista Corp. defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers for future surcharge or rebate to customers. The October 1 rate adjustments recover or rebate power costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a liability of $6.1 million as of December 31, 2017 and a liability of $2.2 million as of December 31, 2016. These deferred power cost balances represent amounts due to customers.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Corp. files a PGA in all three states it serves to adjust natural gas rates for: 1) estimated commodity and pipeline transportation costs to serve natural gas customers for the coming year, and 2) the difference between actual and estimated commodity and transportation costs for the prior year. Total net deferred natural gas costs to be refunded to customers were a liability of $37.5 million as of December 31, 2017 and a liability of $30.8 million as of December 31, 2016. These balances represent amounts due to customers.

Decoupling and Earnings Sharing Mechanisms

Decoupling (also known as an FCA in Idaho) is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. In each of Avista Corp.'s jurisdictions, Avista Corp.'s electric and natural gas revenues are adjusted so as to be based on the number of customers in certain customer rate classes and assumed "normal" kilowatt hour and therm sales, rather than being based on actual kilowatt hour and therm sales. The difference between revenues based on the number of customers and "normal" sales and revenues based on actual usage is deferred and either surcharged or rebated to customers beginning in the following year. Only residential and certain commercial customer classes are included in decoupling mechanisms.

Washington Decoupling and Earnings Sharing

In Washington, the WUTC approved the Company's decoupling mechanisms for electric and natural gas for a five-year period beginning January 1, 2015. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to a 3 percent increase on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

The decoupling mechanisms each include an after-the-fact earnings test. At the end of each calendar year, separate electric and natural gas earnings calculations are made for the calendar year just ended. These earnings tests reflect actual decoupled revenues, normalized power supply costs and other normalizing adjustments. If the Company earns more than its authorized ROR in Washington, 50 percent of excess earnings are rebated to customers through adjustments to decoupling surcharge or rebate balances. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Idaho FCA and Earnings Sharing Mechanisms

In Idaho, the IPUC approved the implementation of FCAs for electric and natural gas (similar in operation and effect to the Washington decoupling mechanisms) for an initial term of three years, beginning January 1, 2016.

For the period 2013 through 2015, the Company had an after-the-fact earnings test, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earned more than a 9.8 percent ROE, the Company was required to share with customers 50 percent of any earnings above the 9.8 percent. This after-the-fact earnings test was discontinued, effective January 1, 2016, as part of the settlement of the Company's 2015 Idaho electric and natural gas general rates cases. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Oregon Decoupling Mechanism

In February 2016, the OPUC approved the implementation of a decoupling mechanism for natural gas, similar to the Washington and Idaho mechanisms described above. The decoupling mechanism became effective on March 1, 2016. There will be an opportunity for interested parties to review the mechanism and recommend changes, if any, by September 2019. In Oregon, an earnings review is conducted on an annual basis. In the annual earnings review, if the Company earns more than 100 basis points above its allowed ROE, one-third of the earnings above the 100 basis points would be deferred and later returned to customers. The earnings review is separate from the decoupling mechanism and was in place prior to decoupling. See below for a summary of cumulative balances under the decoupling and earnings sharing mechanisms.

Cumulative Decoupling and Earnings Sharing Mechanism Balances

As of December 31, 2017 and December 31, 2016, the Company had the following cumulative balances outstanding related to decoupling and earnings sharing mechanisms in its various jurisdictions (dollars in thousands):

	December 31, 2017	December 31, 2016
Washington		
Decoupling surcharge	$ 14,240	$ 30,408
Provision for earnings sharing rebate	(3,420)	(5,113)
Idaho		
Decoupling surcharge	$ 3,471	$ 8,292
Provision for earnings sharing rebate	(2,350)	(5,184)
Oregon		

Decoupling surcharge/(rebate)	$ (1,168)	$ 2,021
Provision for earnings sharing rebate	—	—

Interest Rate Swaps included in the 2017 Washington General Rate Cases

On October 27, 2017, WUTC Staff and other parties to Avista Corp.'s electric and natural gas general rate cases filed their testimony. These parties recommended lower revenue requirements than what was proposed in Avista Corp.'s original filings. Additionally, the WUTC Staff recommended the exclusion of the Company's 2016 settlement costs from the cost of capital calculation. The total amount of the 2016 settlement costs was $54.0 million, with approximately 60 percent of this total being allocable to Washington.

In addition to the settlement costs from 2016, the Company has a net regulatory asset of $8.8 million for interest rate swaps settled during the third quarter of 2017, and a net regulatory asset of $66.0 million for unsettled interest rate swaps as of December 31, 2017 related to forecasted debt issuances. Of those amounts, approximately 60 percent relate to Washington. If recovery of the 2016 settled interest rate swap settlement payments referenced above is disallowed by the WUTC, this could change the Company's current conclusion that settlement payments related to the 2017 settled interest rate swaps and the unsettled interest rate swaps are probable of recovery through rates. If the Company concluded that recovery of these swap related payments were no longer probable, the Company will be required to derecognize the related regulatory assets and liabilities with an adjustment through the income statement, and any subsequent gains and losses would be recognized through the income statement rather than recorded as a regulatory asset or liability.

Interest rate swaps are a tool used throughout multiple industries to manage interest rate risk. They also provide certainty for future cash flows associated with future borrowings. Since interest costs are included in the Company's costs of service to be recovered from customers, the Company has used this tool to manage these costs for the benefit of the Company's customers. The settlement of interest rate swaps results in either a benefit or a cost to the Company which, in either case, has historically been reflected in rates authorized by the WUTC in general rate cases. Accordingly, the Company still believes the interest rate swap payments are probable of recovery and will continue to work through the rate case process. Depending on the outcome of this proceeding, the Company could determine to not manage interest rate risk through swap transactions in the future.

NOTE 17. SUPPLEMENTAL CASH FLOW INFORMATION

Supplemental cash flow information consisted of the following items for the years ended December 31 (dollars in thousands):

	2017	2016
Cash paid for interest	$ 88,368	$ 79,183
Cash paid for income taxes	3,832	4,881
Cash received for income tax refunds	(46,916)	(19,505)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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		(6,649,771)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		(917,738)		
4	Total (lines 2 and 3)		(917,738)		
5	Balance of Account 219 at End of Preceding Quarter/Year		(7,567,509)		
6	Balance of Account 219 at Beginning of Current Year		(7,567,509)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value		(522,033)		
9	Total (lines 7 and 8)		(522,033)		
10	Balance of Account 219 at End of Current Quarter/Year		(8,089,542)		

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(6,649,771)	[redacted]	[redacted]
2				[redacted]	[redacted]
3			(917,738)	[redacted]	[redacted]
4			(917,738)	137,228,107	136,310,369
5			(7,567,509)	[redacted]	[redacted]
6			(7,567,509)	[redacted]	[redacted]
7				[redacted]	[redacted]
8			(522,033)	[redacted]	[redacted]
9			(522,033)	115,916,134	115,394,101
10			(8,089,542)	[redacted]	[redacted]

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

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

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	5,636,334,277	3,968,980,807
4	Property Under Capital Leases	5,777,969	223,615
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,642,112,246	3,969,204,422
9	Leased to Others		
10	Held for Future Use	8,321,112	8,130,526
11	Construction Work in Progress	151,271,170	103,841,950
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,801,704,528	4,081,176,898
14	Accum Prov for Depr, Amort, & Depl	1,876,263,672	1,376,068,208
15	Net Utility Plant (13 less 14)	3,925,440,856	2,705,108,690
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,796,469,363	1,355,247,552
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	79,794,309	20,820,656
22	Total In Service (18 thru 21)	1,876,263,672	1,376,068,208
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,876,263,672	1,376,068,208

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
1,125,489,566				541,863,904	3
254,354				5,300,000	4
					5
					6
					7
1,125,743,920				547,163,904	8
					9
190,586					10
9,974,325				37,454,895	11
					12
1,135,908,831				584,618,799	13
357,528,033				142,667,431	14
778,380,798				441,951,368	15
					16
					17
356,537,862				84,683,949	18
					19
					20
990,171				57,983,482	21
357,528,033				142,667,431	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
357,528,033				142,667,431	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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		
3	(302) Franchises and Consents	44,651,922	
4	(303) Miscellaneous Intangible Plant	18,584,205	5,255,802
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	63,236,127	5,255,802
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	3,577,783	
9	(311) Structures and Improvements	133,753,895	1,245,100
10	(312) Boiler Plant Equipment	171,448,546	3,329,159
11	(313) Engines and Engine-Driven Generators	6,770	
12	(314) Turbogenerator Units	56,655,767	7,537,322
13	(315) Accessory Electric Equipment	27,469,569	1,455,473
14	(316) Misc. Power Plant Equipment	17,902,654	771,751
15	(317) Asset Retirement Costs for Steam Production	12,296,594	2,030,911
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	423,111,578	16,369,716
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	61,693,802	915,798
28	(331) Structures and Improvements	76,191,863	5,141,917
29	(332) Reservoirs, Dams, and Waterways	179,519,624	10,898,027
30	(333) Water Wheels, Turbines, and Generators	217,098,354	10,241,617
31	(334) Accessory Electric Equipment	57,963,383	5,052,259
32	(335) Misc. Power PLant Equipment	12,138,606	1,156,945
33	(336) Roads, Railroads, and Bridges	3,071,035	563,509
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	607,676,667	33,970,072
36	D. Other Production Plant		
37	(340) Land and Land Rights	905,167	
38	(341) Structures and Improvements	16,951,717	118,923
39	(342) Fuel Holders, Products, and Accessories	21,379,703	104,835
40	(343) Prime Movers	23,909,470	
41	(344) Generators	216,208,006	900,610
42	(345) Accessory Electric Equipment	20,610,122	430,469
43	(346) Misc. Power Plant Equipment	1,731,002	14,924
44	(347) Asset Retirement Costs for Other Production	351,683	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	302,046,870	1,569,761
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,332,835,115	51,909,549

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	25,186,985	2,433,117
49	(352) Structures and Improvements	24,160,731	898,269
50	(353) Station Equipment	255,414,404	4,225,096
51	(354) Towers and Fixtures	17,174,301	1,032
52	(355) Poles and Fixtures	211,960,450	33,234,638
53	(356) Overhead Conductors and Devices	137,417,571	8,861,493
54	(357) Underground Conduit	2,987,090	151,606
55	(358) Underground Conductors and Devices	2,342,957	107,405
56	(359) Roads and Trails	2,098,308	5,327
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	678,742,797	49,917,983
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	8,735,862	345,816
61	(361) Structures and Improvements	21,071,048	3,117,688
62	(362) Station Equipment	126,641,535	6,564,542
63	(363) Storage Battery Equipment	2,597,845	
64	(364) Poles, Towers, and Fixtures	359,832,814	23,316,525
65	(365) Overhead Conductors and Devices	232,194,617	21,004,881
66	(366) Underground Conduit	104,109,911	8,486,527
67	(367) Underground Conductors and Devices	185,750,272	12,031,068
68	(368) Line Transformers	242,959,994	11,848,354
69	(369) Services	158,362,035	8,042,626
70	(370) Meters	50,766,975	1,467,948
71	(371) Installations on Customer Premises	219,118	869,586
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	57,563,856	4,882,777
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,550,805,882	101,978,338
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	398,664	
87	(390) Structures and Improvements	8,094,586	214,063
88	(391) Office Furniture and Equipment	8,382,465	179,233
89	(392) Transportation Equipment	38,781,331	4,949,120
90	(393) Stores Equipment	400,506	
91	(394) Tools, Shop and Garage Equipment	4,017,539	643,251
92	(395) Laboratory Equipment	915,711	557,620
93	(396) Power Operated Equipment	32,261,355	364,426
94	(397) Communication Equipment	63,758,935	1,775,752
95	(398) Miscellaneous Equipment	141,144	8,550
96	SUBTOTAL (Enter Total of lines 86 thru 95)	157,152,236	8,692,015
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)	157,152,236	8,692,015
100	TOTAL (Accounts 101 and 106)	3,782,772,157	217,753,687
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)	3,782,772,157	217,753,687

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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
					2
			44,651,922		3
1,282,903			22,557,104		4
1,282,903			67,209,026		5
					6
					7
94			3,577,689		8
54,316			134,944,679		9
3,308,036			171,469,669		10
			6,770		11
207,835			63,985,254		12
555,769			28,369,273		13
120,271			18,554,134		14
			14,327,505		15
4,246,321			435,234,973		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			62,609,600		27
321,708			81,012,072		28
208,932			190,208,719		29
557,641			226,782,330		30
638,720			62,376,922		31
146,674			13,148,877		32
			3,634,544		33
					34
1,873,675			639,773,064		35
					36
			905,167		37
5,175			17,065,465		38
15,771			21,468,767		39
			23,909,470		40
34,592			217,074,024		41
47,595			20,992,996		42
1,585			1,744,341		43
			351,683		44
104,718			303,511,913		45
6,224,714			1,378,519,950		46

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
			27,620,102		48
68,762		4,443	24,994,681		49
4,334,329		344,010	255,649,181		50
			17,175,333		51
1,489,941			243,705,147		52
718,665			145,560,399		53
			3,138,696		54
			2,450,362		55
			2,103,635		56
					57
6,611,697		348,453	722,397,536		58
					59
8,214		1,457,302	10,530,766		60
154,628		13,651	24,047,759		61
2,399,757		-493,298	130,313,022		62
			2,597,845		63
1,253,983		3,075	381,898,431		64
168,114		149,288	253,180,672		65
79,349		22,437	112,539,526		66
607,186		197,444	197,371,598		67
212,726			254,595,622		68
48,412			166,356,249		69
2,531,874			49,703,049		70
			1,088,704		71
					72
3,130,688			59,315,945		73
					74
10,594,931		1,349,899	1,643,539,188		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			398,664		86
69,523			8,239,126		87
5,482,560			3,079,138		88
710,365		-191,521	42,828,565		89
1,257			399,249		90
106,504			4,554,286		91
333			1,472,998		92
678,876			31,946,905		93
1,064,590			64,470,097		94
			149,694		95
8,114,008		-191,521	157,538,722		96
					97
					98
8,114,008		-191,521	157,538,722		99
32,828,253		1,506,831	3,969,204,422		100
					101
					102
					103
32,828,253		1,506,831	3,969,204,422		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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				
3				
4	Distribution Plant Land, Carlin Bay, Idaho	Dec 2010	2020-2025	162,352
5	Distribution Plant Land, Spokane, Washington	Mar 2011	2021-2026	540,307
6	Transmission Plant Land, Spokane, Washington	Dec 2011	2021-2026	431,600
7	Transmission Plant Land, Spokane, Washington	July 2014	2018	62,168
8	Other Production Plant Land, Spokane, Washington	Dec 2011	2018	40,896
9	Steam Production Plant Land, Spokane, Washington	Dec 2015	2026	3,544,725
10	Transmission Plant Land, Noxon, Montana	Mar 2016	2026	3,292,167
11	Transmission Plant Land, Spokane, Washington	Jan 2017	2022-2027	56,311
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			8,130,526

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	Clark Fork Implement PME Agreement	17,241,914
2	Substation Rebuilds	12,724,988
3	Little Falls Powerhouse Redevelopment	7,294,023
4	Westside 230 kV Substation - Rebuild	6,754,472
5	Devils Gap-Lind 115kV Transmission Rebuild Proj	6,438,456
6	Downtown Campus	6,347,399
7	South Region Transmission Voltage Control	6,171,970
8	Nine Mile Redevelopment	5,226,975
9	Irvin Sub - New Construction	3,682,267
10	Regulating Hydro	2,412,098
11	Saddle Mountain Integration	2,398,787
12	Transportation Equip	1,723,395
13	WSDOT Highway Franchise Consolidation	1,640,646
14	Benton-Othello 115 Recond	1,514,161
15	Gen DC Supplied System Upgrade	1,491,016
16	Productivity Initiative	1,459,006
17	Noxon 230 kV Substation - Rebuild	1,204,225
18	Substation Asset Mgmt Capital Maintenance	1,181,846
19	Low Priority Ratings Mitigation	1,132,067
20	Electric Revenue Blanket	1,121,198
21	Minor Projects <$1M	12,114,692
22		
23	Research, Development, & Demonstrating:	
24	Strategic Initiatives	2,566,349
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	103,841,950

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	1,294,760,452	1,294,760,452		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	92,210,101	92,210,101		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	5,541,655	5,541,655		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-43,722	-43,722		
9	Transfers	-59,642	-59,642		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	97,648,392	97,648,392		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	31,236,820	31,236,820		
13	Cost of Removal	3,175,638	3,175,638		
14	Salvage (Credit)	374,416	374,416		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	34,038,042	34,038,042		
16	Other Debit or Cr. Items (Describe, details in footnote):	-3,123,250	-3,123,250		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,355,247,552	1,355,247,552		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	292,869,875	292,869,875		
21	Nuclear Production				
22	Hydraulic Production-Conventional	130,719,748	130,719,748		
23	Hydraulic Production-Pumped Storage				
24	Other Production	117,794,174	117,794,174		
25	Transmission	211,556,284	211,556,284		
26	Distribution	527,773,774	527,773,774		
27	Regional Transmission and Market Operation				
28	General	74,533,697	74,533,697		
29	TOTAL (Enter Total of lines 20 thru 28)	1,355,247,552	1,355,247,552		

Schedule Page: 219 Line No.: 8 Column: c

Schedule Page: 219 Line No.: 8 Column: (c)

Includes:
ARC depreciation expense of $263,254 Account 182376 to 108000
Depreciation offset for non-recoverable plant of ($299,796) for Kettle Falls and Boulder Park
Miscellaneous Adjustment of ($7,167)
Miscellaneous Adjustment of ($13) - Salvage in PowerPlan and Cognos but not General Ledger

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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				
2	Investment in Avista Capital	1997		206,138,971
3	Avista Capital - Equity in Earnings			-145,455,568
4	Investment in AERC	2014		89,816,380
5	AERC - Equity in Earnings			11,304,373
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	161,804,156

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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
		206,138,971		2
-6,942,501	-1,190,235	-153,588,303		3
		89,816,380		4
9,460,262	-2,000,000	18,764,634		5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
2,517,761	-3,190,235	161,131,682		42

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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)	3,566,367	3,958,296	(1)
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	26,085,323	25,905,191	(1)
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	3,084,192	3,271,031	(1)
8	Transmission Plant (Estimated)	109,594	68,875	(1)
9	Distribution Plant (Estimated)	467,705	367,760	(1)
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	7,676,843	8,567,566	(1),(2)
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	37,423,657	38,180,423	
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)	-86		
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	40,989,938	42,138,719	

Schedule Page: 227 Line No.: 1 Column: d

(1) Electric

(2) Natural Gas

Schedule Page: 227 Line No.: 5 Column: d

(1) Electric

(2) Natural Gas

Schedule Page: 227 Line No.: 7 Column: d

(1) Electric

(2) Natural Gas

Schedule Page: 227 Line No.: 8 Column: d

(1) Electric

(2) Natural Gas

Schedule Page: 227 Line No.: 9 Column: d

(1) Electric

(2) Natural Gas

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

(1) Electric

(2) Natural Gas

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2018 No. (d)	2018 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2019		2020		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2018 No. (d)	2018 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2019		2020		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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	EDP Renewables TSR	3,712	186200		
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Saddle Mountain East	93,925	186200	92,743	186210
23	Clearwater Wind Interconnect	601	186200		
24	Rattlesnake Flats Project #49	50,573	186200		
25	Gordon Butte Project #50	1,242	186200		
26	Broadview Solar II Project #51	1,369	186200		
27	Taunton Solar Project #52	27,520	186200		
28	Lind Solar Project #53	40,253	186200	13,652	186210
29	Tokio Solar Project #54	31,039	186200		
30	TImberwolf Solar Lolo Project #55	1,184	186200	1,184	186210
31	Stump Farmers	179	186200		
32					
33					
34					
35					
36					
37					
38					
39					
40					

Schedule Page: 231 Line No.: 2 Column: b

Total life to date costs.

