THIS FILING IS		
Item 1: ☐ An Initial (Original) Submission	OR ☒ Resubmission No. ____	

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Puget Sound Energy, Inc.	End of 2015/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/eforms/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/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.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 1,144 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 150 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 Puget Sound Energy, Inc.	02 Year/Period of Report End of 2015/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* P.O. Box 97034, Bellevue, WA 98009-9734	
05 Name of Contact Person Michael J. Stranik	06 Title of Contact Person Controller & PAO
07 Address of Contact Person *(Street, City, State, Zip Code)* P.O. Box 97034, Bellevue, WA 98009-9734	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(425) 462-3202	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Michael J. Stranik	Michael J. Stranik	04/14/2016
02 Title Controller & PAO		

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".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	
24	Extraordinary Property Losses	230	
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	N/A

LIST OF SCHEDULES (Electric Utility) (continued)

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

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	
	Stockholders' Reports Check appropriate box: ☐ Two copies will be submitted ☒ No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

GENERAL INFORMATION

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

Puget Sound Energy, Inc.
Michael J. Stranik, Controller and Principal Accounting Officer
P.O. Box 97034 PSE-08S
Bellevue, WA 98009-9734

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.

Washington, September 12, 1960

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 - State of Washington
Gas - State of Washington

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) ☒ No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

CONTROL OVER RESPONDENT

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

Puget Energy, Inc., an energy services holding company, holds all outstanding shares of Puget Sound Energy, Inc. common stock. Puget Energy, Inc. is the direct wholly owned subsidiary of Puget Equico, LLC, which is a directly wholly owned subsidiary of Puget Intermediate Holdings, Inc. which is in turn a direct wholly owned subsidiary of Puget Holdings, LLC.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Puget Western, Inc.	Real Estate Operations	100	
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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	President & Chief Executive Officer	Kimberly J. Harris	900,000
2	Sr. V.P. & Chief Financial Officer	Daniel A. Doyle	493,488
3	Sr. V.P. & Chief Administrative Officer	Marla D. Mellies	297,651
4	V.P., G.C., & Chief Ethics & Compliance Officer	Steve R. Secrist	360,721
5	V.P. Customer Solutions	Jason Teller	240,581
6	V.P. Chief Information Officer	Margaret Hopkins	263,616
7	V.P. Corporate Affairs	Andy W. Wappler	251,105
8	Sr. V.P. Operations	Booga K. Glibertson	266,530
9	Sr. V.P. & Chief Customer Officer	Philip K Bussey	296,367
10	V.P. Energy Operations	David E. Mills	279,423
11	Controller & Principal Accounting Officer	Michael J. Stranik	200,348
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Scott Armstrong	Seattle, Washington
2	William Ayer	Seattle, Washington
3	Andrew Chapman	New York, New York
4	Melanie Dressel	Tacoma, Washington
5	Daniel Fetter	Toronto, Ontario, Canada
6	Kimberly Harris, President & CEO	Bellevue, Washington
7	Benjamin Hawkins	Edmonton, Alberta, Canada
8	Steven W. Hooper	Bellevue, Washington
9	Alan James	New York, New York
10	Christopher Leslie	New York, New York
11	David MacMillan	London, England
12	Paul McMillan	Calgary, Alberta, Canada
13	Mary McWilliams	Seattle, Washington
14	Drew Murphy	New York, New York
15	Herbert Simon	Tacoma, Washington
16	Christopher Trumpy	Victoria, British Columbia, Canada
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Schedule Page: 105 Line No.: 1 Column: a

On June 25, 2015, Scott Armstrong joined the PSE Board of Directors.

Schedule Page: 105 Line No.: 2 Column: a

On January 22, 2015, William S. Ayer retired from the Puget Energy and PSE Board of Directors.

Schedule Page: 105 Line No.: 7 Column: a

On April 23, 2015, Benjamin Hawkins resigned from the Puget Energy and PSE Board of Directors.

Schedule Page: 105 Line No.: 8 Column: a

On January 22, 2015, Steven W. Hooper joined the Puget Energy and PSE Board of Directors.

Schedule Page: 105 Line No.: 12 Column: a

On April 23, 2015, Paul McMillan joined the Puget Energy and PSE Board of Directors.

Schedule Page: 105 Line No.: 14 Column: a

On August 31, 2015, Drew Murphy resigned from the Puget Energy and PSE Board of Directors.

Schedule Page: 105 Line No.: 15 Column: a

On January 21, 2016, Herbert B. Simon resigned from the PSE Board of Directors.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

Does the respondent have formula rates?

[X] Yes

[ ] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff	FERC Docket No. ER12-778-001
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[X] Yes
[ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	201309063009	09/16/2013	ER12-778-001	PSE FERC acceptance of OATT FERC	PSE is required to file an annual update
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Schedule Page: 1061 Line No.: 1 Column: e

PSE is required to file an annual update to FERC that FERC must approve per formula rate protocols. PSE does not have an annual update that needs to be approved as stipulated in PSE formula protocol. PSE files an annual update with FERC, but FERC does not send an approval letter or docket number.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1	None			
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.
1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

1. New (replacement) Franchises:

Location (WA)	Type	Start	End	Term (years)	Extension
Tacoma	Gas	9/23/2015	9/22/2040	25	
Yarrow Point	Dual	10/24/2015	10/23/2035	20	
Tukwila	Dual	10/27/2015	10/26/2030	15	
Roy	Electric	11/11/2015	11/10/2045	30	
Lakewood	Dual	1/23/2006	1/22/2026	20	Extended 12/12/2015

No consideration was paid to the granting jurisdiction for any of these franchises. Puget Sound Energy did reimburse the City of Tukwila for costs incurred in the processing of our application as provided under Washington State Law.

2. None

3. None

4. None

5. None

6. On May 26, 2015, PSE issued $425.0 million of senior notes secured by first mortgage bonds. The notes mature in May 2045 and have an interest rate of 4.30%, which is payable semi-annually in May and November. Net proceeds of the issuance were used to fund the early retirement, including accrued interest and make-whole call premiums, of PSE's $150.0 million 5.197% senior notes maturing in October 2015 and PSE's $250.0 million 6.75% senior notes maturing in January 2016.

   As of December 31, 2015, no loans or letters of credit were outstanding under the PSE energy hedging facility, no loans or letters of credit were outstanding under the PSE liquidity facility and $159.0 million was outstanding under the commercial paper program. The credit agreements are syndicated among numerous lenders. PSE is allowed by the Washington Utilities and Transportation Commission (WUTC) to issue obligations as necessary to meet ongoing working capital needs.

7. None

8. Non-represented employees received on average 3% salary increase effective March 1, 2015. Employees represented by the IBEW received a 6% wage increase that went into effect November 1, 2014 and employees represented by the UA received a 3% wage increase that was effective October 1, 2015. The estimated annual effect of these changes is

$8.3 million. The current labor contracts with the IBEW and UA expire March 31, 2017 and September 30, 2017, respectively.

9. Regulation and Rates

PSE filed a settlement agreement with the Washington Commission on March 22, 2013. The agreement was intended to settle all issues regarding decoupling, a power purchase agreement with TransAlta Centralia and the expedited rate filing (ERF) which is limited in scope and rate impact, includes the property tax tracker, and is intended to establish baseline rates on which the decoupling mechanism are to operate. The Washington Commission placed the ERF and decoupling filings under a common procedural schedule.

On June 25, 2013, the Washington Commission issued final orders resolving the amended decoupling petition, the ERF filing and the Petition for Reconsideration (related to the TransAlta Centralia power purchase agreement). Order No. 7 in the ERF/decoupling proceeding approved PSE's ERF filing with a small change to its cost of capital from 7.80% to7.77% to update long term debt costs. This order also approved the property tax tracker discussed below and approved the amended decoupling and rate plan filing with the further condition that PSE and the customers will share 50.0% each in earnings in excess of the 7.77% authorized rate of return. In addition, the rate plan increase allowed decoupling revenue per customer for the recovery of delivery system costs will subsequently increase by 3.0% for the electric customers and 2.2% for the gas customers on January 1 of each year, until the conclusion of PSE's next GRC which will be filed before April 1, 2016. In the rate plan, increases are subject to a cap of 3.0% of the total revenue for customers. Order No. 8 in the TransAlta Centralia proceeding granted in part and denied in part PSE's Petition for Reconsideration, clarifying certain portions of the Washington Commission's original order regarding TransAlta Centralia.

On July 24, 2013, the Public Counsel Division of the Washington State Attorney General's Office (Public Counsel) and the Industrial Customers of Northwest Utilities (ICNU) each filed a petition in Thurston County Superior Court (the Court) seeking judicial reviews of various aspects of the Washington Commission's ERF and decoupling mechanism final order. The parties' petition argued that the order violates various procedural and substantive requirements of the Washington Administrative Procedure Act, and so requests that it be vacated and that the matter be remanded to the Washington Commission. Oral arguments regarding this matter were held on May 9, 2014. On June 25, 2014, the court issued a letter decision in which it affirmed the attrition adjustment (escalating factors referred to as the K-Factor) and the Washington Commission's decision not to consider the case as a GRC, but reversed and remanded the cost of equity for further adjudication consistent with the court's decision. The remand proceeding evidentiary hearings regarding return on equity (ROE) were held in February 2015 and initial briefs and reply briefs were filed in March 2015. The Washington Commission issued a final order on remand on June 29, 2015, in which it found that 9.8% is a reasonable ROE for PSE for the term of the rate plan, taking decoupling and other relevant factors into account.

Expedited Rate Filing

On June 25, 2013, the Washington Commission approved PSE's electric and natural gas decoupling mechanism and ERF tariff filings, effective July 1, 2013. The estimated revenue impact of the decoupling mechanism for electric and natural gas customers is an increase of $21.4 million, or 1.0%, annually and an increase of $10.8 million, or 1.1% annually, respectively. The estimated revenue impact of the ERF filings for electric and natural gas customers is an increase of $30.7 million, or 1.5%, annually and a decrease of $2.0 million, or a decrease of 0.2% annually, respectively. In its order, the Washington Commission approved a weighted cost of capital of 7.77% and a capital structure that included 48.0% common equity with a ROE of 9.8%. Subsequently, certain parties to this proceeding petitioned the Washington Commission to reconsider the order. On December 13, 2013, the Washington Commission approved the settlement agreements for rates effective January 1, 2014. These settlement agreements do not materially change the revenues originally approved in June 2013.

On February 4, 2013, PSE filed revised tariffs in an ERF proceeding seeking to update the rates set by the Washington Commission in the final order of May 2012 in PSE's general rate case (GRC). This ERF filing was limited in scope and rate impact. This filing was primarily intended to establish baseline rates on which the decoupling mechanisms, described below, were proposed to operate. The filing also provided for the collection of property taxes through a property tax tracker mechanism based on cash payments of property tax made by PSE during the year. Any difference between the cash payments and property tax accruals will be deferred and recovered in a property tax tracker.

Decoupling Filings

While fluctuations in weather conditions will continue to affect PSE's billed revenue and energy supply expenses from month to month, PSE's decoupling mechanisms, are expected to mitigate the impact of weather on operating revenue and net income. The Washington Commission has allowed PSE to record a monthly adjustment to its electric and natural gas operating revenues related to electric transmission and distribution, natural gas operations and general administrative costs from residential, commercial and industrial customers to eliminate the effects of abnormal weather, conservation impacts and changes in usage patterns per customer with the exception of the electric business where PCA is not part of the decoupling mechanism. As a result, these electric and natural gas revenues will be recovered on a per customer basis regardless of actual consumption levels. The energy supply costs, which are part of the PCA and PGA mechanisms, are not included in the decoupling mechanism. The revenue recorded under the decoupling mechanisms will be affected by customer growth and not actual consumption. Following each calendar year, PSE will recover or refund the difference between allowed decoupling revenue and the corresponding actual revenue to affected customers during the following May to April time period. The decoupling mechanism will end on February 28, 2017 unless the continuation of the mechanism is approved in PSE’s next GRC filing which PSE is required to file by April 1, 2016 at the latest.

On April 22, 2015, the Washington Commission approved PSE's request to change rates under its electric and natural gas decoupling mechanism, effective May 1, 2015. As part of this filing, PSE also requested to change the methodology of how decoupling deferrals are calculated going forward and adjust deferrals calculated in 2014. The change was done to ensure that the amortization of prior years’ accumulated decoupling deferrals were not included in the calculation of the current year decoupling deferrals. The effect of the methodology change was a reduction of approximately $12.0 million previously recognized revenue from May through December of 2014. The overall changes represent a rate increase for electric customers of $53.8 million, or 2.6%, annually, and a rate increase for natural gas customers of $22.0 million, or 2.1%, annually, effective May 1, 2015. In addition, PSE exceeded the earnings test threshold for its natural gas business in 2014. As a result, PSE recorded a reduction in natural gas decoupling deferral and revenue of $1.3 million. This was reflected as a reduction to the natural gas rate increases noted above. As noted earlier, the Company is also limited to a 3.0% annual decoupling related cap on increases in total revenue. This limitation was triggered for certain rate classes. The resulting amount of deferral that was not included in the 2015 rate increase is $1.9 million for electric revenue and $8.2 million for natural gas revenue that was accrued through December 31, 2014. These amounts may be included in customer rates beginning in May 2016, subject to subsequent application of the earnings test and the 3.0% cap on decoupling related rate increases.

On April 24, 2014, the Washington Commission approved PSE's request to change rates under its electric and natural gas decoupling mechanism, effective May 1, 2014. The rate change incorporated the effects of an increase to the allowed delivery revenue per customer as well as true-ups to the rate from the prior year. This represents a rate increase for electric customers of $10.6 million, or 0.5% annually, and a rate decrease for natural gas customers of $1.0 million, or 0.1% annually.

On December 13, 2013, the Washington Commission approved a series of settlement agreements for rates effective January 1, 2014. These settlement agreements do not materially change the revenues originally approved in June 2013. As a result, certain high volume natural gas industrial customers rate schedules are excluded from the decoupling mechanism and will be subject to certain effects of abnormal weather, conservation impacts and changes in customer usage patterns.

Electric Regulation and Rates

Storm Damage Deferral Accounting

The Washington Commission issued a GRC order that defined deferrable catastrophic/extraordinary losses and provided that costs in excess of $8.0 million annually may be deferred for qualifying storm damage costs that meet the modified IEEE outage criteria for system average interruption duration index. In 2015 and 2014, PSE incurred $33.6 million and $29.7 million, respectively, in storm-related electric transmission and distribution system restoration costs, of which $22.4 million was deferred in 2015 and $18.0 million was deferred in 2014.

Power Cost Only Rate Case

A limited-scope proceeding was approved in 2002 by the Washington Commission to periodically reset power cost rates. In addition to providing the opportunity to reset all power costs, the power cost only rate case (PCORC) proceeding also provides for timely review of new resource acquisition costs and inclusion of such costs in rates at the time the new resource goes into service. To achieve this objective, the Washington Commission has used an expedited six-month PCORC decision timeline rather than the statutory 11-month timeline for a GRC.

The following table sets forth PCORC rate adjustments approved by the Washington Commission and the corresponding impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
December 1, 2014	(0.9)%	$ (19.4)

Electric Property Tax Tracker Mechanism

The purpose of the property tax tracker mechanism is to pass through the cost of all property taxes incurred by the Company. The mechanism was implemented in 2013 and removed property taxes from general rates and included those costs as a component rate. After the implementation, the mechanism acts as a tracker rate schedule and collects the total amount of property taxes assessed. The tracker will be adjusted each year in May based on that year's assessed property taxes and true-ups to the rate from the prior year.

The following table sets forth property tax tracker mechanism rate adjustments approved by the Washington Commission and the corresponding impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
May 1, 2015	0.4%$	8.4
May 1, 2014	0.5	11.0

Electric Conservation Rider

The electric conservation rider collects revenue to cover the costs incurred in providing services and programs for conservation. Rates change annually on May 1 to collect the annual budget that started the prior January.

The following table sets forth conservation rider rate adjustments approved by the Washington Commission and the corresponding impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
May 1, 2014	0.6%$	12.2

Accounting Orders and Petitions

PSE completed the sale of its electric infrastructure assets located in Jefferson County and the transition of electrical services in the county to Jefferson County Public Utility District (JPUD) on March 31, 2013. The proceeds from the sale exceeded the transferred assets' net carrying value of $46.7 million resulting in a pre-tax gain of approximately $60.0 million. In accordance with a 2010 Washington Commission order, PSE deferred the gain and recorded it as a regulatory liability pending the Washington Commission's determination of the accounting and ratemaking treatment. On October 31, 2013, PSE filed an accounting petition for a Washington Commission order that would authorize PSE to retain the gain of $45.0 million and return $15.0 million to its remaining customers over a period of 48 months. On March 28, 2014, intervenors filed response testimonies containing their respective proposals for allocation of the gain, which included a proposal of up to $57.0 million to customers and $3.0 million to PSE. A final order was rendered on September 11, 2014 which authorized PSE to retain $7.5 million of the gain and return $52.7 million to customers. The customer portion was booked to a regulatory liability account in other current liabilities and accrued interest at PSE's after-tax rate of return. PSE paid this amount to customers through a bill credit in the month of December 2014.

Power Cost Adjustment Mechanism

PSE currently has a PCA mechanism that provides for the recovery of power costs from customers or refunding of power cost savings to customers in the event those costs vary from the “power cost baseline” included in revenue requirements. The “power cost baseline” levels are set, in part, based on normalized assumptions about weather and hydroelectric conditions. Excess power costs or power cost savings are apportioned between PSE and its customers pursuant to the graduated scale set forth in the PCA mechanism.

The graduated scale currently applicable is as follows:

Annual Power Cost Variability	Company’s Share	Customers' Share
+/- $20 million	100%	—%
+/- $20 million - $40 million	50	50
+/- $40 million - $120 million	10	90
+/- $120 + million	5	95

On August 7, 2015 the Washington Commission issued an order approving the settlement proposing changes to the PCA mechanism. The settlement agreement will not take effect until January 1, 2017. Key components of the settlement will result in the following changes to the PCA mechanism:

	Company's Share		Customers' Share	
Annual Power Cost Variability	Over	Under	Over	Under
+/- $17 million	100 %	100 %	— %	— %
+/- $17 million - $40 million	35	50	65	50
+/- $40+ million	10	10	90	90

- Reduction to the cumulative deferral trigger for surcharge or refund from $30.0 million to $20.0 million;
- Removal of fixed production costs from the PCA mechanism and placing them in the decoupling mechanism, assuming the decoupling mechanism continues as part of the next GRC. If decoupling was not to continue, those fixed production costs would be treated the same as other non-PCA costs unless permission to treat them in another manner is obtained from the Washington Commission. These fixed production costs include: (i) return and depreciation/amortization on fixed production assets and regulatory assets and liabilities; (ii) return on depreciation, transmission expense and revenues on specific transmission assets; and (iii) hydro, other production and other power related expenses and O&M costs;
- Suspension of the requirement that a GRC must be filed within three months after rates are approved in a PCORC, and agreeing, for a five-year period, that PSE will not file a GRC or PCORC within six months of the date rates go into effect for a PCORC filing; and
- Establishment of a five-year moratorium on changes to the PCA/PCORC.

PSE had an unfavorable PCA imbalance during the year ended December 31, 2015, due to under recovering $8.7 million of power costs that exceeded the "power cost baseline" level of which no amounts were apportioned to customers. This compares to an unfavorable imbalance of $40.1 million for the year ended December 31, 2014 of which $10.1 million was apportioned to customers.

Federal Incentive Tracker Tariff

The Federal Incentive tracker tariff passes the benefits associated with treasury grants received by the company and PTCs available through to its customers. The filing results in a credit back to customers for pass-back of treasury grant amortization and pass-through of interest and any related true-ups. The filing is adjusted annually for new Federal benefits, actual versus forecast interest and to true-up for actual load being different than the forecasted load set in rates.

The following table sets forth Federal Incentive Tracker Tariff rate adjustments approved by the Washington Commission and the corresponding impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Total credit to be passed back to eligible customers (Dollars in Millions)
January 1, 2016	(0.2)%	$ (57.3)
January 1, 2015	(0.2)	(55.2)
January 1, 2014	(0.3)	(58.5)

Environmental Remediation

The Company is subject to environmental laws and regulations by the federal, state and local authorities and is required to undertake certain environmental investigative and remedial efforts as a result of these laws and regulations. The Company has been named by the environmental protection agency (EPA), the Washington State Department of Ecology and/or other third parties as potentially responsible at several contaminated sites and manufactured gas plant sites. PSE has implemented an ongoing program to test, replace and remediate certain underground storage tanks (UST) as required by federal and state laws. The UST replacement component of this effort is finished, but PSE continues its work remediating and/or monitoring relevant sites. During 1992, the Washington Commission issued orders regarding the treatment of costs incurred by the Company for certain sites under its environmental remediation program. The orders authorize the Company to accumulate and defer prudently incurred cleanup costs paid to third parties for recovery in rates established in future rate proceedings, subject to Washington Commission review. The Washington Commission consolidated the gas and electric methodological approaches to remediation and deferred accounting in an order issued October 8, 2008. Per the guidance of ASC 450, "Contingencies," the Company reviews its estimated future obligations and will record adjustments, if any, on a quarterly basis. Management believes it is probable and reasonably estimable that the impact of the potential outcomes of disputes with certain property owners and other potentially responsible parties will result in environmental remediation costs of $32.6 million for gas and $6.1 million for electric. The Company believes a significant portion of its past and future environmental remediation costs are recoverable from insurance companies, from third parties or from customers under a Washington Commission order. The Company is also subject to cost-sharing agreements with third parties regarding environmental remediation projects in Seattle, Washington and Bellingham, Washington. The Company has taken the lead for both projects, and as of December 31, 2015, the Company's share of future remediation costs is estimated to be approximately $23.9 million. The Company's deferred electric environmental costs are $14.0 million and $13.4 million at December 31, 2015 and 2014, respectively, net of insurance proceeds. The Company's deferred natural gas environmental costs are $52.9 million and $52.6 million at December 31, 2015 and 2014, respectively, net of insurance proceeds.

Asset Retirement Obligation

The Company has recorded liabilities for steam generation sites, combustion turbine generation sites, combined cycle generation sites, wind generation sites, distribution and transmission poles, gas mains, and leased facilities where disposal is governed by ASC 410 "ARO".

On April 17, 2015, the U.S. EPA published a final rule, effective October 19, 2015, that regulates Coal Combustion Residuals (CCR) under the Resource Conservation and Recovery Act, Subtitle D. The CCR rule addresses the risks from coal ash disposal, such as leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments by establishing technical requirements for CCR landfills and surface impoundments. The rule also sets out recordkeeping and reporting requirements including requirements to post specific information to a publicly-accessible website.

The CCR rule requires significant changes to the Company's Colstrip, Montana coal-fired steam electric generation facility(Colstrip) operations and those changes were reviewed by the Company and the plant operator in the second and third quarter of 2015. PSE had previously recognized a legal obligation under the EPA rules to dispose of coal ash material at Colstrip, in 2003. Due to the CCR rule, additional disposal costs were added to the ARO.

The actual ARO costs related to the CCR rule requirements may vary substantially from the estimates used to record the increased obligation due to uncertainty about the compliance strategies that will be used and the preliminary nature of available data used to estimate costs. We will continue to gather additional data and coordinate with the plant operator to make decisions about compliance strategies and the timing of closure activities. As additional information becomes available, the Company will update the ARO obligation for these changes, which could be material.

The following table describes the changes to the Company's ARO liability as of December 31, 2015 and 2014:

(Dollars in Thousands)	At December 31, 2015	At December 31, 2014
Asset retirement obligation at beginning of period	$ 48,909	$ 48,687
New asset retirement obligation recognized in the period	34,534	—
Liability adjustment in the period	(3,628)	(602)
Revisions in estimated cash flows	3,403	(480)
Accretion expense	1,810	1,304
Asset retirement obligation at end of period	$ 85,028	$ 48,909

Colstrip

PSE has a 50% ownership interest in Colstrip Units 1 and 2, and a 25% interest in Colstrip Units 3 and 4. On March 6, 2013, the Sierra Club and the Montana Environmental Information Center filed a Clean Air Act citizen suit against all Colstrip owners in the U.S. District Court, District of Montana. Based on a second amended complaint filed in August 2014, plaintiffs' lawsuit currently alleges violations of permitting requirements under the New Source Review program of the Clean Air Act and the Montana State Implementation Plan arising from seven projects undertaken at Colstrip during the time period from 2001 to 2012. Plaintiffs have since indicated that they do not intend to pursue claims with respect to three of the seven projects, leaving a total of four projects remaining subject to the lawsuit. The lawsuit claims that, for each of the four projects, the Colstrip plant should have obtained a permit and installed pollution control equipment at Colstrip. The Plaintiffs' complaint also seeks civil penalties and other appropriate relief. The case has been bifurcated into separate liability and remedy trials. The liability trial is currently set for May 2016, and a date for the remedy trial has yet to be determined. PSE is litigating the allegations set forth in the complaint, and as such, it is not reasonably possible to estimate the outcome of this matter.

Other Proceedings

The Company is also involved in litigation relating to claims arising out of its operations in the normal course of business. The Company has recorded reserves of $0.3 million and $1.7 million relating to these claims as of December 31, 2015 and 2014, respectively.

10. Kimberly Harris, the President and Chief Executive Officer, and a director of Puget Energy and PSE, is married to Kyle Branum, a principal at the law firm Riddell Williams P.S., one of PSE's primary law firms for nearly 50 years. In 2015 and 2014, Riddell Williams was paid $1.81 million and $1.98 million, respectively, for legal services provided to PSE and Mr. Branum is among the lawyers at Riddell Williams who provided such legal services. This work was performed under the supervision of PSE's General Counsel.

On October 10, 2014, U.S. Bancorp announced the appointment of Kimberly Harris to its board of directors effective

October 20, 2014. Ms. Harris is the president and chief executive officer of both Puget Energy and PSE. U.S. Bancorp is the parent company of U.S. Bank N.A., which directly or through its subsidiaries or affiliates provides credit, banking, investment and trust services to both Puget Energy and PSE. For the year ended December 31, 2015 and 2014, Puget Energy and PSE paid a total of approximately $1.0 million in fees and interest each year to U.S. Bank N.A. and its subsidiaries or affiliates.

Scott Armstrong serves on the Board of Directors of the Company, and is the president and Chief Executive Officer of Group Health Cooperative (Group Health). Group Health provides coverage to over 600,000 residents in Washington and Northern Idaho. Certain employees of PSE elect Group Health as their medical provider and as a result, PSE paid Group Health a total of $20.3 million and $17.7 million for medical coverage for the year ended December 31, 2015 and 2014, respectively.

11. (Reserved)

12. None

13. In January 2015 Paul Wiegand, Senior Vice President of Energy Operations retired from his position. His responsibilities were assumed by the Vice President of Energy Supply Operations.

    On January 22, 2015, William S. Ayer retired from his position as Chairman of the Board of Directors of Puget Sound Energy, Inc. Effective January 22, 2015, the Board of Directors appointed Melanie J. Dressel as Chairman of the Board of Directors to replace Mr. Ayer. Also effective January 22, 2015, the sole shareholder of each of the Companies appointed and elected Steven W. Hooper to the Boards of Directors of Puget Sound Energy, Inc. Mr. Hooper will serve on the Audit Committee of Puget Sound Energy.

    On March 25, 2015 Booga Gibertson was named Senior Vice President of Operations. Previously she served as Vice President of Operations since 2011.

    On April 23, 2015, the Company appointed and elected Paul McMillan to the Board of Directors. Mr McMillan was appointed to replace Benjamin Hawkins, who resigned from the Board of Directors effective the same day. Mr. McMillan will serve on the Audit Committee and the Governance and Public Affairs Committee.

    On June 24, 2015, Herb B. Simon provided notice of his intent to resign from his position as a member of the Board of Directors and all of its committees to be effective as of January 21, 2016. Effective June 25, 2015 the Board of Directors appointed Scott Armstrong to the Board of Directors.

    On August 20, 2015, Drew Murphy tendered his resignation from the Board of Directors of Puget Energy, Inc. and Puget Sound Energy, Inc. with such resignation effective on August 31, 2015.