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

Total life to date costs.

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

Total life to date reimbursements.

Schedule Page: 231 Line No.: 23 Column: b

Total life to date costs.

Schedule Page: 231 Line No.: 24 Column: b

Total life to date costs.

Schedule Page: 231 Line No.: 25 Column: b

Total life to date costs.

Schedule Page: 231 Line No.: 26 Column: b

Total life to date costs.

Schedule Page: 231 Line No.: 27 Column: b

Total life to date costs.

Schedule Page: 231 Line No.: 28 Column: b

Total life to date costs.

Schedule Page: 231 Line No.: 28 Column: d

Total life to date reimbursements.

Schedule Page: 231 Line No.: 29 Column: b

Total life to date costs.

Schedule Page: 231 Line No.: 30 Column: b

Total life to date costs.

Schedule Page: 231 Line No.: 30 Column: d

Total life to date reimbursements. Project closed Q3.

Schedule Page: 231 Line No.: 31 Column: b

Total life to date costs.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS: Written off During the Quarter/Year Account Charged	CREDITS: Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	WA Excess Nat Gas Line Extension Allowance	1,444,028	5,184,755			6,628,783
2	Reg Asset Post Ret Liab	240,113,906		228	28,329,830	211,784,076
3	Regulatory Asset FAS109 Utility Plant	98,386,447		283	16,795,594	81,590,853
4	Regulatory Asset FAS109 DSIT Non Plant	1,053,442	620,439			1,673,881
5	Regulatory Asset FAS109 WNP3	1,966,409		283	1,697,010	269,399
6	Regulatory Asset- Spokane River Relicense	307,418		407	78,736	228,682
7	Regulatory Asset- Spokane River PM&E	282,638		557	73,311	209,327
8	Regulatory Asset- Lake CDA Fund	8,593,339		407	211,066	8,382,273
9	Regulatory Asset- Lake CDA IPA Fund	2,000,000				2,000,000
10	Regulatory Asset- Spokane River TDG Idaho	351,670		407	117,223	234,447
11	Reg Assets- Decouplings Surcharge	11,834,500	13,187,286			25,021,786
12	Regulatory Asset- Lake CDA DEF Costs	1,211,984		407	32,721	1,179,263
13	DEF CS2 & COLSTRIP	2,671,668		407	1,357,220	1,314,448
14	Commodity MTM St Regulatory Asset	11,365,088	13,625,611			24,990,699
15	Commodity MTM Lt Regulatory Asset	16,919,204	2,047,482			18,966,686
16	Regulatory Asset FAS143 Asset Retirement Obligation	3,371,735	199,636			3,571,371
17	Reg Asset AN- CDA Lake Settlement	32,748,004		407	884,084	31,863,920
18	Reg Asset WA-CDA Lake Settlement	595,798		407	152,120	443,678
19	Regulatory Asset Workers Comp	1,212,812		407	228,912	983,900
20	Spokane RIver TDG	290,394		407	290,394	
21	Settled Interest Rate Swap Asset	91,878,611	6,885,852			98,764,463
22	DSM Asset	15,669,651	8,950,570			24,620,221
23	Unsettled Interest Rate Swaps Asset	69,629,594	1,309,809			70,939,403
24	Deferred ITC	8,481,289		254	4,357,398	4,123,891
25	Regulatory Asset MDM System		671,660			671,660
26	Regulatory Asset BPA Residential Exchange		137,139			137,139
27	Regulatory Assets FISERV		679,444			679,444
28	Other Reg Assets	84,782		254	84,782	
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	622,464,411	53,499,683		54,690,401	621,273,693

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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						
2	Colstrip Common Fac.	1,110,999				1,110,999
3	Regulatory Asset-Mt Lease Pymt					
4	Regulatory Asset-Mt Lease Pymt					
5	Colstrip Common Fac.	2,355,642				2,355,642
6	Prepd Plane Lease LT-3 yr amort	245,537		931	196,429	49,108
7	Misc DD-plane Lease- 3 yr amort	286,333		VAR	229,066	57,267
8	Plant Alloc of Clearing Jrl	3,520,155	693,819			4,213,974
9	Misc Posting Suspense	284,474		VAR	284,474	
10	Renewable Energy-Cert Fees					
11	Nez Perce Settlement	139,901		557	5,212	134,689
12	Reg Asset ID-Lake CDA 10 yr amt	116,156		506	30,975	85,181
13	Credit Union Labor and Exp	107,357		VAR	33,448	73,909
14	Misc Work Orders <$50,000	-487,375	511,511			24,136
15	Subsidiary Billings	426,993	880,889			1,307,882
16	MiscDeferred Debits (WA)	-1,388,631	1,388,631			
17	Regulatory Assets Consv	1,042,391		VAR	1,042,391	
18	Reg Asset-Decoupling deferred	33,152,204		VAR	29,965,078	3,187,126
19	Optional Wind Power	65,318		909	106,063	-40,745
20	Gas Telemetry equip	4,172	4,721			8,893
21	Deferred Proj Compass - ID 4 yr	2,510,176		407	836,726	1,673,450
22	Saddle Mountain East Trans Line	59,194		235	58,012	1,182
23	AMI Suspense A Base Change Out	299,407	459,313			758,720
24	MiscDeferred Debits (AN)		448,694			448,694
25	Bluff Road Restoration		216,553			216,553
26	CIP v5 Elec Ac Ctl		129,510			129,510
27						
28						
29						
30						
31						
32						
33						
34						
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	43,850,403				15,796,170

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		19,561,839	10,161,086
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	19,561,839	10,161,086
9	Gas		
10		2,568,178	2,120,542
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	2,568,178	2,120,542
17	Other	125,224,690	176,935,152
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	147,354,707	189,216,780

Notes

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 - Common Stock Issued			
2	No Par Value	200,000,000		
3	Restricted shares			
4	Total Common	200,000,000		
5				
6				
7	Account 204 - Preferred Stock Issued	10,000,000		
8				
9				
10	Cumulative			
11				
12				
13	Total Preferred	10,000,000		
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
65,494,333	1,109,643,921					2
				106,053	4,077,738	3
65,494,333	1,109,643,921			106,053	4,077,738	4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

Schedule Page: 250 Line No.: 3 Column: i

Restricted share awards vest in equal thirds each year over a three-year period and are payable in Avista Corp. common stock at the end of each year if the service condition is met. In addition to the service condition, the Company must meet a return on equity target in order for the CEO’s restricted shares to vest. Restricted stock is valued at the close of market of the Company’s common stock on the grant date.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	Equity transactions of subsidiaries	-10,696,711
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40	TOTAL	-10,696,711

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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 - no par	-34,500,271
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	-34,500,271

Schedule Page: 254 Line No.: 1 Column: b

Beginning Balance	$ (32,208,771)
Issuance Costs of Common Stock	$ 684,739
Repurchase and Retirement of Common Stock	$ -
Tax Benefit-Options Excercised	$ (2,059)
Share withholding for taxes on equity awards	$ 3,551,786
VESTED STOCK COMP	$ -
Stock Compensation Accrual	$ (6,525,966)
Ending Balance	**$ (34,500,271)**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	FMBS - SERIES A - 7.53% DUE 05/05/2023	5,500,000	42,712
2	FMBS - SERIES A - 7.54% DUE 5/05/2023	1,000,000	7,766
3	FMBS - SERIES A - 7.39% DUE 5/11/2018	7,000,000	54,364
4	FMBS - SERIES A - 7.45% DUE 6/11/2018	15,500,000	120,377
5	Discount - FMBS - SERIES A - 7.45% DUE 6/11/2018		50,220
6	FMBS - SERIES A - 7.18% DUE 8/11/2023	7,000,000	54,364
7	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	51,547,000	1,296,086
8	FMBS - 6.37% SERIES C	25,000,000	158,304
9	FMBS - 5.45% SERIES	90,000,000	1,192,681
10	Discount- FMBS - 5.45% SERIES		239,400
11	FMBS - 6.25% SERIES	150,000,000	1,812,935
12	Discount- FMBS - 6.25% SERIES		367,500
13	FMBS - 5.70% SERIES	150,000,000	4,702,304
14	Discount- FMBS - 5.70% SERIES		222,000
15	FMBS - 5.95% SERIES	250,000,000	2,246,419
16	Discount- FMBS - 5.95% SERIES		835,000
17	FMBS - 5.125% SERIES	250,000,000	2,284,788
18	Discount- FMBS - 5.125% SERIES		575,000
19	COLSTRIP 2010A PCRBs DUE 2032	66,700,000	
20	COLSTRIP 2010B PCRBs DUE 2034	17,000,000	
21	FMBS - 3.89% SERIES	52,000,000	385,129
22	FMBS - 5.55% SERIES	35,000,000	258,834
23	4.45% SERIES DUE 12-14-2041	85,000,000	692,833
24	4.23% SERIES DUE 11-29-2047	80,000,000	730,833
25	FMBS- 4.11% SERIES	60,000,000	428,205
26	FMBS- 4.37% SERIES	100,000,000	590,761
27	FMBS- 3.54% SERIES	175,000,000	1,042,569
28	FMBS 3.91% SERIES	90,000,000	539,741
29			
30			
31			
32			
33	TOTAL	1,763,247,000	20,931,125

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.
05-06-1993	05-05-2023	05-06-1993	05-05-2023	5,500,000	414,150	1
05-07-1993	05-05-2023	05-07-1993	05-05-2023	1,000,000	75,400	2
05-11-1993	05-11-2018	05-11-1993	05-11-2018	7,000,000	517,300	3
06-09-1993	06-11-2018	06-09-1993	06-11-2018	15,500,000	1,154,750	4
						5
08-12-1993	08-11-2023	08-12-1993	08-11-2023	7,000,000	502,600	6
06-03-1997	06-01-2037	06-03-1997	06-01-2037	51,547,000	830,592	7
06-19-1998	06-19-2028	06-19-1998	06-19-2028	25,000,000	1,592,500	8
11-18-2004	12-01-2019	11-18-2004	12-01-2019	90,000,000	4,905,000	9
						10
11-17-2005	12-01-2035	11-17-2005	12-01-2035	150,000,000	9,375,000	11
						12
12-15-2006	07-01-2037	12-15-2006	07-01-2037	150,000,000	8,550,000	13
						14
04-02-2008	06-01-2018	04-02-2008	06-01-2018	250,000,000	14,875,000	15
						16
09-22-2009	04-01-2022	09-22-2009	04-01-2022	250,000,000	12,812,500	17
						18
12-15-2010	10-1-2032	12-15-2010	10-1-2032	66,700,000		19
12-15-2010	3-1-2034	12-15-2010	3-1-2034	17,000,000		20
12-20-2010	12-20-2020	12-20-2010	12-20-2020	52,000,000	2,022,800	21
12-20-2010	12-20-2040	12-20-2010	12-20-2040	35,000,000	1,942,500	22
12-14-2011	12-14-2041	12-14-2011	12-14-2041	85,000,000	3,782,500	23
11-30-2012	11-29-2047	11-30-2012	11-29-2047	80,000,000	3,384,000	24
12-18-2014	12-1-2044	12-18-2014	12-1-2044	60,000,000	2,466,000	25
12-16-2015	12-1-2045	12-16-2015	12-1-2045	100,000,000	4,370,000	26
12-15-2016	12-1-2051	12-15-2016	12-1-2051	175,000,000	6,195,000	27
12-14-2017	12-1-2047	12-14-2017	12-1/2047	90,000,000	166,175	28
						29
						30
						31
						32
				1,763,247,000	79,933,767	33

Schedule Page: 256 Line No.: 7 Column: a

Upon issuance Avista Capital II issued $1.5 million of Common Trust Securities to the Company. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

Schedule Page: 256 Line No.: 19 Column: a

The Company reacquired this debt in 2010. These bonds have not been retired or canceled; the Company plans, based on liquidity needs and market conditions, to remarket these bonds at a future date.

Schedule Page: 256 Line No.: 19 Column: c

The Company reacquired these bonds in 2010.

Schedule Page: 256 Line No.: 20 Column: a

The Company reacquired this debt in 2010. These bonds have not been retired or canceled; the Company plans, based on liquidity needs and market conditions, to remarket these bonds at a future date.

Schedule Page: 256 Line No.: 20 Column: c

The Company reacquired these bonds in 2010.

Schedule Page: 256 Line No.: 28 Column: a

The new issuance is based on the following state commission orders:

1. Order of the Washington Utilities and Transportation Commission in Docket No. UE-151822 entered October 29, 2015;

2. Order of the Idaho Public Utilities Commission, Order No. 33401, entered October 23, 2015;

3. Order of the Public Utility Commission of Oregon, Order No. 15305, entered October 6, 2015;

Order of the Public Service Commission of the State of Montana, Default Order No. 4535

Schedule Page: 256 Line No.: 28 Column: c

Expenses may change as more invoices related to this issuance become known.

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)	115,916,134
2		
3		
4	Taxable Income Not Reported on Books	
5		6,893,813
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		-11,694,698
11	Income Tax Expense	76,873,300
12		
13		
14	Income Recorded on Books Not Included in Return	
15		17,341,039
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-177,910,892
21		
22		
23		
24	Equity in Subs Earnings	-2,517,761
25	Corporate Overhead Unallocated Subs	2,028,306
26		
27	Federal Tax Net Income	26,929,241
28	Show Computation of Tax:	
29	State Tax	343,796
30	Federal Tax Net Income, less state tax	26,585,445
31	Federal Tax Net Income at @ 35%	9,304,906
32		
33	Prior year true ups and misc adjustments	914,587
34	Cabinet Gorge tax credits	-45,288
35		
36	Total Federal Tax Expense	10,174,205
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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 Tax 2013	806,204				-806,204
3	Income Tax 2014	840,072				
4	Income Tax 2016	-45,328,474		2,068,973	-46,053,256	-3,365,669
5	Income Tax (Current)			3,745,880	2,625,000	317,334
6	Retained Earnings (Current)	-3,371,282				3,371,282
7	Prior Retained Earnings	-483,257				483,257
8	Total Federal	-47,536,737		5,814,853	-43,428,256	
9						
10	STATE OF WASHINGTON:					
11	Property Tax (2015)	-5,841		6,196	355	
12	Property Tax (2016)	16,219,999		-759,669	15,460,330	
13	Property Tax (2017)			16,441,185	-1,846	
14	Excise Tax (2016)	3,798,546		2,643	2,908,238	
15	Excise Tax (2017)			28,031,229	25,226,008	-1
16	Natural Gas Use Tax	654		4,007	4,161	
17	Municipal Occupation Tax	2,922,652		25,200,143	25,111,836	
18	Community Solar	-25,513		-565,612	-573,821	17,304
19	Sales & Use Tax (2016)	157,008			157,006	-2
20	Sales & Use Tax (2017)			1,222,829	1,069,778	2
21	Total Washington	23,067,505		69,582,951	69,362,045	17,303
22						
23	STATE OF IDAHO:					
24	Income Tax (2016)	11,938		-108,778	53,160	150,000
25	Income Tax (2017)			880,920	850,000	-30,920
26	Property Tax (2015)	-13		13		
27	Property Tax (2016)	3,572,375		399	3,572,775	1
28	Property Tax (2017)			7,760,619	3,886,402	
29	Sales & Use Tax (2016)	23,544		1	23,544	
30	Sales & Use Tax (2017)			253,484	242,834	
31	KWH Tax (2016)	30,880		2,110	32,990	
32	KWH Tax (2017)			385,767	350,795	1
33	Franchise Tax (2015)	1				-1
34	Franchise Tax (2016)	1,489,069			1,489,067	-2
35	Franchise Tax (2017)			4,865,724	3,763,347	2
36	Total Idaho	5,127,794		14,040,259	14,264,914	119,081
37						
38	STATE OF MONTANA:					
39	Income Tax (2015)	-304,950		-118,670	-862,858	
40	Income Tax (2016)	118,720		50	50	
41	TOTAL	-16,431,293		109,921,268	60,454,600	155,643

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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	Income Tax (2017)			-557,908		
2	Property Tax (2016)	4,864,493		-18,407	4,846,086	
3	Property Tax (2017)			10,435,154	5,224,474	
4	Colstrip Generation Tax			3,107	3,107	
5	KWH Tax (2016)	274,416			274,416	
6	KWH Tax (2017)			1,126,703	869,303	
7	Consumer Council Fee	11		95	53	
8	Public Commission Fee	43		193	208	
9	Total Montana	4,952,733		10,870,317	10,354,839	
10						
11	STATE OF OREGON:					
12	Income Tax (2015)	1		100,000	100,000	-1
13	Income Tax (2016)			100,000	100,000	
14	Income Tax (2017)			100,000	100,000	
15	Property Tax (2016)	-2,854,826		2,855,005	179	
16	Property Tax (2017)			3,322,842	6,645,862	
17	BETC Credit (2010 and Prior)	-17,483		17,483		
18	BETC Credit (2011)	-29,962		29,962		
19	BETC Credit (2012)	-57,789		57,789		
20	Glendale Regulatory Cr. 2009	-34,911		34,911		
21	Franchise Tax (2016)	929,039			929,039	
22	Franchise Tax (2017)			3,877,693	2,869,005	
23	Total Oregon	-2,065,931		10,495,685	10,744,085	-1
24						
25	STATE OF CALIFORNIA:					
26	Income Tax (2015)			1,844	1,844	
27	Income Tax (2016)	-1,600		1,600		
28	Income Tax (2017)			1,600	1,600	
29	Total California	-1,600		5,044	3,444	
30						
31	MISCELLANEOUS STATES:					
32	Income Tax (2013)					
33	Income Tax (2014)	28,632		-28,632		
34	Income Tax (Current)					1
35	Total Misc States	28,632		-28,632		1
36						
37	MISCELLANEOUS OTHER					
38	CTR Credit (2017)			-1,399	-1,399	
39	Timber Excise Tax (2017)			5,246	5,246	
40	WA Renewable Energy	-5,638		-918,699	-918,410	5,927
41	TOTAL	-16,431,293		109,921,268	60,454,600	155,643