14. None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	13,279,421,639	12,970,138,750
3	Construction Work in Progress (107)	200-201	408,795,066	253,524,842
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		13,688,216,705	13,223,663,592
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	5,029,301,219	4,762,767,983
6	Net Utility Plant (Enter Total of line 4 less 5)		8,658,915,486	8,460,895,609
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)		8,658,915,486	8,460,895,609
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		8,654,564	8,654,564
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		3,759,918	5,141,276
19	(Less) Accum. Prov. for Depr. and Amort. (122)		-398,836	397,105
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	29,897,629	29,865,413
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)		50,595,598	53,230,149
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		20,161,963	20,163,074
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		5,225,474	3,170,484
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		110,039,418	111,173,291
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		39,443,112	31,703,689
36	Special Deposits (132-134)		3,659,936	32,775,117
37	Working Fund (135)		4,207,857	3,826,953
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		3,312,955	835,576
40	Customer Accounts Receivable (142)		247,661,911	191,448,383
41	Other Accounts Receivable (143)		70,009,510	85,075,078
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		9,755,943	7,471,996
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		459,716	440,712
45	Fuel Stock (151)	227	18,852,704	19,977,277
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	74,041,849	78,056,744
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	289,557	34,476
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	4,083	34,267

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	4,198,466	5,098,269
55	Gas Stored Underground - Current (164.1)		38,129,091	46,008,944
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		52,337	635,209
57	Prepayments (165)		26,475,197	25,570,607
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		217,273,664	168,038,918
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		29,643,789	24,348,745
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		5,225,474	3,170,484
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)		762,734,317	703,266,484
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		30,022,060	28,687,998
70	Extraordinary Property Losses (182.1)	230a	125,776,619	118,823,668
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	10,358,135	15,534,174
72	Other Regulatory Assets (182.3)	232	603,400,255	608,272,969
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	200,491
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	19,301
78	Miscellaneous Deferred Debits (186)	233	244,826,311	247,074,196
79	Def. Losses from Disposition of Utility Plt. (187)		543,918	514,431
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		44,984,231	35,667,413
82	Accumulated Deferred Income Taxes (190)	234	609,193,138	654,528,779
83	Unrecovered Purchased Gas Costs (191)		-12,589,440	21,073,055
84	Total Deferred Debits (lines 69 through 83)		1,656,515,227	1,730,396,475
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		11,196,859,012	11,014,386,423

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	end of 2015/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	859,038	859,038
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)		478,145,250	478,145,250
7	Other Paid-In Capital (208-211)	253	2,804,096,691	2,775,196,691
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	7,133,879	7,133,879
11	Retained Earnings (215, 215.1, 216)	118-119	251,173,234	217,249,893
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-14,599,821	-14,632,037
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)	-149,548,979	-170,956,349
16	Total Proprietary Capital (lines 2 through 15)		3,362,991,534	3,278,728,607
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	3,773,860,000	3,760,860,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,887,064	13,140
24	Total Long-Term Debt (lines 18 through 23)		3,771,972,936	3,760,846,860
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	1,894,521
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		175,000	1,080,000
29	Accumulated Provision for Pensions and Benefits (228.3)		105,662,084	130,222,246
30	Accumulated Miscellaneous Operating Provisions (228.4)		302,749,690	331,913,968
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		47,775,658	60,062,562
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		85,027,508	48,909,172
35	Total Other Noncurrent Liabilities (lines 26 through 34)		541,389,940	574,082,469
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		159,004,000	85,000,000
38	Accounts Payable (232)		284,129,757	309,921,826
39	Notes Payable to Associated Companies (233)		0	28,932,785
40	Accounts Payable to Associated Companies (234)		0	0
41	Customer Deposits (235)		30,018,551	24,677,803
42	Taxes Accrued (236)	262-263	114,561,816	107,481,198
43	Interest Accrued (237)		47,771,880	55,345,644
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
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	end of 2015/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		876,546	1,602,518
48	Miscellaneous Current and Accrued Liabilities (242)		20,571,461	19,310,895
49	Obligations Under Capital Leases-Current (243)		378,231	7,578,088
50	Derivative Instrument Liabilities (244)		179,195,973	194,980,461
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		47,775,658	60,062,562
52	Derivative Instrument Liabilities - Hedges (245)		0	1,055,163
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		788,732,557	775,823,819
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		70,204,450	59,178,236
57	Accumulated Deferred Investment Tax Credits (255)	266-267	0	0
58	Deferred Gains from Disposition of Utility Plant (256)		3,420,722	863,174
59	Other Deferred Credits (253)	269	352,032,418	330,906,907
60	Other Regulatory Liabilities (254)	278	138,764,099	136,458,810
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		1,797,521,701	1,729,060,789
64	Accum. Deferred Income Taxes-Other (283)		369,828,655	368,436,752
65	Total Deferred Credits (lines 56 through 64)		2,731,772,045	2,624,904,668
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		11,196,859,012	11,014,386,423

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	3,252,632,659	3,197,806,242		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,665,658,565	1,661,204,032		
5	Maintenance Expenses (402)	320-323	162,856,032	165,811,329		
6	Depreciation Expense (403)	336-337	376,896,678	369,492,120		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	1,379,595	1,468,524		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	40,306,567	42,340,247		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	13,877,143	13,859,026		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		20,604,866	17,495,991		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		45,864,474	50,352,083		
13	(Less) Regulatory Credits (407.4)		49,385,761	94,502,619		
14	Taxes Other Than Income Taxes (408.1)	262-263	319,938,386	310,321,156		
15	Income Taxes - Federal (409.1)	262-263				
16	- Other (409.1)	262-263	800			
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	760,663,099	2,294,996,459		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	549,912,827	2,118,990,660		
19	Investment Tax Credit Adj. - Net (411.4)	266		-2		
20	(Less) Gains from Disp. of Utility Plant (411.6)		694,857	694,857		
21	Losses from Disp. of Utility Plant (411.7)		149,128	149,128		
22	(Less) Gains from Disposition of Allowances (411.8)		37,355	47,072		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		1,798,351	1,303,578		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,809,962,884	2,714,558,463		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		442,669,775	483,247,779		

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 09/27/2016	Year/Period of Report End of 2015/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
2,305,084,095	2,184,947,113	947,548,564	1,012,859,129			2
						3
1,136,679,314	1,067,747,139	528,979,251	593,456,893			4
143,572,687	145,988,003	19,283,345	19,823,326			5
260,052,552	257,633,788	116,844,126	111,858,332			6
1,170,837	992,961	208,758	475,563			7
29,162,204	30,391,040	11,144,363	11,949,207			8
13,877,143	13,859,026					9
20,604,866	17,495,991					10
						11
45,864,474	50,352,083					12
49,385,761	94,502,619					13
220,337,559	207,444,301	99,600,827	102,876,855			14
						15
800						16
503,244,595	1,632,233,298	257,418,504	662,763,161			17
352,492,346	1,517,738,350	197,420,481	601,252,310			18
			-2			19
633,008	633,008	61,849	61,849			20
132,649	132,649	16,479	16,479			21
37,355	47,072					22
						23
1,771,606	1,262,992	26,745	40,586			24
1,973,922,816	1,812,612,222	836,040,068	901,946,241			25
331,161,279	372,334,891	111,508,496	110,912,888			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		442,669,775	483,247,779		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		823,911	1,143,766		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		781,117	1,074,754		
33	Revenues From Nonutility Operations (417)		15,197,033	13,964,522		
34	(Less) Expenses of Nonutility Operations (417.1)		18,427,951	16,633,573		
35	Nonoperating Rental Income (418)					
36	Equity in Earnings of Subsidiary Companies (418.1)	119	32,216	1,899,754		
37	Interest and Dividend Income (419)		7,054,660	5,619,834		
38	Allowance for Other Funds Used During Construction (419.1)		9,325,338	7,002,239		
39	Miscellaneous Nonoperating Income (421)		19,741,745	-16,771,841		
40	Gain on Disposition of Property (421.1)		143,184	7,483,196		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		33,109,019	2,633,143		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		13,316			
44	Miscellaneous Amortization (425)		795	795		
45	Donations (426.1)		31,693	32,754		
46	Life Insurance (426.2)		-2,991,858	-2,942,394		
47	Penalties (426.3)		551,938	335,499		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		5,314,770	5,650,148		
49	Other Deductions (426.5)		13,205,298	74,267,981		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		16,125,952	77,344,783		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	336,682	294,473		
53	Income Taxes-Federal (409.2)	262-263				
54	Income Taxes-Other (409.2)	262-263				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-84,869,098	-87,659,631		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277		27,835		
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)		-84,532,416	-87,392,993		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		101,515,483	12,681,353		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		221,899,412	225,414,534		
63	Amort. of Debt Disc. and Expense (428)		3,034,485	3,165,817		
64	Amortization of Loss on Reaquired Debt (428.1)		2,619,485	2,379,511		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		63,749	181,681		
68	Other Interest Expense (431)		19,954,215	33,784,752		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		7,574,924	5,611,082		
70	Net Interest Charges (Total of lines 62 thru 69)		239,996,422	259,315,213		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		304,188,836	236,613,919		
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)		304,188,836	236,613,919		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		205,361,316	286,201,805
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10			-2,159,482	(630,610)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-2,159,482	(630,610)
16	Balance Transferred from Income (Account 433 less Account 418.1)		304,156,620	234,714,165
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Dividends Declared		-270,233,279	(323,424,044)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-270,233,279	(323,424,044)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			8,500,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		237,125,175	205,361,316
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		14,048,059	11,888,577
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		14,048,059	11,888,577
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		251,173,234	217,249,893
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-14,632,036	(8,031,790)
50	Equity in Earnings for Year (Credit) (Account 418.1)		32,215	1,899,754
51	(Less) Dividends Received (Debit)			8,500,000
52				
53	Balance-End of Year (Total lines 49 thru 52)		-14,599,821	(14,632,036)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	304,188,836	236,613,919
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	416,279,704	372,079,968
5	Amortization of		
6	Utility Plant	13,877,143	13,859,026
7	Property Losses	20,604,886	17,495,991
8	Deferred Income Taxes (Net)	125,881,178	88,318,333
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	-90,575,841	166,236,690
11	Net (Increase) Decrease in Inventory	14,277,099	2,209,066
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-21,731,592	-5,074,458
14	Net (Increase) Decrease in Other Regulatory Assets	-160,379,348	-247,794,087
15	Net Increase (Decrease) in Other Regulatory Liabilities	58,827,352	18,363,850
16	(Less) Allowance for Other Funds Used During Construction	9,325,338	7,002,239
17	(Less) Undistributed Earnings from Subsidiary Companies	32,216	1,899,762
18	Other (provide details in footnote):	63,137,221	237,823,571
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	735,029,084	891,229,868
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-593,270,915	-605,792,026
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	-9,325,338	-7,002,239
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-583,945,577	-598,789,787
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	8,966,724	9,706,447
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		8,500,000
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
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	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):	-2,581,566	106,192,530
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-577,560,419	-474,390,810
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	425,000,000	
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):	33,698,545	4,050,556
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	458,698,545	4,050,556
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-412,000,000	
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)	45,071,215	-77,665,000
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-270,233,279	-323,424,044
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-178,463,519	-397,038,488
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-20,994,854	19,800,570
87			
88	Cash and Cash Equivalents at Beginning of Period	68,305,759	48,505,189
89			
90	Cash and Cash Equivalents at End of period	47,310,905	68,305,759

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

Other components of operating cash flows	**2015**	**2014**
Other Long-Term Assets	$ 6,627,424	$ (76,572,486)
Other Long-Term Liabilities	(22,763,090)	143,094,493
Conservation Amortization	110,865,928	104,095,540
Pension Funding	(18,000,000)	(18,000,000)
Net Unrealized (Gain) Loss on Derivative Transactions	(12,688,453)	85,636,443
Prepayments and Other	(904,588)	(430,419)
	$ 63,137,221	$ 237,823,571

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

Other components of investing cash flows	**2015**	**2014**
Treasury Grant	$ -	$ 107,875,804
Asset Retirement Salvage Value/Life insurance premiums	(2,581,566)	(1,683,274)
	$ (2,581,566)	$ 106,192,530

Schedule Page: 120 Line No.: 67 Column: b

Other components of financing cash flows	**2015**	**2014**
Debt Issuance Costs	$ (6,474,619)	$ (861,734)
Refundable cash received for customer construction projects	20,367,542	12,490,378
Landis Gyr Capital Lease	(9,094,378)	(7,578,088)
Investment from Puget Energy	28,900,000	-
	$ 33,698,545	$ 4,050,556

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Basis of Presentation

These financial statements were 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 generally accepted accounting principles. As a result, the presentation of these financial statements differs from generally accepted accounting principles. Certain disclosures which are required by generally accepted accounting principles and not required by FERC have been excluded from these financial statements.

As required by FERC, Puget Sound Energy, Inc. (PSE) classifies certain items in its Form 1 Balance Sheet (primarily the classification of the components of accumulated deferred income taxes, non-legal asset retirement obligations, certain miscellaneous current and accrued liabilities, maturities of long-term debt, deferred debits and deferred credits) in a manner different than that required by generally accepted accounting principles.

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those estimates.

PSE is a public utility incorporated in the State of Washington that furnishes electric and natural gas services in a territory covering 6,000 square miles, primarily in the Puget Sound region. The results of PSE's subsidiaries are presented on an equity basis.

PSE collected Washington State excise taxes (which are a component of general retail customer rates) and municipal taxes totaling $234.2 million and $231.7 million for 2015 and 2014, respectively. PSE reports the collection of such taxes on a gross basis in operation revenue and as expense in taxes other than income taxes in the accompanying consolidated statements of income.

Utility Plant

PSE capitalizes, at original cost, additions to utility plant, including renewals and betterments. Costs include indirect costs such as engineering, supervision, certain taxes, pension and other employee benefits and an Allowance for Funds Used During Construction (AFUDC). Replacements of minor items of property are included in maintenance expense. When the utility plant is retired and removed from service, the original cost of the property is charged to accumulated depreciation and costs associated with removal of the property, less salvage, are charged to the cost of removal regulatory liability.

Planned Major Maintenance

Planned major maintenance is an activity that typically occurs when PSE overhauls or substantially upgrades various systems and equipment on its natural gas fired combustion turbines on a scheduled basis. Costs related to planned major maintenance are deferred and amortized to the next scheduled major maintenance. This accounting method also follows the Washington Utilities and Transportation Commission (Washington Commission) regulatory treatment related to these generating facilities.

Non-Utility Property, Plant and Equipment

For PSE, the costs of other property, plant and equipment are stated at historical cost. Expenditures for refurbishment and improvements that significantly add to productive capacity or extend useful life of an asset are capitalized. Replacement of minor items are expensed on a current basis. Gains and losses on assets sold or retired, which were previously recorded in utility plant, are apportioned between regulatory assets/liabilities and earnings. However, gains and losses on assets sold or retired, not previously recorded in utility plant, are reflected in earnings.

Depreciation and Amortization

For financial statement purposes, the Company provides for depreciation and amortization on a straight-line basis. Amortization is recorded for intangibles such as regulatory assets and liabilities, computer software and franchises. The depreciation of vehicles and equipment is allocated to the asset and expense accounts based on usage. The annual depreciation provision stated as a percent of a depreciable electric utility plant was 2.8%, for each of 2015 and 2014; depreciable natural gas utility plant was 3.4%, for each of 2015 and 2014; and depreciable common utility plant was 8.5%, for each of 2015 and 2014, respectively. Depreciation on other property, plant and equipment is calculated primarily on a straight-line basis over the useful lives of the assets. The cost of removal is collected from PSE's customers through depreciation expense and any excess is recorded as a regulatory liability.

Cash and Cash Equivalents

Cash and cash equivalents consist of demand bank deposits and short-term highly liquid investments with original maturities of three months or less at the time of purchase. The cash and cash equivalents balance at PSE was $39.5 million and $35.5 million as of December 31, 2015 and 2014, respectively. The 2015 and 2014 balance did not consist of cash equivalents.

Materials and Supplies

Materials and supplies are used primarily in the operation and maintenance of electric and natural gas distribution and transmission systems as well as spare parts for combustion turbines used for the generation of electricity. PSE records these items at weighted-average cost.

Fuel and Natural Gas Inventory

Fuel and natural gas inventory is used in the generation of electricity and for future sales to the Company's natural gas customers. Fuel inventory consists of coal, diesel and natural gas used for generation. Natural gas inventory consists of natural gas and liquefied natural gas (LNG) held in storage for future sales. PSE records these items at the lower of cost or market value using the weighted-average cost method.

Regulatory Assets and Liabilities

PSE accounts for its regulated operations in accordance with ASC 980 "Regulated Operations" (ASC 980). ASC 980 requires PSE to defer certain costs that would otherwise be charged to expense, if it is probable that future rates will permit recovery of such costs. It similarly requires deferral of revenues or gains and losses that are expected to be returned to customers in the future. Accounting under ASC 980 is appropriate as long as rates are established by or subject to approval by independent third-party regulators; rates are designed to recover the specific enterprise's cost of service; and in view of demand for service, it is reasonable to assume that rates set at levels that will recover costs can be charged to and collected from customers. In most cases, PSE classifies regulatory assets and liabilities as long-term due to the length of the amortization. For further details regarding regulatory assets and liabilities, see Note 3.

Allowance for Funds Used During Construction

AFUDC represents the cost of both the debt and equity funds used to finance utility plant additions during the construction period. The amount of AFUDC recorded in each accounting period varies depending primarily upon the level of construction work in progress and the AFUDC rate used. AFUDC is capitalized as a part of the cost of utility plant and is credited to interest expense and as a non-cash item to other income. Cash inflow related to AFUDC does not occur until these charges are reflected in rates.

The AFUDC rates authorized by the Washington Commission for natural gas and electric utility plant additions are based on the effective dates as follows:

Effective Date	Washington Commission AFUDC Rates
July 1, 2013 - present	7.77%

The Washington Commission authorized the Company to calculate AFUDC using its allowed rate of return. To the extent amounts calculated using this rate exceed the AFUDC calculated rate using the FERC formula, PSE capitalizes the excess as a deferred asset, crediting other income. The deferred asset is being amortized over the average useful life of PSE's non-project electric utility plant which is approximately 30 years.

Revenue Recognition

Operating utility revenue is recognized when the basis of services is rendered, which includes estimated unbilled revenue, in accordance with ASC 605, "Revenue Recognition" (ASC 605). PSE's estimate of unbilled revenue is based on a calculation using meter readings from its automated meter reading (AMR) system. The estimate calculates unbilled usage at the end of each month as the difference between the customer meter readings on the last day of the month and the last customer meter readings billed. The unbilled usage is then priced at published rates for each schedule to estimate the unbilled revenues by customer.

The non-utility subsidiary recognizes revenue when services are performed or upon the sale of assets. Revenue from retail sales is billed based on tariff rates approved by the Washington Commission. Sales of Renewable Energy Credits (RECs) are deferred as a regulatory liability.

PSE's electric and natural gas operations contain a revenue decoupling mechanism under which PSE's actual energy delivery revenues related to electric transmission and distribution, natural gas operations and general administrative costs are compared with authorized revenues allowed under the mechanism. The mechanism mitigates volatility in revenue due to weather and gross margin erosion related to energy efficiency. Any differences in revenue are deferred to a regulatory asset for under recovery or regulatory liability for over recovery under alternative revenue recognition standard. To record revenues under this program, the Company must be able to collect the revenue within 24 months based on alternative revenue recognition guidance. Decoupled rate increases are effective May 1 of each year subject to a 3.0% cap of total revenue for decoupled rate schedules. Any excess revenue above 3.0% will be included in the following year's decoupled rate. The Company will be able to recognize revenue below the 3.0% cap of total revenue for decoupled rate schedules. For revenue deferrals exceeding the annual 3.0% rate cap of total revenue for decoupled rate schedules, the Company will assess the excess amount to determine its ability to be collected within 24 months. If the excess amount cannot be collected within 24 months, for GAAP purposes only, the Company will not record any decoupling revenue unless it is within the 24 months of collection, but will collect non-recorded amounts when actually billed. Revenues associated with energy costs under the Power Cost Adjustment (PCA) mechanism and Purchased Gas Adjustment (PGA) mechanism are excluded from the decoupling mechanism.

Allowance for Doubtful Accounts

Allowance for doubtful accounts are provided for electric and natural gas customer accounts based upon a historical experience rate of write-offs of energy accounts receivable along with information on future economic outlook. The allowance account is adjusted monthly for this experience rate. The allowance account is maintained until either receipt of payment or the likelihood of collection is considered remote at which time the allowance account and corresponding receivable balance are written off.

The Company's allowance for doubtful accounts at December 31, 2015 and 2014 was $9.8 million and $7.5 million, respectively.

Self-Insurance

PSE is self-insured for storm damage and environmental contamination occurring on PSE-owned property. In addition, PSE is required to meet a deductible for a portion of the risk associated with comprehensive liability, workers' compensation claims and catastrophic property losses other than those which are storm related. The Washington Commission has approved the deferral of certain uninsured qualifying storm damage costs that exceed $8.0 million which will be requested for collection in future rates. Additionally, costs may only be deferred if the outage meets the Institute of Electrical and Electronics Engineers (IEEE) outage criteria for system average interruption duration index.

Federal Income Taxes

For presentation in PSE's separate financial statements, income taxes are allocated to the subsidiaries on the basis of separate company computations of tax, modified by allocating certain consolidated group limitations which are attributed to the separate company. Taxes payable or receivable are settled with Puget Holdings, who is the ultimate tax payer.

Natural Gas Off-System Sales and Capacity Release

PSE contracts for firm natural gas supplies and holds firm transportation and storage capacity sufficient to meet the expected peak winter demand for natural gas by its firm customers. Due to the variability in weather, winter peaking consumption of natural gas by most of its customers and other factors, PSE holds contractual rights to natural gas supplies and transportation and storage capacity in excess of its average annual requirements to serve firm customers on its distribution system. For much of the year, there is excess capacity available for third-party natural gas sales, exchanges and capacity releases. PSE sells excess natural gas supplies, enters into natural gas supply exchanges with third parties outside of its distribution area and releases to third parties excess interstate natural gas pipeline capacity and natural gas storage rights on a short-term basis to mitigate the costs of firm transportation and storage capacity for its core natural gas customers. The proceeds from such activities, net of transactional costs, are accounted for as reductions in the cost of purchased natural gas and passed on to customers through the PGA mechanism, with no direct impact on net income. As a result, PSE nets the sales revenue and associated cost of sales for these transactions in purchased natural gas.

Non-Core Natural Gas Sales

As part of the Company's electric operations, PSE purchases natural gas for its gas-fired generation facilities. The projected volume of natural gas for power is relative to the price of natural gas. Based on the market prices for natural gas, PSE may use the natural gas it has already purchased to generate power or PSE may sell the already purchased natural gas. The net proceeds from selling natural gas, previously purchased for power generation, are accounted for in other electric operating revenue and are included in the PCA mechanism.

Production Tax Credit

Production Tax Credits (PTCs) represent federal income tax incentives available to taxpayers that generate energy from qualifying renewable sources. PSE records the benefit of the PTCs as a regulatory liability until such time as PSE utilizes the tax credit on its tax return. Once utilized, PSE will pass the benefit to customers.

Accounting for Derivatives

ASC 815 requires that all contracts considered to be derivative instruments be recorded on the balance sheet at their fair value unless the contracts qualify for an exception. PSE enters into derivative contracts to manage its energy resource portfolio and interest rate exposure including forward physical and financial contracts and swaps. Some of PSE's physical electric supply contracts qualify for the Normal Purchase Normal Sale (NPNS) exception to derivative accounting rules. PSE may enter into financial fixed price contracts to economically hedge the variability of certain index-based contracts. Those contracts that do not meet the NPNS exception are marked-to-market to current earnings in the statements of income, subject to deferral under ASC 980, for energy related derivatives due to the PCA mechanism and PGA mechanism.

PSE elected to de-designate all energy related derivative contracts previously recorded as cash flow hedges for the purpose of simplifying its financial reporting in 2009. The contracts that were de-designated related to physical electric supply contracts and natural gas swap contracts used to fix the price of natural gas for electric generation. For these contracts and for contracts initiated after such date, all mark-to-market adjustments are recognized through earnings. The amount previously recorded in accumulated other comprehensive income (AOCI) is transferred to earnings in the same period or periods during which the hedged transaction affects earnings or sooner if management determines that the forecasted transaction is probable of not occurring. When these contracts are settled, the contract price becomes part of purchased electricity or electric generation fuel which becomes part of PSE's PCA mechanism and the unrealized gain or loss is listed separately under energy costs, as it represents the non-rate treatment of energy costs.

The Company may enter into swap instruments or other financial derivative instruments to manage the interest rate risk associated with its long-term debt financing and debt instruments. As of December 31, 2015, Puget Sound Energy did not have any interest rate swap contracts outstanding. For additional information, see Note 9 Accounting for Derivative Instruments and Hedging Activities.

Fair Value Measurements of Derivatives

ASC 820, "Fair Value Measurements and Disclosures" (ASC 820), defines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). As permitted under ASC 820, the Company utilizes a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical expedient for valuing the majority of its assets and liabilities measured and reported at fair value. The Company utilizes market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The Company primarily applies the market approach for recurring fair value measurements as it believes that the approach is used by market participants for these types of assets and liabilities. Accordingly, the Company utilizes valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

The Company values derivative instruments based on daily quoted prices from an independent external pricing service. When external quoted market prices are not available for derivative contracts, the Company uses a valuation model that uses volatility assumptions relating to future energy prices based on specific energy markets and utilizes externally available forward market price curves. All derivative instruments are sensitive to market price fluctuations that can occur on a daily basis. For additional information, see Note 10 Fair Value Measurements.

Debt Related Costs

Debt premiums, discounts, expenses and amounts received or incurred to settle hedges are amortized over the life of the related debt for the Company. The premiums and costs associated with reacquired debt are deferred and amortized over the life of the related new issuance, in accordance with ratemaking treatment for PSE.

(2) New Accounting Pronouncements

Revenue Recognition

In May 2014, the FASB issued Accounting Standards Update (ASU) No. 2014-09, "*Revenue from Contracts with Customers (Topic 606)*", which outlines a single comprehensive model for use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. The ASU is based on the principle that an entity should recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The ASU also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts, including significant judgments and changes in judgments and assets recognized from costs incurred to fulfill a contract.

In August 2015, the FASB issued ASU 2015-14, "*Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date,"* deferring the effective date for ASU 2014-09 to fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017. In addition to the FASB's deferral decision, FASB provided reporting entities with an option to adopt ASU 2014-09 for the fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016, the original effective date. The Company plans to adopt ASU 2014-09 according to the original effective date. Reporting entities also have the option of using either a full retrospective or a modified retrospective approach for the adoption of the new standard. The Company initiated a steering committee and project team to evaluate the impact of this standard, update any policies and procedures that may be affected and implement the new revenue recognition guidance. At this time, the Company cannot determine the impact this standard will have on its consolidated financial statements.

Debt Issuance Costs

In April 2015, the FASB issued ASU 2015-03, "*Interest-Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs.*" ASU 2015-03 requires debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of the debt liability, consistent with the presentation of a debt discount. This new guidance affects only the presentation of debt issuance costs and not the recognition and measurement of debt issuance costs. ASU 2015-03 is to be applied on a retrospective basis, wherein the balance sheet of each individual period presented should be adjusted to reflect the period-specific effects of applying the new guidance.

In August 2015, the FASB issued ASU 2015-15, "*Interest-Imputation of Interest (Subtopic 835-30): Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangement*." In accordance with the United States Securities and Exchange Commission (SEC) Staff Announcement at the June 18, 2015 Emerging Issues Task Force (EITF) meeting about debt issuance costs, ASU 2015-15 amended the accounting guidance updated by ASU 2015-03 to allow reporting entities the option to defer and present debt issuance costs related to line-of-credit arrangements as an asset and subsequently amortize the deferred debt issuance costs ratably over the term of the line-of-credit arrangement.

ASU 2015-03 and ASU 2015-15 are effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. Early adoption of the amendments is permitted for financial statements that have not been previously issued. The Company plans to adopt the amendments during fiscal year 2016. The amount of unamortized debt issuance costs at PSE as of December 31, 2015 and 2014 totaled $30.0 million and $28.7 million, respectively.

Internal-Use Software

In April 2015, the FASB issued ASU 2015-05, "*Intangibles-Goodwill and Other-Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement.*" ASU 2015-05 requires a customer in a cloud computing arrangement to follow internal-use software guidance if both of the following criteria are met: the customer has the contractual right to take possession of the software at any time during the cloud computing arrangement and can feasibly run the software on its own hardware. If the customer does not meet both criteria, the cloud computing arrangement is considered a service contract and separate accounting for a license would not be permitted.

ASU 2015-05 is effective for annual reporting periods, including interim periods within those annual reporting periods, beginning after December 15, 2015. Early adoption is permitted. The Company plans to adopt ASU 2015-05 during fiscal year 2016 and is in the process of evaluating the potential impacts, if any, of this new guidance on its financial statements.

Fair Value Measurement

In May 2015, the FASB issued ASU 2015-07, "*Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (or Its Equivalent)*," which removes the requirement to categorize within the fair value hierarchy all investments for which their fair value is measured using the net asset value per share practical expedient. This ASU also removes the requirement to make certain disclosures for all investments that are eligible to be measured at fair value using the net asset value per share practical expedient. Instead, those disclosures will be limited to investments for which the Company has elected to measure the fair value using that practical expedient.

ASU 2015-07 is effective for annual reporting periods, and interim periods within those reporting periods, beginning after December 15, 2015, and requires reporting entities to apply this ASU retrospectively to all periods presented. Early adoption is permitted. The Company plans to adopt ASU 2015-07 during fiscal year 2016. At this time, the Company cannot determine the impact this standard will have on its consolidated financial statements.

Inventory

In July 2015, the FASB issued ASU 2015-11, "*Inventory (Topic 330): Simplifying the Measurement of Inventory.*" ASU 2015-11 requires inventory within the scope of this Topic 330 to be measured at the lower of cost and net realizable value. This amendment does not apply to inventory that is measured using last-in, first-out (LIFO) or the retail inventory method. This amendment applies to all other inventory, including inventory measured using first-in, first-out (FIFO) or average cost.

The new accounting guidance is effective for annual reporting periods, and interim periods within those annual reporting periods, beginning after December 15, 2016, with early adoption permitted. The Company plans to adopt ASU 2015-11 during fiscal year 2017. At this time, the Company cannot determine the impact this standard will have on its consolidated financial statements.

Retirement Benefits

In July 2015, the FASB issued ASU 2015-12, "*Plan Accounting: Defined Benefit Pension Plans (Topic 960), Defined Contribution Pension Plans (Topic 962), and Health and Welfare Benefit Plans (Topic 965).*" ASU 2015-12 is made up of three parts: Part I, Fully Benefit-Responsive Investment Contracts (Part I); Part II, Plan Investment Disclosures (Part II); and Part III, Measurement Date Practical Expedient (Part III).

Part I requires fully benefit-responsive contracts to be measured, presented and disclosed only at contract value. Part II requires both participant-directed and nonparticipant-directed investments of employee benefit plans be grouped only by general type, and removes the requirement to include the disclosure of (i) the investment strategy of an investment measured using the net asset value per share practical expedient and is part of a fund that files a U.S. Department of Labor Form 5500; and (ii) the net appreciation or depreciation for investments by general type. Part III provides entities that have a fiscal year-end that does not coincide with a month-end a practical expedient to permit plans to measure investments and investment-related accounts as of a month-end date that is closest to the plan's fiscal year-end.

All three parts are effective for fiscal years beginning after December 15, 2015, and early adoption is permitted for each part. Parts I and II must be applied retrospectively for all financial statements presented. The amendments in Part III must be applied prospectively. The Company plans to adopt ASU 2015-12 during the fiscal year 2016, and is in the process of evaluating the potential impacts, if any, of this new guidance on its financial statements.

Derivatives and Hedging

In August 2015, the FASB Issues ASU 2015-13, "*Derivatives and Hedging (Topic 815): Application of the Normal Purchases and Normal Sales Scope Exception to Certain Electricity Contracts within Nodal Energy Markets.*" ASU 2015-13 allows certain reporting entities that enter into derivative contracts for the purchase or sale of electricity on a forward basis and arrange for transmission through a nodal energy market, to designate those contracts as normal purchase or normal sale contracts, if the physical delivery criterion is met. This designation removes the ASC 815, Derivatives and Hedging (ASC 815), requirement to measure those derivative contracts at fair value.

This amendment was effective upon issuance, and if elected, the guidance must be applied prospectively. The Company does not expect this guidance to have a material impact on its results of operations or financial position.

Deferred Income Taxes

In November 2015, the FASB issued ASU 2015-17, "*Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes.*" ASU 2015-17 requires reporting entities to classify deferred tax liabilities and assets as noncurrent in a classified balance sheet instead of separating such deferred taxes into current and noncurrent amounts.

This amendment is effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Earlier adoption is permitted for all entities as of the beginning of any interim or annual reporting period. The Company has early adopted ASU 2015-17 for the annual reporting period ended December 31, 2015, and has applied this amendment retrospectively. Except for changes in Consolidated Balance Sheet presentation, this guidance does not have a material impact on the Company's results of operations or financial position. For additional information on the impact of this guidance, see Note 13, Income Taxes.

(3) Regulation and Rates

Regulatory Assets and Liabilities

Regulatory accounting allows PSE to defer certain costs that would otherwise be charged to expense, if it is probable that future rates will permit recovery of such costs. It similarly requires deferral of revenues or gains that are expected to be returned to customers in the future.

Below is a table with the allowed return on the net regulatory assets and liabilities and the associated time periods:

Period	Rate of Return	After-Tax Return
July 1, 2013 - present	7.77%	6.69%

The net regulatory assets and liabilities at December 31, 2015 and 2014 included the following:

(Dollars in Thousands)	Remaining Amortization Period		December 31, 2015		December 31, 2014
Storm damage costs electric	1 to 3 years		$ 125,777		$ 118,824
Chelan PUD contract initiation	15.8 Years		112,228		119,316
Deferred decoupling revenue		104,150		55,363	
Decoupling revenue in excess of 2 years		(9,980)		—	
Total deferred decoupling revenue	Less than 2 years		94,170		55,363
Lower Snake River	1 to 21.3 years		79,599		86,275
Deferred income taxes	(a)		72,694		94,913
Environmental remediation	(a)		66,887		66,018
Baker Dam licensing operating and maintenance costs	43 years		63,394		61,577
PGA deferral of unrealized losses on derivative instruments	(a)		60,889		69,280
Deferred Washington Commission AFUDC	35 years		52,197		53,709
Unamortized loss on reacquired debt	1 to 20.5 years		44,984		35,667
Property tax tracker	Less than 2 years		40,353		32,253
Energy conservation costs	1 to 2 years		36,646		42,374
White River relicensing and other costs	16.9 years		23,054		26,685
Mint Farm ownership and operating costs	9.3 years		18,320		20,320
Ferndale	3.8 years		15,253		19,232
Electron unrecovered loss	3 years		10,569		14,008
Snoqualmie licensing operating and maintenance costs	29 years		7,980		9,202
Colstrip common property	8.5 years		6,049		6,764
Colstrip major maintenance	2 years		5,897		2,712
Investment in Bonneville Exchange power contract	1.5 years		5,290		8,816
Snoqualmie	2.8 years		5,024		6,798
PGA receivable	1 year		—		21,073
Various other regulatory assets	Varies		24,248		16,223
Total PSE regulatory assets			$ 971,502		$ 987,402
Treasury grants	4 to 43 years		(157,102)		(180,496)
Production tax credits	(c)		(93,616)		(93,616)
Decoupling over-collection	Less than 2 years		(25,483)		(12,582)
PGA payable	1 year		(12,589)		—
Summit purchase option buy-out	4.8 years		(7,612)		(9,188)
Deferral of treasury grant amortization	Less than 4 years		(6,058)		(8,197)
Various other regulatory liabilities	Up to 4 years		(13,751)		(18,215)
Total PSE regulatory liabilities			$ (316,211)		$ (322,294)
PSE net regulatory assets (liabilities)			$ 655,291		$ 665,108

(a) *Amortization periods vary depending on timing of underlying transactions or awaiting regulatory approval in a future Washington Commission rate proceeding.*

(b) *The balance is dependent upon the cost of removal of underlying assets and the life of utility plant.*

(c) *Amortization will begin once PTCs are utilized by PSE on its tax return.*

If the Company determines that it no longer meets the criteria for continued application of ASC 980, the Company would be required to write-off its regulatory assets and liabilities related to those operations not meeting ASC 980 requirements. Discontinuation of ASC 980 could have a material impact on the Company's financial statements.

In accordance with guidance provided by ASC 410, "Asset Retirement and Environmental Obligations (ARO)," PSE reclassified from accumulated depreciation to a regulatory liability $347.5 million and $313.1 million in 2015 and 2014, respectively, for the cost of removal of utility plant. These amounts are collected from PSE's customers through depreciation rates.

2013 Expedited Rate Filing, Decoupling and Centralia Decision

PSE filed a settlement agreement with the Washington Commission on March 22, 2013. The agreement was intended to settle all issues regarding decoupling, a power purchase agreement with TransAlta Centralia and the expedited rate filing (ERF) which is limited in scope and rate impact, includes the property tax tracker, and is intended to establish baseline rates on which the decoupling mechanism are to operate. The Washington Commission placed the ERF and decoupling filings under a common procedural schedule.

On June 25, 2013, the Washington Commission issued final orders resolving the amended decoupling petition, the ERF filing and the Petition for Reconsideration (related to the TransAlta Centralia power purchase agreement). Order No. 7 in the ERF/decoupling proceeding approved PSE's ERF filing with a small change to its cost of capital from 7.80% to7.77% to update long term debt costs. This order also approved the property tax tracker discussed below and approved the amended decoupling and rate plan filing with the further condition that PSE and the customers will share 50.0% each in earnings in excess of the 7.77% authorized rate of return. In addition, the rate plan increase allowed decoupling revenue per customer for the recovery of delivery system costs will subsequently increase by 3.0% for the electric customers and 2.2% for the gas customers on January 1 of each year, until the conclusion of PSE's next GRC which will be filed before April 1, 2016. In the rate plan, increases are subject to a cap of 3.0% of the total revenue for customers. Order No. 8 in the TransAlta Centralia proceeding granted in part and denied in part PSE's Petition for Reconsideration, clarifying certain portions of the Washington Commission's original order regarding TransAlta Centralia.

On July 24, 2013, the Public Counsel Division of the Washington State Attorney General's Office (Public Counsel) and the Industrial Customers of Northwest Utilities (ICNU) each filed a petition in Thurston County Superior Court (the Court) seeking judicial reviews of various aspects of the Washington Commission's ERF and decoupling mechanism final order. The parties' petition argued that the order violates various procedural and substantive requirements of the Washington Administrative Procedure Act, and so requests that it be vacated and that the matter be remanded to the Washington Commission. Oral arguments regarding this matter were held on May 9, 2014. On June 25, 2014, the court issued a letter decision in which it affirmed the attrition adjustment (escalating factors referred to as the K-Factor) and the Washington Commission's decision not to consider the case as a GRC, but reversed and remanded the cost of equity for further adjudication consistent with the court's decision. The remand proceeding evidentiary hearings regarding return on equity (ROE) were held in February 2015 and initial briefs and reply briefs were filed in March 2015. The Washington Commission issued a final order on remand on June 29, 2015, in which it found that 9.8% is a reasonable ROE for PSE for the term of the rate plan, taking decoupling and other relevant factors into account.

Expedited Rate Filing

On June 25, 2013, the Washington Commission approved PSE's electric and natural gas decoupling mechanism and ERF tariff filings, effective July 1, 2013. The estimated revenue impact of the decoupling mechanism for electric and natural gas customers is an increase of $21.4 million, or 1.0%, annually and an increase of $10.8 million, or 1.1% annually, respectively. The estimated revenue impact of the ERF filings for electric and natural gas customers is an increase of $30.7 million, or 1.5%, annually and a decrease of $2.0 million, or a decrease of 0.2% annually, respectively. In its order, the Washington Commission approved a weighted cost of capital of 7.77% and a capital structure that included 48.0% common equity with a ROE of 9.8%. Subsequently, certain parties to this proceeding petitioned the Washington Commission to reconsider the order. On December 13, 2013, the Washington Commission approved the settlement agreements for rates effective January 1, 2014. These settlement agreements do not materially change the revenues originally approved in June 2013.

On February 4, 2013, PSE filed revised tariffs in an ERF proceeding seeking to update the rates set by the Washington Commission in the final order of May 2012 in PSE's general rate case (GRC). This ERF filing was limited in scope and rate impact. This filing was primarily intended to establish baseline rates on which the decoupling mechanisms, described below, were proposed to operate. The filing also provided for the collection of property taxes through a property tax tracker mechanism based on cash payments of property tax made by PSE during the year. Any difference between the cash payments and property tax accruals will be deferred and recovered in a property tax tracker.

Decoupling Filings

While fluctuations in weather conditions will continue to affect PSE's billed revenue and energy supply expenses from month to month, PSE's decoupling mechanisms, are expected to mitigate the impact of weather on operating revenue and net income. The Washington Commission has allowed PSE to record a monthly adjustment to its electric and natural gas operating revenues related to electric transmission and distribution, natural gas operations and general administrative costs from residential, commercial and industrial customers to eliminate the effects of abnormal weather, conservation impacts and changes in usage patterns per customer with the exception of the electric business where PCA is not part of the decoupling mechanism. As a result, these electric and natural gas revenues will be recovered on a per customer basis regardless of actual consumption levels. The energy supply costs, which are part of the PCA and PGA mechanisms, are not included in the decoupling mechanism. The revenue recorded under the decoupling mechanisms will be affected by customer growth and not actual consumption. Following each calendar year, PSE will recover or refund the difference between allowed decoupling revenue and the corresponding actual revenue to affected customers during the following May to April time period. The decoupling mechanism will end on February 28, 2017 unless the continuation of the mechanism is approved in PSE’s next GRC filing which PSE is required to file by April 1, 2016 at the latest.

On April 22, 2015, the Washington Commission approved PSE's request to change rates under its electric and natural gas decoupling mechanism, effective May 1, 2015. As part of this filing, PSE also requested to change the methodology of how decoupling deferrals are calculated going forward and adjust deferrals calculated in 2014. The change was done to ensure that the amortization of prior years’ accumulated decoupling deferrals were not included in the calculation of the current year decoupling deferrals. The effect of the methodology change was a reduction of approximately $12.0 million previously recognized revenue from May through December of 2014. The overall changes represent a rate increase for electric customers of $53.8 million, or 2.6%, annually, and a rate increase for natural gas customers of $22.0 million, or 2.1%, annually, effective May 1, 2015. In addition, PSE exceeded the earnings test threshold for its natural gas business in 2014. As a result, PSE recorded a reduction in natural gas decoupling deferral and revenue of $1.3 million. This was reflected as a reduction to the natural gas rate increases noted above. As noted earlier, the Company is also limited to a 3.0% annual decoupling related cap on increases in total revenue. This limitation was triggered for certain rate classes. The resulting amount of deferral that was not included in the 2015 rate increase is $1.9 million for electric revenue and $8.2 million for natural gas revenue that was accrued through December 31, 2014. These amounts may be included in customer rates beginning in May 2016, subject to subsequent application of the earnings test and the 3.0% cap on decoupling related rate increases.

On April 24, 2014, the Washington Commission approved PSE’s request to change rates under its electric and natural gas decoupling mechanism, effective May 1, 2014. The rate change incorporated the effects of an increase to the allowed delivery revenue per customer as well as true-ups to the rate from the prior year. This represents a rate increase for electric customers of $10.6 million, or 0.5% annually, and a rate decrease for natural gas customers of $1.0 million, or 0.1% annually.

On December 13, 2013, the Washington Commission approved a series of settlement agreements for rates effective January 1, 2014. These settlement agreements do not materially change the revenues originally approved in June 2013. As a result, certain high volume natural gas industrial customers rate schedules are excluded from the decoupling mechanism and will be subject to certain effects of abnormal weather, conservation impacts and changes in customer usage patterns.

Electric Regulation and Rates

Storm Damage Deferral Accounting

The Washington Commission issued a GRC order that defined deferrable catastrophic/extraordinary losses and provided that costs in excess of $8.0 million annually may be deferred for qualifying storm damage costs that meet the modified IEEE outage criteria for system average interruption duration index. In 2015 and 2014, PSE incurred $33.6 million and $29.7 million, respectively, in storm-related electric transmission and distribution system restoration costs, of which $22.4 million was deferred in 2015 and $18.0 million was deferred in 2014.

Power Cost Only Rate Case

A limited-scope proceeding was approved in 2002 by the Washington Commission to periodically reset power cost rates. In addition to providing the opportunity to reset all power costs, the power cost only rate case (PCORC) proceeding also provides for timely review of new resource acquisition costs and inclusion of such costs in rates at the time the new resource goes into service. To achieve this objective, the Washington Commission has used an expedited six-month PCORC decision timeline rather than the statutory 11-month timeline for a GRC.

The following table sets forth PCORC rate adjustments approved by the Washington Commission and the corresponding impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
December 1, 2014	(0.9)%	$ (19.4)

Electric Property Tax Tracker Mechanism

The purpose of the property tax tracker mechanism is to pass through the cost of all property taxes incurred by the Company. The mechanism was implemented in 2013 and removed property taxes from general rates and included those costs as a component rate. After the implementation, the mechanism acts as a tracker rate schedule and collects the total amount of property taxes assessed. The tracker will be adjusted each year in May based on that year's assessed property taxes and true-ups to the rate from the prior year.

The following table sets forth property tax tracker mechanism rate adjustments approved by the Washington Commission and the corresponding impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
May 1, 2015	0.4%	$ 8.4
May 1, 2014	0.5	11.0

Electric Conservation Rider

The electric conservation rider collects revenue to cover the costs incurred in providing services and programs for conservation. Rates change annually on May 1 to collect the annual budget that started the prior January.

The following table sets forth conservation rider rate adjustments approved by the Washington Commission and the corresponding impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
May 1, 2014	0.6%	$ 12.2

Accounting Orders and Petitions

PSE completed the sale of its electric infrastructure assets located in Jefferson County and the transition of electrical services in the county to Jefferson County Public Utility District (JPUD) on March 31, 2013. The proceeds from the sale exceeded the transferred assets' net carrying value of $46.7 million resulting in a pre-tax gain of approximately $60.0 million. In accordance with a 2010 Washington Commission order, PSE deferred the gain and recorded it as a regulatory liability pending the Washington Commission's determination of the accounting and ratemaking treatment. On October 31, 2013, PSE filed an accounting petition for a Washington Commission order that would authorize PSE to retain the gain of $45.0 million and return $15.0 million to its remaining customers over a period of 48 months. On March 28, 2014, intervenors filed response testimonies containing their respective proposals for allocation of the gain, which included a proposal of up to $57.0 million to customers and $3.0 million to PSE. A final order was rendered on September 11, 2014 which authorized PSE to retain $7.5 million of the gain and return $52.7 million to customers. The customer portion was booked to a regulatory liability account in other current liabilities and accrued interest at PSE's after-tax rate of return. PSE paid this amount to customers through a bill credit in the month of December 2014.

Power Cost Adjustment Mechanism

PSE currently has a PCA mechanism that provides for the recovery of power costs from customers or refunding of power cost savings to customers in the event those costs vary from the "power cost baseline" included in revenue requirements. The "power cost baseline" levels are set, in part, based on normalized assumptions about weather and hydroelectric conditions. Excess power costs or power cost savings are apportioned between PSE and its customers pursuant to the graduated scale set forth in the PCA mechanism.

The graduated scale currently applicable is as follows:

Annual Power Cost Variability	Company's Share	Customers' Share
+/- $20 million	100%	—%
+/- $20 million - $40 million	50	50
+/- $40 million - $120 million	10	90
+/- $120 + million	5	95

On August 7, 2015 the Washington Commission issued an order approving the settlement proposing changes to the PCA mechanism. The settlement agreement will not take effect until January 1, 2017. Key components of the settlement will result in the following changes to the PCA mechanism:

	Company's Share		Customers' Share	
Annual Power Cost Variability	Over	Under	Over	Under
+/- $17 million	100%	100%	—%	—%
+/- $17 million - $40 million	35	50	65	50
+/- $40+ million	10	10	90	90

- Reduction to the cumulative deferral trigger for surcharge or refund from $30.0 million to $20.0 million;
- Removal of fixed production costs from the PCA mechanism and placing them in the decoupling mechanism, assuming the decoupling mechanism continues as part of the next GRC. If decoupling was not to continue, those fixed production costs would be treated the same as other non-PCA costs unless permission to treat them in another manner is obtained from the Washington Commission. These fixed production costs include: (i) return and depreciation/amortization on fixed production assets and regulatory assets and liabilities; (ii) return on depreciation, transmission expense and revenues on specific transmission assets; and (iii) hydro, other production and other power related expenses and O&M costs;
- Suspension of the requirement that a GRC must be filed within three months after rates are approved in a PCORC, and agreeing, for a five-year period, that PSE will not file a GRC or PCORC within six months of the date rates go into effect for a PCORC filing; and
- Establishment of a five-year moratorium on changes to the PCA/PCORC.

PSE had an unfavorable PCA imbalance during the year ended December 31, 2015, due to under recovering $8.7 million of power costs that exceeded the “power cost baseline” level of which no amounts were apportioned to customers. This compares to an unfavorable imbalance of $40.1 million for the year ended December 31, 2014 of which $10.1 million was apportioned to customers.

Federal Incentive Tracker Tariff

The Federal Incentive tracker tariff passes the benefits associated with treasury grants received by the company and PTCs available through to its customers. The filing results in a credit back to customers for pass-back of treasury grant amortization and pass-through of interest and any related true-ups. The filing is adjusted annually for new Federal benefits, actual versus forecast interest and to true-up for actual load being different than the forecasted load set in rates.

The following table sets forth Federal Incentive Tracker Tariff rate adjustments approved by the Washington Commission and the corresponding impact on PSE’s revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Total credit to be passed back to eligible customers (Dollars in Millions)
January 1, 2016	(0.2)%	$ (57.3)
January 1, 2015	(0.2)	(55.2)
January 1, 2014	(0.3)	(58.5)

Gas Regulation and Rates

Gas General Rate Cases and Other Filings Affecting Rates

Cost Recovery Mechanism

The purpose of the Cost Recovery Mechanism (CRM) is to recover depreciation expense and return on the investment in the Company's pipeline replacement program to enhance the safety of the natural gas distribution system until included in base rates for gas service. The following table sets forth CRM rate adjustments approved by the Washington Commission and the corresponding impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
November 1, 2015	0.5%$	5.3
November 1, 2014	0.2	2.3

Property Tax Tracker Mechanism

The purpose of the property tax tracker mechanism is to pass through the cost of all property taxes incurred by the Company. The mechanism was implemented in 2013 and removed property taxes from general rates and included those costs as a component rate. After the implementation, the mechanism acts as a tracker rate schedule and collects the total amount of property taxes assessed. The tracker will be adjusted each year in May based on that year's assessed property taxes.

The following table sets forth property tax tracker mechanism rate adjustments approved by the Washington Commission and the corresponding impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
June 1, 2015	(0.2)%$	(2.3)
May 1, 2014	0.6	5.6

Purchased Gas Adjustment

PSE has a PGA mechanism that allows PSE to recover expected natural gas supply and transportation costs and defer, as a receivable or liability, any natural gas supply and transportation costs that exceed or fall short of this expected natural gas cost amount in PGA mechanism rates, including accrued interest. PSE is authorized by the Washington Commission to accrue carrying costs on PGA receivable and payable balances. A receivable or payable balance in the PGA mechanism reflects an under recovery or over recovery, respectively, of natural gas cost through the PGA mechanism.

The following table sets forth PGA rate adjustments approved by the Washington Commission and the corresponding impact on PSE's revenue based on the effective dates:

Effective Date	Average Percentage Increase (Decrease) in Rates	Increase (Decrease) in Revenue (Dollars in Millions)
November 1, 2015	(17.4)%$	(185.9)
November 1, 2014	2.5	23.3

Environmental Remediation

The Company is subject to environmental laws and regulations by the federal, state and local authorities and is required to undertake certain environmental investigative and remedial efforts as a result of these laws and regulations. The Company has been named by the environmental protection agency (EPA), the Washington State Department of Ecology and/or other third parties as potentially responsible at several contaminated sites and manufactured gas plant sites. PSE has implemented an ongoing program to test, replace and remediate certain underground storage tanks (UST) as required by federal and state laws. The UST replacement component of this effort is finished, but PSE continues its work remediating and/or monitoring relevant sites. During 1992, the Washington Commission issued orders regarding the treatment of costs incurred by the Company for certain sites under its environmental remediation program. The orders authorize the Company to accumulate and defer prudently incurred cleanup costs paid to third parties for recovery in rates established in future rate proceedings, subject to Washington Commission review. The Washington Commission consolidated the gas and electric methodological approaches to remediation and deferred accounting in an order issued October 8, 2008. Per the guidance of ASC 450, "Contingencies," the Company reviews its estimated future obligations and will record adjustments, if any, on a quarterly basis. Management believes it is probable and reasonably estimable that the impact of the potential outcomes of disputes with certain property owners and other potentially responsible parties will result in environmental remediation costs of $32.6 million for gas and $6.1 million for electric. The Company believes a significant portion of its past and future environmental remediation costs are recoverable from insurance companies, from third parties or from customers under a Washington Commission order. The Company is also subject to cost-sharing agreements with third parties regarding environmental remediation projects in Seattle, Washington and Bellingham, Washington. The Company has taken the lead for both projects, and as of December 31, 2015, the Company's share of future remediation costs is estimated to be approximately $23.9 million. The Company's deferred electric environmental costs are $14.0 million and $13.4 million at December 31, 2015 and 2014, respectively, net of insurance proceeds. The Company's deferred natural gas environmental costs are $52.9 million and $52.6 million at December 31, 2015 and 2014, respectively, net of insurance proceeds.

(4) Dividend Payment Restrictions

The payment of dividends by PSE to Puget Energy is restricted by provisions of certain covenants applicable to long-term debt contained in PSE's electric and natural gas mortgage indentures. At December 31, 2015, approximately $464.1 million of unrestricted retained earnings was available for the payment of dividends under the most restrictive mortgage indenture covenant.

Pursuant to the terms of the Washington Commission merger order, PSE may not declare or pay dividends if PSE's common equity ratio, calculated on a regulatory basis, is 44.0% or below except to the extent a lower equity ratio is ordered by the Washington

Commission. Also, pursuant to the merger order, PSE may not declare or make any distribution unless on the date of distribution PSE's corporate credit/issuer rating is investment grade, or, if its credit ratings are below investment grade, PSE's ratio of earnings before interest, tax, depreciation and amortization (EBITDA) to interest expense for the most recently ended four fiscal quarter periods prior to such date is equal to or greater than 3 to one. The common equity ratio, calculated on a regulatory basis, was 47.7% at December 31, 2015, and the EBITDA to interest expense was 4.9 to one for the twelve months then ended December 31, 2015.

PSE's ability to pay dividends is also limited by the terms of its credit facilities, pursuant to which PSE is not permitted to pay dividends during any Event of Default (as defined in the facilities), or if the payment of dividends would result in an Event of Default, such as failure to comply with certain financial covenants.

At December 31, 2015, the Company was in compliance with all applicable covenants, including those pertaining to the payment of dividends.

(5) Utility Plant

Utility Plant (Dollars In Thousands)	Estimated Useful Life (Years)	At December 31, 2015	2014
Electric, natural gas and common utility plant classified by prescribed accounts :			
Distribution plant	10-50	$ 6,657,597	$ 6,417,551
Production plant	25-125	3,950,231	3,907,224
Transmission plant	45-65	1,351,216	1,306,009
General plant	5-35	563,850	553,130
Intangible plant (including capitalized software)	3-50	294,380	304,135
Plant acquisition adjustment	7-30	282,792	282,792
Underground storage	25-60	42,545	42,494
Liquefied natural gas storage	25-45	14,498	14,498
Plant held for future use	NA	56,042	55,148
Plant not classified	1-100	65,892	91,519
Capital leases, net of accumulated amortization [1]	5	378	9,473
Less: accumulated provision for depreciation		(5,029,301)	(4,762,767)
Subtotal		$ 8,250,120	$ 8,221,206
Construction work in progress	NA	408,795	239,690
Net utility plant		$ 8,658,915	$ 8,460,896

1 *Accumulated amortization of capital leases at PSE was $32.3 million in 2015 and $28.4 million in 2014.*

Jointly owned generating plant service costs are included in utility plant service cost at the Company's ownership share. The following table indicates the Company's percentage ownership and the extent of the Company's investment in jointly owned generating plants in service at December 31, 2015. These amounts are also included in the Utility Plant table above.

			Puget Sound Energy's Share	
Jointly Owned Generating Plants (Dollars in Thousands)	Energy Source (Fuel)	Company's Ownership Share	Plant in Service at Cost	Accumulated Depreciation
Colstrip Units 1 & 2	Coal	50%	$ 327,843	$ (150,974)
Colstrip Units 3 & 4	Coal	25%	525,072	(304,636)
Colstrip Units 1 – 4 Common Facilities	Coal	various	252	(192)
Frederickson 1	Gas	49.85%	70,725	(16,715)
Jackson Prairie	Gas Storage	33.34%	42,579	(19,182)

Asset Retirement Obligation

The Company has recorded liabilities for steam generation sites, combustion turbine generation sites, combined cycle generation sites, wind generation sites, distribution and transmission poles, gas mains, and leased facilities where disposal is governed by ASC 410 "ARO".

On April 17, 2015, the U.S. EPA published a final rule, effective October 19, 2015, that regulates Coal Combustion Residuals (CCR) under the Resource Conservation and Recovery Act, Subtitle D. The CCR rule addresses the risks from coal ash disposal, such as leaking of contaminants into ground water, blowing of contaminants into the air as dust, and the catastrophic failure of coal ash surface impoundments by establishing technical requirements for CCR landfills and surface impoundments. The rule also sets out recordkeeping and reporting requirements including requirements to post specific information to a publicly-accessible website.

The CCR rule requires significant changes to the Company's Colstrip, Montana coal-fired steam electric generation facility(Colstrip) operations and those changes were reviewed by the Company and the plant operator in the second and third quarter of 2015. PSE had previously recognized a legal obligation under the EPA rules to dispose of coal ash material at Colstrip, in 2003. Due to the CCR rule, additional disposal costs were added to the ARO.

The actual ARO costs related to the CCR rule requirements may vary substantially from the estimates used to record the increased obligation due to uncertainty about the compliance strategies that will be used and the preliminary nature of available data used to estimate costs. We will continue to gather additional data and coordinate with the plant operator to make decisions about compliance strategies and the timing of closure activities. As additional information becomes available, the Company will update the ARO obligation for these changes, which could be material.

The following table describes the changes to the Company's ARO liability as of December 31, 2015 and 2014:

	At December 31,	
(Dollars in Thousands)	2015	2014
Asset retirement obligation at beginning of period	$ 48,909	$ 48,687
New asset retirement obligation recognized in the period	34,534	—
Liability adjustment in the period	(3,628)	(602)
Revisions in estimated cash flows	3,403	(480)
Accretion expense	1,810	1,304
Asset retirement obligation at end of period	$ 85,028	$ 48,909

The Company has identified the following obligations, as defined by ASC 410, "ARO," which were not recognized because the liability for these assets cannot be reasonably estimated at December 31, 2015 due to:

- A legal obligation under Federal Dangerous Waste Regulations to dispose of asbestos-containing material in facilities that are not scheduled for remodeling, demolition or sales. The disposal cost related to these facilities could not be measured since the retirement date is indeterminable; therefore, the liability cannot be reasonably estimated;
- An obligation under Washington state law to decommission the wells at the Jackson Prairie natural gas storage facility upon termination of the project. Since the project is expected to continue as long as the Northwest pipeline continues to operate, the liability cannot be reasonably estimated;
- An obligation to pay its share of decommissioning costs at the end of the functional life of the major transmission lines. The major transmission lines are expected to be used indefinitely; therefore, the liability cannot be reasonably estimated;
- A legal obligation under Washington state environmental laws to remove and properly dispose of certain under and above ground fuel storage tanks. The disposal costs related to under and above ground storage tanks could not be measured since the retirement date is indeterminable; therefore, the liability cannot be reasonably estimated;
- An obligation to pay decommissioning costs at the end of utility service franchise agreements to restore the surface of the franchise area. The decommissioning costs related to facilities at the franchise area could not be measured since the decommissioning date is indeterminable; therefore, the liability cannot be reasonably estimated; and
- A potential legal obligation may arise upon the expiration of an existing FERC hydropower license if FERC orders the project to be decommissioned, although PSE contends that FERC does not have such authority. Given the value of ongoing generation, flood control and other benefits provided by these projects, PSE believes that the potential for decommissioning is remote and cannot be reasonably estimated.

(6) Long-Term Debt

(Dollars in Thousands)			At December 31,	
Series	Type	Due	2015	2014
Puget Sound Energy:				
7.350%	First Mortgage Bond	2015	$ —	$ 10,000
7.360%	First Mortgage Bond	2015	—	2,000
5.197%	Senior Secured Note	2015	—	150,000
6.750%	Senior Secured Note	2016	—	250,000
6.740%	Senior Secured Note	2018	200,000	200,000
7.150%	First Mortgage Bond	2025	15,000	15,000
7.200%	First Mortgage Bond	2025	2,000	2,000
7.020%	Senior Secured Note	2027	300,000	300,000
7.000%	Senior Secured Note	2029	100,000	100,000
3.900%	Pollution Control Bond	2031	138,460	138,460
4.000%	Pollution Control Bond	2031	23,400	23,400
5.483%	Senior Secured Note	2035	250,000	250,000
6.724%	Senior Secured Note	2036	250,000	250,000
6.274%	Senior Secured Note	2037	300,000	300,000
5.757%	Senior Secured Note	2039	350,000	350,000
5.795%	Senior Secured Note	2040	325,000	325,000
5.764%	Senior Secured Note	2040	250,000	250,000
4.434%	Senior Secured Note	2041	250,000	250,000
5.638%	Senior Secured Note	2041	300,000	300,000
4.300%	Senior Secured Note	2045	425,000	—
4.700%	Senior Secured Note	2051	45,000	45,000
6.974%	Junior Subordinated Note	2067	250,000	250,000
	Unamortized discount on senior notes		(1,888)	(13)
Total PSE long-term debt			$ 3,771,972	$ 3,760,847

PSE's senior secured notes will cease to be secured by the pledged first mortgage bonds on the date that all of the first mortgage bonds issued and outstanding under the electric or natural gas utility mortgage indenture have been retired. As of December 31, 2015, the latest maturity date of the first mortgage bonds, other than pledged first mortgage bonds, is December 22, 2025.

Puget Sound Energy Long-Term Debt

PSE has in effect a shelf registration statement under which it may issue, from time to time, senior notes secured by first mortgage bonds. As of December 31, 2015, PSE may issue up to $375.0 million of senior notes under the shelf registration statement which are secured by first mortgage bonds. PSE remains subject to the restrictions of PSE’s indentures and credit agreements on the amount of first mortgage bonds that PSE may issue.

Substantially all utility properties owned by PSE are subject to the lien of the Company’s electric and natural gas mortgage indentures. To issue additional first mortgage bonds under these indentures, PSE’s earnings available for interest must exceed certain minimums as defined in the indentures. At December 31, 2015, the earnings available for interest exceeded the required amount.

On May 26, 2015, PSE issued $425.0 million of senior notes secured by first mortgage bonds. The notes mature in May 2045 and have an interest rate of 4.30%, which is payable semi-annually in May and November. Net proceeds of the issuance were used to fund the early retirement, including accrued interest and make-whole call premiums, of the Company's $150.0 million 5.197% senior notes maturing in October 2015 and the Company's $250.0 million 6.75% senior notes maturing in January 2016.

Puget Sound Energy Pollution Control Bonds

PSE has two series of Pollution Control Bonds (the Bonds) outstanding. Amounts outstanding were borrowed from the City of Forsyth, Montana who obtained the funds from the sale of Customized Pollution Control Refunding Bonds issued to finance pollution control facilities at Colstrip Units 3 & 4.

Each series of the Bonds is collateralized by a pledge of PSE’s first mortgage bonds, the terms of which match those of the Bonds. No payment is due with respect to the related series of first mortgage bonds so long as payment is made on the Bonds.

Long-Term Debt Maturities

The principal amounts of long-term debt maturities for the next five years and thereafter are as follows:

(Dollars in Thousands)	2016	2017	2018	2019	2020	Thereafter	Total
Maturities of:							
PSE long-term debt	$ —	$ —	$ 200,000	$ —	$ —	$ 3,573,860	$ 3,773,860

(7) Liquidity Facilities and Other Financing Arrangements

As of December 31, 2015 and 2014, PSE had $159.0 million and $85.0 million in short-term debt outstanding, respectively, exclusive of the demand promissory note with Puget Energy. PSE’s weighted-average interest rate on short-term debt, including borrowing rate, commitment fees and the amortization of debt issuance costs, during 2015 and 2014 was 4.24% and 4.05%, respectively. As of December 31, 2015, PSE had several committed credit facilities that are described below.

Puget Sound Energy

Credit Facilities

PSE has two unsecured revolving credit facilities which provide, in aggregate, $1.0 billion of short-term liquidity needs. These facilities consist of a $650.0 million revolving liquidity facility (which includes a liquidity letter of credit facility and a swingline facility) to be used for general corporate purposes, including a backstop to the Company's commercial paper program and a $350.0 million revolving energy hedging facility (which includes an energy hedging letter of credit facility). The $650.0 million liquidity facility includes a swingline feature allowing same day availability on borrowings up to $75.0 million. The credit facilities also have an accordion feature which, upon the banks' approval, would increase the total size of these facilities to $1.450 billion.