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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)	BALANCE AT BEGINNING OF YEAR		Taxes Charged During Year	Taxes Paid During Year	Adjust-ments
		Taxes Accrued (Account 236)	Prepaid Taxes (Include in Account 165)			
	(a)	(b)	(c)	(d)	(e)	(f)
1	Misc Distribution			22,564	35,896	13,332
2	Thermal Fuel Tax	1,949		33,079	32,196	
3	Total Other	-3,689		-859,209	-846,471	19,259
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	-16,431,293		109,921,268	60,454,600	155,643

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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
						2
840,072						3
-571,914		171,271			1,897,702	4
1,438,214		11,527,029			-7,781,149	5
						6
						7
1,706,372		11,698,300			-5,883,447	8
						9
						10
		5,162			1,034	11
		-680,586			-79,083	12
16,443,031		13,431,429			3,009,756	13
892,951		3,019			-376	14
2,805,220		21,449,491			6,581,738	15
500		4,007				16
3,010,959		18,964,825			6,235,318	17
					-565,612	18
						19
153,053					1,222,829	20
23,305,714		53,177,347			16,405,604	21
						22
						23
		-87,022			-21,756	24
		748,781			132,139	25
		13				26
		5,378			-4,979	27
3,874,217		6,132,304			1,628,315	28
1					1	29
10,650					253,484	30
		2,770			-660	31
34,973		385,767				32
						33
						34
1,102,379		3,633,461			1,232,263	35
5,022,220		10,821,452			3,218,807	36
						37
						38
439,238		-118,670				39
118,720		50				40
36,514,038	3,323,020	89,313,878			20,607,390	41

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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)	
-557,908		-557,908				1
		-18,407				2
5,210,680		10,435,154				3
		3,107				4
						5
257,400		1,126,703				6
53		95				7
28		193				8
5,468,211		10,870,317				9
						10
						11
					100,000	12
					100,000	13
					100,000	14
		1,262,754			1,592,251	15
	3,323,020	1,483,708			1,839,134	16
					17,483	17
					29,962	18
					57,789	19
					34,911	20
						21
1,008,688					3,877,693	22
1,008,688	3,323,020	2,746,462			7,749,223	23
						24
						25
					1,844	26
					1,600	27
					1,600	28
					5,044	29
						30
						31
						32
					-28,632	33
1						34
1					-28,632	35
						36
						37
					-1,399	38
					5,246	39
					-918,699	40
36,514,038	3,323,020	89,313,878			20,607,390	41

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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)	
					22,564	1
2,832					33,079	2
2,832					-859,209	3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
36,514,038	3,323,020	89,313,878			20,607,390	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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%						
4	7%						
5	10%						
6		31,438,487			411	1,216,256	
7							
8	TOTAL	31,438,487				1,216,256	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Property (100%	15,654			411	5,232	
11		47,790			411	14,832	
12	TOTAL PROPERTY	63,444				20,064	
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

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
			3
			4
			5
30,222,231			6
			7
30,222,231			8
			9
10,422			10
32,958			11
43,380			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	Defer Gas Exchange (253028)	1,125,000				1,125,000
2	Rathdrum Refund (253120)	104,288	550	33,825		70,463
3	NE Tank Spill (253130)	3,230	552	3,230		
4	Kettle Falls Diesel Leak (254135)	376,095	186	116,002		260,093
5	Bills Pole Rentals (253140)	162,942			965	163,907
6	DOC EECE Grant (253155)	25,828			277	26,105
7	Defer Comp Active Execs (253910)	7,683,200			780,065	8,463,265
8	Executive Incent Plan (253920)	140,000				140,000
9	Unbilled Revenue (253990)	2,098,569	908	84,203		2,014,366
10	WA Energy Recovery Mechanism	3,342,983	186	1,658,182		1,684,801
11	Misc Deferred Credits	199,983	407	198,820		1,163
12	Decoupling Deferred Credits				11,666,738	11,666,738
13	WA REC				176,311	176,311
14	Deferred Treasury Suspense				2,127,252	2,127,252
15	Conservation Program Projects				112,679	112,679
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	15,262,118		2,094,262	14,864,287	28,032,143

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

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

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

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

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

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	502,903,879	42,058,648	
3	Gas	153,909,427	17,383,562	
4	Other	74,348,815	12,080,906	
5	TOTAL (Enter Total of lines 2 thru 4)	731,162,121	71,523,116	
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	731,162,121	71,523,116	
10	Classification of TOTAL			
11	Federal Income Tax	731,162,121	71,523,116	
12	State Income Tax			
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (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
			225,028,224			319,934,303	2
			95,821,885			75,471,104	3
						86,429,721	4
			320,850,109			481,835,128	5
							6
							7
							8
			320,850,109			481,835,128	9
							10
			320,850,109			481,835,128	11
							12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	Electric	17,390,392	-9,881,479	523,661
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	17,390,392	-9,881,479	523,661
10	Gas			
11	Gas	-3,288,789	-5,798,489	
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	-3,288,789	-5,798,489	
18	Other	232,356,148	587,954	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	246,457,751	-15,092,014	523,661
20	Classification of TOTAL			
21	Federal Income Tax	246,457,751	-15,092,014	523,661
22	State Income Tax			
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
			575,021			6,410,231	3
							4
							5
							6
							7
							8
			575,021			6,410,231	9
							10
					3,590,460	-5,496,818	11
							12
							13
							14
							15
							16
					3,590,460	-5,496,818	17
-31,155,687			35,129,259			166,659,156	18
-31,155,687			35,704,280		3,590,460	167,572,569	19
							20
-31,155,687			35,704,280		3,590,460	167,572,569	21
							22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	Idaho Investment Tax Credit (254005)	9,194,403	190	1,726,290		7,468,113
2	Oregon BETC Credit (254010)	1,011,429			99,998	1,111,427
3	Settled Int Rate Swaps (254090)	12,441,840			1,293,409	13,735,249
4	Unsettled Int Rate Swaps (254100)	8,749,555	182	3,846,989		4,902,566
5	FAS 109 Invest Credit (254180)	34,161	190	22,322		11,839
6	Nez Perce (254220)	594,332	557	22,008		572,324
7	Idaho Earnings Test (254229)	3,696,873	407	2,834,093		862,780
8	Decoupling Rebate (254338)	2,404,916	456	2,404,916		
9	BPA RES EXCH (254345)	667,625	407	667,625		
10	Other Regulatory Liabilities	1,814,545	190	407,400		1,407,145
11	WA ERM	17,947,670			4,101,145	22,048,815
12	ID PCA	2,237,397			3,901,950	6,139,347
13	Deferred Federal ITC	16,945,522	182	8,697,738		8,247,784
14	Plant Excess Deferred				416,959,206	416,959,206
15	Non Plant Excess Deferred				17,634,985	17,634,985
16	Reg Liability MDM System				41,907	41,907
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	77,740,268		20,629,381	444,032,600	501,143,487

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	381,682,174	339,210,392
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	311,592,956	305,612,410
5	Large (or Ind.) (See Instr. 4)	110,982,373	107,296,247
6	(444) Public Street and Highway Lighting	7,483,805	7,662,138
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	1,277,422	1,193,923
10	TOTAL Sales to Ultimate Consumers	813,018,730	760,975,110
11	(447) Sales for Resale	88,779,014	118,815,965
12	TOTAL Sales of Electricity	901,797,744	879,791,075
13	(Less) (449.1) Provision for Rate Refunds	1,181,583	-931,768
14	TOTAL Revenues Net of Prov. for Refunds	900,616,161	880,722,843
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	360,115	437,415
18	(453) Sales of Water and Water Power	363,668	356,663
19	(454) Rent from Electric Property	2,767,738	2,802,518
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	69,867,100	107,066,515
22	(456.1) Revenues from Transmission of Electricity of Others	15,957,476	13,511,670
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	89,316,097	124,174,781
27	TOTAL Electric Operating Revenues	989,932,258	1,004,897,624

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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
3,840,417	3,527,707	334,848	330,699	2
				3
3,222,374	3,182,594	42,153	41,785	4
1,814,733	1,763,248	1,328	1,342	5
20,054	23,317	569	558	6
				7
				8
13,148	12,464	129	123	9
8,910,726	8,509,330	379,027	374,507	10
3,070,079	3,224,296			11
11,980,805	11,733,626	379,027	374,507	12
				13
11,980,805	11,733,626	379,027	374,507	14

Line 12, column (b) includes $ -1,769,378 of unbilled revenues.
Line 12, column (d) includes -34,179 MWH relating to unbilled revenues

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

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

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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	RESIDENTIAL SALES (440)					
2	1 Residential Service	3,707,373	353,173,985	318,137	11,653	0.0953
3	2 Residential Service	6,392	403,780	464	13,776	0.0632
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	88,585	12,332,731	14,457	6,127	0.1392
6	15 MOPS II Residential					
7	22 Res. & Farm Lg. Gen. Service	41,737	3,690,048	66	632,379	0.0884
8	30 Pumping-Special					
9	32 Res. & Farm Pumping Service	8,847	1,089,841	1,724	5,132	0.1232
10	48 Res. & Farm Area Lighting	3,726	1,068,508			0.2868
11	49 Area Lighting-High-Press.	215	76,805			0.3572
12	56 Centralia Refund					
13	95 Wind Power		162,102			
14	72 Residential Service					
15	73 Residential Service					
16	74 Residential Service					
17	76 Residential Service					
18	77 Residential Service					
19	58A Tax Adjustment		-34,135			
20	58 Tax Adjustment		10,478,324			
21	SubTotal	3,856,875	382,441,989	334,848	11,518	0.0992
22	Residential-Unbilled	-16,458	-759,815			0.0462
23	Total Residential Sales	3,840,417	381,682,174	334,848	11,469	0.0994
24						
25	COMMERCIAL SALES (442)					
26	2 General Service					
27	3 General Service					
28	11 General Service	917,829	103,709,712	38,145	24,062	0.1130
29	12 Res. & Farm Gen. Service					
30	16 MOPS II Commercial					
31	19 Contract-General Service					
32	21 Large General Service	1,835,401	162,933,115	2,800	655,500	0.0888
33	25 Extra Lg. Gen. Service	373,571	23,921,250	14	26,683,643	0.0640
34	28 Contract-Extra Large Serv					
35	31 Pumping Service	102,621	8,748,494	1,195	85,875	0.0853
36	47 Area Lighting-Sod. Vap	5,261	1,360,108			0.2585
37	49 Area Lighting-High-Press.	2,467	646,021			0.2619
38	56 Centralia Refune					
39	95 Wind Power		79,972			
40	74 Large General Service					
41	TOTAL Billed	12,014,984	903,567,122	379,027	31,700	0.0752
42	Total Unbilled Rev.(See Instr. 6)	-34,179	-1,769,378	0	0	0.0518
43	TOTAL	11,980,805	901,797,744	379,027	31,609	0.0753

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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	75 Large General Service					
2	76 Large General Service					
3	77 General Service					
4	58A Tax Adjustment		-51,014			
5	58 Tax Adjustment		11,075,081			
6	SubTotal	3,237,150	312,422,739	42,154	76,793	0.0965
7	Commercial-Unbilled	-14,776	-829,783			0.0562
8	Total Commercial	3,222,374	311,592,956	42,154	76,443	0.0967
9						
10	INDUSTRIAL SALES (442)					
11	2 General Service					
12	3 General Service					
13	8 Lg Gen Time of Use					
14	11 General Service	11,085	1,277,286	250	44,340	0.1152
15	12 Res. & Farm Gen. Service					
16	21 Large General Service	183,611	16,171,194	143	1,283,993	0.0881
17	25 Extra Lg. Gen. Service	1,534,361	85,456,828	20	76,718,050	0.0557
18	28 Contract - Extra Large Service					
19	29 Contract Lg. Gen. Service					
20	30 Pumping Service - Special	26,957	1,900,144	49	550,143	0.0705
21	31 Pumping Service	57,037	5,026,971	737	77,391	0.0881
22	32 Pumping Svc Res & Firm	4,432	398,869	129	34,357	0.0900
23	47 Area Lighting-Sod. Vap.	129	31,736			0.2460
24	49 Area Lighting - High-Press	64	15,501			0.2422
25	95 Wind Power		840			
26	48 Area Lighting-Sod. Vap.	1	239			0.2390
27	73 General Service					
28	74 Large General Service					
29	75 Large General Service					
30	76 Pumping Service					
31	77 General Service					
32	58A Tax Adjustment		-1,219			
33	58 Tax Adjustment		883,764			
34	SubTotal	1,817,677	111,162,153	1,328	1,368,733	0.0612
35	Industrial-Unbilled	-2,944	-179,780			0.0611
36	Total Industrial	1,814,733	110,982,373	1,328	1,366,516	0.0612
37						
38	STREET AND HWY LIGHTING (444)					
39	6 Mercury Vapor St. Ltg.					
40	7 HP Sodium Vap. St. Ltg					
41	TOTAL Billed	12,014,984	903,567,122	379,027	31,700	0.0752
42	Total Unbilled Rev.(See Instr. 6)	-34,179	-1,769,378	0	0	0.0518
43	TOTAL	11,980,805	901,797,744	379,027	31,609	0.0753

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	11 General Service					
2	41 Co-Owned St. Lt. Service	91	21,724	9	10,111	0.2387
3	42 Co-Owned St. Lt. Service	16,635	6,845,371	463	35,929	0.4115
4	High-Press. Sod. Vap.					
5	43 Cust-Owned St. Lt. Energy					
6	and Maint. Service					
7	44 Cust-Owned St. Lt. Energy	406	66,596	26	15,615	0.1640
8	and Maint. Svce - High-Pres					
9	Sodium Vapor					
10	45 Cust. Owned St. Lt. Energy Svc	888	72,698	14	63,429	0.0819
11	46 Cust. Owned St. Lt. Energy Svc	2,034	215,745	57	35,684	0.1061
12	58A Tax Adjustment		-762			
13	58 Tax Adjustment		262,433			
14	SubTotal	20,054	7,483,805	569	35,244	0.3732
15	Street & Hwy Lighting-Unbilled					
16	Total Street & Hwy Lighting	20,054	7,483,805	569	35,244	0.3732
17						
18	OTHER SALES TO PUBLIC					
19	(445)					
20	None					
21						
22	INTERDEPARTMENTAL SALES	13,148	1,276,624	129	101,922	0.0971
23	58 Tax Adjustment		799			
24	Total Interdepartmental	13,148	1,277,423	129	101,922	0.0972
25						
26	SALES FOR RESALE (447)					
27	61 Sales to Other Utilities (NDA)	3,070,079	88,779,014			0.0289
28						
29						
30	Total Sales for Resale	3,070,079	88,779,014			0.0289
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	12,014,984	903,567,122	379,027	31,700	0.0752
42	Total Unbilled Rev.(See Instr. 6)	-34,179	-1,769,378	0	0	0.0518
43	TOTAL	11,980,805	901,797,744	379,027	31,609	0.0753

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Avangrid Renewables, LLC	SF	Tariff 9			
2	Avangrid Renewables, LLC	IF	Tariff 9			
3	Avangrid Renewables, LLC	SF	Tariff 9			
4	BP Energy Company	SF	Tariff 9			
5	Bonneville Power Administration	LF	Tariff 8			
6	Bonneville Power Administration	SF	Tariff 9			
7	Bonneville Power Administration	LF	Tariff 12			
8	British Columbia Hydro and Power Author	LF	Tariff 12			
9	Brookfield Energy Marketing, LP	SF	Tariff 9			
10	California Independent System Operator	SF	Tariff 9			
11	Calpine Energy Services LP	SF	Tariff 9			
12	Cargill Power Markets, LLC	SF	Tariff 9			
13	Chelan County PUD No. 1	SF	Tariff 9			
14	Chelan County PUD No. 1	LF	Tariff 12			
	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
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Citigroup Energy, Inc.	SF	Tariff 9			
2	Clark County PUD No. 1	SF	Tariff 9			
3	Clatskanie Peoples PUD	SF	Tariff 9			
4	ConocoPhillips	SF	Tariff 9			
5	Direct Energy Business Marketing, LLC	LF	Tariff 9			
6	Douglas County PUD No. 1	SF	Tariff 9			
7	EDF Trading North America, LLC	SF	Tariff 9			
8	Energy Keepers, Inc.	SF	Tariff 9			
9	Eugene Water & Electric Board	SF	Tariff 9			
10	Exelon Generation Company, LLC	SF	Tariff 9			
11	Grant County PUD No. 2	LF	Tariff 12			
12	Gridforce Energy Management, LLC	LF	Tariff 12			
13	Idaho Power Company	SF	Tariff 9			
14	Idaho Power Company	LF	Tariff 12			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Idaho Power Company Balancing	SF	Tariff 9			
2	Idaho Power Company Balancing	IF	Tariff 9			
3	Kootenai Electric Cooperative	LF	Tariff 8			
4	Macquarie Energy, LLC	SF	Tariff 9			
5	Mizuho Securities USA, Inc.	OS	NA			
6	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
7	Morgan Stanley Capital Group, Inc.	IF	Tariff 9			
8	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
9	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
10	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
11	NaturEner Power Watch, LLC	SF	Tariff 9			
12	NaturEner Power Watch, LLC	LF	Tariff 9			
13	NaturEner Power Watch, LLC	LF	Tariff 9			
14	NaturEner Power Watch, LLC	LF	Tariff 12			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	NaturEner Power Watch, LLC	SF	Tariff 9			
2	NaturEner Power Watch, LLC	SF	Tariff 9			
3	NorthWestern Energy LLC	SF	Tariff 9			
4	Northwestern Energy LLC	IF	Tariff 9			
5	NorthWestern Energy LLC	LF	Tariff 12			
6	NorthWestern Energy LLC	LF	Tariff 9			
7	NorthWestern Energy LLC	SF	Tariff 10			
8	Okanogan County PUD	SF	Tariff 9			
9	PacifiCorp	SF	Tariff 9			
10	PacifiCorp	LF	Tariff 12			
11	PacifiCorp	LF	Tariff 9			
12	Pacific Northwest Generating Coop	SF	Tariff 9			
13	Pend Oreille Public Utility District	IF	Tariff 9			
14	Pend Oreille Public Utility District	IF	Tariff 9			
	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
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Pend Oreille Public Utility District	SF	Tariff 9			
2	Portland General Electric Company	SF	Tariff 9			
3	Portland General Electric Company	LF	Tariff 12			
4	Powerex	SF	Tariff 9			
5	Public Service Company of Colorado	SF	Tariff 9			
6	Puget Sound Energy	LF	Tariff 9			
7	Puget Sound Energy	SF	Tariff 9			
8	Puget Sound Energy	LF	Tariff 12			
9	Rainbow Energy Marketing	SF	Tariff 9			
10	Sacramento Municipal Utility District	SF	Tariff 9			
11	Sacramento Municipal Utility District	LF	Tariff 12			
12	Seattle City Light	SF	Tariff 9			
13	Seattle City Light	LF	Tariff 9			
14	Seattle City Light	LF	Tariff 12			
	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
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	Shell Energy N.A.	SF	Tariff 9			
2	Shell Energy N.A.	SF	Tariff 9			
3	Shell Energy N.A.	SF	Tariff 9			
4	Sierra Pacific Power Company	LF	Tariff 12			
5	Snohomish County PUD	SF	Tariff 9			
6	Sovereign Power	LF	Tariff 9			
7	Sovereign Power	LF	Tariff 9			
8	Tacoma Power	SF	Tariff 9			
9	Tacoma Power	LF	Tariff 9			
10	Tacoma Power	LF	Tariff 12			
11	Talen Energy Marketing, LLC	SF	Tariff 9			
12	Talen Energy Montana, LLC	LF	Tariff 9			
13	Tenaska Power Services Co.	SF	Tariff 9			
14	The Energy Authority	SF	Tariff 9			
	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
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	TransAlta Energy Marketing	SF	Tariff 9			
2	TransAlta Energy Marketing	IF	Tariff 9			
3	Turlock Irrigation District	SF	Tariff 9			
4	Vitol, Inc.	SF	Tariff 9			
5	Wells Fargo securities, LLC	OS	NA			
6	IntraCompany Wheeling	LF				
7	IntraCompany Generation	LF				
8						
9						
10						
11						
12						
13						
14						
	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.
313,235		6,850,396		6,850,396	1
26		1,260		1,260	2
	292,418			292,418	3
442		10,038		10,038	4
21,930		2,051,925		2,051,925	5
65,731		2,091,498		2,091,498	6
100		2,817		2,817	7
10		176		176	8
2,361		70,814		70,814	9
151,559		5,378,544		5,378,544	10
36,332		879,706		879,706	11
4,800		111,850		111,850	12
39,200		1,216,000		1,216,000	13
5		45		45	14
0	0	0	0	0	
3,070,079	4,719,051	61,336,737	22,723,226	88,779,014	
3,070,079	**4,719,051**	**61,336,737**	**22,723,226**	**88,779,014**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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.
110,784		3,122,009		3,122,009	1
2,275		76,425		76,425	2
2,156		53,062		53,062	3
6,000		146,540		146,540	4
461,430		11,618,143		11,618,143	5
7,290		189,615		189,615	6
73,977		1,615,848		1,615,848	7
1,010		12,853		12,853	8
24,299		579,322		579,322	9
23,621		542,117		542,117	10
19		612		612	11
134		3,758		3,758	12
3,873		80,876		80,876	13
28		607		607	14
0	0	0	0	0	
3,070,079	4,719,051	61,336,737	22,723,226	88,779,014	
3,070,079	**4,719,051**	**61,336,737**	**22,723,226**	**88,779,014**	