In April 2014, the Company completed a one-year extension on both of the liquidity and hedging facilities, extending the maturity from February 2018 to April 2019, and updating or clarifying the definitions of other terms and conditions of the facilities from when they were committed in 2013. The credit agreements are syndicated among numerous lenders and contain usual and customary affirmative and negative covenants that, among other things, place limitations on PSE's ability to transact with affiliates, make asset dispositions and investments or permit liens to exist. The credit agreements also contain a financial covenant of total debt to total capitalization of 65% or less. PSE certifies its compliance with such covenants to participating banks each quarter. As of December 31, 2015, PSE was in compliance with all applicable covenant ratios.

The credit agreements provide PSE with the ability to borrow at different interest rate options. The credit agreements allow PSE to borrow at the bank's prime rate or to make floating rate advances at the London Interbank Offered Rate (LIBOR) plus a spread that is based upon PSE's credit rating. PSE must pay a commitment fee on the unused portion of the credit facilities. The spreads and the commitment fee depend on PSE's credit ratings. As of the date of this report, the spread to the LIBOR is 1.25% and the commitment fee is 0.175%.

As of December 31, 2015, no amounts were drawn under either PSE's $650.0 million facility or PSE's $350.0 million energy hedging facility. No letters of credit were outstanding under either facility, and $159.0 million was outstanding under the commercial paper program. Outside of the credit agreements, PSE had a $3.9 million letter of credit in support of a long-term transmission contract and a $1.0 million letter of credit in support of natural gas purchases in Canada.

Demand Promissory Note

PSE entered into a revolving credit facility with Puget Energy, in the form of a credit agreement and a demand promissory note (Note) pursuant to which PSE may borrow up to $30.0 million from Puget Energy subject to approval by Puget Energy. Under the terms of the Note, PSE pays interest on the outstanding borrowings based on the lower of the weighted-average interest rates of PSE’s outstanding commercial paper interest rate or PSE’s senior unsecured revolving credit facility. Absent such borrowings, interest is charged at one-month LIBOR plus 0.25%. On June 30, 2015, PSE repaid in full the $28.9 million outstanding balance under the Note.

(8) Leases

PSE leases buildings and assets under operating leases. Certain leases contain purchase options, renewal options and escalation provisions. Operating lease expenses net of sublease receipts were:

(Dollars in Thousands)
At December 31,

Years	Operating Lease Expense
2015	$ 27,843
2014	30,737

Payments received for the subleases of properties were immaterial for each of the years ended 2015 and 2014. Future minimum lease payments for non-cancelable leases net of sublease receipts are:

(Dollars in Thousands)

At December 31,	Future Minimum Lease Payments	
Years	Operating	Capital
2016	$ 22,254	$ 391
2017	22,849	—
2018	20,468	—
2019	17,403	—
2020	15,425	—
Thereafter	108,085	—
Total minimum lease payments	$ 206,484	$ 391

(9) Accounting for Derivative Instruments and Hedging Activities

PSE employs various energy portfolio optimization strategies, but is not in the business of assuming risk for the purpose of realizing speculative trading revenue. The nature of serving regulated electric customers with its portfolio of owned and contracted electric generation resources exposes PSE and its customers to some volumetric and commodity price risks within the sharing mechanism of the PCA. Therefore, wholesale market transactions and PSE's related hedging strategies are focused on reducing costs and risks where feasible, thus reducing volatility in costs in the portfolio. In order to manage its exposure to the variability in future cash flows for forecasted energy transactions, PSE utilizes a programmatic hedging strategy which extends out three years. PSE's energy risk portfolio management function monitors and manages these risks using analytical models and tools. In order to manage risks effectively, PSE enters into forward physical electric and natural gas purchase and sale agreements, fixed-for-floating swap contracts, and commodity call/put options. The forward physical electric agreements are both fixed and variable (at index), while the physical natural gas contracts are variable. To fix the price of wholesale electricity and natural gas, PSE may enter into fixed-for-floating swap (financial) contracts with various counterparties. PSE also utilizes natural gas call and put options as an additional hedging instrument to increase the hedging portfolio's flexibility to react to commodity price fluctuations.

The Company manages its interest rate risk through the issuance of mostly fixed-rate debt with varied maturities. The Company utilizes internal cash from operations, borrowings under its commercial paper program, and its credit facilities to meet short-term funding needs. The Company may enter into swap instruments or other financial hedge instruments to manage the interest rate risk associated with these debts. As of December 31, 2015, PSE did not have any outstanding interest rate swap instruments.

The following table presents the volumes, fair values and locations of the Company's derivative instruments recorded on the balance sheets:

	Year Ended December 31,					
(Dollars in Thousands)	Volumes (millions)		Assets [1]		Liabilities [2]	
	2015	2014	2015	2014	2015	2014
Electric portfolio derivatives	*	*	23,443	4,822	112,106	107,228
Natural gas derivatives (MMBtus) [3]	369.5	360.4	6,200	19,526	67,090	88,807
Total derivative contracts			$ 29,643	$ 24,348	$ 179,196	$ 196,035
Current			$ 24,418	$ 21,178	$ 131,420	$ 135,973
Long-term			5,225	3,170	47,776	60,062
Total derivative contracts			$ 29,643	$ 24,348	$ 179,196	$ 196,035

1 *Balance sheet location: Current and Long-term Unrealized gain on derivative instruments.*

2 *Balance sheet location: Current and Long-term Unrealized loss on derivative instruments.*

3 *All fair value adjustments on derivatives relating to the natural gas business have been deferred in accordance with ASC 980, "Regulated Operations," due to the PGA mechanism. The net derivative asset or liability and offsetting regulatory liability or asset are related to contracts used to economically hedge the cost of physical gas purchased to serve natural gas customers.*

* *Net purchase and sale volumes for electric portfolio derivatives consist of electric generation fuel of 202.1 million One Million British Thermal Units (MMBtus) and purchased electricity of 0.1 million Megawatt Hours (MWhs) at December 31, 2015 and 140.2 million MMBtus and 5.4 million MWhs at December 31, 2014.*

For further details regarding the fair value of derivative instruments, see Note 10.

It is the Company's policy to record all derivative transactions on a gross basis at the contract level, without offsetting assets or liabilities. The Company generally enters into transactions using the following master agreements: WSPP, Inc. (WSPP) agreements which standardize physical power contracts; International Swaps and Derivatives Association (ISDA) agreements which standardize financial gas and electric contracts; and North American Energy Standards Board (NAESB) agreements which standardize physical gas contracts. The Company believes that such agreements reduce credit risk exposure because such agreements provide for the netting and offsetting of monthly payments as well as right of set-off in the event of counterparty default. The set-off provision can be used as a final settlement of accounts which extinguishes the mutual debts owed between the parties in exchange for a new net amount.

The following tables present the potential effect of netting arrangements, including rights of set-off associated with the Company's derivative assets and liabilities:

At December 31, 2015 (Dollars in Thousands)	Gross Amounts Recognized in the Statement of Financial Position [1]	Gross Amounts Offset in the Statement of Financial Position	Net of Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position		Net Amount
				Commodity Contracts	Cash Collateral Received/Posted	
Assets						
Energy derivative contracts	$ 29,643	$ —	$ 29,643	$ (23,998)	$ —	$ 5,645
Liabilities						
Energy derivative contracts	179,196	—	179,196	(23,998)	—	155,198

At December 31, 2014 (Dollars in Thousands)	Gross Amounts Recognized in the Statement of Financial Position [1]	Gross Amounts Offset in the Statement of Financial Position	Net of Amounts Presented in the Statement of Financial Position	Gross Amounts Not Offset in the Statement of Financial Position		Net Amount
				Commodity Contracts	Cash Collateral Received/Posted	
Assets						
Energy derivative contracts	$ 24,348	$ —	$ 24,348	$ (23,066)	$ —	$ 1,282
Liabilities						
Energy derivative contracts	196,035	—	196,035	(23,066)	(20)	172,949

1 *All Derivative Contract deals are executed under ISDA, NAESB and WSPP Master Netting Agreements with Right of set-off.*

The following tables present the effect and locations of the Company's derivatives not designated as hedging instruments, recorded on the statements of income:

(Dollars in Thousands)	Location	Year Ended December 31, 2015	Year Ended December 31, 2014
Commodity contracts:			
Electric derivatives	Unrealized gain (loss) on derivative instruments, net	$ 12,688	$ (85,636)
	Electric generation fuel	(44,648)	6,511)
	Purchased electricity	(39,137)	(4,212))
Total gain (loss) recognized in income on derivatives		$ (71,097)	$ (83,337)

The unrealized gain or loss on derivative contracts is reported in the statement of cash flows under the operating activities section. For derivative instruments previously designated as cash flow hedges (including both commodity and interest rate swap contracts), the effective portion of the gain or loss on the derivative was recorded as a component of OCI, and then reclassified into earnings in the same period(s) during which the hedged transaction affects earnings. The Company does not attempt cash flow hedging for any new transactions and records all mark-to-market adjustments through earnings.

The following tables present the Company's pre-tax gain (loss) on derivatives that were previously in a cash flow hedge relationship, and subsequently reclassified out of accumulated OCI into income:

		Year Ended December 31,	
(Dollars in Thousands)	Location	2015	2014
Interest rate contracts:	Interest expense [1]	$ (488)	$ (488)
Commodity contracts:			
Electric derivatives	Purchased electricity	(1,055)	(2,063)
Total		$ (1,543)	$ (2,551)

1 *Within the next twelve months, $0.5 million of losses in AOCI will be reclassified into earnings.*

The Company is exposed to credit risk primarily through buying and selling electricity and natural gas to serve its customers. Credit risk is the potential loss resulting from a counterparty's non-performance under an agreement. The Company manages credit risk with policies and procedures for, among other things, counterparty credit analysis, exposure measurement, exposure monitoring and exposure mitigation.

The Company monitors counterparties that have significant swings in credit default swap rates, have credit rating changes by external rating agencies, have changes in ownership or are experiencing financial distress. Where deemed appropriate, the Company may request collateral or other security from its counterparties to mitigate potential credit default losses. Criteria employed in this decision include, among other things, the perceived creditworthiness of the counterparty and the expected credit exposure.

It is possible that volatility in energy commodity prices could cause the Company to have material credit risk exposure with one or more counterparties. If such counterparties fail to perform their obligations under one or more agreements, the Company could suffer a material financial loss. However, as of December 31, 2015, approximately 99.2% of the Company's energy portfolio exposure, excluding NPNS transactions, is with counterparties that are rated at least investment grade by the major rating agencies and 0.8% are either rated below investment grade or not rated by rating agencies. The Company assesses credit risk internally for counterparties that are not rated.

The Company computes credit reserves at a master agreement level by counterparty. The Company considers external credit ratings and market factors, such as credit default swaps and bond spreads, in the determination of reserves. The Company recognizes that external ratings may not always reflect how a market participant perceives a counterparty's risk of default. The Company uses both default factors published by Standard & Poor's and factors derived through analysis of market risk, which reflect the application of an industry standard recovery rate. The Company selects a default factor by counterparty at an aggregate master agreement level based on a weighted-average default tenor for that counterparty's deals. The default tenor is determined by weighting the fair value and contract tenors for all deals for each counterparty to derive an average value. The default factor used is dependent upon whether the counterparty is in a net asset or a net liability position after applying the master agreement levels.

The Company applies the counterparty's default factor to compute credit reserves for counterparties that are in a net asset position. The Company calculates a non-performance risk on its derivative liabilities by using its estimated incremental borrowing rate over the risk-free rate. Credit reserves are netted against unrealized gain (loss) positions. As of December 31, 2015, the Company was in a net liability position with the majority of counterparties, so the default factors of counterparties did not have a significant impact on reserves for the quarter. The majority of the Company's derivative contracts are with financial institutions and other utilities operating within the Western Electricity Coordinating Council. As of December 31, 2015, PSE has posted a $1.0 million letter of credit as a condition of transacting on a physical energy exchange and clearinghouse in Canada. PSE did not trigger any collateral requirements with any of its counterparties nor were any of PSE's counterparties required to post collateral resulting from credit rating downgrades.

The table below presents the fair value of the overall contractual contingent liability positions for the Company's derivative activity at December 31, 2015:

Contingent Feature (Dollars in Thousands)	Fair Value Liability [1]	Posted Collateral	Contingent Collateral
Credit rating [2]	$ 24,187	$ —	$ 24,187
Requested credit for adequate assurance	67,003	—	—
Total	$ 91,190	$ —	$ 24,187

1 *Represents the derivative fair value of contracts with contingent features for counterparties in net derivative liability positions. Excludes NPNS, accounts payable and accounts receivable.*

2 *Failure by PSE to maintain an investment grade credit rating from each of the major credit rating agencies provides counterparties a contractual right to demand collateral.*

(10) Fair Value Measurements

ASC 820 established a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy categorizes the inputs into three levels with the highest priority given to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority given to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 - Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Level 1 primarily consists of financial instruments such as exchange-traded derivatives and listed equities. Equity securities that are also classified as cash equivalents are considered Level 1 if there are unadjusted quoted prices in active markets for identical assets or liabilities.

Level 2 - Pricing inputs are other than quoted prices in active markets included in Level 1, 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. Instruments in this category include non-exchange-traded derivatives such as over-the-counter forwards and options.

Level 3 - Pricing inputs include significant inputs that have little or no observability as of the reporting date. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value.

Financial assets and liabilities measured at fair value are classified in their entirety in the appropriate fair value hierarchy 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. The Company primarily determines fair value measurements classified as Level 2 or Level 3 using a combination of the income and market valuation approaches. The process of determining the fair values is the responsibility of the derivative accounting department which reports to the Controller and Principal Accounting Officer. Inputs used to estimate the fair value of forwards, swaps and options include market-price curves; contract terms and prices; credit-risk adjustments; and discount factors. Additionally, for options, the Black-Scholes option valuation model and implied market volatility curves are used. Inputs used to estimate fair value in industry-standard models are categorized as Level 2 inputs because substantially all assumptions and inputs are observable in active markets throughout the full term of the instruments. On a daily basis, the Company obtains quoted forward prices for the electric and natural gas markets from an independent external pricing service. For interest rate swaps, the Company obtains monthly mark-to-market values from an independent external pricing service for LIBOR forward rates, which is a significant input. Some of the inputs of the interest rate swap valuations, which are less significant, include the credit standing of the counterparties, assumptions for time value and the impact of the Company's nonperformance risk of its liabilities. The Company classifies cash and cash equivalents, and restricted cash as Level 1 financial instruments due to cash being at stated value, and cash equivalents at quoted market prices.

The Company considers its electric, natural gas and interest rate swap contracts as Level 2 derivative instruments as such contracts are commonly traded as over-the-counter forwards with indirectly observable price quotes. Management's assessment was based on the trading activity in real-time and forward electric and natural gas markets. Each quarter, the Company confirms the validity of pricing-service quoted prices (e.g., Level 2 in the fair value hierarchy) used to value commodity contracts with the actual prices of commodity contracts entered into during the most recent quarter. However, certain energy derivative instruments with maturity dates falling outside the range of observable price quotes are classified as Level 3 in the fair value hierarchy.

Assets and Liabilities with Estimated Fair Value

The following table presents the carrying value for cash, cash equivalents, restricted cash, notes receivable and short-term debt by level, within the fair value hierarchy. The carrying values below are representative of fair values due to the short-term nature of these financial instruments.

	Carrying / Fair Value At December 31, 2015			Carrying / Fair Value At December 31, 2014		
(Dollars in Thousands)	Level 1	Level 2	Total	Level 1	Level 2	Total
Assets:						
Cash and Cash Equivalents	$ 39,451	$ —	$ 39,451	$ 35,531	$ —	$ 35,531
Restricted Cash	7,860	—	7,860	32,775	—	32,775
Notes Receivable and Other	—	52,820	52,820	—	53,503	53,503
Total assets	$ 47,311	$ 52,820	$ 100,131	$ 68,306	$ 53,503	$ 121,809
Liabilities:						
Short-term debt	$ 159,004	$ —	$ 159,004	$ 85,000	$ —	$ 85,000
Short-term debt owed to parent	—	—	—	—	28,933	28,933
Total liabilities	$ 159,004	$ —	$ 159,004	$ 85,000	$ 28,933	$ 113,933

The fair value of the junior subordinated and long-term notes were estimated using the discounted cash flow method with U.S. Treasury yields and Company credit spreads as inputs, interpolating to the maturity date of each issue. Carrying values and estimated fair values were as follows:

		December 31, 2015		December 31, 2014	
(Dollars in Thousands)	Level	Carrying Value	Fair Value	Carrying Value	Fair Value
Liabilities:					
Junior subordinated notes	2	$ 250,000	$ 211,173	$ 250,000	$ 276,235
Long-term debt (fixed-rate), net of discount	2	3,521,972	4,326,875	3,510,847	4,434,816
Total		$ 3,771,972	$ 4,538,048	$ 3,760,847	$ 4,711,051

Assets and Liabilities Measured at Fair Value on a Recurring Basis

The following tables present the Company's financial assets and liabilities by level, within the fair value hierarchy, that were accounted for at fair value on a recurring basis and the reconciliation of the changes in the fair value of Level 3 derivatives in the fair value hierarchy:

	Fair Value At December 31, 2015			Fair Value At December 31, 2014		
(Dollars in Thousands)	Level 2	Level 3	Total	Level 2	Level 3	Total
Assets:						
Electric derivative instruments	$ 10,709	$ 12,734	$ 23,443	$ 1,654	$ 3,168	$ 4,822
Natural gas derivative instruments	4,538	1,662	6,200	18,064	1,462	19,526
Total assets	$ 15,247	$ 14,396	$ 29,643	$ 19,718	$ 4,630	$ 24,348
Liabilities:						
Electric derivative instruments	$ 92,027	$ 20,079	$ 112,106	$ 91,998	$ 15,230	$ 107,228
Natural gas derivative instruments	63,045	4,045	67,090	85,305	3,502	88,807
Total liabilities	$ 155,072	$ 24,124	$ 179,196	$ 177,303	$ 18,732	$ 196,035

Level 3 Roll-Forward Net (Liability) (Dollars in Thousands)	Year Ended December 31, 2015			2014		
	Electric	Gas	Total	Electric	Gas	Total
Balance at beginning of period	$ (12,062)	$ (2,040)	$ (14,102)	$ (15,421)	$ (361)	$ (15,782)
Changes during period						
Realized and unrealized energy derivatives:						
Included in earnings [1]	(6,432)	—	(6,432)	(5,537)	—	(5,537)
Included in regulatory assets / liabilities	—	3,695	3,695	—	1,630	1,630
Settlements [2]	902	(3,885)	(2,983)	1,036	(1,534)	(498)
Transferred into Level 3	(787)	—	(787)	5,155	(585)	4,570
Transferred out of Level 3	11,034	(153)	10,881	2,705	(1,190)	1,515
Balance at end of period	$ (7,345)	$ (2,383)	$ (9,728)	$ (12,062)	$ (2,040)	$ (14,102)

1 *Income Statement location: Unrealized (gain) loss on derivative instruments, net. Includes unrealized gains (losses) on derivatives still held in position as of the reporting date for electric derivatives of $(7.4) million and $(9.6) million for the years ended December 31, 2015 and 2014, respectively.*

2 *The Company had no purchases, sales or issuances during the reported periods.*

Realized gains and losses on energy derivatives for Level 3 recurring items are included in energy costs in the Company's consolidated statements of income under purchased electricity, electric generation fuel or purchased natural gas when settled. Unrealized gains and losses on energy derivatives for Level 3 recurring items are included in net unrealized (gain) loss on derivative instruments in the Company's consolidated statements of income.

In order to determine which assets and liabilities are classified as Level 3, the Company receives market data from its independent external pricing service defining the tenor of observable market quotes. To the extent any of the Company's commodity contracts extend beyond what is considered observable as defined by its independent pricing service, the contracts are classified as Level 3. The actual tenor of what the independent pricing service defines as observable is subject to change depending on market conditions. Therefore, as the market changes, the same contract may be designated Level 3 one month and Level 2 the next, and vice versa. The changes of fair value classification into or out of Level 3 are recognized each month, and reported in the Level 3 Roll-forward table above. The Company did not have any transfers between Level 2 and Level 1 during the years ended December 31, 2015 and 2014. The Company does periodically transact at locations, or market price points, that are illiquid or for which no prices are available from the independent pricing service. In such circumstances the Company uses a more liquid price point and performs a 15-month regression against the illiquid locations to serve as a proxy for market prices. Such transactions are classified as Level 3. The Company does not use internally developed models to make adjustments to significant unobservable pricing inputs.

The only significant unobservable input into the fair value measurement of the Company's Level 3 assets and liabilities is the forward price for electric and natural gas contracts. Below are the forward price ranges for the Company's commodity contracts, as of December 31, 2015:

(Dollars in Thousands)

	Fair Value				Range		
Derivative Instrument	Assets [1]	Liabilities [1]	Valuation Technique	Unobservable Input	Low	High	Weighted Average
Electric	$12,734	$20,079	Discounted cash flow	Power Prices	$10.69 per MWh	$29.18 per MWh	$23.39 per MWh
Natural gas	$1,662	$4,045	Discounted cash flow	Natural Gas Prices	$1.12 per MMBtu	$2.95 per MMBtu	$2.25 per MMBtu

1 *The valuation techniques, unobservable inputs and ranges are the same for asset and liability positions.*

The significant unobservable inputs listed above would have a direct impact on the fair values of the above instruments if they were adjusted. Consequently, significant increases or decreases in the forward prices of electricity or natural gas in isolation would result in a significantly higher or lower fair value for Level 3 assets and liabilities. Generally, interrelationships exist between market prices of natural gas and power. As such, an increase in natural gas pricing would potentially have a similar impact on forward power markets. At December 31, 2015, a hypothetical 10% increase or decrease in market prices of natural gas and electricity would change the fair value of the Company's derivative portfolio, classified as Level 3 within the fair value hierarchy, by $1.3 million.

(11) Employee Investment Plans

The Company's Investment Plan is a qualified employee 401(k) plan, under which employee salary deferrals and after-tax contributions are used to purchase several different investment fund options. PSE's contributions to the employee Investment Plan were $16.1 million and $14.9 million for the years 2015 and 2014, respectively. The employee Investment Plan eligibility requirements are set forth in the plan documents.

Non-represented employees and United Association of Journeymen and Apprentices of the Plumbing and Pipefitting Industry (UA) represented employees hired before January 1, 2014, and International Brotherhood of Electrical Workers Local Union 77 (IBEW) represented employees hired before December 12, 2014, have the following company contributions:

- For employees under the Cash Balance retirement plan formula, PSE will match 100% of an employee's contribution up to 6% of plan compensation each paycheck, and will make an additional year-end contribution equal to 1% of base pay.
- For employees grandfathered under the Final Average Earning retirement plan formula, PSE will match 55% of an employee's contribution up to 6% of plan compensation each paycheck.

UA-represented employees hired on or after January 1, 2014 will have access to the 401(k) Plan. Non-represented employees hired on or after January 1, 2014, and IBEW-represented employees hired on or after December 12, 2014, will have access to the 401(k) plan and will choose how they want to accumulate funds for retirement, choosing from one of the two contribution sources from PSE:

- 401(k) Company Matching: New non-represented, UA-represented and IBEW-represented employees will receive company match each paycheck based on a new schedule-100% match on the first 3% of pay contributed and 50% match on the next 3% of pay contributed. An employee who contributes 6% of pay will receive 4.5% of pay in company match. Company matching will be immediately vested.

- Company Contribution: New UA-represented employees will receive an annual company contribution of 4% of eligible pay placed in the Cash Balance retirement plan. New non-represented and IBEW-represented employees will receive an annual company contribution of 4% of eligible pay, placed either in the Investment Plan 401(k) plan or in PSE's Cash Balance retirement plan. New non-represented and IBEW-represented employees will make a one-time election within 30 days of hire and direct that PSE put the 4% contribution either into the 401(k) plan or into an account in the Cash Balance retirement plan. The Company's 4% contribution will vest after three years of service.

(12) Retirement Benefits

PSE has a defined benefit pension plan (Qualified Pension Benefits) covering the largest portion of PSE employees. Pension benefits earned are a function of age, salary, years of service and, in the case of employees in the cash balance formula plan, the applicable annual interest crediting rates. Starting with January 1, 2014, all newly hired non-represented employees, United Association of Journeymen and Apprentices of the Plumbing and Pipe Fitting Industry employees, and International Brotherhood of Electrical Workers Local Union 77 hired on or after December 12, 2014 who elect to accumulate the Company contribution in the cash balance formula portion of the pension plan, will receive annual pay credits of 4% each year. They will also receive interest credits like other participants in the cash balance pension formula of the pension plan, which are at least 1% per quarter. When an employee with a vested cash balance formula benefit leaves PSE, he or she will have annuity and lump sum options for distribution. Those who select the lump sum option will receive their current cash balance amount. PSE also maintains a non-qualified Supplemental Executive Retirement Plan (SERP) for its key senior management employees.

In addition to providing pension benefits, PSE provides legacy group health care and life insurance benefits (Other Benefits) for certain retired employees. These benefits are provided principally through an insurance company. The insurance premiums, paid primarily by retirees, are based on the benefits provided during the prior year.

The following tables summarize the Company's change in benefit obligation, change in plan assets and amounts recognized in the Statements of Financial Position for the years ended December 31, 2015 and 2014:

	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2015	2014	2015	2014	2015	2014
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 690,194	$ 573,317	$ 55,855	$ 47,279	$ 15,688	$ 14,939
Service cost	21,287	17,437	1,108	1,042	112	112
Interest cost	28,088	28,039	2,281	2,310	621	684
Actuarial loss (gain)	(55,665)	104,618	(4,430)	7,162	(1,416)	1,108
Benefits paid	(39,963)	(33,217)	(3,535)	(1,938)	(1,354)	(1,424)
Medicare part D subsidy received	—	—	—	—	295	269
Administrative expense	(853)	—	—	—	—	—
Benefit obligation at end of period	$ 643,088	$ 690,194	$ 51,279	$ 55,855	$ 13,946	$ 15,688

	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2015	2014	2015	2014	2015	2014
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 626,173	$ 615,721	$ —	$ —	$ 8,360	$ 8,774
Actual return on plan assets	(4,489)	25,669	—	—	(378)	522
Employer contribution	18,000	18,000	3,535	1,938	575	488
Benefits paid	(39,963)	(33,217)	(3,535)	(1,938)	(1,354)	(1,424)
Administrative expense	(856)	—	—	—	—	—
Fair value of plan assets at end of period	$ 598,865	$ 626,173	$ —	$ —	$ 7,203	$ 8,360
Funded status at end of period	$ (44,223)	$ (64,021)	$ (51,279)	$ (55,855)	$ (6,743)	$ (7,328)

	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2015	2014	2015	2014	2015	2014
Amounts recognized in Statement of Financial Position consist of:						
Noncurrent assets	$ —	$ —	$ —	$ —	$ —	$ —
Current liabilities	—	—	(2,545)	(4,386)	(353)	(355)
Noncurrent liabilities	(44,223)	(64,021)	(48,734)	(51,469)	(6,390)	(6,973)
Net assets (liabilities)	$ (44,223)	$ (64,021)	$ (51,279)	$ (55,855)	$ (6,743)	$ (7,328)

	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2015	2014	2015	2014	2015	2014
Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:						
Projected benefit obligation	$ 643,088	$ 690,194	$ 51,279	$ 55,855	$ 13,946	$ 15,688
Accumulated benefit obligation	635,599	681,745	46,978	50,137	13,828	15,553
Fair value of plan assets	598,865	626,173	—	—	7,203	8,360

The following tables summarize PSE's pension benefit amounts recognized in AOCI for the years ended December 31, 2015 and 2014:

	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2015	2014	2015	2014	2015	2014
Amounts recognized in Accumulated Other Comprehensive Income consist of:						
Net loss (gain)	$ 221,064	$ 247,331	$ 13,202	$ 19,751	$ 3,834	$ (3,733)
Prior service cost (credit)	(9,379)	(10,952)	295	339	—	3
Total	$ 211,685	$ 236,379	$ 13,497	$ 20,090	$ 3,834	$ (3,730)

The following tables summarize PSE's net periodic benefit cost for the years ended December 31, 2015 and 2014:

	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2015	2014	2015	2014	2015	2014
Components of net periodic benefit cost:						
Service cost	$ 21,287	$ 17,437	$ 1,108	$ 1,042	$ 112	$ 112
Interest cost	28,088	28,039	2,281	2,310	621	684
Expected return on plan assets	(45,462)	(43,252)	—	—	(531)	(535)
Amortization of prior service cost (credit)	(1,573)	(1,573)	44	44	3	3
Amortization of net loss(gain)	20,555	13,195	2,120	1,461	(406)	(702)
Net periodic benefit cost	$ 22,895	$ 13,846	$ 5,553	$ 4,857	$ (201)	$ (438)

The following tables summarize PSE's benefit obligations recognized in OCI for the years ended December 31, 2015 and 2014:

	Qualified Pension Benefit		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2015	2014	2015	2014	2015	2014
Other changes (pre-tax) in plan assets and benefit obligations recognized in other comprehensive income:						
Net loss (gain)	$ (5,711)	$ 122,202	$ (4,430)	$ 7,162	$ (508)	$ 1,121
Amortization of net (loss) gain	(20,556)	(13,195)	(2,120)	(1,461)	407	702
Amortization of prior service cost (credit)	1,573	1,573	(44)	(44)	(3)	(3)
Total change in other comprehensive income for year	$ (24,694)	$ 110,580	$ (6,594)	$ 5,657	$ (104)	$ 1,820

The estimated net (loss) gain and prior service cost (credit) for the pension plans that will be amortized from accumulated OCI into net periodic benefit cost in 2016 by PSE are $15.0 million and $1.6 million, respectively. The estimated net (loss) gain for the SERP that will be amortized from accumulated OCI into net periodic benefit cost in 2016 is $1.3 million. The estimated prior service cost (credit) for the SERP that will be amortized from accumulated OCI into net periodic benefit cost in 2016 is immaterial. The estimated net (loss) gain and prior service cost (credit) for the other postretirement plans that will be amortized from accumulated OCI into net periodic benefit cost in 2016 is immaterial.

The aggregate expected contributions by the Company to fund the qualified pension plan, SERP and the other postretirement plans for the year ending December 31, 2016 are expected to be at least $18.0 million, $2.5 million and $0.5 million, respectively.

Assumptions

In accounting for pension and other benefit obligations and costs under the plans, the following weighted-average actuarial assumptions were used by the Company:

	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
Benefit Obligation Assumptions	2015	2014	2015	2014	2015	2014
Discount rate	4.65 %	4.25 %	4.65 %	4.25 %	4.65 %	4.25 %
Rate of compensation increase	4.50	4.50	4.50	4.50	4.50	4.50
Medical trend rate	—	—	—	—	7.20	5.70
Benefit Cost Assumptions						
Discount rate	4.25 %	5.10 %	4.25 %	5.10 %	4.25 %	5.10 %
Return on plan assets	7.75	7.75	—	—	7.00	7.00
Rate of compensation increase	4.50	4.50	4.50	4.50	4.50	4.50
Medical trend rate	—	—	—	—	7.20	6.70

The assumed medical inflation rate used to determine benefit obligations is 7.20% in 2016 grading down to 4.30% in 2017. A 1.0% change in the assumed medical inflation rate would have the following effects:

	2015		2014	
(Dollars in Thousands)	1% Increase	1% Decrease	1% Increase	1% Decrease
Effect on post-retirement benefit obligation	$ 52	$ (42)	$ 47	$ (47)
Effect on service and interest cost components	2	(2)	2	(2)

The Company has selected the expected return on plan assets based on a historical analysis of rates of return and the Company's investment mix, market conditions, inflation and other factors. The expected rate of return is reviewed annually based on these factors. The Company's accounting policy for calculating the market-related value of assets for the Company's retirement plan is as follows. PSE market-related value of assets is based on a five-year smoothing of asset gains (losses) measured from the expected return on market-related assets. This is a calculated value that recognizes changes in fair value in a systematic and rational manner over five years. The same manner of calculating market-related value is used for all classes of assets, and is applied consistently from year to year.