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.
36,167		1,032,929		1,032,929	1
1,996		68,839		68,839	2
1,483		34,755		34,755	3
53,971		1,215,134		1,215,134	4
			868,936	868,936	5
90,818		2,468,918		2,468,918	6
12,739		223,464		223,464	7
	275,940			275,940	8
	643,860			643,860	9
	368,157			368,157	10
114		4,034		4,034	11
278		6,109		6,109	12
9,279		186,955		186,955	13
100		1,872		1,872	14
0	0	0	0	0	
3,070,079	4,719,051	61,336,737	22,723,226	88,779,014	
3,070,079	**4,719,051**	**61,336,737**	**22,723,226**	**88,779,014**	

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.
	116,620			116,620	1
	275,940			275,940	2
26,925		812,212		812,212	3
111		568		568	4
166		4,756		4,756	5
7,240		149,535		149,535	6
	5,570			5,570	7
3,240		95,635		95,635	8
207,383		6,621,325		6,621,325	9
215		6,209		6,209	10
4,609		95,159		95,159	11
55,225		1,366,645		1,366,645	12
	609,831			609,831	13
16,408		353,346		353,346	14
0	0	0	0	0	
3,070,079	4,719,051	61,336,737	22,723,226	88,779,014	
3,070,079	**4,719,051**	**61,336,737**	**22,723,226**	**88,779,014**	

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.
273,408		4,906,038		4,906,038	1
123,495		3,498,175		3,498,175	2
103		3,410		3,410	3
127,567		2,470,299		2,470,299	4
800		20,400		20,400	5
21,066		435,012		435,012	6
141,680		3,550,727		3,550,727	7
14		360		360	8
7,481		137,488		137,488	9
29		1,484		1,484	10
19		1,494		1,494	11
16,070		411,075		411,075	12
486		9,336		9,336	13
15		179		179	14
0	0	0	0	0	
3,070,079	4,719,051	61,336,737	22,723,226	88,779,014	
3,070,079	**4,719,051**	**61,336,737**	**22,723,226**	**88,779,014**	

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.
191,588		4,894,741		4,894,741	1
	17,890			17,890	2
	1,965,600			1,965,600	3
9		250		250	4
28,038		826,256		826,256	5
	147,225			147,225	6
11,475		264,067		264,067	7
8,670		243,427		243,427	8
1,340		30,309		30,309	9
27		562		562	10
6,866		105,742		105,742	11
16,457		339,853		339,853	12
3,571		34,233		34,233	13
24,357		846,785		846,785	14
0	0	0	0	0	
3,070,079	4,719,051	61,336,737	22,723,226	88,779,014	
3,070,079	**4,719,051**	**61,336,737**	**22,723,226**	**88,779,014**	

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.
169,337		3,733,245		3,733,245	1
17		359		359	2
400		6,800		6,800	3
14,600		352,300		352,300	4
			2,138,449	2,138,449	5
		-17,242,924	17,242,924		6
			2,472,917	2,472,917	7
					8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
3,070,079	4,719,051	61,336,737	22,723,226	88,779,014	
3,070,079	**4,719,051**	**61,336,737**	**22,723,226**	**88,779,014**	

Name of Respondent Avista Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report 2017/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 2 Column: b
Financially Settled Transmission Losses

Schedule Page: 310 Line No.: 3 Column: b
Capacity

Schedule Page: 310 Line No.: 5 Column: b
BPA Contract Terminates September 30, 2028.

Schedule Page: 310 Line No.: 7 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310 Line No.: 8 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310 Line No.: 14 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.1 Line No.: 5 Column: a
Name changed June 01, 2017. Formerly Energy America, LLC.

Schedule Page: 310.1 Line No.: 5 Column: b
Contract terminates December 31, 2019.

Schedule Page: 310.1 Line No.: 11 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.1 Line No.: 12 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.1 Line No.: 14 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.2 Line No.: 2 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.2 Line No.: 3 Column: b
Kootenai Contract Terminates March 31,2019

Schedule Page: 310.2 Line No.: 5 Column: b
Financial SWAP

Schedule Page: 310.2 Line No.: 7 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.2 Line No.: 8 Column: b
Capacity

Schedule Page: 310.2 Line No.: 9 Column: b
Capacity

Schedule Page: 310.2 Line No.: 10 Column: b
Reserves

Schedule Page: 310.2 Line No.: 12 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.2 Line No.: 13 Column: b
Energy Associated with Dynamic Capacity and Energy Service Agreement

Schedule Page: 310.2 Line No.: 14 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.3 Line No.: 1 Column: b
Reserves

Schedule Page: 310.3 Line No.: 2 Column: b
Capacity

Schedule Page: 310.3 Line No.: 4 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.3 Line No.: 5 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.3 Line No.: 6 Column: b
NorthWestern Energy LLC sale expires October 31, 2018.

Schedule Page: 310.3 Line No.: 7 Column: b
Reserves

Schedule Page: 310.3 Line No.: 10 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.3 Line No.: 11 Column: b
PacifiCorp sale terminates October 31, 2018.

Schedule Page: 310.3 Line No.: 13 Column: b
Contract expires 9/30/2019.

Schedule Page: 310.3 Line No.: 14 Column: b
Contract expires 9/30/2019.

Schedule Page: 310.4 Line No.: 3 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.4 Line No.: 6 Column: b
Puget Sound Energy sale terminates October 31, 2018.

Schedule Page: 310.4 Line No.: 8 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.4 Line No.: 11 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.4 Line No.: 13 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.4 Line No.: 14 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 2 Column: b
Reserves

Schedule Page: 310.5 Line No.: 3 Column: b
Capacity

Schedule Page: 310.5 Line No.: 4 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 6 Column: b
Sovereign Power contract terminates 9-30-2019

Schedule Page: 310.5 Line No.: 7 Column: b
Sovereign Power Contract terminates 9-30-2019

Schedule Page: 310.5 Line No.: 9 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.5 Line No.: 10 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 12 Column: b
Sale terminates October 31,2018.

Schedule Page: 310.6 Line No.: 2 Column: b
Financially Settled Transmission Losses

Schedule Page: 310.6 Line No.: 5 Column: b
Financial SWAP

Schedule Page: 310.6 Line No.: 6 Column: b
IntraCompany Wheeling terminates 09/30/2023.

Schedule Page: 310.6 Line No.: 7 Column: b
IntraCompany Generation - Sale of Ancillary Services.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	351,615	318,679
5	(501) Fuel	28,164,386	30,542,478
6	(502) Steam Expenses	4,498,751	4,462,449
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,240,901	1,201,074
10	(506) Miscellaneous Steam Power Expenses	2,798,619	3,277,448
11	(507) Rents	39,448	41,383
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	37,093,720	39,843,511
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	500,387	582,812
16	(511) Maintenance of Structures	704,022	705,123
17	(512) Maintenance of Boiler Plant	6,404,383	7,206,904
18	(513) Maintenance of Electric Plant	2,866,901	2,431,551
19	(514) Maintenance of Miscellaneous Steam Plant	1,373,253	1,707,818
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	11,848,946	12,634,208
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	48,942,666	52,477,719
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	2,483,025	2,884,533
45	(536) Water for Power	1,126,313	1,081,024
46	(537) Hydraulic Expenses	8,017,097	7,226,698
47	(538) Electric Expenses	7,342,763	7,143,773
48	(539) Miscellaneous Hydraulic Power Generation Expenses	971,164	909,432
49	(540) Rents	6,308,734	6,760,553
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	26,249,096	26,006,013
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	916,539	904,296
54	(542) Maintenance of Structures	379,782	514,792
55	(543) Maintenance of Reservoirs, Dams, and Waterways	2,963,625	2,372,453
56	(544) Maintenance of Electric Plant	3,068,063	3,060,034
57	(545) Maintenance of Miscellaneous Hydraulic Plant	696,335	723,863
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	8,024,344	7,575,438
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	34,273,440	33,581,451

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	623,537	1,218,661
63	(547) Fuel	69,526,481	77,198,987
64	(548) Generation Expenses	1,711,153	1,584,424
65	(549) Miscellaneous Other Power Generation Expenses	491,137	595,889
66	(550) Rents	-32,172	-33,671
67	TOTAL Operation (Enter Total of lines 62 thru 66)	72,320,136	80,564,290
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	721,322	631,364
70	(552) Maintenance of Structures	194,208	127,187
71	(553) Maintenance of Generating and Electric Plant	4,471,719	3,197,659
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	423,855	270,149
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	5,811,104	4,226,359
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	78,131,240	84,790,649
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	130,674,108	147,226,728
77	(556) System Control and Load Dispatching	734,819	750,333
78	(557) Other Expenses	75,130,324	79,059,451
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	206,539,251	227,036,512
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	367,886,597	397,886,331
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,705,830	2,540,071
84			
85	(561.1) Load Dispatch-Reliability	77,944	58,701
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,471,441	1,533,643
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,407,937	1,241,357
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	2,609,186	
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	318,441	436,845
94	(563) Overhead Lines Expenses	426,023	513,129
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	17,569,670	17,251,359
97	(566) Miscellaneous Transmission Expenses	2,048,338	2,431,975
98	(567) Rents	153,496	190,703
99	TOTAL Operation (Enter Total of lines 83 thru 98)	28,788,306	26,197,783
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	860,108	1,019,083
102	(569) Maintenance of Structures	800,208	673,664
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,712,538	1,331,446
108	(571) Maintenance of Overhead Lines	1,069,453	1,783,246
109	(572) Maintenance of Underground Lines	492	1,656
110	(573) Maintenance of Miscellaneous Transmission Plant	117,575	83,000
111	TOTAL Maintenance (Total of lines 101 thru 110)	4,560,374	4,892,095
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	33,348,680	31,089,878

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	3,865,697	4,319,006
135	(581) Load Dispatching		
136	(582) Station Expenses	747,725	726,116
137	(583) Overhead Line Expenses	2,142,515	2,193,999
138	(584) Underground Line Expenses	1,414,741	1,259,690
139	(585) Street Lighting and Signal System Expenses	6,619	13,783
140	(586) Meter Expenses	1,856,753	1,814,182
141	(587) Customer Installations Expenses	822,859	760,909
142	(588) Miscellaneous Expenses	7,314,051	8,042,296
143	(589) Rents	385,866	350,728
144	TOTAL Operation (Enter Total of lines 134 thru 143)	18,556,826	19,480,709
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,414,040	1,459,904
147	(591) Maintenance of Structures	508,452	464,296
148	(592) Maintenance of Station Equipment	1,042,345	922,580
149	(593) Maintenance of Overhead Lines	9,317,466	7,888,006
150	(594) Maintenance of Underground Lines	905,731	663,260
151	(595) Maintenance of Line Transformers	522,741	376,486
152	(596) Maintenance of Street Lighting and Signal Systems	194,354	308,865
153	(597) Maintenance of Meters	39,978	23,154
154	(598) Maintenance of Miscellaneous Distribution Plant	334,614	605,435
155	TOTAL Maintenance (Total of lines 146 thru 154)	14,279,721	12,711,986
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	32,836,547	32,192,695
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	242,260	338,763
160	(902) Meter Reading Expenses	3,187,082	3,314,512
161	(903) Customer Records and Collection Expenses	9,762,223	9,634,087
162	(904) Uncollectible Accounts	2,752,406	3,170,040
163	(905) Miscellaneous Customer Accounts Expenses	246,534	245,092
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	16,190,505	16,702,494

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		
168	(908) Customer Assistance Expenses	29,150,863	23,708,390
169	(909) Informational and Instructional Expenses	904,617	960,519
170	(910) Miscellaneous Customer Service and Informational Expenses	326,924	236,300
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	30,382,404	24,905,209
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	31,907,256	33,574,266
182	(921) Office Supplies and Expenses	4,037,875	4,377,759
183	(Less) (922) Administrative Expenses Transferred-Credit	127,148	125,486
184	(923) Outside Services Employed	7,648,426	7,629,675
185	(924) Property Insurance	1,226,498	1,275,339
186	(925) Injuries and Damages	3,288,356	3,364,064
187	(926) Employee Pensions and Benefits	1,461,496	1,337,953
188	(927) Franchise Requirements	1,685	4,607
189	(928) Regulatory Commission Expenses	6,576,717	6,168,547
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses		
192	(930.2) Miscellaneous General Expenses	3,645,390	3,880,076
193	(931) Rents	671,679	1,071,360
194	TOTAL Operation (Enter Total of lines 181 thru 193)	60,338,230	62,558,160
195	Maintenance		
196	(935) Maintenance of General Plant	11,629,675	11,428,338
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	71,967,905	73,986,498
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	552,612,638	576,763,105

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	Avangrid Renewables, LLC	SF	WSPP			
2	BP Energy Company	SF	WSPP			
3	Black Hills Power, Inc.	SF	WSPP			
4	Bonneville Power Administration	LF	WNP#3 Agr.			
5	Bonneville Power Administration	SF	WSPP			
6	Bonneville Power Administration	LF	NWPP			
7	Bonneville Power Administration	LF	Tariff 8			
8	Bonneville Power Administration	OS	BPA OATT			
9	Brookfield Energy Marketing LP	SF	WSPP			
10	California Independent System Operator	SF	Tariff 9			
11	Calpine Energy Services LP	SF	WSPP			
12	Cargill Power Markets	SF	WSPP			
13	City of Spokane	LU	PURPA			
14	City of Spokane	IU	PURPA			
	Total					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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	Chelan County PUD	IU	Rocky Reach			
2	Chelan County PUD	SF	WSPP			
3	Chelan County PUD	LF	NWPP			
4	Chelan County PUD	IU	Chelan Sys			
5	Citigroup Energy	SF	WSPP			
6	City of Redding	SF	WSPP			
7	Clark County PUD No. 1	SF	WSPP			
8	Clatskanie PUD	SF	WSPP			
9	Community Solar	LU	PURPA			
10	ConocoPhillips Company	SF	WSPP			
11	Deep Creek Energy, LLC	IU	PURPA			
12	Douglas County PUD No. 1	LU	Wells			
13	Douglas County PUD No. 1	LU	Wells Settlement			
14	Douglas County PUD No. 1	SF	WSPP			
	Total					

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	Douglas County PUD No. 1	LF	NWPP			
2	Douglas County PUD No. 1	EX	554			
3	EDF Trading No America	SF	WSPP			
4	Energy Keepers, Inc.	SF	WSPP			
5	Eugene Water & Electric Board	SF	WSPP			
6	Exelon Generation Company, LLC	SF	WSPP			
7	Exelon Generation Company, LLC	SF	WSPP			
8	Ford Hydro Limited Partnership	LU	PURPA			
9	Grant County PUD No. 2	LU	Priest Rapids			
10	Grant County PUD No. 2	LF	NWPP			
11	Grant County PUD No. 2	EX	FERC #104			
12	Gridforce Energy Management, LLC	LF	NWPP			
13	Hydro Technology Systems	IU	PURPA			
14	Idaho County Power & Light	LU	PURPA			
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Idaho Power Company	SF	WSPP			
2	Inland Power & Light Company	RQ	208			
3	Jim White	LU	PURPA			
4	Kootenai Electric Cooperative	LF	Tariff 8			
5	Macquarie Energy LLC	SF	WSPP			
6	Mizuho Securities USA, Inc.	OS	NA			
7	Morgan Stanley Capital Group	SF	WSPP			
8	NaturEner Power Watch	LF	NWPP			
9	NextEra Energy Power Marketing LLC	SF	WSPP			
10	NorthWestern Energy LLC	SF	WSPP			
11	NorthWestern Energy LLC	LF	NWPP			
12	Okanogan County PUD No. 1	SF	WSPP			
13	PacifiCorp	SF	WSPP			
14	PacifiCorp	LF	NWPP			
	Total					

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/11/2018	End of 2017/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	Palouse Wind LLC	LU	PPA			
2	Pend Oreille County PUD No. 1	SF	Pend O'			
3	Pend Oreille County PUD No. 1	IF	Pend O'			
4	Phillips Ranch	LU	PURPA			
5	Portland General Electric Company	EX	304			
6	Portland General Electric Company	EX	178			
7	Portland General Electric Company	SF	WSPP			
8	Portland General Electric Company	LF	NWPP			
9	Powerex Corp	SF	WSPP			
10	Puget Sound Energy	SF	WSPP			
11	Puget Sound Energy	LF	NWPP			
12	Rainbow Energy Marketing Co.	SF	WSPP			
13	Rathdrum Power LLC	LU	Lancaster			
14	Sacramento Municipal Utility District	SF	WSPP			
	Total					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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	Seattle City Light	SF	WSPP			
2	Seattle City Light	LF	NWPP			
3	Sheep Creek Hydro	LU	PURPA			
4	Shell Energy	SF	WSPP			
5	Snohomish County PUD No. 1	SF	WSPP			
6	Sovereign Power	LF	Sovereign			
7	Spokane County	LU	PURPA			
8	Stimson Lumber	IU	PURPA			
9	Tacoma Power	SF	WSPP			
10	Tacoma Power	LF	NWPP			
11	Talen Energy Marketing	SF	WSPP			
12	The Energy Authority	SF	WSPP			
13	TransAlta Energy Marketing	SF	WSPP			
14	Vitol Inc.	SF	WSPP			
	Total					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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	Wells Fargo Securities, LLC	OS	NA			
2	Western Area Power Admin	LF	NWPP			
3	IntraCompany Generation Services	OS	OATT			
4	Other - Inadvertent Interchange	EX				
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)	
102,835				1,855,656		1,855,656	1
544				7,448		7,448	2
600				16,600		16,600	3
417,238				16,843,634		16,843,634	4
275,855				4,701,676		4,701,676	5
272				9,243		9,243	6
21,378				455,998	5,642	461,640	7
					44,584	44,584	8
1,400				45,950		45,950	9
10,097				-102,304		-102,304	10
23,683				486,856		486,856	11
2,200				26,900		26,900	12
47,072				2,515,338		2,515,338	13
115,875				5,485,164		5,485,164	14
4,998,184	44,907	43,012	15,498,835	114,249,790	925,483	130,674,108	

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)	
-24,240							1
4,000				124,100		124,100	2
12				408		408	3
466,801			13,873,093			13,873,093	4
23,184				641,838		641,838	5
5				10		10	6
5,381				56,034		56,034	7
773				17,896		17,896	8
486				25,499		25,499	9
2,000				76,720		76,720	10
20				2,036		2,036	11
137,984			1,625,112			1,625,112	12
28,112				974,372		974,372	13
26,023				687,415		687,415	14
4,998,184	44,907	43,012	15,498,835	114,249,790	925,483	130,674,108	

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	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
(g)	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				173		173	1
	33,795	33,795		253,750	-206	253,544	2
13,400				354,200		354,200	3
327				1,775		1,775	4
3,935				62,275		62,275	5
40,208				478,468		478,468	6
			630			630	7
3,834				252,631		252,631	8
343,735				7,156,877		7,156,877	9
24				809		809	10
					22,517	22,517	11
10				322		322	12
11,033				515,068		515,068	13
2,859				142,880		142,880	14
4,998,184	44,907	43,012	15,498,835	114,249,790	925,483	130,674,108	

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)	
277,625				4,644,673		4,644,673	1
118				8,621		8,621	2
1,234				119,794		119,794	3
1,540				35,847		35,847	4
37,975				1,012,515		1,012,515	5
					-1,778,749	-1,778,749	6
54,422				837,395		837,395	7
2				56		56	8
4,635				86,340		86,340	9
23,937				489,014		489,014	10
23				867		867	11
13,280				169,187		169,187	12
92,165				1,684,615		1,684,615	13
48				1,748		1,748	14
4,998,184	44,907	43,012	15,498,835	114,249,790	925,483	130,674,108	

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)	
300,380				18,521,900		18,521,900	1
65,304				1,436,809		1,436,809	2
20,969				366,197		366,197	3
48				2,329		2,329	4
	1,350						5
	9,215	9,217			39,663	39,663	6
50,174				549,206		549,206	7
41				1,536		1,536	8
67,485				2,316,955		2,316,955	9
86,129				1,833,824		1,833,824	10
42				1,636		1,636	11
8,576				254,052		254,052	12
1,327,247				25,724,026		25,724,026	13
150				7,500		7,500	14
4,998,184	44,907	43,012	15,498,835	114,249,790	925,483	130,674,108	

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)	
31,144				577,826		577,826	1
30				1,035		1,035	2
8,031				335,556		335,556	3
170,399				2,626,241		2,626,241	4
38,788				576,605		576,605	5
8,182				133,278		133,278	6
1,201				52,155		52,155	7
33,832				1,694,901		1,694,901	8
19,550				526,755		526,755	9
17				554		554	10
7,277				147,029		147,029	11
21,114				342,472		342,472	12
104,309				2,630,928		2,630,928	13
11,800				324,070		324,070	14
4,998,184	44,907	43,012	15,498,835	114,249,790	925,483	130,674,108	

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)	
					119,115	119,115	1
1				28		28	2
					2,472,917	2,472,917	3
	547						4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
4,998,184	44,907	43,012	15,498,835	114,249,790	925,483	130,674,108	

Schedule Page: 326 Line No.: 4 Column: a

BPA Contract Terminates June 30, 2019

Schedule Page: 326 Line No.: 6 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326 Line No.: 7 Column: a

BPA Contract Terminates September 30, 2028

Schedule Page: 326 Line No.: 8 Column: a

Ancillary Services - Spinning & Supplemental

Schedule Page: 326.1 Line No.: 3 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.2 Line No.: 1 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.2 Line No.: 2 Column: a

Exchange

Schedule Page: 326.2 Line No.: 10 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.2 Line No.: 12 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.3 Line No.: 2 Column: a

Service to Deer Lake from Inland Power and Light. No demand charges associated with the agreement.

Schedule Page: 326.3 Line No.: 4 Column: a

Kootenai Contract Terminates March 31, 2019

Schedule Page: 326.3 Line No.: 6 Column: a

Financial SWAP

Schedule Page: 326.3 Line No.: 8 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.3 Line No.: 11 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.3 Line No.: 14 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.4 Line No.: 8 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.4 Line No.: 11 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.5 Line No.: 2 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.5 Line No.: 6 Column: a

Sovereign Contract Terminates September 30, 2019

Schedule Page: 326.5 Line No.: 10 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.6 Line No.: 1 Column: a

Financial SWAP

Schedule Page: 326.6 Line No.: 2 Column: a

Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.

Schedule Page: 326.6 Line No.: 3 Column: a

Ancillary Services

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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	PacifiCorp	PacifiCorp	OLF
2	Seattle City Light	Seattle City Light	Grant County PUD	OLF
3	Tacoma Power	Tacoma Power	Grant County PUD	OLF
4	Grant County Public Utility District	Grant County PUD	Grant County PUD	OLF
5	Spokane Tribe	Bonneville Power Administration	Spokane Tribe of Indians	LFP
6	East Greenacres	Bonneville Power Administration	East Greenacres	LFP
7	Consolidated Irrigation District	Bonneville Power Administration	Consolidated Irrigation District	LFP
8	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	FNO
9	City of Spokane	City of Spokane	Avista Corporation	OLF
10	Stimson	Plummer	Avista Corporation	OLF
11	Hydro Tech Industries	Meyers Falls	Avista Corporation	OLF
12	First Wind Energy Marketing	Palouse Wind	Avista Corporation	OLF
13	Deep Creek Hydro	Deep Creek	Avista Corporation	OLF
14	Shell Energy North America (US) LP	Bonneville Power Administration	Idaho Power Company	SFP
15	Shell Energy North America (US) LP	Grant County PUD	Idaho Power Company	SFP
16	Morgan Stanley Capital Group	Avista Corporation	Idaho Power Company	SFP
17	Morgan Stanley Capital Group	Avista Corporation	Idaho Power Company	SFP
18	Morgan Stanley Capital Group	Avista Corporation	NorthWestern Energy	SFP
19	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	SFP
20	Morgan Stanley Capital Group	Bonneville Power Administration	NorthWestern Energy	SFP
21	Morgan Stanley Capital Group	NorthWestern Energy	Idaho Power Company	SFP
22	Morgan Stanley Capital Group	NorthWestern Energy	Bonneville Power Administration	SFP
23	Morgan Stanley Capital Group	Puget Sound Energy	Idaho Power Company	SFP
24	Morgan Stanley Capital Group	Grant County PUD	Idaho Power Company	SFP
25	Morgan Stanley Capital Group	Grant County PUD	NorthWestern Energy	SFP
26	Morgan Stanley Capital Group	Chelan County PUD	Idaho Power Company	SFP
27	Morgan Stanley Capital Group	Chelan County PUD	NorthWestern Energy	SFP
28	Puget Sound Energy	NorthWestern Energy	Bonneville Power Administration	SFP
29	PacifiCorp	PacifiCorp	Bonneville Power Administration	SFP
30	Idaho Power Company	Avista Corporation	Bonneville Power Administration	SFP
31	Idaho Power Company	Avista Corporation	Idaho Power Company	SFP
32	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	SFP
33	Idaho Power Company	Bonneville Power Administration	NorthWestern Energy	SFP
34	Idaho Power Company	Bonneville Power Administration	PacifiCorp	SFP
	TOTAL			

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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	Idaho Power Company	Chelan County PUD	NorthWestern Energy	SFP
2	Idaho Power Company	Chelan County PUD	PacifiCorp	SFP
3	Powerex	Bonneville Power Administration	NorthWestern Energy	NF
4	Powerex	NorthWestern Energy	Bonneville Power Administration	NF
5	Bonneville Power Administration	Bonneville Power Administration	Avista Corporation	NF
6	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	NF
7	Shell Energy North America (US) LP	Bonneville Power Administration	Idaho Power Company	NF
8	Shell Energy North America (US) LP	Bonneville Power Administration	NorthWestern Energy	NF
9	Shell Energy North America (US) LP	NorthWestern Energy	Bonneville Power Administration	NF
10	Shell Energy North America (US) LP	NorthWestern Energy	Grant County Public Utility	NF
11	Kootenai Electric	Kootenai Electric	Idaho Power Company	LFP
12	Morgan Stanley Capital Group	Avista Corporation	Idaho Power Company	NF
13	Shell Energy North America (US) LP	NorthWestern Energy	Grant County PUD	SFP
14	Shell Energy North America (US) LP	PacifiCorp	Bonneville Power Administration	SFP
15	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	NF
16	Morgan Stanley Capital Group	Bonneville Power Administration	NorthWestern Energy	NF
17	Morgan Stanley Capital Group	NorthWestern Energy	Bonneville Power Administration	NF
18	Morgan Stanley Capital Group	NorthWestern Energy	Chelan County PUD	NF
19	Morgan Stanley Capital Group	NorthWestern Energy	Idaho Power Company	NF
20	Morgan Stanley Capital Group	NorthWestern Energy	Grant County PUD	NF
21	Morgan Stanley Capital Group	NorthWestern Energy	Pacific Corp	NF
22	Morgan Stanley Capital Group	Portland General Electric	Idaho Power Company	NF
23	Morgan Stanley Capital Group	Avista Corporation	Bonneville Power Administration	NF
24	Morgan Stanley Capital Group	Grant County PUD	Idaho Power Company	NF
25	Morgan Stanley Capital Group	Grant County PUD	NorthWestern Energy	NF
26	Morgan Stanley Capital Group	Chelan County PUD	Idaho Power Company	NF
27	Morgan Stanley Capital Group	Chelan County PUD	NorthWestern Energy	NF
28	Morgan Stanley Capital Group	Avista Corporation	NorthWestern Energy	NF
29	Puget Sound Energy	NorthWestern Energy	Bonneville Power Administration	NF
30	Powerex	Bonneville Power Administration	Idaho Power Company	NF
31	Transalta Energy Marketing	Bonneville Power Administration	Idaho Power Company	NF
32	PacifiCorp	PacifiCorp	Bonneville Power Administration	NF
33	PacifiCorp	PacifiCorp	Idaho Power Company	NF
34	PacifiCorp	Idaho Power Company	PacifiCorp	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	NF
2	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
3	Morgan Stanley Capital Group	Bonneville Power Administration	NorthWestern Energy	LFP
4	Shell Energy North America (US) LP	PacifiCorp	Bonneville Power Administration	NF
5	Shell Energy North America (US) LP	Grant County Public Utility	Idaho Power Company	NF
6	Talen Energy Marketing, LLC	Avista Corporation	NorthWestern Energy	NF
7	NorthWestern Energy	Bonneville Power Administration	NorthWestern Energy	NF
8	Portland General Electric	NorthWestern Energy	Bonneville Power Administration	NF
9	Avangrid Renewables	Bonneville Power Administration	Idaho Power Company	NF
10	Avangrid Renewables	NorthWestern Energy	Bonneville Power Administration	NF
11	Shell Energy North America (US) LP	PacifiCorp	Bonneville Power Administration	NF
12	Energy Keepers, Inc.	Bonneville Power Administration	NorthWestern Energy	NF
13	EDF Trading N.A. LLC	Bonneville Power Administration	NorthWestern Energy	NF
14	EDF Trading N.A. LLC	NorthWestern Energy	Avista Corporation	NF
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/11/2018	End of 2017/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.
FERC No. 182	Dry Gulch	Dry Gulch		65,651	65,651	1
FERC Trf No. 8	Chelan-Stratford	Stratford		213,657	213,657	2
FERC Trf No. 8	Chelan-Stratford	Stratford		213,641	213,641	3
FERC No. 104	Stratford	Coulee City/Wilson		90,307	90,307	4
FERC Trf No. 8	AVA.BPAT	AVA.SYS	3	2,939	2,939	5
FERC Trf No. 8	AVA.BPAT	AVA.SYS	3	3,875	3,875	6
FERC Trf No. 8	AVA.BPAT	AVA.SYS	4	6,554	6,554	7
FERC Trf No. 8	AVA.BPAT	AVA.SYS		1,983,042	1,983,042	8
						9
						10
						11
FERC Trf No. 8						12
						13
FERC Trf No. 8				199,902	199,902	14
FERC Trf No. 8				5,893	5,893	15
FERC Trf No. 8				4,800	4,800	16
FERC Trf No. 8				414	414	17
FERC Trf No. 8				12	12	18
FERC Trf No. 8				69,349	69,349	19
FERC Trf No. 8				760	760	20
FERC Trf No. 8				43,890	43,890	21
FERC Trf No. 8				70	70	22
FERC Trf No. 8				350	350	23
FERC Trf No. 8				21,422	21,422	24
FERC Trf No. 8				480	480	25
FERC Trf No. 8				104,938	104,938	26
FERC Trf No. 8				1,841	1,841	27
FERC Trf No. 8				52,556	52,556	28
FERC Trf No. 8				4,162	4,162	29
FERC Trf No. 8				2,400	2,400	30
FERC Trf No. 8				287	287	31
FERC Trf No. 8				53,296	53,296	32
FERC Trf No. 8				3,178	3,178	33
FERC Trf No. 8				2,712	2,712	34
			38	**3,380,342**	**3,380,342**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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.
FERC Trf No. 8				86	86	1
FERC Trf No. 8				24	24	2
FERC Trf No. 8				485	485	3
FERC Trf No. 8				25	25	4
FERC Trf No. 8				11	11	5
FERC Trf No. 8				10,691	10,691	6
FERC Trf No. 8				457	457	7
FERC Trf No. 8				180	180	8
FERC Trf No. 8				1,249	1,249	9
FERC Trf No. 8				789	789	10
FERC Trf No. 8	AVA.SYS	LOLO	3	11,490	11,490	11
FERC Trf No. 8				50	50	12
FERC Trf No. 8				2,370	2,370	13
FERC Trf No. 8				64	64	14
FERC Trf No. 8				12,854	12,854	15
FERC Trf No. 8				2,970	2,970	16
FERC Trf No. 8				1,776	1,776	17
FERC Trf No. 8				277	277	18
FERC Trf No. 8				6,000	6,000	19
FERC Trf No. 8				128	128	20
FERC Trf No. 8				50	50	21
FERC Trf No. 8				50	50	22
FERC Trf No. 8				55	55	23
FERC Trf No. 8				2,690	2,690	24
FERC Trf No. 8				599	599	25
FERC Trf No. 8				6,731	6,731	26
FERC Trf No. 8				899	899	27
FERC Trf No. 8						28
FERC Trf No. 8				2,370	2,370	29
FERC Trf No. 8				1,187	1,187	30
FERC Trf No. 8				560	560	31
FERC Trf No. 8				2,977	2,977	32
FERC Trf No. 8				4,323	4,323	33
FERC Trf No. 8				61	61	34
			38	**3,380,342**	**3,380,342**	

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)	
FERC Trf No. 8				4,551	4,551	1
T1110						2
FERC Trf No. 8	BPATPUD	AVAT.NWMT	25	139,691	139,691	3
FERC Trf No. 8				1	1	4
FERC Trf No. 8				3,555	3,555	5
FERC Trf No. 8				24	24	6
FERC Trf No. 8				3,706	3,706	7
FERC Trf No. 8				330	330	8
FERC Trf No. 8				832	832	9
FERC Trf No. 8				25	25	10
FERC Trf No. 8				68	68	11
FERC Trf No, 8				555	555	12
FERC Trf No. 8				96	96	13
FERC Trf No. 8				2	2	14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			38	**3,380,342**	**3,380,342**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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.
271,839			271,839	1
146,816		90,228	237,044	2
215,000		90,228	305,228	3
28,032			28,032	4
28,800		5,863	34,663	5
10,800		6,252	17,052	6
32,160		9,821	41,981	7
6,991,211		2,428,433	9,419,644	8
		27,973	27,973	9
		9,480	9,480	10
		6,120	6,120	11
1,000,000			1,000,000	12
		603	603	13
892,070			892,070	14
36,209			36,209	15
18,993			18,993	16
1,444			1,444	17
42			42	18
277,974			277,974	19
2,878			2,878	20
182,616			182,616	21
320			320	22
3,855			3,855	23
86,724			86,724	24
2,022			2,022	25
415,567			415,567	26
7,002			7,002	27
150,449			150,449	28
77,901			77,901	29
7,508			7,508	30
904			904	31
166,521			166,521	32
10,015			10,015	33
8,547			8,547	34
12,290,758	**0**	**5,889,635**	**18,180,393**	

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.
271			271	1
76			76	2
3,713			3,713	3
144			144	4
107			107	5
72,555			72,555	6
4,171			4,171	7
1,829			1,829	8
10,185			10,185	9
6,738			6,738	10
72,000		22,549	94,549	11
441			441	12
19,224			19,224	13
519			519	14
95,986			95,986	15
18,878			18,878	16
15,236			15,236	17
2,074			2,074	18
43,408			43,408	19
1,152			1,152	20
337			337	21
337			337	22
546			546	23
20,142			20,142	24
3,883			3,883	25
52,758			52,758	26
6,283			6,283	27
577			577	28
16,664			16,664	29
7,499			7,499	30
3,231			3,231	31
19,271			19,271	32
26,488			26,488	33
376			376	34
12,290,758	**0**	**5,889,635**	**18,180,393**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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.
29,421			29,421	1
		3,192,000	3,192,000	2
600,000		85	600,085	3
6			6	4
21,423			21,423	5
138			138	6
21,384			21,384	7
1,904			1,904	8
10,838			10,838	9
166			166	10
392			392	11
3,202			3,202	12
554			554	13
12			12	14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
12,290,758	**0**	**5,889,635**	**18,180,393**	

Schedule Page: 328 Line No.: 2 Column: m
Use of facilities.