The discount rates were determined by using market interest rate data and the weighted-average discount rate from Citigroup Pension Liability Index Curve. The Company also takes into account in determining the discount rate the expected changes in market interest rates and anticipated changes in the duration of the plan liabilities.

Plan Benefits

The expected total benefits to be paid during the next five years and the aggregate total to be paid for the five years thereafter are as follows:

(Dollars in Thousands)	2016	2017	2018	2019	2020	2021-2025
Qualified Pension total benefits	$ 41,300	$ 42,400	$ 43,100	$ 43,300	$ 45,000	$ 235,600
SERP Pension total benefits	2,545	1,922	5,210	5,564	4,455	19,875
Other Benefits total with Medicare Part D subsidy	1,031	1,091	1,064	1,038	1,003	5,568
Other Benefits total without Medicare Part D subsidy	1,369	1,358	1,339	1,319	1,292	5,934

Plan Assets

Plan contributions and the actuarial present value of accumulated plan benefits are prepared based on certain assumptions pertaining to interest rates, inflation rates and employee demographics, all of which are subject to change. Due to uncertainties inherent in the estimations and assumptions process, changes in these estimates and assumptions in the near term may be material to the financial statements.

The Company has a Retirement Plan Committee that establishes investment policies, objectives and strategies designed to balance expected return with a prudent level of risk. All changes to the investment policies are reviewed and approved by the Retirement Plan Committee prior to being implemented.

The Retirement Plan Committee invests trust assets with investment managers who have historically achieved above-median long-term investment performance within the risk and asset allocation limits that have been established. Interim evaluations are routinely performed with the assistance of an outside investment consultant. To obtain the desired return needed to fund the pension benefit plans, the Retirement Plan Committee has established investment allocation percentages by asset classes as follows:

	Allocation		
Asset Class	Minimum	Target	Maximum
Domestic large cap equity	25%	31%	40%
Domestic small cap equity	0	9	15
Non-U.S. equity	10	25	30
Fixed income	15	25	30
Real estate	0	0	10
Absolute return	5	10	15
Cash	0	0	5

Plan Fair Value Measurements

ASC 715, "Compensation – Retirement Benefits" (ASC 715) directs companies to provide additional disclosures about plan assets of a defined benefit pension or other postretirement plan. The objectives of the disclosures are to disclose the following: (1) how investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies; (2) major categories of plan assets; (3) inputs and valuation techniques used to measure the fair value of plan assets; (4) effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period; and (5) significant concentrations of risk within plan assets.

ASC 820 allows the reporting entity, as a practical expedient, to measure the fair value of investments that do not have readily determinable fair values on the basis of the net asset value per share of the investment if the net asset value of the investment is calculated in a matter consistent with ASC 946, "Financial Services – Investment Companies." The standard requires disclosures about the nature and risk of the investments and whether the investments are probable of being sold at amounts different from the net asset value per share.

The following table sets forth by level, within the fair value hierarchy, the qualified pension plan as of December 31, 2015 and 2014:

	Recurring Fair Value Measures As of December 31, 2015				Recurring Fair Value Measures As of December 31, 2014			
(Dollars in Thousands)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Equities:								
Non-US equity [1]	$ 69,127	$ 76,071	$ —	$ 145,198	$ 71,026	$ 74,131	$ —	$ 145,157
Domestic large cap equity [2]	119,512	65,287	—	184,799	134,765	68,336	—	203,101
Domestic small cap equity [3]	53,985	—	—	53,985	59,657	—	—	59,657
Total equities	242,624	141,358	—	383,982	265,448	142,467	—	407,915
Fixed income securities [4]	81,696	58,425	—	140,121	72,331	67,182	—	139,513
Absolute return [5]	—	—	64,925	64,925	—	—	65,251	65,251
Cash and cash equivalents [6]	340	17,041	—	17,381	12,650	—	—	12,650
Subtotal	$ 324,660	$ 216,824	$ 64,925	$ 606,409	$ 350,429	$ 209,649	$ 65,251	$ 625,329
Net (payable) receivable	—	—	—	(7,544)	—	—	—	844
Accrued income	—	—	—	—	—	—	—	—
Total assets				$ 598,865				$ 626,173

1 *Non – US Equity investments are comprised of a mutual fund (at level 1); and a commingled fund (at level 2). The investment in the mutual fund is valued at the daily closing price as reported by the funds. The investment in the commingled fund is valued at the net asset value per share multiplied by the number of shares held as of December 31, 2015.*

2 *Domestic large cap equity investments are comprised of common stock (at level 1), and a commingled fund (at level 2). Investments in common stock traded on a national securities exchange are valued at the last reported sales price on the last business day of the year. Securities traded in the over-the-counter market and listed securities for which no sale was reported on that date are valued at the last reported sale or bid price, as available or at values based upon bid quotations for identical or similar instruments. The investment in the commingled fund is valued at the net asset value per share multiplied by the number of shares held as of December 31, 2015.*

3 *Domestic small cap equity investments are comprised of common stock and a mutual fund, please see 1 and 2 above for a description.*

4 *Fixed income securities consist of mutual funds and US treasury bonds (at level 1), and government securities and corporate bonds (at level 2). Please see 1 above for a description of mutual funds. Government securities and corporate bonds are valued using pricing models maximizing the use of observable inputs for similar securities. When quoted prices are not available for identical or similar bonds, the bond is valued under a discounted cash flow approach maximizing observable inputs.*

5 *As of December 31, 2015 absolute return investments consist of two partnerships. The partnerships are valued based on the net asset value provided by the Plan's investment custodians, and reported in the funds' financial statements which are audited annually by independent accountants. These investments are at Level 3 under ASC 820 because the significant valuation inputs are primarily internal to the partnerships with little third party involvement.*

6 *The investment consists of a money market fund (at level 1) and a collective trust fund (at level 2). The money market fund is valued at the net asset value per share of $1.00 per unit as of December 31, 2015. The collective trust fund invests primarily in commercial paper, notes, repurchase agreements, and other evidences of indebtedness which are payable on demand or short-term in nature.*

Level 3 Roll-Forward

The following table sets forth a reconciliation of changes in the fair value of the plan's Level 3 assets:

	As of December 31, 2015		As of December 31, 2014	
(Dollars in Thousands)	Partnership	Total	Partnership	Total
Balance at beginning of year	$ 65,251	$ 65,251	$ 62,278	$ 62,278
Additional investments	—	—	—	—
Distributions	—	—	—	—
Realized losses on distributions	—	—	—	—
Unrealized gain (loss) instruments still held at the reporting date	(326)	(326)	2,973	2,973
Transferred in/out of level 3 [1]	—	—	—	—
Balance at end of year	$ 64,925	$ 64,925	$ 65,251	$ 65,251

1 *The plan had no transfers between level 2 and level 1 during the years ended December 31, 2015 or 2014.*

The following table sets forth by level, within the fair value hierarchy, the Other Benefits plan assets which consist of insurance benefits for retired employees, at fair value:

	Recurring Fair Value Measures As of December 31, 2015			Recurring Fair Value Measures As of December 31, 2014		
(Dollars in Thousands)	Level 1	Level 2	Total	Level 1	Level 2	Total
Assets:						
Mutual fund [1]	$ 7,135	$ —	$ 7,135	$ 8,301	$ —	$ 8,301
Cash equivalents [2]	—	68	68	59	—	59
Total assets	$ 7,135	$ 68	$ 7,203	$ 8,360	$ —	$ 8,360

1 *This is a publicly traded balanced mutual fund. The fund seeks regular income, conservation of principal, and an opportunity for long-term growth of principal and income. The fair value is determined by taking the number of shares owned by the plan, and multiplying by the market price as of December 31, 2015.*

2 *The investment consists of a money market fund (at level 1) and a collective trust fund (at level 2). The money market fund is valued at the net asset value per share of $1.00 per unit as of December 31, 2015. The collective trust fund invests primarily in commercial paper, notes, repurchase agreements, and other evidences of indebtedness which are payable on demand or short-term in nature.*

(13) Income Taxes

The details of income tax (benefit) expense are as follows:

(Dollars in Thousands)	Year Ended December 31, 2015	2014
Charged to expenses:		
Deferred:		
Federal	$ 125,882	$ 88,318
State	—	—
Total income tax expense	$ 125,882	$ 88,318

The following reconciliation compares pre-tax book income at the federal statutory rate of 35.0% to the actual income tax expense in the Statements of Income:

(Dollars in Thousands)	Year Ended December 31, 2015	2014
Income taxes at the statutory rate	$ 150,514	$ 113,061
Increase (decrease):		
Production tax credit	(19,470)	(23,073)
AFUDC excluded from taxable income	(5,386)	(3,790)
Capitalized interest	3,397	2,948
Utility plant differences	5,671	7,090
Treasury grant amortization	(8,807)	(8,808)
Other - net	(37)	890
Total income tax expense	$ 125,882	$ 88,318
Effective tax rate	29.3%	27.1 %

The Company's net deferred tax liability at December 31, 2015 and 2014 is composed of amounts related to the following types of temporary differences:

	At December 31,	
(Dollars In Thousands)	2015	2014
Utility plant and equipment	$ 1,788,078	$ 1,720,730
Regulatory asset for income taxes	72,694	94,913
Other deferred tax liabilities	80,351	50,229
Subtotal deferred tax liabilities	1,941,123	1,865,872
Net operating loss carryforward	(110,063)	(181,514)
Production tax credit carryforward	(178,075)	(158,604)
Regulatory liability on production tax credit	(94,828)	(84,344)
Subtotal deferred tax assets	(382,966)	(424,462)
Total net deferred tax liabilities	$ 1,558,157	$ 1,441,410

In November 2015, the FASB issued ASU 2015-17, "Income Taxes (Topic 740): Balance Sheet Classification of Deferred Taxes." ASU 2015-17 requires reporting entities to classify deferred tax liabilities and assets as noncurrent in a classified balance sheet instead of separating such deferred taxes into current and noncurrent amounts.

The Company adopted ASU 2015-17 for year ended December 31, 2015 and the impact to PSE was a reclass in 2014 from current to noncurrent of $208.4 million. Except for changes in Consolidated Balance Sheet presentation, this guidance does not have a material impact on the Company's results of operations or financial position.

The Company calculates its deferred tax assets and liabilities under ASC 740, "Income Taxes" (ASC 740). ASC 740 requires recording deferred tax balances, at the currently enacted tax rate, on assets and liabilities that are reported differently for income tax purposes than for financial reporting purposes. The utilization of deferred tax assets requires sufficient taxable income in future years. ASC 740 requires a valuation allowance on deferred tax assets when it is more likely than not that the deferred tax assets will not be realized. The Company's PTC carryforwards expire from 2027 through 2035. The Company's net operating loss carryforwards expire from 2029 through 2033. No valuation allowance has been provided for PTC or net operating loss carryforwards.

For ratemaking purposes, deferred taxes are not provided for certain temporary differences. PSE has established a regulatory asset for income taxes recoverable through future rates related to those temporary differences for which no deferred taxes have been provided, based on prior and expected future ratemaking treatment.

The Company accounts for uncertain tax position under ASC 740, which clarifies the accounting for uncertainty in income taxes recognized in the financial statements. ASC 740 requires the use of a two-step approach for recognizing and measuring tax positions taken or expected to be taken in a tax return. First, a tax position should only be recognized when it is more likely than not, based on technical merits, that the position will be sustained upon challenge by the taxing authorities and taken by management to the court of last resort. Second, a tax position that meets the recognition threshold should be measured at the largest amount that has a greater than 50.0% likelihood of being sustained.

As of December 31, 2015 and 2014, the Company had no material unrecognized tax benefits. As a result, no interest or penalties were accrued for unrecognized tax benefits during the year.

For ASC 740 purposes, the Company has open tax years from 2012 through 2015. The Company classifies interest as interest expense and penalties as other expense in the financial statements.

(14) Litigation

Colstrip

PSE has a 50% ownership interest in Colstrip Units 1 and 2, and a 25% interest in Colstrip Units 3 and 4. On March 6, 2013, the Sierra Club and the Montana Environmental Information Center filed a Clean Air Act citizen suit against all Colstrip owners in the U.S. District Court, District of Montana. Based on a second amended complaint filed in August 2014, plaintiffs' lawsuit currently alleges violations of permitting requirements under the New Source Review program of the Clean Air Act and the Montana State Implementation Plan arising from seven projects undertaken at Colstrip during the time period from 2001 to 2012. Plaintiffs have since indicated that they do not intend to pursue claims with respect to three of the seven projects, leaving a total of four projects remaining subject to the lawsuit. The lawsuit claims that, for each of the four projects, the Colstrip plant should have obtained a permit and installed pollution control equipment at Colstrip. The Plaintiffs' complaint also seeks civil penalties and other appropriate relief. The case has been bifurcated into separate liability and remedy trials. The liability trial is currently set for May 2016, and a date for the remedy trial has yet to be determined. PSE is litigating the allegations set forth in the complaint, and as such, it is not reasonably possible to estimate the outcome of this matter.

Other Proceedings

The Company is also involved in litigation relating to claims arising out of its operations in the normal course of business. The Company has recorded reserves of $0.3 million and $1.7 million relating to these claims as of December 31, 2015 and 2014, respectively.

(15) Commitments and Contingencies

For the year ended December 31, 2015, approximately 13.9% of the Company’s energy output was obtained at an average cost of approximately $0.022 per Kilowatt Hour (kWh) through long-term contracts with three of the Washington Public Utility Districts (PUDs) that own hydroelectric projects on the Columbia River. The purchase of power from the Columbia River projects is on a pro rata share basis under which the Company pays a proportionate share of the annual debt service, operating and maintenance costs and other expenses associated with each project, in proportion to the contractual share of power that PSE obtains from that project. In these instances, PSE’s payments are not contingent upon the projects being operable; therefore, PSE is required to make the payments even if power is not delivered. These projects are financed through substantially level debt service payments and their annual costs should not vary significantly over the term of the contracts unless additional financing is required to meet the costs of major maintenance, repairs or replacements, or license requirements. The Company’s share of the costs and the output of the projects is subject to reduction due to various withdrawal rights of the PUDs and others over the contract lives.

The Company's expenses under these PUD contracts were as follows for the years ended December 31:

(Dollars in Thousands)	2015	2014
PUD contract costs	$ 72,833	$ 69,661

As of December 31, 2015, the Company purchased portions of the power output of the PUDs' projects as set forth in the following table:

		Company's Current Share of					
(Dollars in Thousands)	Contract Expiration	Percent of Output	Megawatt Capacity	Estimated 2016 Costs	2016 Debt Service Costs	Interest included in 2016 Debt Service Costs	Debt Outstanding
Chelan County PUD:							
Rock Island Project	2031	25.0%	156	$ 28,422	$ 10,496	$ 5,868	$ 92,603
Rocky Reach Project	2031	25.0%	325	31,243	7,870	3,117	49,081
Douglas County PUD:							
Wells Project	2018	29.9%	251	17,146	9,384	2,487	59,942
Grant County PUD:							
Priest Rapids Development	2052	0.6%	8	3,073	1,874	1,093	18,271
Wanapum Development	2052	0.6%	9	3,073	1,874	1,093	18,271
Total			749	$ 82,957	$ 31,498	$ 13,658	$ 238,168

The following table summarizes the Company's estimated payment obligations for power purchases from the Columbia River projects, contracts with other utilities and contracts with non-utilities. These contracts have varying terms and may include escalation and termination provisions.

(Dollars in Thousands)	2016	2017	2018	2019	2020	Thereafter	Total
Columbia River projects	$ 77,331	$ 77,474	$ 67,371	$ 55,866	$ 53,531	$ 566,081	$ 897,654
Other utilities	16,421	10,357	1,257	890	—	—	28,925
Non-utility contracts	158,874	199,125	204,658	209,590	213,352	1,164,975	2,150,574
Total	$ 252,626	$ 286,956	$ 273,286	$ 266,346	$ 266,883	$ 1,731,056	$ 3,077,153

Total purchased power contracts provided the Company with approximately 11.2 million, 12.1 million and 10.7 million MWhs of firm energy at a cost of approximately $373.8 million and $401.4 million for the years 2015 and 2014, respectively.

PSE enters into short-term energy supply contracts to meet its core customer needs. These contracts are sometimes classified as NPNS, however in most cases recorded at fair value in accordance with ASC 815. Commitments under these contracts are $133.0 million, $37.3 million and $7.3 million in 2016, 2017 and 2018, respectively.

Natural Gas Supply Obligations

The Company has entered into various firm supply, transportation and storage service contracts in order to ensure adequate availability of natural gas supply for its customers and generation requirements. The Company contracts for its long-term natural gas supply on a firm basis, which means the Company has a 100% daily take obligation and the supplier has a 100% daily delivery obligation to ensure service to PSE's customers and generation requirements. The transportation and storage contracts, which have remaining terms from less than one year to 29 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage. The Company incurred demand charges for 2015 for firm transportation, storage and peaking services for its natural gas customers of $120.3 million. The Company incurred demand charges in 2015 for firm transportation and storage services for the natural gas supply for its combustion turbines in the amount of $35.1 million.

The following table summarizes the Company's obligations for future natural gas supply and demand charges through the primary terms of its existing contracts. The quantified obligations are based on the FERC and NEB (National Energy Board) currently authorized rates, which are subject to change.

Natural Gas Supply and Demand Charge Obligations (Dollars in Thousands)	2016	2017	2018	2019	2020	Thereafter	Total
Natural gas supply	$ 247,017	$ 204,798	$ 451,815	$ 233,865	$ 151,664	$ —	$ 1,289,159
Firm transportation service	153,590	147,998	143,076	138,360	132,391	612,778	1,328,193
Firm storage service	6,616	6,616	3,861	2,943	1,950	4,093	26,079
Total	$ 407,223	$ 359,412	$ 598,752	$ 375,168	$ 286,005	$ 616,871	$ 2,643,431

Service Contracts

The following table summarizes the Company's estimated obligations for service contracts through the terms of its existing contracts.

Service Contract Obligations (Dollars in Thousands)	2016	2017	2018	2019	2020	Thereafter	Total
Energy production service contracts	$ 50,557	$ 42,576	$ 23,038	$ 22,160	$ 39,948	$ 173,898	$ 352,177
Automated meter reading system	17,566	17,596	18,348	19,092	19,860	137,784	230,246
Total	$ 68,123	$ 60,172	$ 41,386	$ 41,252	$ 59,808	$ 311,682	$ 582,423

Other Commitments and Contingencies

For information regarding PSE's environmental remediation obligations, see Note 3 Regulation and Rates.

(16) Related Party Transactions

Scott Armstrong serves on the Board of Directors of the Company, and is the president and Chief Executive Officer of Group Health Cooperative (Group Health). Group Health provides coverage to over 600,000 residents in Washington and Northern Idaho. Certain employees of PSE elect Group Health as their medical provider and as a result, PSE paid Group Health a total of $20.3 million and $17.7 million for medical coverage for the year ended December 31, 2015 and 2014, respectively.

Kimberly Harris, the President and Chief Executive Officer, and a director of Puget Energy and PSE, is married to Kyle Branum, a principal at the law firm Riddell Williams P.S., one of PSE's primary law firms for nearly 50 years. In 2015 and 2014, Riddell Williams was paid $1.81 million and $1.98 million, respectively, for legal services provided to PSE and Mr. Branum is among the lawyers at Riddell Williams who provided such legal services. This work was performed under the supervision of PSE's General Counsel.

On October 10, 2014, U.S. Bancorp announced the appointment of Kimberly Harris to its board of directors effective October 20, 2014. Ms. Harris is the president and chief executive officer of both Puget Energy and PSE. U.S. Bancorp is the parent company of

U.S. Bank N.A., which directly or through its subsidiaries or affiliates provides credit, banking, investment and trust services to both Puget Energy and PSE. For the year ended December 31, 2015 and 2014, Puget Energy and PSE paid a total of approximately $1.0 million in fees and interest each year to U.S. Bank N.A. and its subsidiaries or affiliates.

(17) Segment Information

PSE operates one reportable business segment referred to as the regulated utility segment. PSE's regulated utility operation generates, purchases and sells electricity and purchases, transports and sells natural gas. The service territory of PSE covers approximately 6,000 square miles in the state of Washington. In managing the business, management reviews the consolidated financial statements for PSE during the year.

(18) Accumulated Other Comprehensive Income (Loss)

The following tables present the changes in the Company's (loss) AOCI by component for the years ended December 31, 2015 and 2014, respectively.

Changes in AOCI, net of tax (Dollars in Thousands)	Net unrealized gain (loss) and prior service cost on pension plans	Net unrealized gain (loss) on energy derivative instruments	Net unrealized gain (loss) on treasury interest rate swaps	Total
Balance at December 31, 2013	$ (87,405)	$ (2,027)	$ (6,307)	$ (95,739)
Other comprehensive income (loss) before reclassifications	(84,955)	—	—	(84,955)
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	8,079	1,341	317	9,737
Net current-period other comprehensive income (loss)	(76,876)	1,341	317	(75,218)
Balance at December 31, 2014	$ (164,281)	$ (686)	$ (5,990)	$ (170,957)
Other comprehensive income (loss) before reclassifications	6,922	—	—	6,922
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	13,482	686	317	14,485
Net current-period other comprehensive income (loss)	20,404	686	317	21,407
Balance at December 31, 2015	$ (143,877)	$ —	$ (5,673)	$ (149,550)

Details about the reclassifications out of AOCI (loss) for the years ended December 31, 2015 and 2014, respectively, are as follows:

Details about accumulated other comprehensive income (loss) components (Dollars in Thousands)	Affected line item in the statement where net income (loss) is presented	Amount reclassified from accumulated other comprehensive income (loss)	
		2015	2014
Net unrealized gain (loss) and prior service cost on pension plans:			
Amortization of prior service cost	(a)	$ 1,526	$ 1,526
Amortization of net gain (loss)	(a)	(22,268)	(13,954)
	Total before tax	(20,742)	(12,428)
	Tax (expense) or benefit	7,260	4,349
	Net of tax	$ (13,482)	$ (8,079)
Net unrealized gain (loss) on energy derivative instruments:			
Commodity contracts: Electric derivatives	Purchased electricity	(1,055)	(2,063)
	Tax (expense) or benefit	369	722
	Net of Tax	$ (686)	$ (1,341)
Net unrealized gain (loss) on treasury interest rate swaps:			
Interest rate contracts	Interest expense	(488)	(488)
	Tax (expense) or benefit	171	171
	Net of Tax	$ (317)	$ (317)
Total reclassification for the period	Net of Tax	$ (14,485)	$ (9,737)

(a) *These AOCI components are included in the computation of net periodic pension cost (see Note 12 for additional details).*

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year		(87,404,091)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value		(76,876,803)		
4	Total (lines 2 and 3)		(76,876,803)		
5	Balance of Account 219 at End of Preceding Quarter/Year		(164,280,894)		
6	Balance of Account 219 at Beginning of Current Year		(164,280,894)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income		13,482,570		
8	Current Quarter/Year to Date Changes in Fair Value		6,921,976		
9	Total (lines 7 and 8)		20,404,546		
10	Balance of Account 219 at End of Current Quarter/Year		(143,876,348)		

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges Gas for Power (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	(6,306,567)	(2,027,090)	(95,737,748)		
2	316,968	1,341,235	1,658,203		
3			(76,876,803)		
4	316,968	1,341,235	(75,218,600)	236,613,919	161,395,319
5	(5,989,599)	(685,855)	(170,956,348)		
6	(5,989,599)	(685,855)	(170,956,348)		
7	316,968	685,855	14,485,393		
8			6,921,976		
9	316,968	685,855	21,407,369	304,188,836	325,596,205
10	(5,672,631)		(149,548,979)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	12,874,317,089	9,088,280,487
4	Property Under Capital Leases	378,231	
5	Plant Purchased or Sold		
6	Completed Construction not Classified	65,892,342	35,067,732
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	12,940,587,662	9,123,348,219
9	Leased to Others		
10	Held for Future Use	56,042,302	49,903,527
11	Construction Work in Progress	408,795,066	247,426,745
12	Acquisition Adjustments	282,791,675	282,791,675
13	Total Utility Plant (8 thru 12)	13,688,216,705	9,703,470,166
14	Accum Prov for Depr, Amort, & Depl	5,029,301,219	3,560,045,779
15	Net Utility Plant (13 less 14)	8,658,915,486	6,143,424,387
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	4,793,517,561	3,418,665,999
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	124,309,224	29,905,346
22	Total In Service (18 thru 21)	4,917,826,785	3,448,571,345
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	-134,269	-134,269
29	Amortization		
30	Total Held for Future Use (28 & 29)	-134,269	-134,269
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	111,608,703	111,608,703
33	Total Accum Prov (equals 14) (22,26,30,31,32)	5,029,301,219	3,560,045,779

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/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
3,315,161,396				470,875,206	3
				378,231	4
					5
30,778,732				45,878	6
					7
3,345,940,128				471,299,315	8
					9
6,138,775					10
84,010,942				77,357,379	11
					12
3,436,089,845				548,656,694	13
1,278,270,641				190,984,799	14
2,157,819,204				357,671,895	15
					16
					17
1,272,611,416				102,240,146	18
					19
					20
5,659,225				88,744,653	21
1,278,270,641				190,984,799	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
1,278,270,641				190,984,799	33

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
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/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
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	114,202	
3	(302) Franchises and Consents	55,115,176	304,321
4	(303) Miscellaneous Intangible Plant	73,045,316	1,620,958
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	128,274,694	1,925,279
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	3,795,631	
9	(311) Structures and Improvements	175,418,940	1,486,624
10	(312) Boiler Plant Equipment	675,645,119	17,069,007
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	335,813,775	2,522,428
13	(315) Accessory Electric Equipment	45,589,526	942,646
14	(316) Misc. Power Plant Equipment	15,252,677	377,822
15	(317) Asset Retirement Costs for Steam Production	1,419,579	34,533,829
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,252,935,247	56,932,356
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	4,943,534	413,369
28	(331) Structures and Improvements	164,958,241	-838,643
29	(332) Reservoirs, Dams, and Waterways	350,070,732	634,503
30	(333) Water Wheels, Turbines, and Generators	122,053,648	353,391
31	(334) Accessory Electric Equipment	46,080,868	20,812
32	(335) Misc. Power PLant Equipment	13,774,120	514,303
33	(336) Roads, Railroads, and Bridges	5,031,351	383
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	706,912,494	1,098,118
36	D. Other Production Plant		
37	(340) Land and Land Rights	16,089,508	
38	(341) Structures and Improvements	128,855,710	113,362
39	(342) Fuel Holders, Products, and Accessories	25,633,030	
40	(343) Prime Movers		
41	(344) Generators	1,586,052,758	12,136,268
42	(345) Accessory Electric Equipment	152,107,029	589,561
43	(346) Misc. Power Plant Equipment	13,873,723	373,012
44	(347) Asset Retirement Costs for Other Production	18,844,058	-2,758,777
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,941,455,816	10,453,426
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,901,303,557	68,483,900

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	47,860,414	2,965,317
49	(352) Structures and Improvements	7,028,449	
50	(353) Station Equipment	549,145,599	19,097,337
51	(354) Towers and Fixtures	92,207,824	75
52	(355) Poles and Fixtures	323,761,444	9,051,034
53	(356) Overhead Conductors and Devices	282,625,667	1,886,110
54	(357) Underground Conduit	700,575	
55	(358) Underground Conductors and Devices	6,434,339	43,898
56	(359) Roads and Trails	1,878,482	14,249
57	(359.1) Asset Retirement Costs for Transmission Plant	3,311,626	148,042
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,314,954,419	33,206,062
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	34,946,064	355,794
61	(361) Structures and Improvements	7,838,017	90,452
62	(362) Station Equipment	425,890,541	7,134,053
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	311,898,784	20,596,619
65	(365) Overhead Conductors and Devices	365,621,950	26,097,444
66	(366) Underground Conduit	632,234,028	23,688,862
67	(367) Underground Conductors and Devices	793,176,582	43,898,346
68	(368) Line Transformers	439,228,849	19,695,176
69	(369) Services	177,235,166	3,643,674
70	(370) Meters	131,724,778	3,816,168
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	51,631,533	1,005,780
74	(374) Asset Retirement Costs for Distribution Plant	2,515,558	181,352
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	3,373,941,850	150,203,720
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	5,481,624	
87	(390) Structures and Improvements	49,165,293	1,163,979
88	(391) Office Furniture and Equipment	30,579,135	1,624,868
89	(392) Transportation Equipment	8,730,331	153,727
90	(393) Stores Equipment	734,362	372
91	(394) Tools, Shop and Garage Equipment	11,928,930	389,965
92	(395) Laboratory Equipment	11,781,844	249,283
93	(396) Power Operated Equipment	5,966,069	71,719
94	(397) Communication Equipment	84,241,913	5,785,917
95	(398) Miscellaneous Equipment	263,027	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	208,872,528	9,439,830
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)	208,872,528	9,439,830
100	TOTAL (Accounts 101 and 106)	8,927,347,048	263,258,791
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)	8,927,347,048	263,258,791

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
			114,202		2
49,846			55,369,651		3
9,015,890		1,718	65,652,102		4
9,065,736		1,718	121,135,955		5
					6
					7
249			3,795,382		8
412,215		-3,883	176,489,466		9
10,219,645		-35,656	682,458,825		10
					11
3,116,653		42,055	335,261,605		12
43,302		1,138	46,490,008		13
5,524		-3,410	15,621,565		14
			35,953,408		15
13,797,588		244	1,296,070,259		16
					17
					18
					19
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					22
					23
					24
					25
					26
			5,356,903		27
			164,119,598		28
336,897			350,368,338		29
1,175,547			121,231,492		30
871			46,100,809		31
11,459		53,347	14,330,311		32
			5,031,734		33
					34
1,524,774		53,347	706,539,185		35
					36
72,746			16,016,762		37
965,662		4,427	128,007,837		38
			25,633,030		39
					40
9,950,590	14,029	-5,964	1,588,246,501		41
19,253		1	152,677,338		42
			14,246,735		43
			16,085,281		44
11,008,251	14,029	-1,536	1,940,913,484		45
26,330,613	14,029	52,055	3,943,522,928		46