Schedule Page: 328 Line No.: 3 Column: m
Use of facilities.

Schedule Page: 328 Line No.: 5 Column: m
Ancillary services.

Schedule Page: 328 Line No.: 6 Column: m
Ancillary services.

Schedule Page: 328 Line No.: 7 Column: m
Ancillary services.

Schedule Page: 328 Line No.: 8 Column: m
Ancillary services.

Schedule Page: 328 Line No.: 9 Column: e
PURPA Interconnection under state jurisdiction.

Schedule Page: 328 Line No.: 9 Column: m
Use of facilities.

Schedule Page: 328 Line No.: 10 Column: e
PURPA Interconnection under state jurisdiction.

Schedule Page: 328 Line No.: 10 Column: m
Use of facilities.

Schedule Page: 328 Line No.: 11 Column: e
PURPA Interconnection under state jurisdiction.

Schedule Page: 328 Line No.: 11 Column: m
Use of facilities.

Schedule Page: 328 Line No.: 13 Column: e
PURPA Interconnection under state jurisdiction.

Schedule Page: 328 Line No.: 13 Column: m
Use of facilities.

Schedule Page: 328.1 Line No.: 11 Column: m
Ancillary services.

Schedule Page: 328.2 Line No.: 2 Column: m
Parallel Capacity Support Agreement.

Schedule Page: 328.2 Line No.: 3 Column: m
Adjustment to February for additional secondary non-firm. Volume was already recorded in Q1.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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	Bonneville Power Admin	LFP			1,494,953			1,494,953
2	Bonneville Power Admin	LFP			10,278,678		2,120,475	12,399,153
3	Bonneville Power Admin	LFP			943,402			943,402
4	Bonneville Power Admin	OS					54,432	54,432
5	Bonneville Power Admin	FNS			1,181,840		242,064	1,423,904
6	Bonneville Power Admin	NF	8,362	8,362		43,093		43,093
7	Morgan Stanley Capital	NF	20	20		25		25
8	Kootenai Electric Coop	LFP			45,222			45,222
9	Northern Lights	LFP			139,528			139,528
10	NorthWestern Energy	SFP			111,448		11,623	123,071
11	NorthWestern Energy	NF	27,211	27,211		117,824		117,824
12	Portland General Elec	LFP			628,000		14,989	642,989
13	Portland General Elec	NF	16,402	16,402		20,177		20,177
14	Snohomish County PUD	NF	38,344	38,344		51,734		51,734
15	Puget Sound Energy	NF	565	565		1,860	543	2,403
16	Energy Keepers, Inc.	NF	519	519		1,557		1,557
	TOTAL		142,527	142,527	14,823,071	302,473	2,444,126	17,569,670

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	Seattle City Light	NF	50,903	50,903		65,939		65,939
2	Talen Energy Marketing	NF	21	21		58		58
3	Shell Energy North Amer	NF	90	90		112		112
4	The Energy Authority	NF	90	90		94		94
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		142,527	142,527	14,823,071	302,473	2,444,126	17,569,670

Schedule Page: 332 Line No.: 2 Column: g

Ancillary Services

Schedule Page: 332 Line No.: 4 Column: g

Use of Facilities

Schedule Page: 332 Line No.: 5 Column: g

Ancillary Services

Schedule Page: 332 Line No.: 10 Column: g

Ancillary Services

Schedule Page: 332 Line No.: 12 Column: g

Ancillary Services

Schedule Page: 332 Line No.: 15 Column: g

Ancillary Services

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	601,910
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	403,718
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Community Relations	12,852
7	Director Expenses	646,687
8	Education and information	28,284
9	Rating agency fees	136,104
10	Aircraft operations and fees	197,916
11	Misc vendors >5K	1,473,465
12	Misc vendors <5K	144,454
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	3,645,390

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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			3,137,693		3,137,693
2	Steam Production Plant	8,098,309	259,817			8,358,126
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	11,531,285				11,531,285
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	9,726,289	3,437		2,450,030	12,179,756
7	Transmission Plant	12,323,650				12,323,650
8	Distribution Plant	46,769,541				46,769,541
9	Regional Transmission and Market Operation					
10	General Plant	3,761,028		48,031		3,809,059
11	Common Plant-Electric	14,447,037		17,329,948		31,776,985
12	TOTAL	106,657,139	263,254	20,515,672	2,450,030	129,886,095

B. Basis for Amortization Charges

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	STEAM PLANT						
13	Colstrip No. 3						
14	311	52,576	70.00	-10.00	1.56	S1.5	22.10
15	312	78,850	60.00	-10.00	1.93	R1	21.50
16	313	3					
17	314	32,311	40.00	-5.00	2.79	R0.5	19.40
18	315	9,543	50.00		1.73	R3	21.00
19	316	10,992	53.00		1.46	R2	20.90
20	Subtotal	184,275					
21							
22	Colstrip No. 4						
23	311	53,677	70.00	-10.00	1.68	S1.5	23.90
24	312	57,387	60.00	-10.00	2.20	R1	23.30
25	313	3					
26	314	13,905	40.00	-5.00	2.88	R0.5	20.90
27	315	6,673	50.00		1.88	R3	22.90
28	316	5,044	53.00		1.62	R2	22.70
29	Subtotal	136,689					
30							
31	Kettle Falls					0	
32	310	148			1.45	SQ	18.00
33	311	28,692	70.00	-10.00	1.51	S1.5	17.10
34	312	42,544	60.00	-10.00	1.93	R1	16.70
35	314	17,769	40.00	-5.00	2.12	R0.5	14.90
36	315	12,154	50.00		1.56	R3	16.40
37	316	2,518	53.00		1.74	R2	16.80
38	Subtotal	103,825					
39							
40	HYDRO PLANT						
41	Cabinet Gorge						
42	330	8,431	100.00		2.00	R4	43.20
43	331	16,511	110.00	-20.00	1.50	R2	51.50
44	332	44,182	100.00		1.13	R1	47.70
45	333	45,904	65.00	-10.00	2.04	R1.5	43.90
46	334	7,510	38.00	-5.00	2.97	R2.5	19.70
47	335	4,575	65.00		0.38	R1.5	49.90
48	336	1,671	55.00		1.96	S2	19.00
49	Subtotal	128,784					
50							

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	Noxon Rapids						
13	330	30,477	100.00		1.80	R4	48.80
14	331	19,618	110.00	-20.00	1.48	R2	58.40
15	332	35,137	100.00		1.12	R1	52.60
16	333	88,682	65.00	-10.00	1.98	R1.5	47.50
17	334	17,240	38.00	-5.00	2.79	R2.5	29.50
18	335	3,765	65.00		0.80	R1.5	53.60
19	336	247	55.00		1.89	S2	32.00
20	Subtotal	195,166					
21							
22	Post Falls						
23	330	2,908	75.00		2.81	R3	25.20
24	331	3,411	110.00	-20.00	2.09	R2	45.60
25	332	27,040	100.00		1.71	R1	44.70
26	333	2,234	65.00	-10.00	2.42	R1.5	29.60
27	334	730	38.00	-5.00	2.78	R2.5	18.20
28	335	467	65.00		1.15	R1.5	42.10
29	336	563					
30	Subtotal	37,353					
31							
32	Long Lake						
33	330	418	75.00		4.42	R3	11.00
34	331	6,089	110.00	-20.00	1.99	R2	38.90
35	332	35,130	100.00		1.65	R1	40.00
36	333	8,738	65.00	-10.00	2.46	R1.5	33.30
37	334	3,364	38.00	-5.00	2.63	R2.5	22.50
38	335	516	65.00		1.22	R1.5	39.40
39	Subtotal	54,255					
40							
41	Little Falls						
42	330	4,217	100.00		3.35	R4	24.40
43	331	3,618	110.00	-20.00	1.94	R2	42.30
44	332	5,149	100.00		1.72	R1	43.60
45	333	28,297	65.00	-10.00	2.40	R1.5	33.60
46	334	8,063	38.00	-5.00	2.74	R2.5	22.20
47	335	549	65.00		0.69	R1.5	40.60
48	Subtotal	49,893					
49							
50	Upper Falls						

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	330	64	100.00		3.66	R4	22.20
13	331	975	110.00	-20.00	1.77	R2	41.40
14	332	7,607	100.00		1.85	R1	45.20
15	333	1,166	65.00	-10.00	2.53	R1.5	30.00
16	334	4,269	38.00	-5.00	2.81	R2.5	35.10
17	335	104	65.00		1.05	R1.5	41.20
18	336	508	55.00		1.94	S2	26.20
19	Subtotal	14,693					
20							
21	Nine Mile						
22	330	11	100.00		2.48	R4	35.90
23	331	18,687	110.00	-20.00	1.98	R2	46.50
24	332	25,989	100.00		1.83	R1	45.10
25	333	40,730	65.00	-10.00	2.17	R1.5	40.30
26	334	19,115	38.00	-5.00	2.80	R2.5	22.50
27	335	3,140	65.00		0.88	R1.5	41.20
28	336	595	55.00		1.93	S2	36.20
29	Subtotal	108,267					
30							
31	Monroe Street						
32	331	12,104	110.00	-20.00	1.71	R2	56.90
33	332	9,972	100.00		1.39	R1	53.20
34	333	11,031	65.00	-10.00	1.95	R1.5	45.50
35	334	2,086	38.00	-5.00	2.82	R2.5	23.40
36	335	34	65.00		1.19	R1.5	48.30
37	336	50	55.00		1.86	S2	36.60
38	Subtotal	35,277					
39							
40	OTHER PRODUCTION						
41	Northeast Turbine						
42	341	751	55.00		1.64	S4	8.00
43	342	31	55.00	-10.00	2.93	R3	8.00
44	343	9,058	55.00		0.81	S2.5	8.00
45	344	2,604	45.00		2.50	R1	7.40
46	345	1,243	20.00	-5.00	12.49	S2	7.90
47	346	399	35.00		2.51	R3	7.80
48	Subtotal	14,086					
49							
50	Rathdrum Turbine						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	341	3,540	55.00		3.12	S4	24.00
13	342	1,696	55.00	-10.00	3.57	R3	23.50
14	343	5,722	55.00		2.77	S2.5	23.50
15	344	49,619	45.00		3.77	R1	21.60
16	345	3,142	20.00	-5.00	5.89	S2	15.20
17	346	308	35.00		2.51	R3	7.80
18	Subtotal	64,027					
19							
20	Kettle Falls CT						
21	342	89	55.00	-10.00	3.66	R3	17.70
22	343	9,071	55.00		3.24	S2.5	17.80
23	344	4	45.00		4.09	R1	16.60
24	345	14	20.00	-5.00	6.68	S2	11.40
25	Subtotal	9,178					
26							
27	Boulder Park						
28	341	1,262	55.00		2.54	S4	31.90
29	342	252	55.00	-10.00	2.62	R3	30.40
30	343	57	55.00		2.52	S2.5	30.90
31	344	31,118	45.00		2.94	R1	26.90
32	345	646	20.00	-5.00	6.03	S2	14.30
33	346	39	35.00		2.87	R3	26.20
34	Subtotal	33,374					
35							
36	Coyote Springs 2						
37	341	11,513	55.00		2.34	S4	32.80
38	342	19,309	55.00	-10.00	2.72	R3	31.40
39	344	135,671	45.00		3.00	R1	27.90
40	345	15,866	20.00	-5.00	6.14	S2	13.40
41	346	998	35.00		2.95	R3	27.40
42	Subtotal	183,357					
43							
44	Solar Power						
45	344 & 345	482	25.00		5.30	S2.5	17.90
46	Subtotal	482					
47							
48	Lancaster						
49	342	92	55.00	-10.00	3.67	R3	29.40
50	344	209	45.00		3.70	R1	26.60

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	345	49					
13	Subtotal	350					
14							
15	TRANSMISSION PLANT						
16	350	21,372	75.00		1.30	R4	56.80
17	352	24,995	60.00	-5.00	1.65	S2	48.00
18	353	255,649	45.00	-10.00	2.33	R2.5	33.10
19	354	17,175	70.00	-15.00	1.80	R4	41.00
20	355	243,705	65.00	-15.00	1.38	R2.5	54.70
21	356	145,560	65.00	-10.00	1.59	R2.5	50.20
22	357	3,139	60.00		1.64	R4	51.70
23	358	2,450	50.00		2.02	S2	35.40
24	359	2,104	65.00		1.66	R4	39.70
25	Subtotal	716,149					
26							
27	DISTRIBUTION PLANT						
28	360	2,948	75.00		1.34	R4	74.40
29	361	24,048	60.00	-10.00	1.62	R2.5	47.30
30	362	130,313	45.00		1.97	R1.5	34.20
31	363	2,598					
32	364	381,897	55.00	-25.00	2.31	R2.5	41.10
33	365	253,181	50.00	-20.00	2.82	R3	32.70
34	366	112,540	50.00	-25.00	2.71	S2	37.60
35	367	197,373	28.00	-20.00	5.63	S2	16.80
36	368	254,596	44.00	-5.00	2.11	R2	33.00
37	369	166,356	55.00	-40.00	2.70	R4	37.55
38	370 - AN	157	15.00		7.65	S2.5	12.50
39	370.2 - ID	22,755	15.00		7.65	S2.5	12.50
40	370.3 - WA	26,791	35.00		3.39	S0.5	23.60
41	371	1,089					
42	373	21,169	35.00	-25.00	1.91	R2.5	26.45
43	373.4	25,657	35.00	-25.00	3.48	R2.5	26.80
44	373.5	12,490					
45	Subtotal	1,635,958					
46							
47	GENERAL PLANT						
48	390.1	8,239	48.00	-5.00	1.67	S2	39.00
49	391.1	3,079	5.00		21.28	SQ	3.30
50	393	399	25.00		4.58	SQ	19.40

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	394	4,554	20.00		4.78	SQ	10.20
13	395	1,473	15.00		13.73	SQ	4.00
14	397	64,472	15.00		2.81	SQ	11.70
15	398	150	10.00		13.31	SQ	7.00
16	Subtotal	82,366					
17							
18	MISC POWER						
19	392	6,741	15.00	20.00	1.83	L2.5	13.70
20	396	3,363	16.00	5.00	5.79	S0.5	11.80
21	Subtotal	10,104					
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32	TOTAL COMPANY	3,797,908					
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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	Charges include annual fee and license fees				
3	for the Spokane River Project, the Cabinet				
4	Gorge Project and the Noxon Rapids Project.	2,526,991	63,658	2,590,649	
5					
6					
7					
8					
9	Washington Utilities and Transportation				
10	Commission: includes annual fee and various				
11	other electric dockets	1,039,372	1,109,434	2,148,806	
12					
13	Includes annual fee and various other natural				
14	gas dockets	301,362	299,167	600,529	
15					
16	Idaho Public Utilities Commission				
17	Includes annual fee and various other electric				
18	dockets	557,289	338,524	895,813	
19					
20	Includes annual fee and various other natural				
21	gas dockets	140,322	100,053	240,375	
22					
23	Public Utility Commission of Oregon				
24	Includes annual fees and various other natural				
25	gas dockets	591,921	535,137	1,127,058	
26					
27	Not directly assigned electric		941,449	941,449	
28	Not directly assigned natural gas		398,049	398,049	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	5,157,257	3,785,471	8,942,728	

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
							2
							3
Electric	928	2,590,649					4
							5
							6
							7
							8
							9
							10
Electric	928	2,148,806					11
							12
							13
Gas	928	600,529					14
							15
							16
							17
Electric	928	895,813					18
							19
							20
Gas	928	240,375					21
							22
							23
							24
Gas	928	1,127,058					25
							26
Electric	928	941,449					27
Gas	928	398,049					28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		8,942,728					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	A 3 Electric - Distribution	Battery Storage and Electric Vehicle Supply Equipment
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
749,952	1,789,094	107	2,539,046		1
43,261	37,310	584	80,571		2
	116,923	587	116,923		3
745		598	745		4
11	3,858	909	3,869		5
28,136		920	28,136		6
10	13,457	930	13,467		7
					8
					9
					10
					11
					12
					13
					14
					15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34
					35
					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	11,732,722		
4	Transmission	3,246,196		
5	Regional Market			
6	Distribution	8,042,074		
7	Customer Accounts	7,505,286		
8	Customer Service and Informational	661,988		
9	Sales			
10	Administrative and General	19,310,835		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	50,499,101		
12	Maintenance			
13	Production	4,276,704		
14	Transmission	1,228,398		
15	Regional Market			
16	Distribution	3,928,339		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	9,433,441		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	16,009,426		
21	Transmission (Enter Total of lines 4 and 14)	4,474,594		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	11,970,413		
24	Customer Accounts (Transcribe from line 7)	7,505,286		
25	Customer Service and Informational (Transcribe from line 8)	661,988		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	19,310,835		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	59,932,542	15,165,812	75,098,354
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	879,118		
34	Storage, LNG Terminaling and Processing	11,709		
35	Transmission			
36	Distribution	5,377,631		
37	Customer Accounts	3,230,554		
38	Customer Service and Informational	347,530		
39	Sales			
40	Administrative and General	7,748,519		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	17,595,061		
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	1,231,446		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	3,128,408		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	4,359,854		
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)	879,118		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	11,709		
56	Transmission (Lines 35 and 47)	1,231,446		
57	Distribution (Lines 36 and 48)	8,506,039		
58	Customer Accounts (Line 37)	3,230,554		
59	Customer Service and Informational (Line 38)	347,530		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	7,748,519		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	21,954,915	5,557,198	27,512,113
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	81,887,457	20,723,010	102,610,467
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	42,214,060	14,220,767	56,434,827
69	Gas Plant	10,529,300	4,917,591	15,446,891
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	52,743,360	19,138,358	71,881,718
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,310,427	575,573	2,886,000
74	Gas Plant	365,185	90,974	456,159
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,675,612	666,547	3,342,159
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense	2,225,547	-2,225,547	
79	Preliminary Survey and Investigation	19,904		19,904
80	Small Tools Expense	4,096,673	-4,096,673	
81	Miscellaneous Def Debits	1,515,549		1,515,549
82	Non-Operating Expenses	653,917		653,917
83	Retirement Bonus/SERP/HRA Settlement	46,069		46,069
84	Activities	1,737,663		1,737,663
85	Employee Incentive Plan	14,054,771	-14,054,771	
86	DSM Tariff Rider and Payroll Equalization	22,274,579	-20,150,948	2,123,631
87	Incentive/Stock Compensation	148,894		148,894
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	46,773,566	-40,527,939	6,245,627
96	TOTAL SALARIES AND WAGES	184,079,995	-24	184,079,971

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

COMMON UTILITY PLANT AND EXPENSES

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

1 & 2. Common Plant in service and accumulated provision for depreciation

Acct. No.	Description	
303	Intangible	228,957,211
389	Land and Land Rights	11,596,692
390	Structures and Improvements	127,012,510
391	Office Furniture and Equipment	75,918,151
392	Transportation Equipment	12,743,006
393	Stores Equipment	4,481,129
394	Tools, Shop & Garage Equipment	14,841,062
395	Laboratory Equipment	384,734
396	Power Operated Equipment	1,793,585
397	Communications Equipment	68,084,166
398	Miscellaneous Equipment	403,786
399	Asset Retirement Cost	0
	Total Common Plant	546,216,032
	Const. Work in Progress	37,454,896
	Total Utility Plant	583,670,928
	Acc. Prov. for Dep. & Amort.	142,667,432
	Net Utility Plant	441,003,496

3. Common Expenses allocated to Electric and Gas departments:

Acct. No.	Description	Total	Allocation to Electric Dept	Allocated to Gas Dept	Basis of Allocation
901	Cust acct/collect supervision	460,772	242,260	218,512	#of cust @ yr end
902	Meter reading expenses	5,208,944	3,184,644	2,024,300	#of cust @ yr end
903	Cust rec & collectn expenses	17,605,721	9,256,560	8,349,161	#of cust @ yr end
903.90-99	A/R misc fees	0	0	0	net direct plant
904	Uncollectible accts	5,235,000	2,752,406	2,482,594	#of cust @ yr end
905	Misc cust acct exp	468,901	246,534	222,367	#of cust @ yr end
907	Cust svce & Info exp supervision	0	0	0	#of cust @ yr end
908	Cust assistance exp	1,077,366	658,680	418,686	#of cust @ yr end
909	Info & instruct exp	1,451,927	887,679	564,248	#of cust @ yr end
910	Misc cust serv & info expenses	621,800	326,924	294,876	#of cust @ yr end

COMMON UTILITY PLANT AND EXPENSES

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

911	Sales expense -supervision	0	0	0	#of cust @ yr end
912	Demo and selling expenses	0	0	0	#of cust @ yr end
913	Advertising expenses	0	0	0	#of cust @ yr end
916	Misc sales expenses	0	0	0	#of cust @ yr end
920	Admin & gen salaries	42,138,003	29,634,815	12,503,188	four factor
921	Office supplies & expenses	5,519,877	3,882,019	1,637,858	four factor
922	Admin expenses tranf-credit	0	0	0	four factor
923	Outside services employed	10,020,856	7,047,467	2,973,388	four factor
924	Property insurance	1,409,089	990,984	418,105	four factor
925	Injuries and damages	6,429,315	4,300,638	2,128,677	four factor
926	Employee pensions&benefits	70,134,090	49,323,903	20,810,187	four factor
927	Franchise requirement	0	0	0	four factor
928	Regulatory commission expenses	2,709,830	1,905,770	804,061	four factor
929	Duplicate charges-credit	0	0	0	four factor
930.1	General advertising expenses	0	0	0	four factor
930.2	Misc general expenses	4,054,241	2,851,267	1,202,974	four factor
931	Rents	912,361	641,645	270,716	four factor
935	Maint of general plant	14,281,665	10,044,009	4,237,656	four factor
403	Depreciation	20,369,750	14,325,638	6,044,112	four factor
404	Amort of LTD term plant	24,636,750	17,326,533	7,310,216	four factor

Note 1: The 4 factor allocator is made up of 25% each -customer counts, direct labor, direct O&M & Net direct plant

4. Letters of approval received from staffs of State Regulatory Commissions in 1993

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

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

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	(94,315)	(145,974)	(102,466)	(126,067)
3	Net Sales (Account 447)	(65,048)	(975,624)	(3,347,384)	(5,249,619)
4	Transmission Rights				
5	Ancillary Services	(424)	(12,493)	(30,478)	(36,890)
6	Other Items (list separately)				
7	Access Charge	38,953	65,965	74,333	87,145
8	Cost Recovery	980	1,120	1,383	2,646
9	Day Ahead Energy-Congestion Losses	176	(506)	(980)	866
10	FERC Fees	254	415	470	558
11	GMC	5,664	22,041	47,525	72,354
12	Hour Ahead Scheduling Process-RT Se	5,181	9,953	4,965	9,431
13	Other	(307)	(35)	(52)	(90)
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	(108,886)	(1,035,138)	(3,352,684)	(5,239,666)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	676	MW	240,556			
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response				79,419	MW	1,018,947
4	Energy Imbalance				665	MW	3,832,752
5	Operating Reserve - Spinning	1,016	MW/h	22,210	65,013	MW/h	1,317,985
6	Operating Reserve - Supplement	1,016	MW/h	22,210	42,147	MW/h	1,022,283
7	Other	843,076	MW	10,561,207	843,076	MW	10,561,207
8	Total (Lines 1 thru 7)	845,784		10,846,183	1,030,320		17,753,174

Schedule Page: 398 Line No.: 7 Column: b

Interdepartmental frequency and regulation and spinning and non-spinning reserve service for Native Load.

Schedule Page: 398 Line No.: 7 Column: d

Interdepartmental frequency and regulation and spinning and non-spinning reserve service for Native Load.

Schedule Page: 398 Line No.: 7 Column: e

Interdepartmental frequency and regulation and spinning and non-spinning reserve service for Native Load.

Schedule Page: 398 Line No.: 7 Column: g

Interdepartmental frequency and regulation and spinning and non-spinning reserve service for Native Load.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	2,459	5	800	1,694	410	263	26	92	
2	February	2,268	2	800	1,561	368	263	25	76	117
3	March	2,019	7	800	1,382	300	270	14	67	511
4	Total for Quarter 1				4,637	1,078	796	65	235	628
5	April	1,935	11	800	1,241	258	277	17	159	319
6	May	2,053	30	1700	1,401	261	280	17	111	304
7	June	2,160	26	1700	1,411	272	176	29	301	103
8	Total for Quarter 2				4,053	791	733	63	571	726
9	July	2,470	6	1800	1,595	312	179	35	383	103
10	August	2,321	3	1800	1,590	306	173	32	252	80
11	September	1,996	6	1800	1,346	249	171	25	230	66
12	Total for Quarter 3				4,531	867	523	92	865	249
13	October	1,902	21	1900	1,143	223	169	13	367	17
14	November	2,111	27	1800	1,421	260	163	11	267	304
15	December	2,326	21	1900	1,428	295	163	17	440	203
16	Total for Quarter 4				3,992	778	495	41	1,074	524
17	Total Year to Date/Year				17,213	3,514	2,547	261	2,745	2,127

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	8,910,726
3	Steam	1,713,436			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	3,978,060			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,070,079
7	Other	1,762,809			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	7,454,305	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	10,586
10	Purchases	4,998,184	27	Total Energy Losses	462,993
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	12,454,384
12	Received	44,907			
13	Delivered	43,012			
14	Net Exchanges (Line 12 minus line 13)	1,895			
15	Transmission For Other (Wheeling)				
16	Received	3,380,342			
17	Delivered	3,380,342			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	12,454,384			

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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:

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	1,239,511	257,188	1,681	5	800
30	February	1,071,535	268,598	1,556	2	800
31	March	1,080,637	285,894	1,371	7	1800
32	April	991,107	293,931	1,252	10	1000
33	May	919,829	223,800	1,410	30	1700
34	June	907,841	222,142	1,413	26	1700
35	July	1,047,060	230,554	1,586	6	1700
36	August	981,862	177,560	1,596	3	1800
37	September	881,704	201,424	1,349	1	1800
38	October	941,094	219,616	1,241	31	800
39	November	1,107,163	321,459	1,369	30	1800
40	December	1,285,041	367,913	1,496	27	1800
41	TOTAL	12,454,384	3,070,079			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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: Coyote Springs 2 (b)			Plant Name: Spokane N.E. (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Not Applicable			Not Applicable		
3	Year Originally Constructed	2003			1978		
4	Year Last Unit was Installed	2003			1978		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	295.00			61.80		
6	Net Peak Demand on Plant - MW (60 minutes)	319			55		
7	Plant Hours Connected to Load	6397			7		
8	Net Continuous Plant Capability (Megawatts)	295			65		
9	When Not Limited by Condenser Water	295			0		
10	When Limited by Condenser Water	295			0		
11	Average Number of Employees	15			1		
12	Net Generation, Exclusive of Plant Use - KWh	1659029000			390000		
13	Cost of Plant: Land and Land Rights	0			138753		
14	Structures and Improvements	11513327			751025		
15	Equipment Costs	171844065			13335295		
16	Asset Retirement Costs	351682			0		
17	Total Cost	183709074			14225073		
18	Cost per KW of Installed Capacity (line 17/5) Including	622.7426			230.1792		
19	Production Expenses: Oper, Supv, & Engr	456573			11571		
20	Fuel	36279452			11962		
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	1162111			44899		
26	Misc Steam (or Nuclear) Power Expenses	215348			31260		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	209197			12271		
30	Maintenance of Structures	196153			-3207		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	3147227			120274		
33	Maintenance of Misc Steam (or Nuclear) Plant	193373			64359		
34	Total Production Expenses	41859434			293389		
35	Expenses per Net KWh	0.0252			0.7523		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	GAS			GAS		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF			MCF		
38	Quantity (Units) of Fuel Burned	11149405	0	0	4957	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1020000	0	0	1020000	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.254	0.000	0.000	2.413	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.254	0.000	0.000	2.413	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.190	0.000	0.000	2.366	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.022	0.000	0.000	0.031	0.000	0.000
44	Average BTU per KWh Net Generation	6855.000	0.000	0.000	12964.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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: Boulder Park (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Internal Comb					
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional					
3	Year Originally Constructed	2002					
4	Year Last Unit was Installed	2002					
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	24.60			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	33			0		
7	Plant Hours Connected to Load	1373			0		
8	Net Continuous Plant Capability (Megawatts)	25			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	2			0		
12	Net Generation, Exclusive of Plant Use - KWh	26649000			0		
13	Cost of Plant: Land and Land Rights	185629			0		
14	Structures and Improvements	1261571			0		
15	Equipment Costs	32112803			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	33560003			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	1364.2278			0		
19	Production Expenses: Oper, Supv, & Engr	15497			0		
20	Fuel	753502			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	265979			0		
26	Misc Steam (or Nuclear) Power Expenses	39228			0		
27	Rents	1650			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	28495			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	260063			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	85928			0		
34	Total Production Expenses	1450342			0		
35	Expenses per Net KWh	0.0544			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	243798	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1020000	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.091	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.091	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.030	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.028	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9331.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
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	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			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	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
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	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			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	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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: *Kettle Falls* (d)			Plant Name: *Colstrip* (e)			Plant Name: *Rathdrum* (f)			Line No.
Steam			Steam			Gas Turbine			1
Conventional			Conventional			Not Applicable			2
1983			1984			1995			3
1983			1985			1995			4
50.70			233.40			166.50			5
50			227			168			6
8445			7593			672			7
54			222			167			8
54			222			0			9
54			222			0			10
30			329			2			11
290117000			1423319000			71741000			12
2289077			1288612			621682			13
28691774			106252905			3539544			14
74985342			214710990			60487448			15
450687			13876819			0			16
106416880			336129326			64648674			17
2098.9523			1440.1428			388.2803			18
174182			177433			14841			19
7467268			20697118			2270135			20
0			0			0			21
751073			3747678			0			22
0			0			0			23
0			0			0			24
1082593			158308			171060			25
479456			2225869			46112			26
0			39448			0			27
0			0			0			28
149874			341925			44606			29
107729			596293			0			30
1849860			4554524			0			31
226776			2640125			907108			32
481677			891575			57968			33
12770488			36070296			3511830			34
0.0440			0.0253			0.0490			35
WOOD	GAS		COAL	OIL		GAS			36
TON	MCF		TON	BBL		MCF			37
508426	9160	0	901281	2270	0	818334	0	0	38
8600000	1020000	0	16970000	5880000	0	1020000	0	0	39
14.629	3.207	0.000	22.770	76.954	0.000	2.774	0.000	0.000	40
14.629	3.207	0.000	22.770	76.954	0.000	2.774	0.000	0.000	41
1.701	3.145	0.000	1.342	13.087	0.000	2.720	0.000	0.000	42
0.026	0.037	0.000	0.014	0.000	0.000	0.032	0.000	0.000	43
15113.000	0.000	0.000	10755.000	0.000	0.000	11635.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

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

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

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

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

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

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

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

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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

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

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

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: -1 Column: b

Operated by Portland General Electric.

Schedule Page: 402 Line No.: -1 Column: c

Designed for peak load service

Schedule Page: 403 Line No.: -1 Column: e

Joint project operated by Talen Montana LLC.

Schedule Page: 403 Line No.: -1 Column: f

Designed for peak load service

Schedule Page: 402.1 Line No.: -1 Column: b

Designed for peak load service

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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. 2545 Plant Name: Monroe Street (b)	FERC Licensed Project No. 2545 Plant Name: Upper Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1890	1922
4	Year Last Unit was Installed	1992	1922
5	Total installed cap (Gen name plate Rating in MW)	14.80	10.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	15	12
7	Plant Hours Connect to Load	8,040	8,473
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	15	10
10	(b) Under the Most Adverse Oper Conditions	15	10
11	Average Number of Employees	4	3
12	Net Generation, Exclusive of Plant Use - Kwh	95,459,000	68,396,000
13	Cost of Plant		
14	Land and Land Rights	51,600	1,081,854
15	Structures and Improvements	12,103,398	974,617
16	Reservoirs, Dams, and Waterways	9,972,020	7,607,241
17	Equipment Costs	13,150,850	5,539,522
18	Roads, Railroads, and Bridges	50,448	508,242
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	35,328,316	15,711,476
21	Cost per KW of Installed Capacity (line 20 / 5)	2,387.0484	1,571.1476
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	426
26	Electric Expenses	623,142	573,449
27	Misc Hydraulic Power Generation Expenses	36,761	33,181
28	Rents	0	0
29	Maintenance Supervision and Engineering	6	1,055
30	Maintenance of Structures	6,493	17,682
31	Maintenance of Reservoirs, Dams, and Waterways	161,189	226,948
32	Maintenance of Electric Plant	157,569	54,182
33	Maintenance of Misc Hydraulic Plant	16,912	942
34	Total Production Expenses (total 23 thru 33)	1,002,072	907,865
35	Expenses per net KWh	0.0105	0.0133

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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. 2058 Plant Name: Noxon Rapids (b)	FERC Licensed Project No. 2545 Plant Name: Long Lake (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1959	1915
4	Year Last Unit was Installed	1977	1924
5	Total installed cap (Gen name plate Rating in MW)	487.80	70.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	564	90
7	Plant Hours Connect to Load	5,736	6,772
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	581	90
10	(b) Under the Most Adverse Oper Conditions	623	90
11	Average Number of Employees	13	6
12	Net Generation, Exclusive of Plant Use - Kwh	1,866,144,000	508,341,000
13	Cost of Plant		
14	Land and Land Rights	35,772,759	2,502,135
15	Structures and Improvements	18,891,028	6,080,948
16	Reservoirs, Dams, and Waterways	35,137,207	35,130,615
17	Equipment Costs	109,431,347	12,481,115
18	Roads, Railroads, and Bridges	246,561	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	199,478,902	56,194,813
21	Cost per KW of Installed Capacity (line 20 / 5)	408.9358	802.7830
22	Production Expenses		
23	Operation Supervision and Engineering	123,362	610
24	Water for Power	0	0
25	Hydraulic Expenses	93,536	9,190
26	Electric Expenses	1,520,335	822,414
27	Misc Hydraulic Power Generation Expenses	182,098	73,772
28	Rents	0	129
29	Maintenance Supervision and Engineering	114,343	74,086
30	Maintenance of Structures	74,784	47,246
31	Maintenance of Reservoirs, Dams, and Waterways	301,057	1,116,991
32	Maintenance of Electric Plant	510,668	449,932
33	Maintenance of Misc Hydraulic Plant	38,714	11,798
34	Total Production Expenses (total 23 thru 33)	2,958,897	2,606,168
35	Expenses per net KWh	0.0016	0.0051

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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. 2545 Plant Name: Nine Mile Falls (d)	FERC Licensed Project No. 2545 Plant Name: Post Falls (e)	FERC Licensed Project No. 2058 Plant Name: Cabinet Gorge (f)	Line No.
Run-of-River	Storage	Storage	1
Conventional	Conventional	Outdoor	2
1908	1906	1952	3
1994	1980	1953	4
37.60	14.80	265.00	5
30	17	263	6
6,346	7,120	7,538	7
			8
34	18	255	9
34	18	295	10
5	5	13	11
114,367,000	79,120,000	1,062,811,000	12
			13
33,429	3,570,115	15,169,637	14
18,324,602	3,410,946	16,511,352	15
25,989,530	27,041,257	44,181,877	16
62,985,287	3,429,686	57,939,727	17
594,870	563,408	1,671,013	18
0	0	0	19
107,927,718	38,015,412	135,473,606	20
2,870.4180	2,568.6089	511.2212	21
			22
20	455	94,721	23
0	0	147	24
82	3,643	19	25
670,612	750,390	1,611,313	26
62,733	69,162	165,906	27
0	0	0	28
5,546	41,142	112,052	29
41,004	44,479	75,186	30
361,306	309,610	155,271	31
183,073	543,119	669,725	32
7,300	19,523	22,406	33
1,331,676	1,781,523	2,906,746	34
0.0116	0.0225	0.0027	35

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. 2545 Plant Name: Little Falls (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Run-of-River			1
Conventional			2
1910			3
1911			4
40.40	0.00	0.00	5
36	0	0	6
7,257	0	0	7
			8
37	0	0	9
37	0	0	10
5	0	0	11
183,422,000	0	0	12
			13
4,325,371	0	0	14
3,618,230	0	0	15
5,148,973	0	0	16
36,908,744	0	0	17
0	0	0	18
0	0	0	19
50,001,318	0	0	20
1,237.6564	0.0000	0.0000	21
			22
85	0	0	23
0	0	0	24
9,321	0	0	25
706,641	0	0	26
21,349	0	0	27
982,845	0	0	28
90	0	0	29
49,881	0	0	30
242,721	0	0	31
102,972	0	0	32
8,630	0	0	33
2,124,535	0	0	34
0.0116	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