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 09/27/2016	Year/Period of Report End of 2015/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
390,080			50,435,651		48
		1,614,838	8,643,287		49
5,290,772		12,691,806	575,643,970		50
3,971			92,203,928		51
1,487,468		-343,459	330,981,551		52
67,641		926,259	285,370,395		53
		510,284	1,210,859		54
		30,478,494	36,956,731		55
		63,104	1,955,835		56
			3,459,668		57
7,239,932		45,941,326	1,386,861,875		58
					59
276,792		1,624,724	36,649,790		60
34,750		69,198	7,962,917		61
4,979,719		-14,253,675	413,791,200		62
					63
2,416,438	484	-408,300	329,671,149		64
5,539,769	-454	-152,450	386,026,721		65
1,134,282	-21	-651,410	654,137,177		66
5,013,876	43	-30,534,095	801,527,000		67
4,224,811	7,086	-25,064	454,681,236		68
414,993	203	5,968	180,470,018		69
1,496,348		5,968	134,050,566		70
					71
					72
1,112,659			51,524,654		73
			2,696,910		74
26,644,437	7,341	-44,319,136	3,453,189,338		75
					76
					77
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					83
					84
					85
		-52,695	5,428,929		86
		31,561	50,360,833		87
918,909		168,452	31,453,546		88
			8,884,058		89
			734,734		90
		-244	12,318,651		91
			12,031,127		92
			6,037,788		93
		1,097,600	91,125,430		94
			263,027		95
918,909		1,244,674	218,638,123		96
					97
					98
918,909		1,244,674	218,638,123		99
70,199,627	21,370	2,920,637	9,123,348,219		100
					101
					102
					103
70,199,627	21,370	2,920,637	9,123,348,219		104

Schedule Page: 204 Line No.: 52 Column: f

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 204 Line No.: 52 Column: g

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 204 Line No.: 53 Column: f

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 204 Line No.: 53 Column: g

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 204 Line No.: 54 Column: f

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 204 Line No.: 54 Column: g

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 204 Line No.: 55 Column: f

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 204 Line No.: 55 Column: g

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 204 Line No.: 64 Column: f

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 204 Line No.: 64 Column: g

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 204 Line No.: 65 Column: f

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 204 Line No.: 65 Column: g

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 204 Line No.: 66 Column: f

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 204 Line No.: 66 Column: g

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 204 Line No.: 67 Column: f

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 204 Line No.: 67 Column: g

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/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					
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47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	ALDERTON-KRAIN CORNER LAND	6/30/2013	12/31/2016	3,290,286
3	AUTUMN GLEN SUBSTATION LAND	3/31/2009	1/31/2021	770,620
4	BAINBRIDGE SUBSTATION LAND	2/28/2009	1/1/2018	618,392
5	BEL-RED SUBSTATION LAND	12/31/2009	1/31/2020	2,184,109
6	BETHEL SUBSTATION LAND	12/31/2005	1/31/2025	710,313
7	BPA KITSAP NAVAL TRANS PLANT LAND RTS	12/31/1992	10/1/2019	407,661
8	BUCKLEY SUBSTATION LAND	1/30/2009	12/31/2019	488,523
9	CARPENTER SUBSTATION LAND	4/30/2009	1/31/2019	1,041,420
10	CLYDE HILL SUBSTATION LAND	10/31/2014	1/31/2024	397,742
11	HAZELWOOD SUBSTATION - LAND	1/31/2014	1/1/2017	460,994
12	HOFFMAN SWITCHING STATION DISTR LAND	3/31/2005	12/31/2021	714,663
13	JENKINS CREEK SUBSTATION LAND	10/31/2009	1/31/2019	1,000,290
14	KENDALL SUBSTATION LAND	1/31/2010	1/31/2025	353,720
15	LAKE HOLMS SUBSTATION LAND	1/31/2012	1/31/2017	912,413
16	MAXWELTON SUBSTATION LAND	9/30/2008	2/29/2016	651,297
17	PLUM STREET SUBSTATION LAND	2/28/2014	1/31/2025	305,609
18	SO. BREMERTON-BANGOR LAND	9/4/2007	12/31/2016	1,005,331
19	UPPER BAKER HYDRO PROD FACILITY LAND	6/30/2014	1/1/2016	738,598
20	VERNELL SUBSTATION LAND	2/28/2013	12/31/2019	7,361,844
21	Other Property:			
22	SAINT CLAIR - PLEASANT GLADE # 2 - TRANS LINE	1/31/2014	1/31/2018	1,870,639
23	OTHER PROPERTY (less than $250,000)			500,474
24				
25	Land and Rights (continued)			
26	LOWER SNAKE RIVER WIND DEVELOPMENT RIGHTS	3/31/2014	1/31/2023	22,243,546
27	VERNELL SUBSTATION STRUCTURE	2/28/2013	12/31/2019	1,875,043
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46				
47	Total			49,903,527

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	3rd AC Intertie Project	1,895,269
2	BainBridge Island Substation Transmission Loop Project	1,680,678
3	Baker Project	23,217,848
4	Bellevue Project	4,258,768
5	Bellingham Service Center Remodel Project	1,252,139
6	Bellingham Sedro Project	3,263,972
7	BerryDale Project	1,232,949
8	Bremerton Bangor Project	1,467,476
9	Colstrip Project	4,899,898
10	Cottage Replacement Breakers Project	1,005,933
11	Distribution Outage Duration Project	2,145,008
12	Eastside Transmission Project	26,615,630
13	Fredonia Project	3,654,905
14	Glacier Project	6,074,012
15	Lakeside 115 KV Transmission Project	4,805,911
16	Langley Tap Preconstruction Project	1,020,490
17	Maxwelton Substation Project	8,036,970
18	MTV ALLEY Project	1,887,137
19	Orting Substation Project	1,399,178
20	Hickox Feeder Tie Project	1,199,863
21	Phantom lake - Lake Hills Project	3,529,189
22	Pierce Co 230 KV Project	5,270,979
23	Sammamish Substation Power Replacement Project	3,438,622
24	Sam-Jua Transmission Line Project	3,997,569
25	Snoqualmie Hydro Project	3,860,603
26	Spurgeon Substation Project	8,355,574
27	Sinclair Feeder Project	1,919,318
28	Distribution Underground Relocation Project	3,189,006
29	Thorp Sub Rebuild Project	1,060,999
30	Whidbey Project	1,270,722
31	White River, Electron and Alderton Projects	9,448,728
32	Woodland St Clair Project	3,352,902
33	WSDOT Project	4,103,184
34	Electric Distribution - Misc CWIP less than $1,000,000 each	66,944,671
35	Electric Transmission - Misc CWIP less than $1,000,000 each	16,734,060
36	Electric General & Intangibles - Misc CWIP less than $1,000,000 each	8,169,550
37	Electric Generation - Misc CWIP less than $1,000,000 each	1,767,035
38		
39		
40		
41		
42		
43	TOTAL	247,426,745

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 09/27/2016	Year/Period of Report End of 2015/Q4

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

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

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	3,246,755,644	3,246,454,487	301,157	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	245,908,505	245,908,505		
4	(403.1) Depreciation Expense for Asset Retirement Costs	1,053,320	1,053,320		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,147,654	1,147,654		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	248,109,479	248,109,479		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	61,569,328	61,133,890	435,438	
13	Cost of Removal	19,362,338	19,361,717	621	
14	Salvage (Credit)	7,465,983	7,465,394	589	
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	73,465,683	73,030,213	435,470	
16	Other Debit or Cr. Items (Describe, details in footnote):	-2,867,710	-2,867,754	44	
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,418,531,730	3,418,665,999	-134,269	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	754,769,967	754,769,967		
21	Nuclear Production				
22	Hydraulic Production-Conventional	140,845,622	140,845,622		
23	Hydraulic Production-Pumped Storage				
24	Other Production	696,501,343	696,501,343		
25	Transmission	428,562,103	428,696,372	-134,269	
26	Distribution	1,309,301,950	1,309,301,950		
27	Regional Transmission and Market Operation				
28	General	88,550,745	88,550,745		
29	TOTAL (Enter Total of lines 20 thru 28)	3,418,531,730	3,418,665,999	-134,269	

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

Included transfers, gains/losses, and manual adjustments.

Schedule Page: 219 Line No.: 25 Column: b

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 219 Line No.: 25 Column: c

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 219 Line No.: 26 Column: b

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 219 Line No.: 26 Column: c

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	PUGET WESTERN, INC.	05/31/1960		
2	Common			10,200
3	Retained Earnings			-14,632,031
4	Additional Paid in Capital			44,487,244
5	Subtotal			29,865,413
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
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36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 32,216		TOTAL	29,865,413

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/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
		10,200		2
32,216		-14,599,815		3
		44,487,244		4
32,216		29,897,629		5
				6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
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				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
32,216		29,897,629		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/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)	19,977,277	18,852,704	Electric & Gas
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)	63,051,131	60,924,062	Electric & Gas
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	8,080,869	6,971,830	Electric & Gas
8	Transmission Plant (Estimated)	796,552	480,322	Electric & Gas
9	Distribution Plant (Estimated)	3,967,176	3,989,760	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	2,161,016	1,675,875	Electric & Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	78,056,744	74,041,849	Electric & Gas
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	34,476	289,557	Electric & Gas
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	5,098,269	4,198,466	Electric & Gas
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	103,166,766	97,382,576	

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

These amounts are primarily from damage claims, miscellaneous projects for customers at the customers'premises, and various other merchandising material.

Schedule Page: 227 Line No.: 14 Column: b

This account is for landfill gas pipeline imbalance.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/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)	2016 No. (d)	2016 Amt. (e)
1	Balance-Beginning of Year	32,864.00	34,267	9,030.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Talen Montana	15.00			
10					
11					
12					
13					
14					
15	Total	15.00			
16					
17	Relinquished During Year:				
18	Charges to Account 509	29.00			
19	Other:				
20	CCA's Relinquished	2,558.00	30,184		
21	Cost of Sales/Transfers:				
22	Talen Montana	4,310.00			
23					
24					
25					
26					
27					
28	Total	4,310.00			
29	Balance-End of Year	25,982.00	4,083	9,030.00	
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	6,571.00			
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA	513.00			
39	Cost of Sales				
40	Balance-End of Year	6,058.00			
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		18		
45	Gains		18		
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

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.

2017		2018		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
9,034.00		9,030.00		235,087.00		295,045.00	34,267	1
								2
								3
				3,686.00		3,686.00		4
								5
								6
								7
								8
				5,325.00		5,340.00		9
								10
								11
								12
								13
								14
				5,325.00		5,340.00		15
								16
								17
						29.00		18
								19
						2,558.00	30,184	20
								21
						4,310.00		22
								23
								24
								25
								26
								27
						4,310.00		28
9,034.00		9,030.00		244,098.00		297,174.00	4,083	29
								30
								31
								32
								33
								34
								35
						6,571.00		36
								37
						513.00		38
								39
						6,058.00		40
								41
								42
								43
							18	44
							18	45
								46

Schedule Page: 228 Line No.: 36 Column: b

The following table reflects 2015 estimated beginning and end of year balances and associated sales of allowances held by the Environmental Protection Agency (EPA). Because the EPA does not provide a definite number of allowances sold upon remittance of sales proceeds, the figures below were estimated based on the weighted average cost from months when the sales were held.

Plant	12/31/14 Estimated Balance of Withheld Allowances Years 2009-2025	Estimated EPA Withheld Allowances Sold During 2015	12/31/15 Estimated Balance of Withheld Allowances Years 2009-2025
Colstrip Unit 1	1,761	108	1,653
Colstrip Unit 2	1,732	107	1,625
Colstrip Unit 3	1,108	277	831
Colstrip Unit 4	1,970	21	1,949
	6,571	513	6,058

Schedule Page: 228 Line No.: 44 Column: c

2015 proceeds from sales of allowances withheld by the Environmental Protection Agency were as follows:

Plant	2015 Proceeds
Colstrip Unit 1	8
Colstrip Unit 2	8
Colstrip Unit 3	2
Colstrip Unit 4	1
Total Proceeds	18

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/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)	2016 No. (d)	2016 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				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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.

2017		2018		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
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								46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/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	12/13/2006 Storm	30,510,829		407	7,959,336	22,551,493
2	2010 Storm	10,044,328		407	7,518,060	2,526,268
3	2012 Storm	60,295,490				60,295,490
4	2014 Storm	17,973,019	212,654			18,185,673
5	2015 Storm		22,217,695			22,217,695
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL	118,823,666	22,430,349		15,477,396	125,776,619

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	White River Plant Costs	31,255,625	-1,683	407	1,494,702	29,759,240
22	White River Plant Sales	-30,211,680				-30,211,680
23	Upper Baker Regulatory Study Cost	482,536		407	241,268	241,268
24	Electron Unrecovered Plant Costs	14,007,694	-46,887	407	3,391,500	10,569,307
25						
26						
27						
28						
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34						
35						
36						
37						
38						
39						
40						
41						
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48						
49	TOTAL	15,534,175	-48,570		5,127,470	10,358,135

Schedule Page: 230 Line No.: 1 Column: a

The 12/13/2006 storm deferral cost was approved for amortization over 10 years in WUTC Dockets UE-072300 and UG-072301. Monthly amortization commenced on November 1, 2008 for $7,959,341 annually. The storm is amortized separately from the other storm losses.

Schedule Page: 230 Line No.: 2 Column: a

The 2010 storm deferral cost was approved for amortization over four years in WUTC Dockets UE-090704 and UG 090705. Monthly amortization commenced on May 14, 2012 for $7,518,060 annually. The 2010 storm has been continuing to be applied after completing the 2008 storm amortization in June 2014.

Schedule Page: 230 Line No.: 21 Column: a

In May 2005, WUTC approved PSE’s request for rate recovery of its unrecovered investment in the White River Project of approximately $47.8 million over a 31 year period in Docket AC05-33-000. Monthly amortization for the recovery commenced in January 2004 for $1,494,702 annually and the amortization will be completed in 2035.

Schedule Page: 230 Line No.: 22 Column: a

In May 2009, WUTC approved the sale of certain assets related to White River Hydro Electric Project to Cascade Water Alliance in Docket UE-090399. PSE received $39.6 million for the sale which included $29.9 million purchased price along with reimbursement of $9.7 million for processing and conveyance costs. The White River land was sold to City of Buckley for $300K in April 2011.

The amortization for gain has not yet been approved and as per WUTC commission order is dependent upon the sale of all remaining properties associated with White River, with such approval to be sought in the rate filing thereafter.

Schedule Page: 230 Line No.: 23 Column: a

In December 2011, WUTC approved PSE’s accounting petition to defer non-construction related regulatory study costs and to amortize $1.2 million over a five year period in Dockets UE-021577 and UE-070074. Monthly amortization for the regulatory study costs commenced in January 2012 for $241K annually and the amortization will be completing in 2016.

Schedule Page: 230 Line No.: 24 Column: a

In November 2014, WUTC approved Docket UE-141141 granted PSE’s request for the recovery of Electron Unrecovered Plant cost as a regulatory asset amortized over 48 months. Monthly amortization for the regulatory costs commenced in December 2014 for $3,392K annually and the amortization will be completing in March 2019.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	Glacier Battery SGIA SIS	15,556	186	(15,556)	186
23	Bainbridge Battery SGIA IFS	4,019	186	(22,484)	186
24	Bainbridge Battery SGIA SIS		186	(6,127)	186
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
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39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Unamortized Conservation Costs - 1 to 10 years	42,374,460	222,474,860	908	228,202,922	36,646,398
2	Deferred AFUDC	53,708,794	926,002	406	2,437,557	52,197,239
3	Colstrip Common - 37.5 years	7,947,724		406,501	1,076,479	6,871,245
4	Colstrip Deferred - 27.5 years	1,316,449		406	138,804	1,177,645
5	BPA Power Exchange - 27.5 years	8,816,458		555	3,526,620	5,289,838
6	Regulatory Tax Asset	94,913,489	20,355,055	283	42,574,819	72,693,725
7	Environmental Remidiation Costs	3,587,170	1,650,308	228	982,355	4,255,123
8	Property Tax Tracker	32,253,254	60,290,686	408	52,191,178	40,352,762
9	Decoupling Mechanism	55,363,162	138,181,370	456,182	89,394,928	104,149,604
10	Power Cost Adjustment Mechanism	4,623,329	125,398	557,419		4,748,727
11	White River Relicensing & Reg Asset	25,641,285	1,114,709	182	3,249,620	23,506,374
12	Chelan PUD - 20 years	119,315,771		555	7,088,065	112,227,706
13	Mint Farm Deferral - 1.9 years and 15 years	29,405,543		407	2,885,052	26,520,491
14	Lower Snake River Deferral - 4 years and 20 years	94,440,384		407,253	8,404,796	86,035,588
15	Ferndale Deferral - 6 years	21,848,710		407	4,520,424	17,328,286
16	Baker Deferral - 6 years	2,581,181		407	673,356	1,907,825
17	Snoqualmie Deferral - 6 years	10,135,806		407	2,644,127	7,491,679
18						
19						
20						
21						
22						
23						
24						
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26						
27						
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44	TOTAL	608,272,969	445,118,388		449,991,102	603,400,255

Schedule Page: 232 Line No.: 1 Column: a
Included in Washington Commission Dockets UE-080389, UE-080390, UE-970686 and UG-120812.

Schedule Page: 232 Line No.: 2 Column: a
Included in Washington Commission Dockets UE-130137 and UG-130138 and UE-072300 and UG-072301.

Schedule Page: 232 Line No.: 3 Column: a
Included in Washington Commission Docket U-89-2688, UE-111048 and UG-111049. Amortization expires in June 2024.

Schedule Page: 232 Line No.: 4 Column: a
Included in Washington Commission Dockets UE-072300, UG-072301, UE-130137 and UG-130138. Amortization expires in June 2024.

Schedule Page: 232 Line No.: 5 Column: a
Included in Washington Commission Dockets UE-89-2688-T, and UE-090704. Amortization expires in June 2017.

Schedule Page: 232 Line No.: 6 Column: a
No docket number required. FAS 109 balance.

Schedule Page: 232 Line No.: 7 Column: a
Included in Washington Commission Dockets UE-991796, UE-072300, UG-072301, UE-911476 and UE-021537, UE-130137 and UG-130138.

Schedule Page: 232 Line No.: 8 Column: a
Included in Washington Commission Dockets UE-130137 and UG-130138.

Schedule Page: 232 Line No.: 9 Column: a
Included in Washington Commission Dockets UE-121697 and UG-121705.

Schedule Page: 232 Line No.: 10 Column: a
Included in Washington Commission Docket UE-011570. Total includes interest recorded on the customer balance of the PCA.

Schedule Page: 232 Line No.: 11 Column: a
Included in Washington Commission Dockets UE-032043, UE-031471, UG-040640 and UE-040641.

Schedule Page: 232 Line No.: 12 Column: a
Included in Washington Commission Dockets UE-060266, UE-060539. Amortization began in November 2011 and expires in October 2031.

Schedule Page: 232 Line No.: 13 Column: a
Included in Washington Commission Dockets UE-090704, UG-090705. Amortization began April 2010 and expires in March 2025.

Schedule Page: 232 Line No.: 14 Column: a
Included in Washington Commission Dockets UE-111048, UG-111049, UE-130583, UE-131099 and UE-131230. Amortization began in May 2012 and expires in April 2016 and April 2037.

Schedule Page: 232 Line No.: 15 Column: a
Included in Washington Commission Docket UE-130617, UE-131230, UE-131099, UE-130583. Amortization is for 6 years which began in November 2013 and expires in October 2019.

Schedule Page: 232 Line No.: 16 Column: a
Included in Washington Commission Docket UE-130617, UE-130583, UE-131099, UE-131230. Amortization is for 6 years which began in November 2013 and expires in October 2019.

Schedule Page: 232 Line No.: 17 Column: a
Included in Washington Commission Docket UE-130617, UE-130583, UE-131099, UE-131230. Amortization is for 6 years which began in November 2013 and expires in October 2019.

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	Incurred not Report Worker Comp	4,143,510	4,686,690	186,253	5,649,488	3,180,712
2	Carbon Offset Program	167,754	60,933	253	65,456	163,231
3	Damage Claims	3,443,589	27,339,377	184	27,004,035	3,778,931
4	Clearing Account Charges	230,130	154,774	184,186	238,576	146,328
5	FAS 133 Net Unrealized	69,280,455	795,693,828	244	804,084,908	60,889,375
6	Chelan Prepayments	7,813,209	80,977	555	468,962	7,425,224
7	Ferndale		2,843,428	186,513	77,743	2,765,685
8	Encogen		5,104,843	186	2,153,185	2,951,658
9	Environmental Remediation Exp	58,464,930	7,407,254	186,228	7,220,741	58,651,443
10	Real Estate	5,178,362	2,489,352	186,253	211,613	7,456,101
11	Snoqualmie	11,506,984	16,565	186,253	1,239,142	10,284,407
12	Baker	66,938,490	3,857,492	186,253	2,916,350	67,879,632
13	Colstrip	2,705,545	8,510,942	Various	5,292,418	5,924,069
14	Fredonia	6,582,516	1,216	553	699,028	5,884,704
15	Goldendale	3,761,745		513	1,437,308	2,324,437
16	Electron	909,655		186,228		909,655
17	Fredrickson	1,174,437		553	260,113	914,324
18	Mint Farm	3,331,537	1,703,189	553	1,823,736	3,210,990
19	Minor Items	1,441,348	19,677,268	Various	21,033,211	85,405
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47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	247,074,196				244,826,311

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Derivative Instruments	46,103,085	47,390,710
3	Net Operating Loss Carryforward	145,775,447	94,895,713
4	Pension and Other Compensation	112,333,731	101,354,076
5	Production Tax Credit	158,604,125	178,074,520
6	Regulatory Assets	98,841,270	105,513,170
7	Other	14,944,861	24,670,015
8	TOTAL Electric (Enter Total of lines 2 thru 7)	576,602,519	551,898,204
9	Gas		
10	Derivative Instruments	31,082,475	23,481,555
11	Net Operating Loss Carryforward	34,616,055	15,167,737
12	Pension and Other Compensation	4,742,432	4,747,925
13	Regulatory Assets	1,120,636	928,523
14	Other	6,364,663	12,969,194
15	Production Tax Credit		
16	TOTAL Gas (Enter Total of lines 10 thru 15	77,926,261	57,294,934
17	Other Non-Operating		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	654,528,780	609,193,138

Notes

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201 - Common Stock	150,000,000	0.01	
2				
3				
4	Total Common	150,000,000		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
85,903,791	859,038					1
						2
						3
85,903,791	859,038					4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 211 - Miscellaneous Paid in Capital	2,804,096,691
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40	TOTAL	2,804,096,691

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	Account 214 - Common Stock Expense	7,133,879
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22	TOTAL	7,133,879

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	ACCOUNT 221		
2			
3	First Mortgage Bonds Senior MTN 7.02% Series A	300,000,000	3,010,746
4	First Mortgage Bonds Senior MTN 6.74% Series A	200,000,000	2,018,425
5	First Mortgage Bonds Senior MTN 7.00% Series B	100,000,000	954,608
6	5.483% Senior Notes Due 06/35	250,000,000	2,460,125
7	5.197% Senior Notes Due 10/15		1,206,051
8	6.724% Senior Notes Due 06/36	250,000,000	2,527,628
9	6.274% Senior Notes Due 03/37	300,000,000	2,921,148
10	Junior Subordinated Notes (Hybrid) 6.974%	250,000,000	4,400,860
11	6.75% Senior Notes Due 01/16		1,900,142
12	5.757% Senior Notes Due 10/39	350,000,000	3,557,361
13	5.795% Senior Notes Due 03/40	325,000,000	3,384,066
14	5.764% Senior Notes Due 07/40	250,000,000	2,587,276
15	4.434% Senior Notes Due 11/41	250,000,000	2,592,616
16	4.700% Senior Notes Due 11/51	45,000,000	511,229
17	5.638% Senior Notes Due 04/41	300,000,000	3,071,895
18	5.638% Senior Notes Due 04/41 (D)		15,000
19	4.300% Senior Notes Due 05/45	425,000,000	3,718,750
20	4.300% Senior Notes Due 05/45 (D)		1,912,500
21	3.9% Pollution Control Bonds Rev Series 2013A	138,460,000	1,473,301
22	4.0% Pollution Control Bonds Rev Series 2013B	23,400,000	248,243
23	SUBTOTAL	3,756,860,000	44,471,970
24			
25	Bonds assumed which were originally issued by Washington Natural Gas Company		
26			
27	Secured Medium Term Notes - 7.35% Series C		113,301
28	Secured Medium Term Notes - 7.36% Series C		22,660
29	Secured Medium Term Notes - 7.15% Series C	15,000,000	112,500
30	Secured Medium Term Notes - 7.20% Series C	2,000,000	15,000
31	SUBTOTAL	17,000,000	263,461
32			
33	TOTAL	3,773,860,000	44,735,431

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
12/22/97	12/01/27	12/22/97	12/01/27	300,000,000	21,060,000	3
06/15/98	06/15/18	06/15/98	06/15/18	200,000,000	13,480,000	4
03/09/1999	03/09/29	03/09/99	03/09/29	100,000,000	7,000,000	5
05/27/05	06/01/35	05/27/05	06/01/35	250,000,000	13,707,500	6
10/12/05	10/01/15	10/12/05	10/01/15		3,334,742	7
06/30/06	06/15/36	6/30/06	6/15/36	250,000,000	16,810,000	8
09/18/06	03/15/37	9/18/06	3/15/37	300,000,000	18,822,000	9
06/01/07	06/01/67	06/01/07	06/01/67	250,000,000	17,435,000	10
01/23/09	01/15/16	01/23/09	01/15/16		7,171,875	11
09/11/09	10/01/39	09/11/09	10/01/39	350,000,000	20,149,500	12
03/08/10	03/15/40	03/08/10	03/15/40	325,000,000	18,833,750	13
06/29/10	07/15/40	06/29/10	07/15/40	250,000,000	14,410,000	14
11/16/11	11/15/41	11/16/11	11/15/41	250,000,000	11,085,000	15
11/22/11	11/15/51	11/22/11	11/15/51	45,000,000	2,115,000	16
03/25/11	04/15/41	3/25/11	4/15/41	300,000,000	16,914,000	17
03/25/11	04/15/41	3/25/11	4/15/41			18
5/26/15	5/20/45	5/26/15	5/20/45	425,000,000	10,914,236	19
5/26/15	5/20/45	5/26/15	5/20/45			20
05/23/13	03/01/31	5/23/13	3/1/31	138,460,000	5,399,940	21
05/23/13	03/01/31	5/23/13	3/1/31	23,400,000	936,000	22
				3,756,860,000	219,578,543	23
						24
						25
						26
09/11/95	09/11/15	09/11/95	09/11/15		512,458	27
09/15/95	09/15/15	09/11/95	09/15/15		104,267	28
12/20/95	12/19/25	12/20/95	12/19/25	15,000,000	1,072,500	29
12/22/95	12/22/25	12/22/95	12/22/25	2,000,000	144,000	30
				17,000,000	1,833,225	31
						32
				3,773,860,000	221,411,768	33

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

The 5.197% Senior Note dated 10/12/15 was fully redeemed on 6/5/15 at the following price of the principal amount with interest accrued: CUSIP #745332BV7; Maturity Date 10/01/2015; Rate 5.197%; Amount $150M, Price 101.613805353%.

Schedule Page: 256 Line No.: 11 Column: a

The 6.75% Senior Note dated 1/23/09 was fully redeemed on 6/5/15 at the following price of the principal amount with interest accrued: CUSIP #745332BZ8; Maturity Date 1/15/16; Rate 6.75%; Amount $250M, Price 103.7254055%.

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

A Commission authorization number was not requested.

Schedule Page: 256 Line No.: 27 Column: a

Medium Term Note for $10M at coupon rate of 7.35% fully amortized on 9/11/15; CUSIP #93936KBB4.

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

Medium Term Note for $2M at coupon rate of 7.36% fully amortized on 9/15/15; CUSIP #93936KBF5.

Schedule Page: 256 Line No.: 31 Column: a

The total of Account 427 includes an additional $487,644 of treasury lock and forward swap interest expenses not reported in the Interest for Year Amount (i).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	304,188,836
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Provision for Federal Income Taxes	125,881,973
11	Others	32,302,611
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Others	462,373,419
21		
22		
23		
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26		
27	Federal Tax Net Income	
28	Show Computation of Tax:	
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Schedule Page: 261 Line No.: 11 Column: b

Line 11 Details:	
Capitalized Interest	9,705,987
Derivative Instruments	(12,688,450)
Electric and Gas Purchase Contracts	2,921,284
Non Deductible Items	2,377,120
Regulatory Asset for PTC	29,954,454
Income from Subsidiary	32,216
	32,302,611

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

Line 20 Details:	
Allowance for Funds Used During Construction	(15,388,707)
Conservation Activity	4,531,062
Decoupling Revenue	(25,906,227)
Depreciation Related Activity	(189,167,143)
Environmental Cost	(3,351,359)
Green Attributes	(972,033)
NOL Carryforward	(193,101,715)
Other Items	(8,958,595)
Pensions and Other Compensation	(3,380,647)
Property Tax Rate Tracker	(8,099,508)
Regulatory Assets	14,956,510
Renewable Energy Credits	(1,418,121)
Storm Related Activity	(6,952,955)
Treasury Grant Amortization	(25,163,981)
	(462,373,419)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	FEDERAL					
2	Income			800	-2,400	
3	Employment	21,437		18,353,817	-18,370,136	
4	Other	264	1,503	12,979	-12,561	
5						
6	STATE					
7	Property	72,976,044		79,077,484	-85,364,260	8,166,198
8	State Excise	18,235,687		116,068,146	-112,850,399	
9	Municipal Excise	15,717,896		118,390,770	-116,523,848	
10	Other State Taxes	529,870		3,880,654	-3,746,207	
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41	TOTAL	107,481,198	1,503	335,784,650	-336,869,811	8,166,198

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-1,600					800	2
5,119		9,247,159			9,106,658	3
264	1,085				12,979	4
						5
						6
74,855,465		51,323,139			27,754,345	7
21,453,434		80,664,654			35,403,492	8
17,584,817		77,502,130			40,888,640	9
664,317		1,600,477			2,280,177	10
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114,561,816	1,085	220,337,559			115,447,091	41

Schedule Page: 262 Line No.: 3 Column: i

Puget Sound Energy ("PSE") discovered an error in the amount recorded in Column I and Column L of page 262 in the 2015 Q4 filing of its FERC Form No. 1. A total of $9,247,159 should have been recorded in Column I line 3("Electric") and $9,106,658 should have been recorded in Column L line 3("Other").

Footnote

		As Originally Filed	
		Col I	Col L
		Distribution of Taxes Charged	
Employment	Line 3	-	17,817,701
Total	Line 41	211,090,400	124,158,134
		As Adjusted	
		Col I	Col L
Employment	Line 3	9,247,159	9,106,658
Total	Line 41	220,337,559	115,447,091

Schedule Page: 262 Line No.: 3 Column: l

Puget Sound Energy ("PSE") discovered an error in the amount recorded in Column I and Column L of page 262 in the 2015 Q4 filing of its FERC Form No. 1. A total of $9,247,159 should have been recorded in Column I line 3("Electric") and $9,106,658 should have been recorded in Column L line 3("Other").

Footnote

		As Originally Filed	
		Col I	Col L
		Distribution of Taxes Charged	
Employment	Line 3	-	17,817,701
Total	Line 41	211,090,400	124,158,134
		As Adjusted	
		Col I	Col L
Employment	Line 3	9,247,159	9,106,658
Total	Line 41	220,337,559	115,447,091

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year 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							
7							
8	TOTAL						
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Deferred Comp - Salary	11,420,672	Various	4,091,294	1,463,034	8,792,412
2	SFAS 106 Unfunded Liability	7,182,964	Various	5,285,522	6,639,867	8,537,309
3	Low Income Program	4,814,112	908	31,722,640	34,092,802	7,184,274
4	Sch 85 Extension Cost	8,952,054	456	303,991	1,178,692	9,826,755
5	Green Power Tariff	3,270,480	456	533,623	1,850,447	4,587,304
6	Landlord Incentives/Improvements	5,150,167	Various	2,033,199	6,965,167	10,082,135
7	PTC Deferred Post June '10	147,366,818	407		29,954,454	177,321,272
8	Landis Gyr AMR	1,748,000	902	1,509,833	50,833	289,000
9	Workers Comp - IBNR	4,143,509	186	1,683,694	720,894	3,180,709
10	Residential Exchange	28,241,478	555	195,687,321	172,899,643	5,453,800
11	Operating Leases Obligation	4,620,520	186	11,403	2,194,490	6,803,607
12	Decoupling		495,456	56,934,097	66,913,925	9,979,828
13	Lower Snake River	13,144,157	565,419	10,592,594	8,727,217	11,278,780
14	Snoqualmie	12,540,680	419,186	2,109,978	16,565	10,447,267
15	Ferndale	2,616,300	419	541,304		2,074,996
16	Baker	62,416,324	186,419	2,158,316	3,755,903	64,013,911
17	Unearned Revenue	3,148,477	454	6,475,011	6,400,683	3,074,149
18	Deferred Credit	9,345,717	419,186	2,682,641	2,058,243	8,721,319
19	Minor Items	784,478	Various	8,748,125	8,347,238	383,591
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47	TOTAL	330,906,907		333,104,586	354,230,097	352,032,418

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

3. 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
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NOTES (Continued)

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) ☐ An Original (2) ☒ A Resubmission	Date of Report (Mo, Da, Yr) 09/27/2016	Year/Period of Report End of 2015/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,235,348,839	50,540,628	4,457,516
3	Gas	493,711,951	40,795,435	18,417,636
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,729,060,790	91,336,063	22,875,152
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,729,060,790	91,336,063	22,875,152
10	Classification of TOTAL			
11	Federal Income Tax	1,729,060,790	91,460,911	22,875,152
12	State Income Tax			
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
						1,281,431,951	2
						516,089,750	3
							4
						1,797,521,701	5
							6
							7
							8
						1,797,521,701	9
							10
						1,797,646,549	11
							12
							13

NOTES (Continued)

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 09/27/2016	Year/Period of Report End of 2015/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	SFAS109	85,350,926		
4	Pension Related	63,888,533	3,067,448	2,489,228
5	Storm Damage	41,588,283	7,946,695	5,513,161
6	Derivative Instruments	7,035,669	9,597,694	3,080,389
7	Regulatory Assets	99,081,105	26,296,596	24,440,589
8	IRS Audit	-2,329,559	241,306	
9	TOTAL Electric (Total of lines 3 thru 8)	294,614,957	47,149,739	35,523,367
10	Gas			
11	SFAS109	9,562,563		
12	Pension Related	3,223,178	1,444,832	1,172,478
13	Derivative Instruments	31,082,475	9,697,130	17,298,050
14	Regulatory Assets	29,420,336	23,425,674	3,973,783
15	IRS Audit	533,244	110,709	
16	Others			
17	TOTAL Gas (Total of lines 11 thru 16)	73,821,796	34,678,345	22,444,311
18	Other Non-Operating			
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	368,436,753	81,828,084	57,967,678
20	Classification of TOTAL			
21	Federal Income Tax	368,436,753	81,828,084	57,967,678
22	State Income Tax			
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS						
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
							2
		Various	31,080,457	Various	8,478,657	62,749,126	3
						64,466,753	4
						44,021,817	5
		Various	248,741			13,304,233	6
						100,937,112	7
						-2,088,253	8
			31,329,198		8,478,657	283,390,788	9
							10
		Various	2,860,452	Various	3,242,489	9,944,600	11
						3,495,532	12
						23,481,555	13
						48,872,227	14
						643,953	15
							16
			2,860,452		3,242,489	86,437,867	17
							18
			34,189,650		11,721,146	369,828,655	19
							20
			34,189,650		11,721,146	369,828,655	21
							22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Unamort. Gain from Disposition of Allowance	78,501	411.8	37,337		41,164
2	Summit Purchase Buyout	9,187,500	456,495	1,575,000		7,612,500
3	BNP-Westcoast Cap Agrmnt-Non-Core Gas	2,060,901	547	537,626		1,523,275
4	FBE-Westcoast Cap Agrmnt-Non-Core Gas	1,503,317	547	392,169		1,111,148
5	Renewable Energy Credits	3,056,543	456,431,407.4	33,073,404	32,861,968	2,845,107
6	Biogas Principal and Interest	1,445,981	456,417	2,482,824	1,510,791	473,948
7	PTC Cost Deferral	93,615,823	407.3			93,615,823
8	Deferred Treasury Grant Amortization	8,196,617	431, 407.4	2,138,244		6,058,373
9	Decoupling	12,582,373	456,431	30,159,710	43,060,098	25,482,761
10	Total JPUD Gain to Customers	4,731,254	407,431	43,771,837	39,040,583	
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41	TOTAL	136,458,810		114,168,151	116,473,440	138,764,099

Schedule Page: 278 Line No.: 1 Column: a

Included in Washington Commission Docket UE-001157. Effective in June 2000, each sale amortizes over ten years from the date of sale. Amortization will expire in May 2016, June 2017, May 2018, May 2019, April 2020, and in April 2021.

Schedule Page: 278 Line No.: 2 Column: a

Included in Washington Commission Docket UE-071876. Amortization expires October 2020.

Schedule Page: 278 Line No.: 3 Column: a

Included in Washington Commission Docket UE-100503. Amortization expires October 2018.

Schedule Page: 278 Line No.: 4 Column: a

Included in Washington Commission Docket UE-082013. Amortization expires October 2018.

Schedule Page: 278 Line No.: 5 Column: a

Included in Washington Commission Docket UE-070725, UE-101581, UE-111048, UE-120277. The REC liability balance is used to offset PTC receivables.

Schedule Page: 278 Line No.: 6 Column: a

Included in Washington Commission Docket UE-131276, effective in November 2013. Washington Commission Docket UE-132185, effective January 2014.

Schedule Page: 278 Line No.: 7 Column: a

Included in Washington Commission Docket UE-070725, UE-101581. The REC liability balance is used to offset PTC receivables.

Schedule Page: 278 Line No.: 8 Column: a

Included in Washington Commission Docket UE-130583, UE-130617, UE131099, UE-131230. Amortization Expires June 2044. Included in Washington Commission Docket UE-141141. Amortization Expires October 2018.

Schedule Page: 278 Line No.: 9 Column: a

Included in Washington Commission Docket UG-121697 and UG121705, effective July 2013 and will remain in place, at minimum, until the effective date of new rates set in PSE's next general rate case which will be filed in March 11, 2016.

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

Included in Washington Commission Docket UE-132027. PSE credited remaining amount by December 2015.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/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	1,061,117,006	1,003,205,239
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	868,093,914	825,091,211
5	Large (or Ind.) (See Instr. 4)	117,310,875	110,582,583
6	(444) Public Street and Highway Lighting	19,890,411	19,369,715
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	2,066,412,206	1,958,248,748
11	(447) Sales for Resale	193,653,719	107,556,910
12	TOTAL Sales of Electricity	2,260,065,925	2,065,805,658
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	2,260,065,925	2,065,805,658
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,746,073	3,646,521
17	(451) Miscellaneous Service Revenues	15,029,277	10,798,722
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	16,211,355	16,218,258
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-15,442,913	58,501,702
22	(456.1) Revenues from Transmission of Electricity of Others	26,474,378	29,976,252
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	45,018,170	119,141,455
27	TOTAL Electric Operating Revenues	2,305,084,095	2,184,947,113

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
10,164,703	10,349,928	970,830	960,708	2
				3
8,999,068	8,900,863	123,073	121,334	4
1,257,958	1,226,588	3,449	3,452	5
88,035	91,570	6,275	6,015	6
				7
				8
				9
20,509,764	20,568,949	1,103,627	1,091,509	10
7,673,384	1,399,818	8	8	11
28,183,148	21,968,767	1,103,635	1,091,517	12
				13
28,183,148	21,968,767	1,103,635	1,091,517	14

Line 12, column (b) includes $ 51,897,344 of unbilled revenues.

Line 12, column (d) includes 69,289 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 4 Column: b

Total includes $307,451 of transportation revenues.

Schedule Page: 300 Line No.: 4 Column: c

Total includes $313,108 of transportation revenues.

Schedule Page: 300 Line No.: 4 Column: f

Commercial - firm	122,912
Commercial - interuptible	160
Commercial - transportation	1
Total Commercial Customers	123,073

Schedule Page: 300 Line No.: 4 Column: g

Commercial - firm	121,171
Commercial - interuptible	161
Commercial - transportation	2
Total Commercial Customers	121,334

Schedule Page: 300 Line No.: 5 Column: b

Total includes $3,087,898 of transportation revenues.

Schedule Page: 300 Line No.: 5 Column: c

Total includes $2,833,029 of transportation revenues.

Schedule Page: 300 Line No.: 5 Column: f

Industrial - firm	3,430
Industrial - interuptible	4
Industrial - transporation	15
Total Industrial Customers	3,449

Schedule Page: 300 Line No.: 5 Column: g

Industrial - firm	3,433
Industrial - interuptible	4
Industrial - transporation	15
Total Industrial Customers	3,452

Schedule Page: 300 Line No.: 14 Column: d

Total does not include net of 2,620,865 MWh's billed and unbilled transportation.

Schedule Page: 300 Line No.: 14 Column: e

Total does not include net of 2,099,219 MWh's billed and unbilled transportation.

Schedule Page: 300 Line No.: 17 Column: b

Amount of $250,000 or Greater
Account 451 - Misc. Service Revenue:

Misc. SD revenue - electric	$	642,748
SD line extention revenue - elec.	$	1,173,139
Temporary service charge - elec.	$	798,763
Reconnection charge - elec	$	1,452,876
Acct. service charges - electric	$	1,363,055
modified service charges	$	1,277,739
Sch. 87 tax surchage -electric	$	7,624,310
non-consumption utility taxes	$	316,220

Schedule Page: 300 Line No.: 17 Column: c

Amount of $250,000 or Greater
Account 451 - Misc. Service Revenue:

Temporary Service charge = $722,299
Reconnection Charge -Electric = $1,245,002
Acct. Service Charges -Electric = $1,351,260
Modified Svc Chrg-Misc Svc Revenues-Elec = $527,764
Schedule 87 Tax Surcharge - Electric = $6,510,405

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

Amount of $250,000 or Greater

Account 456 - Electric Other Revenue

Green energy option	$	(1,316,825)
Summit lease buyout settlement credit to customers	$	1,026,108
Lifetime O&M revenue - electric	$	303,991
Sales of renewable energy credits (REC's)	$	2,132,729
Decoupling revenues	$	9,810,162
Electric ROR Over-Earnings on Decoupling Mechanism	$	(12,814,144)
Gain on sales or assignment of non-core gas	$	(15,489,205)
biogas principle amortization	$	393,711

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

Amount of $250,000 or Greater
Account 456 - Electric Other Revenue

Other Electric Revenue	2,176,505
PCS Revenue	578,076
Green Energy Option	(1,011,146)
Biogas Principle Amortization	10,472,183
Gain on Sales or Assignment of Non-Core Gas	8,264,681
Summit Lease buyout Settlement Credit to Customers	1,026,108
Sales of Renewable Energy credit (RECs)	4,721,901
Decoupling Revenues	34,788,915
Electric ROR Over-Earnings on Decoupling Mechanism	(3,445,055)
Lifetime O&M Revenue - Electric	283,621
Other Common Revenues - Misc Income (Non-Consumption Billing)	301,146

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/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					
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28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL SALES					
2	SCH_7E Residential	10,162,208	1,061,006,484	970,826	10,468	0.1044
3	SCH_7AE Residential	2,495	225,307	4	623,750	0.0903
4	Total	10,164,703	1,061,231,791	970,830	10,470	0.1044
5						
6						
7	COMMERCIAL SALES					
8	SCH_8E Commercial	259,740	27,123,886	29,481	8,810	0.1044
9	SCH_10E Commercial	32,949	2,398,898	13	2,534,538	0.0728
10	SCH_11E Commercial	151,154	12,843,760	313	482,920	0.0850
11	SCH_12E Commercial	18,858	1,489,686	13	1,450,615	0.0790
12	SCH_24EC Commercial	2,346,499	252,408,616	83,113	28,233	0.1076
13	SCH_25EC Commercial	2,523,448	253,472,027	6,298	400,674	0.1004
14	SCH_26EC Commercial	1,669,428	150,579,102	681	2,451,436	0.0902
15	SCH_29E Commercial	16,230	1,199,739	549	29,563	0.0739
16	SCH_31EC Commercial	797,626	71,412,376	341	2,339,079	0.0895
17	SCH_35E Commercial	5,385	265,350	1	5,385,000	0.0493
18	SCH_43E Commercial	119,184	11,912,207	159	749,585	0.0999
19	SCH_46EC Commercial	78	115,017	1	78,000	1.4746
20	SCH_49EC Commercial	444,312	31,952,770	15	29,620,800	0.0719
21	SCH_55E Commercial	2,032	608,457	814	2,496	0.2994
22	SCH_56E Commercial	1,931	584,254	854	2,261	0.3026
23	SCH_58E Commercial	2,247	487,879	277	8,112	0.2171
24	SCH_59E Commercial	80	20,198	25	3,200	0.2525
25	SCH_40EC Commercial	607,886	48,999,842	124	4,902,306	0.0806
26	Total	8,999,067	867,874,064	123,072	73,120	0.0964
27						
28						
29	INDUSTRIAL SALES					
30	SCH_24EI Industrial	92,044	10,068,521	2,758	33,373	0.1094
31	SCH_25EI Industrial	179,554	19,184,652	451	398,124	0.1068
32	SCH_26EI Industrial	248,973	23,620,034	89	2,797,449	0.0949
33	SCH_31EI Industrial	488,116	42,981,463	121	4,034,017	0.0881
34	SCH_46EI Industrial	55,476	4,125,460	4	13,869,000	0.0744
35	SCH_49EI Industrial	132,736	9,393,675	5	26,547,200	0.0708
36	SCH_40EI Industrial	61,059	4,870,478	6	10,176,500	0.0798
37	Total	1,257,958	114,244,283	3,434	366,324	0.0908
38						
39						
40						
41	TOTAL Billed	22,450,787	2,014,518,248	0	0	0.0897
42	Total Unbilled Rev.(See Instr. 6)	71,804	51,893,958	0	0	0.7227
43	TOTAL	22,522,591	2,066,412,206	0	0	0.0917

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	PUBLIC STREET LIGHTING					
2	SCH_03E Lighting	7	749	1	7,000	0.1070
3	SCH_24EL Lighting	13,778	1,565,721	1,145	12,033	0.1136
4	SCH_25EL Lighting	1,020	132,524	8	127,500	0.1299
5	SCH_50E Lighting	66	10,445	11	6,000	0.1583
6	SCH_51E Lighting	224	100,546	80	2,800	0.4489
7	SCH_52E Lighting	13,535	3,399,776	2,489	5,438	0.2512
8	SCH_53E Lighting	46,717	13,420,134	2,386	19,580	0.2873
9	SCH_54E Lighting	8,036	990,329	44	182,636	0.1232
10	SCH_57E Lighting	4,652	472,365	111	41,910	0.1015
11	Total	88,035	20,092,589	6,275	14,029	0.2282
12						
13						
14	TRANSPORTATION					
15	SCH_449EC Transportation	68,896	542,330	1	68,896,000	0.0079
16	SCH_449EI Transportation	1,666,017	1,516,370	12	138,834,750	0.0009
17	SCH_459EI Transportation	277,915	1,336,650	3	92,638,333	0.0048
18	Total	2,012,828	3,395,350	16	125,801,750	0.0017
19						
20						
21	NON-CONSUMPTION					
22	Residential		-114,785			
23	Commercial		-87,603			
24	Industrial		-21,305			
25	Public Street Lighting		-202,178			
26	Total		-425,871			
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	22,450,787	2,014,518,248	0	0	0.0897
42	Total Unbilled Rev.(See Instr. 6)	71,804	51,893,958	0	0	0.7227
43	TOTAL	22,522,591	2,066,412,206	0	0	0.0917

Schedule Page: 304 Line No.: 2 Column: c

Includes rate schedule adjustments for $(10), account 184 clearing adjustments of $(2,409), and customer class reclass adjustments of $101,216 for unbilled revenues.

Schedule Page: 304 Line No.: 8 Column: c

Includes $(66) rate schedule adjustments.

Schedule Page: 304 Line No.: 9 Column: c

Includes rate schedule adjustments for $738,705.

Schedule Page: 304 Line No.: 12 Column: c

Includes rate schedule adjustments for $(917).

Schedule Page: 304 Line No.: 13 Column: c

Includes account 184 clearing adjustments of $(386), and customer class reclass adjustments of $(92,084) for unbilled revenues.

Schedule Page: 304 Line No.: 33 Column: c

Includes customer class reclass adjustments of $(9,132) for unbilled revenues.

Schedule Page: 304.1 Line No.: 8 Column: c

Includes account clearing adjustments of $(36).

Schedule Page: 304.1 Line No.: 14 Column: a

Excludes $6,747,288 for electric transportation revenues classifed on page 300 as (456.1), Revenues from Transmission of Electricity of Others.

Schedule Page: 304 Line No.: 41 Column: b

Excludes 1,949,257 MWh of Sales for Resale.

Schedule Page: 304 Line No.: 41 Column: c

Includes $2,021,691,408 in total billed revenue and $(425,871) in non-consumption revenue.

Excludes $46,991,953 of sales for Resale.

Schedule Page: 304 Line No.: 42 Column: b

Unbilled MWh as of the end of the year for each applicable revenue account subheading are as follows:

Residential	26,899
Commercial	31,944
Industrial	9,518
Public Street Lighting	822
Transportation	2,621

Schedule Page: 304 Line No.: 42 Column: c

Excluding unbilled revenue of $3,387 for 447-01 Sales for Resale, which is reported on pages 310-311.

Unbilled revenue as of the end of the year for each applicable revenue account subheading are as follows:

Residential	$34,805,411
Commercial	$14,588,061
Industrial	$1,900,971
Public Street Lighting	$524,662
Transportation	$74,853

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Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	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	Port of Bremerton	RQ	Sch005	0.125	0.125	0.125
2	Port of Brownsville	RQ	Sch005	0.151	0.151	0.151
3	City of Des Moines	RQ	Sch005	0.250	0.250	0.250
4	Kingston Port District	RQ	Sch005	0.106	0.106	0.106
5	Kittitas Co PUD	RQ	Sch005	0.023	0.023	0.023
6	City of Oak Harbor	RQ	Sch005	0.121	0.121	0.121
7	Poulsbo Port District	RQ	Sch005	0.075	0.075	0.075
8	Port of Skagit - LaConner Marina	RQ	Sch005	0.086	0.086	0.086
9	Port of Skagit - North Basin	RQ	Sch005	0.140	0.140	0.140
10	Change in Unbilled Revenue	RQ	Sch005			
11	Avista Corp. WWP Division	OS	FERC #8			
12	Avista Corp. WWP Division	OS	FERC #9			
13	BC Hydro	OS	FERC #9			
14	Black Hills Power, Inc.	OS	FERC #8			
	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
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	Bonneville Power Administration	AD	FERC #8			
2	Bonneville Power Administration	OS	FERC #8			
3	BP Energy Company	AD	FERC #8			
4	BP Energy Company	OS	FERC #8			
5	Calpine Energy Services	OS	FERC #8			
6	Cargill Power Markets, LLC	OS	FERC #8			
7	Chelan County PUD	OS	FERC #8			
8	Chelan County PUD	OS	FERC #9			
9	Citigroup Energy Inc.	AD	FERC #8			
10	Citigroup Energy Inc.	OS	FERC #8			
11	Clark Public Utilities	AD	FERC #8			
12	Clark Public Utilities	OS	FERC #8			
13	Clatskanie Peoples Utility District	OS	FERC #8			
14	ConocoPhillips Company	OS	FERC #8			
	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
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Constellation Power Source, Inc.	OS	FERC #9			
2	CP Energy Marketing (US) Inc.	OS	FERC #8			
3	EDF Trading N.A., LLC	AD	FERC #8			
4	EDF Trading N.A., LLC	OS	FERC #8			
5	Enmax Energy Marketing, Inc.	OS	FERC #8			
6	Eugene Water & Electric Board	OS	FERC #8			
7	Exelon Generation Company LLC	OS	FERC #8			
8	FortisBC	OS	FERC #8			
9	Grant County PUD No.2	OS	FERC #8			
10	Grant County PUD No.2	OS	FERC #9			
11	Iberdrola Renewables, LLC.	AD	FERC #8			
12	Iberdrola Renewables, LLC.	OS	FERC #8			
13	Idaho Power Company	OS	FERC #8			
14	Idaho Power Company	OS	FERC #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
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	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	J. Aron & Company	OS	FERC #8			
2	JPMorgan Ventures Energy	OS	FERC #8			
3	Morgan Stanley Capital Group Inc.	AD	FERC #8			
4	Morgan Stanley Capital Group Inc.	OS	FERC #8			
5	NaturEner Power Watch, LLC	OS	FERC #8			
6	NaturEner Power Watch, LLC	OS	FERC #9			
7	Nevada Power Company	OS	FERC #8			
8	Nevada Power Company	OS	FERC #9			
9	NextEra Energy Power Marketing, LLC	OS	FERC #8			
10	NorthPoint Energy Solutions	OS	FERC #8			
11	NorthWestern Energy	AD	FERC #8			
12	NorthWestern Energy	OS	FERC #8			
13	NorthWestern Energy	OS	FERC #9			
14	P.U.D. No. 1 of Douglas County	OS	FERC #8			
	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
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	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	P.U.D. No. 1 of Okanogan County	OS	FERC #8			
2	PacifiCorp	AD	FERC #8			
3	PacifiCorp	OS	FERC #8			
4	PacifiCorp	OS	FERC #9			
5	Portland General Electric Company	OS	FERC #8			
6	Portland General Electric Company	OS	FERC #9			
7	Powerex Corp.	AD	FERC #8			
8	Powerex Corp.	OS	FERC #8			
9	Public Service Company of Colorado	OS	FERC #8			
10	Rainbow Energy Marketing	AD	FERC #8			
11	Rainbow Energy Marketing	OS	FERC #8			
12	Sacramento Municipal Utility District	OS	FERC #8			
13	Sacramento Municipal Utility District	OS	FERC #9			
14	Seattle City Light Marketing	AD	FERC #8			
	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
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Seattle City Light Marketing	OS	FERC #8			
2	Seattle City Light Marketing	OS	FERC #9			
3	Shell Energy North America (US)	AD	FERC #8			
4	Shell Energy North America (US)	OS	FERC #8			
5	Snohomish County PUD	OS	FERC #8			
6	Southern California Edison	OS	FERC #8			
7	Tacoma Power	OS	FERC #8			
8	Tacoma Power	OS	FERC #9			
9	Talen Energy Marketing, LLC	AD	FERC #8			
10	Talen Energy Marketing, LLC	OS	FERC #8			
11	Tenaska Power Services Co.	OS	FERC #8			
12	The Energy Authority	AD	FERC #8			
13	The Energy Authority	OS	FERC #8			
14	TransAlta Energy Marketing U.S.	AD	FERC #8			
	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
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	TransAlta Energy Marketing U.S.	OS	FERC #8			
2	TransCanada Energy Sales Ltd.	OS	FERC #8			
3	Turlock Irrigation District	OS	FERC #8			
4	Vitol Inc.	OS	FERC #8			
5	Western Area Power Admin	OS	FERC #9			
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
681	7,907	23,930	2,440	34,277	1
1,323	13,192	46,490	2,532	62,214	2
1,551	15,731	54,513	2,966	73,210	3
555	6,689	19,504	1,067	27,260	4
163	2,540	5,739		8,279	5
704	7,707	24,748	653	33,108	6
435	4,836	15,280	1,327	21,443	7
461	5,409	16,182	1,079	22,670	8
833	8,795	29,275	1,645	39,715	9
106	-346	3,733		3,387	10
59,285		1,522,832		1,522,832	11
49		1,376		1,376	12
28		888		888	13
30		810		810	14
6,812	72,460	239,394	13,709	325,563	
7,666,572	0	193,327,530	626	193,328,156	
7,673,384	**72,460**	**193,566,924**	**14,335**	**193,653,719**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			1	1	1
284,002		7,379,712		7,379,712	2
			28	28	3
303,763		7,527,013		7,527,013	4
117,995		2,587,569		2,587,569	5
176,345		4,855,504		4,855,504	6
4,200		85,596		85,596	7
7		218		218	8
			1	1	9
327,954		8,446,845		8,446,845	10
25			550	550	11
6,007		155,737		155,737	12
3,692		78,906		78,906	13
5,200		130,480		130,480	14
6,812	72,460	239,394	13,709	325,563	
7,666,572	0	193,327,530	626	193,328,156	
7,673,384	**72,460**	**193,566,924**	**14,335**	**193,653,719**	

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.
89		1,895		1,895	1
902		36,305		36,305	2
			725	725	3
1,158,465		29,397,691		29,397,691	4
346		11,810		11,810	5
22,601		511,803		511,803	6
154,413		3,897,859		3,897,859	7
13,980		114,653		114,653	8
34,895		999,632		999,632	9
9		167		167	10
			100	100	11
465,716		11,009,811		11,009,811	12
28,130		681,348		681,348	13
36		949		949	14
6,812	72,460	239,394	13,709	325,563	
7,666,572	0	193,327,530	626	193,328,156	
7,673,384	**72,460**	**193,566,924**	**14,335**	**193,653,719**	

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
10,000		269,800		269,800	1
64,335		1,480,724		1,480,724	2
-225			-12,375	-12,375	3
800,073		19,048,523		19,048,523	4
		-318		-318	5
61		1,143		1,143	6
1,201		56,608		56,608	7
66		1,268		1,268	8
1,748		45,276		45,276	9
50		950		950	10
			52	52	11
27,492		697,033		697,033	12
93		1,797		1,797	13
2,350		47,050		47,050	14
6,812	72,460	239,394	13,709	325,563	
7,666,572	0	193,327,530	626	193,328,156	
7,673,384	**72,460**	**193,566,924**	**14,335**	**193,653,719**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,425		38,390		38,390	1
			196	196	2
269,975		6,592,336		6,592,336	3
378		8,155		8,155	4
154,100		3,563,034		3,563,034	5
3		92		92	6
-18			-450	-450	7
165,748		3,050,743		3,050,743	8
600		12,300		12,300	9
			200	200	10
5,067		119,324		119,324	11
15,677		298,688		298,688	12
34		657		657	13
			1	1	14
6,812	72,460	239,394	13,709	325,563	
7,666,572	0	193,327,530	626	193,328,156	
7,673,384	**72,460**	**193,566,924**	**14,335**	**193,653,719**	

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 09/27/2016	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
34,970		907,386		907,386	1
12		419		419	2
			150	150	3
349,844		9,418,580		9,418,580	4
7,576		217,210		217,210	5
200		6,000		6,000	6
15,019		330,656		330,656	7
42		736		736	8
-1			-28	-28	9
70,878		1,532,337		1,532,337	10
828		25,280		25,280	11
-25			-550	-550	12
41,364		996,050		996,050	13
225			12,025	12,025	14
6,812	72,460	239,394	13,709	325,563	
7,666,572	0	193,327,530	626	193,328,156	
7,673,384	**72,460**	**193,566,924**	**14,335**	**193,653,719**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
637,337		13,527,539		13,527,539	1
7,621		281,917		281,917	2
208		5,670		5,670	3
1,812,075		51,306,725		51,306,725	4
2		43		43	5
					6
					7
					8
					9
					10
					11
					12
					13
					14
6,812	72,460	239,394	13,709	325,563	
7,666,572	0	193,327,530	626	193,328,156	
7,673,384	**72,460**	**193,566,924**	**14,335**	**193,653,719**	

Schedule Page: 310 Line No.: 1 Column: j
Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 2 Column: j
Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 3 Column: j
Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 4 Column: j
Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 6 Column: j
Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 7 Column: j
Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 8 Column: j
Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 9 Column: j
Other charges to municipalities included State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310.1 Line No.: 1 Column: j
Current period accounting adjustment.

Schedule Page: 310.1 Line No.: 3 Column: j
Current period accounting adjustment.

Schedule Page: 310.1 Line No.: 9 Column: j
Current period accounting adjustment.

Schedule Page: 310.1 Line No.: 11 Column: j
Prior period adjustment.

Schedule Page: 310.2 Line No.: 3 Column: j
Current period accounting adjustment.

Schedule Page: 310.2 Line No.: 11 Column: j
Prior period adjustment.

Schedule Page: 310.3 Line No.: 3 Column: j
Prior period adjustment.

Schedule Page: 310.3 Line No.: 11 Column: j
Prior period adjustment.

Schedule Page: 310.4 Line No.: 2 Column: j
Prior period adjustment.

Schedule Page: 310.4 Line No.: 7 Column: j
Prior period adjustment & current period accounting adjustment.

Schedule Page: 310.4 Line No.: 10 Column: j
Prior period adjustment.

Schedule Page: 310.4 Line No.: 14 Column: j
Current period accounting adjustment.

Schedule Page: 310.5 Line No.: 3 Column: j
Prior period adjustment.

Schedule Page: 310.5 Line No.: 9 Column: a
Formerly PPL EnergyPlus, LLC.

Schedule Page: 310.5 Line No.: 9 Column: j
Prior period adjustment.

FOOTNOTE DATA

Schedule Page: 310.5 Line No.: 10 Column: a

Formerly PPL EnergyPlus, LLC.

Schedule Page: 310.5 Line No.: 12 Column: j

Prior period adjustment.

Schedule Page: 310.5 Line No.: 14 Column: j

Prior period adjustment.