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

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

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			29
			30
			31
			32
			33
			34
			35
			36
			37
			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	Kettle Falls CT	2002	7.20	8.0	5,000,000	9,204,197
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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.
1,274,698	149,151	177,635	52,393	Nat Gas	303	1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	Group Sum		60.00	60.00		1.00		
2								
3	Group Sum		115.00	115.00		1,525.00		
4								
5	Beacon Sub #4	BPA Bell Sub	230.00	230.00	Steel Tower	1.00		1
6	Beacon Sub #4	BPA Bell Sub	230.00	230.00	H Type	5.00		1
7	Beacon Sub #5	BPA Bell Sub	230.00	230.00	Steel Pole	3.00		1
8	Beacon Sub #5	BPA Bell Sub	230.00	230.00	H Type	3.00		1
9	Beacon	Cabinet Gorge Plant	230.00	230.00	Steel Tower		1.00	1
10	Beacon	Cabinet Gorge Plant	230.00	230.00	Steel Pole	27.00		2
11	Beacon	Cabinet Gorge Plant	230.00	230.00	H Type	53.00		1
12	Beacon Sub	Lolo Sub	230.00	230.00	Steel Tower	1.00		1
13	Beacon Sub	Lolo Sub	230.00	230.00	Steel Pole	6.00		2
14	Beacon Sub	Lolo Sub	230.00	230.00	H Type	96.00		1
15	Benewah	Shawnee	230.00	230.00	Steel Pole	1.00		1
16	Benewah	Shawnee	230.00	230.00	Steel Pole	59.00		1
17	Noxon Plant	Pine Creek Sub	230.00	230.00	Steel Pole	29.00		1
18	Noxon Plant	Pine Creek Sub	230.00	230.00	H Type	1.00		1
19	Noxon Plant	Pine Creek Sub	230.00	230.00	H Type	14.00		1
20	Cabinet Gorge Plant	Noxon	230.00	230.00	H Type	2.00		1
21	Cabinet Gorge Plant	Noxon	230.00	230.00	H Type	17.00		1
22	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	Steel Tower			1
23	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	H Type	43.00		1
24	Divide Creek	Lolo Sub	230.00	230.00	Steel Tower			1
25	Divide Creek	Lolo Sub	230.00	230.00	H Type	43.00		1
26	N. Lewiston	Walla Walla	230.00	230.00	H Type	39.00		1
27	N. Lewiston	Walla Walla	230.00	230.00	H Type	4.00		1
28	N. Lewiston	Walla Walla	230.00	230.00	Steel Pole	4.00		1
29	N. Lewiston	Shawnee	230.00	230.00	Steel Pole	7.00		1
30	N. Lewiston	Shawnee	230.00	230.00	H Type	27.00		1
31	Walla Walla	Wanapum	230.00	230.00	Alum.			1
32	Walla Walla	Wanapum	230.00	230.00	H Type	15.00		1
33	Walla Walla	Wanapum	230.00	230.00	H Type	63.00		1
34	BPA (Libby)	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
35	BPA/Hot Springs #1	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
36					TOTAL	2,188.00	3.00	42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	BPA/Hot Springs #2	Noxon Plant (dead)	230.00	230.00	Steel Tower		2.00	1
2	BPA/Hot Springs #2	Noxon Plant	230.00	230.00	Steel Pole	2.00		1
3	BPA/Hot Springs #2	Noxon Plant	230.00	230.00	H Type	66.00		1
4	Coulee	West Side Sub	230.00	230.00	Steel Pole	1.00		2
5	BPA Line	West Side Sub	230.00	230.00	Steel Pole	1.00		2
6	Hatwai	N. Lewiston Sub	230.00	230.00	H Type	7.00		1
7	Divide Creek	Imnaha	230.00	230.00	H Type	20.00		1
8	Colstrip Plant	Broadview	500.00	500.00				
9								
10								
11								
12								
13								
14								
15								
16								
17								
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	2,188.00	3.00	42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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)	
	136,038	636,193	772,231					1
								2
	11,120,912	202,455,507	213,576,419	200,839	605,573		806,412	3
								4
1272 ACSS								5
1272 ACSS	17,912	1,429,560	1,447,472		8,399		8,399	6
1272 ACSS								7
1272 ACSS	30,323	3,275,357	3,305,680					8
1272 ACSS								9
1590 ACSS								10
1590 ACSR	1,156,196	41,995,911	43,152,107		91,574		91,574	11
1590 ACSS								12
1590 ACSS								13
1272 McMAL	456,162	23,125,382	23,581,544		47,796		47,796	14
1622 ACSS								15
1590 ACSS	570,207	48,748,289	49,318,496		4,265		4,265	16
1272 ACSR								17
1590 ACSS								18
954 AAC	1,097,679	19,139,261	20,236,940	17,772	83,758		101,530	19
795 ACSR								20
954 AAC	184,211	1,776,908	1,961,119		30,503		30,503	21
1622 ACSS								22
954 AAC	350,325	5,124,937	5,475,262		30,795		30,795	23
1272 AAC								24
1272 AAC	86,228	6,857,467	6,943,695	5,056	26,635		31,691	25
1272 AAC								26
1272 ACSR					19,433		19,433	27
1272 ACSR	623,984	7,826,084	8,450,068					28
1272 ACSR								29
1272 ACSR	872,150	10,043,831	10,915,981	8,127	2,841		10,968	30
1272 McMAL								31
1272 ACSR								32
1272 AAC	205,347	8,087,025	8,292,372	9,578	88,224		97,802	33
1272 ACSR								34
1272 ACSR		19,521	19,521					35
	21,448,421	426,634,351	448,082,772	360,910	1,246,536	88,756	1,696,202	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272 McMAL								1
1272 ACSR								2
1272 McMAL	3,539,508	9,914,183	13,453,691		71,207		71,207	3
1272 ACSR	8,482		8,482					4
1272 ACSR	36,462	594,543	631,005		109		109	5
1590 ACSR	155,244	2,605,674	2,760,918	1,093	27,402		28,495	6
1272 AAC	205,262	1,312,224	1,517,486		13,240		13,240	7
	595,789	31,666,494	32,262,283	118,445	94,782	88,756	301,983	8
								9
								10
								11
								12
								13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	21,448,421	426,634,351	448,082,772	360,910	1,246,536	88,756	1,696,202	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	No new transmission lines	added in 2017					
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

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)	
									1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
									44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	STATE OF WASHINGTON				
2					
3	Airway Heights	Distr. Unattended	115.00	13.80	
4	Barker Road	Distr. Unattended	115.00	13.80	
5	Beacon	Trnsm. & Distr Unatt	230.00	115.00	13.80
6	Boulder	Trnsm. Unattended	230.00	115.00	13.80
7	Chester	Distr. Unattended	115.00	13.80	
8	Chewelah 115Kv	Distr. Unattended	115.00	13.80	
9	Colbert	Distr. Unattended	115.00	13.80	
10	College & Walnut	Distr. Unattended	115.00	13.80	
11	Colville 115Kv	Distr. Unattended	115.00	13.80	
12	Critchfield	Distr. Unattended	115.00	13.80	
13	Deer Park	Dist. Unattended	115.00	13.80	
14	Dry Creek	Transm. Unattended	230.00	115.00	13.80
15	Dry Gulch	Distr. Unattended	115.00	13.80	
16	East Colfax	Distr. Unattended	115.00	13.80	
17	East Farms	Distr. Unattended	115.00	13.80	
18	Fort Wright	Distr. Unattended	115.00	13.80	
19	Francis and Cedar	Distr. Unattended	115.00	13.80	
20	Gifford	Distr. Unattended	115.00	34.00	
21	Glenrose	Distr. Unattended	115.00	13.80	
22	Greenwood	Distr. Unattended	115.00	13.80	
23	Hallett & White	Distr. Unattended	115.00	13.80	
24	Indian Trail	Dist. Unattended	115.00	13.80	
25	Industrial Park	Dist. Unattended	115.00	13.80	
26	Kettle Falls	Distr. Unattended	115.00	13.80	
27	Lee & Reynolds	Distr. Unattended	115.00	13.80	
28	Liberty Lake	Distr. Unattended	115.00	13.80	
29	Little Falls 115/34Kv	Distr. Unattended	115.00	34.00	
30	Lyons & Standard	Distr. Unattended	115.00	13.80	
31	Mead	Distr. Unattended	115.00	13.80	
32	Metro	Distr. Unattended	115.00	13.80	
33	Milan	Distr. Unattended	115.00	13.80	
34	Millwood	Dist. Unattended	115.00	13.80	
35	Ninth & Central	Distr. Unattended	115.00	13.80	
36	Northeast	Distr. Unattended	115.00	13.80	
37	Northwest	Distr. Unattended	115.00	13.80	
38	Opportunity	Dist. Unattended	115.00	13.80	
39	Othello	Distr. Unattended	115.00	13.80	
40	Post Street	Distr. Unattended	115.00	13.80	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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	Pound Lane	Distr. Unattended	115.00	13.80	
2	Ross Park	Distr. Unattended	115.00	13.80	
3	Roxboro	Distr. Unattended	115.00	24.00	
4	Shawnee	Trans. Unattended	230.00	115.00	13.80
5	Silver Lake	Distr. Unattended	115.00	13.80	
6	Southeast	Distr. Unattended	115.00	13.80	
7	South Othello	Distr. Unattended	115.00	13.80	
8	South Pullman	Distr. Unattended	115.00	13.80	
9	Sunset	Distr. Unattended	115.00	13.80	
10	Terre View	Dist. Unattended	115.00	13.80	
11	Third & Hatch	Distr. Unattended	115.00	13.80	
12	Turner	Dist. Unattended	115.00	13.80	
13	Waikiki	Distr. Unattended	115.00	13.80	
14	West Side	Trans. Unattended	230.00	115.00	13.80
15	Other: 28 substa less than 10MVA	Distr. Unattended			
16					
17	STATE OF IDAHO				
18	Appleway	Dist. Unattended	115.00	13.80	
19	Avondale	Dist. Unattended	115.00	13.80	
20	Benewah	Trans. Unattended	230.00	115.00	13.80
21	Big Creek	Distr. Unattended	115.00	13.80	
22	Blue Creek	Distr. Unattended	115.00	13.80	
23	Bunker Hill Limited	Distr. Unattended	115.00	13.80	
24	Cabinet Gorge (Switchyard)	Trans. Unattended	230.00	115.00	13.80
25	Clark Fork	Distr. Unattended	115.00	21.80	
26	Coeur d'Alene 15th Ave	Distr. Unattended	115.00	13.80	
27	Cottonwood	Distr. Unattended	115.00	24.90	
28	Dalton	Distr. Unattended	115.00	13.80	
29	Grangeville	Distr. Unattended	115.00	13.80	
30	Holbrook	Distr. Unattended	115.00	13.80	
31	Huetter	Distr. Unattended	115.00	13.80	
32	Idaho Road	Distr Unattended	115.00	13.80	
33	Juliaetta	Distr. Unattended	115.00	13.80	
34	Kamiah	Dist. Unattended	115.00	13.80	
35	Kooskia	Distr. Unattended	115.00	13.80	
36	Lewiston Mill Rd	Distr. Unattended	115.00	13.20	
37	Lolo	Tran & Dist Unattnd	230.00	115.00	13.80
38	Moscow	Distr. Unattended	115.00	13.80	
39	Moscow 230Kv	Tran & Dist Unattnd	230.00	115.00	13.80
40	North Moscow	Distr. Unattended	115.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	North Lewiston 230kV	Tran & Dist Unattnd	230.00	115.00	13.80
2	Oden	Distr. Unattended	115.00	21.80	
3	Oldtown	Distr. Unattended	115.00	21.80	
4	Orofino	Distr. Unattended	115.00	13.80	
5	Osburn	Distr. Unattended	115.00	13.80	
6	Pine Creek	Tran & Dist Unattnd	230.00	115.00	13.80
7	Pleasant View	Distr. Unattended	115.00	13.80	
8	Plummer	Dist Unattended	115.00	13.80	
9	Post Falls	Distr. Unattended	115.00	13.80	
10	Potlatch	Distr. Unattended	115.00	13.80	
11	Prarie	Distr. Unattended	115.00	13.80	
12	Priest River	Distr. Unattended	115.00	20.80	
13	Rathdrum	Trans & Distr Unattd	230.00	115.00	13.80
14	Sagle	Dist. Unattended	115.00	20.80	
15	Sandpoint	Distr. Unattended	115.00	20.80	
16	South Lewiston	Distr. Unattended	115.00	13.80	
17	Sweetwater	Distr. Unattended	115.00	24.90	
18	St. Maries	Distr. Unattended	115.00	23.90	
19	Tenth & Stewart	Distr. Unattended	115.00	13.80	
20	Wallace	Distr. Unattended	115.00	13.80	
21	Other: 13 substa less than 10 MVA	Distr. Unattended			
22					
23	STATE OF MONTANA				
24	1 substation less than 10 MVA	Distr. Unattended			
25					
26	SUBSTA. @ GENERATING PLANTS				
27	STATE OF WASHINGTON				
28	Boulder Park	Trans. Attended	115.00	13.80	
29	Kettle Falls	Trans. Attended	115.00	13.80	
30	Long Lake	Trans. Attended	115.00	4.00	
31	Nine Mile	Trans. Attended	115.00	13.80	
32	Little Falls	Trans. Attended	115.00	4.00	
33	Northeast	Trans. Attended	115.00	13.80	
34	Post Street	Trans. Attended	13.80	4.00	
35					
36	STATE OF IDAHO				
37	Cabinet Gorge (HED)	Trans. Attended	230.00	13.80	
38	Post Falls	Trans. Attended	115.00	2.30	
39	Rathdrum	Trans. Attended	115.00	13.80	
40	STATE OF MONTANA				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	Noxon	Trans. Attended	230.00	13.80	
2					
3	STATE OF OREGON				
4	Coyote Springs II	Trans. Attended	500.00	13.80	18.00
5					
6	SUMMARY:				
7	Washington:				
8	4 subs	Trans. Unattended			
9	75 subs	Distr. Unattended			
10	1 subs	Tran & Dist Unattnd			
11	7 subs	Trans. Attended			
12	Idaho:				
13	2 subs	Trans. Unattended			
14	48 subs	Distr. Unattended			
15	5 subs	Tran & Dist Unattnd			
16	3 subs	Trans. Attended			
17	Montana: 1 sub	Trans. Attended			
18	1 sub	Distr. Unattended			
19	Oregon: 1 sub	Trans. Unattended			
20	System: 148 subs				
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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
24	2		Frcd Oil&Air Fan&Cap	39	40	3
12	1		Two Stage Fan	1	20	4
536	4		Two Stage Fan	2	560	5
300	2		Two Stage Fan	2	500	6
24	2		Frcd Oil & Air Fan	2	40	7
12	1		Two Stage Fan	1	20	8
12	1		Frcd Oil & Air Fan	16	20	9
36	2		Two Stage Fan	2	60	10
32	3		Frcd Oil & Air Fan	3	45	11
12	1		Two Stage Fan	1	20	12
12	1		Two Stage Fan	1	20	13
150	1		Two Stage Fan & Caps	223	250	14
24	2		Frcd Oil & Air Fan	2	40	15
12	1		FrOil/Air Fan	1	20	16
12	1		Two Stage Fan	1	20	17
24	2	1	Fr Oil/Air/2StgFan	2	40	18
36	2		Two Stage Fan	2	60	19
12	1					20
12	1		Frcd Oil & Air Fan	1	20	21
12	1		Two Stage Fan	1	20	22
12	1		Two Stg Fan	1	20	23
12	1		Two Stage Fan	1	20	24
24	2		Two Stg/Pt/Frcd Oil	14	40	25
12	1		Frcd Oil & Air Fan	1	20	26
12	1		Two Stage Fan	1	20	27
24	2		Two Stage Fan	2	40	28
12	1					29
36	2		Two Stage Fan	2	60	30
18	1		Two Stage Fan	1	30	31
24	2		Two Stage Fan	2	40	32
24	2		Frcd Oil & Air Fan	2	40	33
24	2	2	Two Stage Fan	2	40	34
24	2	1	Frcd & Two Stage Fan	2	40	35
24	2		Two Stage Fan	2	40	36
24	2		Two Stage Fan	2	40	37
12	1		Two Stage Fan	1	20	38
24	2		FrOil/AirFan	2	40	39
36	2		Frcd Oil & Wt Fan	2	60	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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.
24	2		Two Stage Fan	2	40	1
30	2		Two Stage Fan	2	54	2
24	2		Two Stage Fan	2	40	3
150	1		Two Stage Fan	1	250	4
12	1		Two Stage Fan	2	20	5
30	2		Two Stage Fan	2	50	6
12	1		Two Stage Fan	1	20	7
30	2		Two Stage Fan	2	50	8
33	2		Two Stage Fan & Caps	50	55	9
12	1		Two Stage Fan	1	20	10
54	3		Two Stg Fan & Cap	103	90	11
36	2		Two Stg Fan	2	60	12
24	2		Two Stage Fan	2	40	13
250	2					14
165	32					15
						16
						17
36	2		Two Stage Fan	2	60	18
12	1		Two Stage Fan	1	20	19
75	1		Two Stage Fan & Caps	223	125	20
18	2		Portable Fan	2	22	21
12	1		Two Stage Fan	1	20	22
12	1		Frcd Air Fan	1	16	23
75	1		Two Stage Fan	1	125	24
10	1		Frcd Air Fan	1	13	25
36	2		Two Stage Fan	2	60	26
12	1		Two Stage Fan	1	20	27
24	2		FrcOil/Air2StgFan	2	40	28
25	4		FrcdOil/Air/Pt Fan&C	17	34	29
12	1		Two Stage Fan	1	20	30
12	1		Two Stage Fan	1	20	31
12	1		Two Stage Fan	1	20	32
12	1		Frcd Oil & Air Fan	1	20	33
12	1		Two Stage Fan	1	20	34
15	3		Frcd Air Fan	3	20	35
18	1		Two Stage Fan	1	30	36
262	3		Frcd Oil/Air/Two Stg	1	270	37
24	2		FrOil/Air/2Stg Fan	2	40	38
162	2		Frcd Air Fan & Caps	76	270	39
12	1		Two Stage Fan	1	20	40

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2018	Year/Period of Report End of 2017/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.
258	2		Frcd Air Fan & Caps	48	260	1
10	1		Frcd Air Fan	1	13	2
18	2		Frcd Air Fan	2	22	3
20	2		Frcd Oil & Air Fan	1	28	4
12	1		Portable Fan	1	15	5
212	3		Two Stg Fan/Capacito	45	270	6
12	1		Two Stage Fan	1	20	7
12	1		Two Stage Fan	1	20	8
18	1		Two Stage Fan	1	30	9
15	2		Portable Fan	2	19	10
12	1		Frcd Oil & Air Fan	1	20	11
10	1		Frcd Air Fan	1	13	12
474	4		Frcd Oil & Air Fan	50	490	13
12	1		Two Stage Fan	1	20	14
30	3		Frcd Air Fan	3	38	15
27	4		Port Fan/FrcdOil/Air	4	39	16
12	1		Frcd Oil & Air Fan	1	20	17
24	2		Two Stage Fan	2	40	18
30	2		Frcd Oil/Air/Two Stg	2	50	19
10	3					20
73	13					21
						22
						23
5	1					24
						25
						26
						27
36	1		Two Stage Fan	1	60	28
34	1	1	Two Stage Fan	1	62	29
80	4	1				30
42	2		Two Stage Fan	1	56	31
24	2		Frcd Oil & Air Fan	2	40	32
36	1		Two Stage Fan	1	60	33
35	2					34
						35
						36
300	6	1	Frcd Oil and Air Fan			37
16	2		Frcd Air/Oil/Air Fan	2	21	38
114	2	1	Two Stage Fan	2	190	39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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.
435	9	1	Two Stage Fan	2	635	1
						2
						3
213	1	1	Two Stage fan	1	355	4
						5
						6
						7
850						8
1183						9
536						10
287						11
						12
150						13
670						14
1368						15
430						16
435						17
5						18
213						19
6127						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2018	End of 2017/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	Corporate Support	Salix Inc.	146000	620,675
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule | Page No.