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	2,076,591	1,905,577
5	(501) Fuel	79,989,980	81,919,012
6	(502) Steam Expenses	9,180,411	8,966,057
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,678,135	2,197,201
10	(506) Miscellaneous Steam Power Expenses	8,597,345	2,434,160
11	(507) Rents	82,176	106,695
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	102,604,638	97,528,702
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,982,397	1,942,232
16	(511) Maintenance of Structures	3,218,656	3,023,469
17	(512) Maintenance of Boiler Plant	15,244,750	14,062,196
18	(513) Maintenance of Electric Plant	5,996,574	4,750,466
19	(514) Maintenance of Miscellaneous Steam Plant	2,637,035	2,707,551
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	29,079,412	26,485,914
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	131,684,050	124,014,616
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	1,596,893	1,551,439
45	(536) Water for Power		
46	(537) Hydraulic Expenses	3,265,257	4,017,897
47	(538) Electric Expenses	305,827	474,029
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,669,231	3,752,976
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	7,837,208	9,796,341
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures	403,806	750,450
55	(543) Maintenance of Reservoirs, Dams, and Waterways	533,348	542,539
56	(544) Maintenance of Electric Plant	1,844,725	1,002,906
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,827,863	4,629,390
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,609,742	6,925,285
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	14,446,950	16,721,626

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	2,964,558	4,064,400
63	(547) Fuel	169,917,384	181,574,417
64	(548) Generation Expenses	10,693,854	9,853,362
65	(549) Miscellaneous Other Power Generation Expenses	4,214,334	4,473,493
66	(550) Rents	7,088,519	7,759,514
67	TOTAL Operation (Enter Total of lines 62 thru 66)	194,878,649	207,725,186
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	671,408	807,699
70	(552) Maintenance of Structures	592,805	564,699
71	(553) Maintenance of Generating and Electric Plant	24,138,595	25,368,172
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	947,614	1,125,270
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	26,350,422	27,865,840
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	221,229,071	235,591,026
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	411,550,632	341,468,493
77	(556) System Control and Load Dispatching	86,846	255,758
78	(557) Other Expenses	10,066,230	-630,667
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	421,703,708	341,093,584
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	789,063,779	717,420,852
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,723,467	1,964,232
84			
85	(561.1) Load Dispatch-Reliability	44,217	93,326
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,776,163	2,567,154
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,167,064	1,092,695
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	209,454	262,354
90	(561.6) Transmission Service Studies	27,409	33,366
91	(561.7) Generation Interconnection Studies	47,554	55,479
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,210,127	1,090,644
94	(563) Overhead Lines Expenses	462,209	471,534
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	110,658,354	108,412,773
97	(566) Miscellaneous Transmission Expenses	950,723	1,090,896
98	(567) Rents	151,425	90,097
99	TOTAL Operation (Enter Total of lines 83 thru 98)	119,428,166	117,224,550
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	111,360	124,457
102	(569) Maintenance of Structures	264	683
103	(569.1) Maintenance of Computer Hardware	398	311
104	(569.2) Maintenance of Computer Software	624,578	1,039,803
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,163,252	3,954,963
108	(571) Maintenance of Overhead Lines	6,547,522	7,418,188
109	(572) Maintenance of Underground Lines	584,119	238,889
110	(573) Maintenance of Miscellaneous Transmission Plant		
111	TOTAL Maintenance (Total of lines 101 thru 110)	11,031,493	12,777,294
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	130,459,659	130,001,844

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	579,072	1,501,440
135	(581) Load Dispatching	2,680,562	2,853,035
136	(582) Station Expenses	1,511,168	1,782,714
137	(583) Overhead Line Expenses	4,282,776	4,225,052
138	(584) Underground Line Expenses	2,670,725	2,530,156
139	(585) Street Lighting and Signal System Expenses	433,159	579,534
140	(586) Meter Expenses	1,334,953	1,949,762
141	(587) Customer Installations Expenses	4,374,214	4,357,523
142	(588) Miscellaneous Expenses	3,764,166	3,947,726
143	(589) Rents	929,870	862,882
144	TOTAL Operation (Enter Total of lines 134 thru 143)	22,560,665	24,589,824
145	Maintenance		
146	(590) Maintenance Supervision and Engineering		
147	(591) Maintenance of Structures		7,246
148	(592) Maintenance of Station Equipment	3,250,095	2,758,666
149	(593) Maintenance of Overhead Lines	37,039,439	38,069,571
150	(594) Maintenance of Underground Lines	16,517,894	16,182,168
151	(595) Maintenance of Line Transformers	233,454	251,934
152	(596) Maintenance of Street Lighting and Signal Systems	2,406,964	2,295,109
153	(597) Maintenance of Meters	418,580	430,624
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of lines 146 thru 154)	59,866,426	59,995,318
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	82,427,091	84,585,142
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	167,142	164,034
160	(902) Meter Reading Expenses	14,157,421	18,268,249
161	(903) Customer Records and Collection Expenses	20,735,185	20,383,733
162	(904) Uncollectible Accounts	14,034,501	20,289,821
163	(905) Miscellaneous Customer Accounts Expenses	2,295	
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	49,096,544	59,105,837

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	117,113,803	110,929,798
169	(909) Informational and Instructional Expenses	1,236,121	2,153,374
170	(910) Miscellaneous Customer Service and Informational Expenses	87,888	148,834
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	118,437,812	113,232,006
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	389,058	526,019
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	389,058	526,019
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	29,597,632	29,051,159
182	(921) Office Supplies and Expenses	2,805,851	4,744,088
183	(Less) (922) Administrative Expenses Transferred-Credit	178,687	195,285
184	(923) Outside Services Employed	8,264,546	7,501,069
185	(924) Property Insurance	5,165,688	5,059,153
186	(925) Injuries and Damages	3,369,466	3,435,985
187	(926) Employee Pensions and Benefits	31,411,082	28,430,720
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	7,311,311	7,752,917
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	16,492	9,269
192	(930.2) Miscellaneous General Expenses	4,466,170	3,850,494
193	(931) Rents	7,513,313	7,285,521
194	TOTAL Operation (Enter Total of lines 181 thru 193)	99,742,864	96,925,090
195	Maintenance		
196	(935) Maintenance of General Plant	10,635,194	11,938,352
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	110,378,058	108,863,442
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,280,252,001	1,213,735,142

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	3 Bar G Wind Turbine #3 LLC	LU				
2	Barclays Bank Plc	IF				
3	Powerex (Point Roberts)	LF				
4	Powerex (Point Roberts)	AD				
5	BIO ENERGY (Washington) LLC	LU				
6	Black Creek Hydro	LU				
7	Bonneville Power Admistration	LF				
8	Bonneville Power Admin(WNP#3)	LF				
9	California Air Resources Board	AD				
10	California ISO	OS				
11	Cascade Community Solar	LU				
12	Chelan PUD - Rock Island and Rocky Rea	LF				
13	Douglas PUD - Wells Project	LF				
14	Edaleen Dairy, LLC	LU				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Farm Power Lynden LLC	LU				
2	Farm Power Rexville LLC	LU				
3	Grant PUD - Priest Rapids Project	LF				
4	Island Community Solar	LU				
5	Iberdrola Renewables (Klamath Falls)	LF				
6	Iberdrola Renewables (Klondike Wind Po	LF				
7	Iberdrola Renewables (Klondike Wind Po	AD				
8	Knudsen Wind Turbine#1	LU				
9	Rainer BioGas	LU				
10	Skookumchuck Hydro	LU				
11	Smith Creek Hydro	LU				
12	Swauk Wind LLC	LU				
13	Transalta Centralia Generation LLC	LF				
14	Van Dyk S Holsteins	LU				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	VanderHaak Dairy Digester	LU				
2	BioFuels Energy, LLC	LU				
3	Electron Hydro, LLC	LU				
4	Emerald City Renewables, LLC	LU				
5	Hutchinson Creek Hydro	LU				
6	Koma Kulshan Associates	LU				
7	Lake Washington School District #414	LU				
8	Puget Sound Hydro (Nooksack)	LU				
9	Cascade Clean Energy(Sygitowicz)	SF				
10	Twin Falls Hydro	LU				
11	South Fork II Associates(Weeks Falls)	LU				
12	Avista Nichols Pump	EX				
13	Constellation Power Source, Inc.	EX				
14	System Deviation	EX				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Pacific Gas & Elec - Exchange	EX				
2	Cargill (Financial)	OS				
3	Citigroup Energy (Financial)	OS				
4	EDF Trading (Financial)	OS				
5	Exelon Generation (Financial)	OS				
6	Morgan Stanley CG (Financial)	OS				
7	Shell Energy NA (Financial)	OS				
8	Avista Corp. WWP Division	OS				
9	Barclays Bank Plc	AD				
10	Black Hills Power	OS				
11	BP Energy Co.	OS				
12	Bonneville Power Admistration	OS				
13	British Columbia Transmission Corp	OS				
14	California ISO	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Calpine Energy Management	OS				
2	Cargill Power Markets	OS				
3	Chelan County PUD #1	OS				
4	Citigroup Energy Inc	OS				
5	Citigroup Energy Inc	AD				
6	Clark Public Utilities	OS				
7	Clatskanie PUD	OS				
8	Clatskanie PUD	AD				
9	Conoco, Inc.	OS				
10	Constellation Power Source, Inc.	OS				
11	Constellation Power Source, Inc.	AD				
12	Douglas County PUD #1	OS				
13	Douglas County PUD #1	AD				
14	EDF Trading NA LLC	OS				
	Total					

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PURCHASED POWER (Account 555)
(Including power exchanges)

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1	ENMAX Energy Marketing, Inc.	OS				
2	Eugene Water & Electric	OS				
3	Eugene Water & Electric	AD				
4	Exelon Generation Co LLC	OS				
5	Grant County PUD #2	OS				
6	Iberdrola Renewables (PPM Energy)	OS				
7	Iberdrola Renewables (PPM Energy)	AD				
8	Idaho Power Company	OS				
9	J. Aron & Company	OS				
10	JP Morgan Ventures Energy	OS				
11	Morgan Stanley CG	OS				
12	NextEra Energy Power Marketing	OS				
13	Noble Americas Energy Solutions	OS				
14	NorthPoint Energy Solutions, Inc.	OS				
	Total					

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1	Northwestern Energy	OS				
2	Northwestern Energy	AD				
3	Okanogan PUD	OS				
4	Pacificorp	OS				
5	Portland General Electric	OS				
6	Powerex Corp.	OS				
7	Public Service of Colorado	OS				
8	Rainbow Energy Marketing	OS				
9	Sacramento Municipal	OS				
10	Seattle City Light Marketing	OS				
11	Shell Energy (Coral Pwr)	OS				
12	Shell Energy (Coral Pwr)	AD				
13	Snohomish County PUD #1	OS				
14	Southern Cal - Edison	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Tacoma Power	OS				
2	Talen Energy Marketing	OS				
3	Tenaska Power Services Co.	OS				
4	The Energy Authority	OS				
5	TransAlta Energy Marketing	OS				
6	TransCanada Energy Sales Ltd	OS				
7	Turlock Irrigation District	OS				
8	Vitol Inc.	OS				
9	Western Area Power Association	OS				
10	Western Area Power Association	AD				
11	BEP Amortization	AD				
12	Residential Exchange	AD				
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.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
138				14,164		14,164	1
106,200				8,044,650		8,044,650	2
19,584				1,184,618		1,184,618	3
					-12,801	-12,801	4
2				156		156	5
6,366				534,298		534,298	6
7,000							7
343,584				14,160,757		14,160,757	8
					551	551	9
					-4,083	-4,083	10
23				1,381		1,381	11
2,177,002				21,959,070	36,511,369	58,470,439	12
1,094,705				16,058,065		16,058,065	13
4,697				394,255		394,255	14
16,874,776	488,630	413,000	1,340,000	474,745,459	-64,534,827	411,550,632	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
4,858				498,460		498,460	1
4,485				460,226		460,226	2
53,743				-1,695,628		-1,695,628	3
62				5,179		5,179	4
400			1,340,000	471,518		1,811,518	5
119,141				7,246,239		7,246,239	6
					37,296	37,296	7
130				13,301		13,301	8
4,950				474,236		474,236	9
4,961				475,283		475,283	10
163				15,601		15,601	11
11,369				954,183		954,183	12
1,651,177				76,474,456		76,474,456	13
1,619				155,127		155,127	14
16,874,776	488,630	413,000	1,340,000	474,745,459	-64,534,827	411,550,632	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,455				354,563		354,563	1
32,657				2,740,861		2,740,861	2
62,833				3,755,544		3,755,544	3
1,087				91,240		91,240	4
744				18,088		18,088	5
36,094				2,943,179		2,943,179	6
279				23,390		23,390	7
22,257				1,868,023		1,868,023	8
739				23,726		23,726	9
52,604				3,945,330		3,945,330	10
8,527				639,496		639,496	11
	22,743			489,674		489,674	12
				750		750	13
	52,887						14
16,874,776	488,630	413,000	1,340,000	474,745,459	-64,534,827	411,550,632	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	413,000	413,000					1
					414,054	414,054	2
					6,225,764	6,225,764	3
					-837,092	-837,092	4
					1,883,405	1,883,405	5
					-527,894	-527,894	6
					691,676	691,676	7
127,355				2,542,637		2,542,637	8
-30					-2,273	-2,273	9
1,200				63,700		63,700	10
340,839				9,396,720		9,396,720	11
141,462				2,921,785		2,921,785	12
67				1,199		1,199	13
12,114				499,692		499,692	14
16,874,776	488,630	413,000	1,340,000	474,745,459	-64,534,827	411,550,632	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
350,294				8,122,516		8,122,516	1
779,739				26,015,621		26,015,621	2
857				17,244		17,244	3
507,538				15,521,302		15,521,302	4
-20					-606	-606	5
5,045				97,497		97,497	6
2,013				57,275		57,275	7
8					264	264	8
2,000				54,200		54,200	9
5				110		110	10
2					85	85	11
271,759				4,892,732		4,892,732	12
					31,899	31,899	13
2,085,606				55,491,686		55,491,686	14
16,874,776	488,630	413,000	1,340,000	474,745,459	-64,534,827	411,550,632	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
990				22,960		22,960	1
10,913				223,517		223,517	2
-8					-264	-264	3
183,085				4,547,206		4,547,206	4
14,148				323,970		323,970	5
677,793				14,283,494		14,283,494	6
-8					-135	-135	7
14,768				304,291		304,291	8
10,400				192,996		192,996	9
67,092				1,934,157		1,934,157	10
1,304,649				45,871,634		45,871,634	11
113,998				3,502,195		3,502,195	12
800				25,552		25,552	13
300				5,600		5,600	14
16,874,776	488,630	413,000	1,340,000	474,745,459	-64,534,827	411,550,632	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
10,644				224,162		224,162	1
-25					-750	-750	2
15,430				358,163		358,163	3
26,590				588,613		588,613	4
109,691				3,311,363		3,311,363	5
144,388				4,356,859		4,356,859	6
800				19,400		19,400	7
12,393				242,987		242,987	8
5,966				149,211		149,211	9
96,380				2,020,519		2,020,519	10
309,223				8,908,530		8,908,530	11
24					710	710	12
18,557				328,550		328,550	13
42,837				691,238		691,238	14
16,874,776	488,630	413,000	1,340,000	474,745,459	-64,534,827	411,550,632	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
38,385				929,559		929,559	1
242,781				4,849,464		4,849,464	2
297				-272		-272	3
57,242				1,280,529		1,280,529	4
1,275,174				32,430,300		32,430,300	5
15,993				400,881		400,881	6
24,277				647,881		647,881	7
1,563,318				51,280,555		51,280,555	8
1				20		20	9
2					85	85	10
					3,526,620	3,526,620	11
					-112,472,707	-112,472,707	12
							13
							14
16,874,776	488,630	413,000	1,340,000	474,745,459	-64,534,827	411,550,632	

Schedule Page: 326 Line No.: 1 Column: a
Contract Expires Dec, 2019

Schedule Page: 326 Line No.: 2 Column: a
Contract Expires Feb, 2015

Schedule Page: 326 Line No.: 3 Column: a
Contract Expires Sep, 2019

Schedule Page: 326 Line No.: 4 Column: l
Prior Period Adjustment.

Schedule Page: 326 Line No.: 5 Column: a
Contract Expires Dec, 2021

Schedule Page: 326 Line No.: 6 Column: a
Contract Expires Dec, 2021

Schedule Page: 326 Line No.: 7 Column: a
Contract Expires Sep, 2029

Schedule Page: 326 Line No.: 8 Column: a
Contract Expires Jun, 2017

Schedule Page: 326 Line No.: 9 Column: l
Ca. Carbon Allowances

Schedule Page: 326 Line No.: 10 Column: l
True up of Ca. Carbon Allowance liability

Schedule Page: 326 Line No.: 11 Column: a
Contract Expires Dec, 2026

Schedule Page: 326 Line No.: 12 Column: a
Contract Expires Oct, 2031

Schedule Page: 326 Line No.: 12 Column: l

Amortization:	7,557,027
Debt Service:	19,084,679
Administrative:	5,790,453
Other:	4,079,210
Total:	36,511,369

Schedule Page: 326 Line No.: 13 Column: a
Contract Expires Aug, 2018

Schedule Page: 326 Line No.: 14 Column: a
Contract Expires Dec, 2021

Schedule Page: 326.1 Line No.: 1 Column: a
Contract Expires Dec, 2019

Schedule Page: 326.1 Line No.: 2 Column: a
Contract Expires Dec, 2019

Schedule Page: 326.1 Line No.: 3 Column: a
Contract Expires Apr, 2052

Schedule Page: 326.1 Line No.: 4 Column: a
Contract Expires Dec, 2021

Schedule Page: 326.1 Line No.: 5 Column: a
Contract Expires Feb, 2016

Schedule Page: 326.1 Line No.: 6 Column: a
Contract Expires Nov, 2027

Schedule Page: 326.1 Line No.: 7 Column: l
Prior period true up.

Schedule Page: 326.1 Line No.: 8 Column: a
Contract Expires Dec, 2019

Schedule Page: 326.1 Line No.: 9 Column: a

Contract Expires Dec, 2020

Schedule Page: 326.1 Line No.: 10 Column: a

Contract Expires Dec, 2020

Schedule Page: 326.1 Line No.: 11 Column: a

Contract Expires Dec, 2020

Schedule Page: 326.1 Line No.: 12 Column: a

Contract Expires Dec, 2021

Schedule Page: 326.1 Line No.: 13 Column: a

Contract Expires Dec, 2025

Schedule Page: 326.1 Line No.: 14 Column: a

Contract Expires Dec, 2020

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

Contract Expires Dec, 2019

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

Contract Expires Dec, 2021

Schedule Page: 326.2 Line No.: 3 Column: a

Contract Expires Nov, 2024

Schedule Page: 326.2 Line No.: 4 Column: a

Contract Expires Dec, 2029

Schedule Page: 326.2 Line No.: 5 Column: a

Contract Expires Sep, 2016

Schedule Page: 326.2 Line No.: 6 Column: a

Contract Expires Mar, 2037

Schedule Page: 326.2 Line No.: 7 Column: a

Contract Expires Dec, 2021

Schedule Page: 326.2 Line No.: 8 Column: a

Contract Expires Dec, 2021

Schedule Page: 326.2 Line No.: 9 Column: a

Contract Expires Apr, 2015

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

Contract Expires Mar, 2025

Schedule Page: 326.2 Line No.: 11 Column: a

Contract Expires Nov, 2022

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

Power Financial Hedging Transactions

Schedule Page: 326.3 Line No.: 3 Column: l

Power Financial Hedging Transactions

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

Power Financial Hedging Transactions

Schedule Page: 326.3 Line No.: 5 Column: l

Power Financial Hedging Transactions

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

Power Financial Hedging Transactions

Schedule Page: 326.3 Line No.: 7 Column: l

Power Financial Hedging Transactions

Schedule Page: 326.3 Line No.: 9 Column: l

Prior period true up.

Schedule Page: 326.4 Line No.: 5 Column: l

Prior period true up.

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

Prior period true up.

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

Prior period true up.

Schedule Page: 326.4 Line No.: 13 Column: l

Prior period true up.

Schedule Page: 326.5 Line No.: 3 Column: l

Prior period true up.

Schedule Page: 326.5 Line No.: 7 Column: l

Prior period true up.

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

Prior period true up.

Schedule Page: 326.6 Line No.: 12 Column: l

Prior period true up.

Schedule Page: 326.7 Line No.: 10 Column: l

Prior period true up.

Schedule Page: 326.7 Line No.: 11 Column: l

Amortization of Bonneville Power Administration WNP#3 Settlement.

Schedule Page: 326.7 Line No.: 12 Column: l

Offset to purchased power for Residential Exchange Refunding.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Seattle City Light	Seattle City Light	Seattle City Light	OLF
2	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	OS
3	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	OLF
4	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	OLF
5	Tacoma City Light	Tacoma City Light	Tacoma City Light	OS
6				
7	Bonneville Power Admin	Bonneville Power Admin	City of Blaine	FNO
8	Bonneville Power Admin	Bonneville Power Admin	City of Sumas	FNO
9	Bonneville Power Admin	Bonneville Power Admin	Kittitas County PUD	FNO
10	Bonneville Power Admin	Bonneville Power Admin	Orcas Power & Light	FNO
11	Bonneville Power Admin	Bonneville Power Admin	Tanner Electric Cooperative	FNO
12	Bonneville Power Admin	Bonneville Power Admin	Tanner Electric Cooperative	FNO
13	Bonneville Power Admin	Bonneville Power Admin	Tanner Electric Cooperative	SFP
14	Bonneville Power Admin	Bonneville Power Admin	Port of Seattle and Various	FNO
15				
16	Bonneville Power Admin	Bonneville Power Admin	City of Blaine	AD
17	Bonneville Power Admin	Bonneville Power Admin	City of Sumas	AD
18	Bonneville Power Admin	Bonneville Power Admin	Kittitas County PUD	AD
19	Bonneville Power Admin	Bonneville Power Admin	Tanner Electric Cooperative	AD
20	Bonneville Power Admin	Bonneville Power Admin	Tanner Electric Cooperative	AD
21	Bonneville Power Admin	Bonneville Power Admin	Tanner Electric Cooperative	AD
22	Bonneville Power Admin	Bonneville Power Admin	Port of Seattle and Various	AD
23				
24	Morgan Stanley Capital	Various	Various	LFP
25	Powerex	Various	Various	LFP
26	Powerex	Various	Various	LFP
27	Powerex	Various	Various	LFP
28	Sierra Pacific Industries	Various	Various	LFP
29	TransAlta Energy	Various	Various	LFP
30	Vantage Wind Energy LLC- Invenergy	Various	Various	LFP
31	Whatcom County PUD	Whatcom County PUD	Whatcom County PUD	LFP
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Maquarie Energy, LLC	Various	Various	SFP
2	Morgan Stanley Capital	Various	Various	SFP
3	Powerex	Various	Various	SFP
4	Powerex	Various	Various	SFP
5	Shell Energy North America	Various	Various	SFP
6	What com County PUD	What com County PUD	What com County PUD	SFP
7				
8	Shell Energy North America	Various	Various	AD
9				
10	Bonneville Power Admin	Various	Various	NF
11	Cargill Power Marketers	Various	Various	NF
12	Eagle Energy Partners	Various	Various	NF
13	Excelon Generation Company, LLC	Various	Various	NF
14	Macquarie Energy, LLC	Various	Various	NF
15	Morgan Stanley Capital	Various	Various	NF
16	NextEra Energy Power Marketing, LLC	Various	Various	NF
17	Portland General Electric Marketing	Various	Various	NF
18	Powerex	Various	Various	NF
19	Powerex	Various	Various	NF
20	Seattle City Light Marketing	Various	Various	NF
21	Shell Energy North America	Various	Various	NF
22	Shell Energy North America	Various	Various	NF
23	Sierra Pacific Industries	Various	Various	NF
24	Tacoma Power	Various	Various	NF
25	Tenaska Power Services Co	Various	Various	NF
26	The Energy Authority	Various	Various	NF
27	The Energy Authority	Various	Various	NF
28	TransAlta Energy	Various	Various	NF
29	Turlock Irrigation District	Various	Various	NF
30				
31	Barclays Bank	Various	Various	AD
32	Bonneville Power Administration	Various	Various	AD
33	Cargill Power Marketers	Various	Various	AD
34	Citigroup Energy, Inc.	Various	Various	AD
	TOTAL			

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 09/27/2016	Year/Period of Report End of 2015/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Conocophillips Company	Various	Various	AD
2	CP Energy Marketing (US) Inc.	Various	Various	AD
3	Eagle Energy Partners	Various	Various	AD
4	Excelon Generation Company, LLC	Various	Various	AD
5	Excelon Generation Company, LLC	Various	Various	AD
6	Iberdrola Renewables	Various	Various	AD
7	Macquarie Energy, LLC	Various	Various	AD
8	Macquarie Energy, LLC	Various	Various	AD
9	Morgan Stanley Capital	Various	Various	AD
10	Morgan Stanley Capital	Various	Various	AD
11	NextEra Energy Power Marktng, LLC	Various	Various	AD
12	NextEra Energy Power Marktng, LLC	Various	Various	AD
13	Noble Americas Gas and Power	Various	Various	AD
14	Portland General Electric Martng	Various	Various	AD
15	Powerex	Various	Various	AD
16	Powerex	Various	Various	AD
17	Powerex	Various	Various	AD
18	Port of Seattle	Various	Various	AD
19	PPL Energy Plus, LLC	Various	Various	AD
20	Seattle City Light Marketing	Various	Various	AD
21	Sempra Energy Trading Corp.	Various	Various	AD
22	Shell Energy North America	Various	Various	AD
23	Sierra Pacific Industries	Various	Various	AD
24	Snohomish County PUD	Various	Various	AD
25	Southern California Edison	Various	Various	AD
26	Tacoma Power	Various	Various	AD
27	The Energy Authority	Various	Various	AD
28	The Energy Authority	Various	Various	AD
29	TransAlta Energy	Various	Various	AD
30	TransAlta Energy	Various	Various	AD
31	Turlock Irrigation District	Various	Various	AD
32	Turlock Irrigation District	Various	Various	AD
33	Vantage Wind Energy LLC-Invenergy	Various	Various	AD
34	Watcom County PUD	Watcom County PUD	Watcom County PUD	AD
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1				
2	Transportation Customers			
3	Air Liquide	Various	Air Liquide	FNO
4	Air Products	Various	Air Products	FNO
5	AMCOR Rigid Plastics USA	Various	AMCOR Rigid Plastics USA	FNO
6	Bellingham Cold Storage - Orchard	Various	Bellingham Cold Storage - Orchar	FNO
7	Bellingham Cold Storage - Roeder	Various	Bellingham Cold Storage - Roeder	FNO
8	Boeing	Various	Boeing	FNO
9	BP Westcoast Products	Various	BP Westcoast Products	FNO
10	Intel	Various	Intel	FNO
11	Shell Oil Products (Equilon)	Various	Shell (Equilon)	FNO
12	Tesoro	Various	Tesoro	FNO
13				
14	Air Liquide	Various	Air Liquide	AD
15	Air Products	Various	Air Products	AD
16	AMCOR Rigid Plastics USA	Various	AMCOR Rigid Plastics USA	AD
17	Bellingham Cold Storage - Orchard	Various	Bellingham Cold Storage - Orchar	AD
18	Boeing	Various	Boeing	AD
19	BP Westcoast Products	Various	BP Westcoast Products	AD
20	Intel	Various	Intel	AD
21	Shell Oil Products (Equilon)	Various	Shell (Equilon)	AD
22	Tesoro	Various	Tesoro	AD
23				
24	Miscellaneous			
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 09/27/2016	Year/Period of Report End of 2015/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FRS #155	Stillwater Substn	Bothell Substation		48,847	48,847	1
FRS #60	Beverly Park Substn	Goldbar Substation				2
FRS #28	Beverly Park Substn	Hilton Lake Substn		86,038	86,038	3
FRS #28	Beverly Park Substn	Olympic Pipe Substn		10,233	10,233	4
FRS #62	Starwood Substation	Baldi Substation				5
						6
PSE OATT	Custer Substation	Blaine&Semiahmo Sub		77,376	77,376	7
PSE OATT	Bellingham Substn	City of Sumas Sub		31,788	31,788	8
PSE OATT	White River Substn	Teanaway Substation		15,999	15,999	9
PSE OATT	Murray Bellingham	Fidalgo Substation		204,658	204,658	10
PSE OATT	Maple Valley Substn	Ames Lake Tap		19,237	19,237	11
PSE OATT	Olympia Substation	Luhr Beach Tap		12,411	12,411	12
PSE OATT	Maple Valley Substn	North Bend Substn		61,534	61,534	13
PSE OATT	Various	Sea Tac Airport		143,448	143,448	14
						15
PSE OATT	Custer Substation	Blaine&Semiahmo Sub				16
PSE OATT	Bellingham Substn	City of Sumas Sub				17
PSE OATT	White River Substn	Teanaway Substation				18
PSE OATT	Maple Valley Substn	Ames Lake Tap				19
PSE OATT	Olympia Substation	Luhr Beach Tap				20
PSE OATT	Maple Valley Substn	North Bend Substn				21
PSE OATT	Various	Sea Tac Airport				22
						23
PSE OATT	John Day, COB	John Day, COB	100	806,400	806,400	24
PSE OATT	John Day, COB	John Day, COB	225	1,896,984	1,896,984	25
PSE OATT	Various Washington	Various Washington	193	571,129	571,129	26
PSE OATT	Various Washington	Various Washington	90	788,400	788,400	27
PSE OATT	Various Washington	Various Washington	19	166,455	166,455	28
PSE OATT	John Day, COB	John Day, COB	75	657,000	657,000	29
PSE OATT	Various Washington	Various Washington				30
PSE OATT	Custer Substation	Enterprise Sub	2	17,520	17,520	31
						32
						33
						34
			18,649	**9,521,013**	**9,521,013**	

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 09/27/2016	Year/Period of Report End of 2015/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
PSE OATT	John Day, COB	John Day, COB	450	21,600	21,600	1
PSE OATT	John Day, COB	John Day, COB	625	103,200	103,200	2
PSE OATT	John Day, COB	John Day, COB	538	72,960	72,960	3
PSE OATT	Various Washington	Various Washington	12,609	1,124,087	1,124,087	4
PSE OATT	Various Washington	Various Washington	3,723	309,483	309,483	5
PSE OATT	Custer Substation	Enterprise Sub		1	1	6
						7
PSE OATT	Various Washington	Various Washington				8
						9
PSE OATT	John Day, COB	John Day, COB		1	1	10
PSE OATT	Various Washington	Various Washington		1,464	1,464	11
PSE OATT	John Day, COB	John Day, COB		15	15	12
PSE OATT	John Day, COB	John Day, COB		2,247	2,247	13
PSE OATT	John Day, COB	John Day, COB		47,661	47,661	14
PSE OATT	John Day, COB	John Day, COB		2,005	2,005	15
PSE OATT	John Day, COB	John Day, COB		5,774	5,774	16
PSE OATT	John Day, COB	John Day, COB		2	2	17
PSE OATT	John Day, COB	John Day, COB		143,567	143,567	18
PSE OATT	Various Washington	Various Washington		14,240	14,240	19
PSE OATT	John Day, COB	John Day, COB		1,168	1,168	20
PSE OATT	John Day, COB	John Day, COB		6,934	6,934	21
PSE OATT	Various Washington	Various Washington		22,826	22,826	22
PSE OATT	Various Washington	Various Washington		12,931	12,931	23
PSE OATT	Various Washington	Various Washington		91	91	24
PSE OATT	John Day, COB	John Day, COB		86	86	25
PSE OATT	John Day, COB	John Day, COB		1,150	1,150	26
PSE OATT	Various Washington	Various Washington		5	5	27
PSE OATT	John Day, COB	John Day, COB		1,239	1,239	28
PSE OATT	John Day, COB	John Day, COB		612	612	29
						30
PSE OATT	Various Washington	Various Washington				31
PSE OATT	Various Washington	Various Washington				32
PSE OATT	Various Washington	Various Washington				33
PSE OATT	Various Washington	Various Washington				34
			18,649	**9,521,013**	**9,521,013**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
PSE OATT	Various Washington	Various Washington				1
PSE OATT	Various Washington	Various Washington				2
PSE OATT	VVarious Washington	Various Washington				3
PSE OATT	John Day, COB	John Day, COB				4
PSE OATT	Various Washington	Various Washington				5
PSE OATT	Various Washington	Various Washington				6
PSE OATT	John Day, COB	John Day, COB				7
PSE OATT	Various Washington	Various Washington				8
PSE OATT	John Day, COB	John Day, COB				9
PSE OATT	Various Washington	Various Washington				10
PSE OATT	John Day, COB	John Day, COB				11
PSE OATT	Various Washington	Various Washington				12
PSE OATT	Various Washington	Various Washington				13
PSE OATT	Various Washington	Various Washington				14
PSE OATT	John Day, COB	John Day, COB				15
PSE OATT	Various Washington	Various Washington				16
PSE OATT	Various Washington	Various Washington				17
PSE OATT	Various Washington	Various Washington				18
PSE OATT	Various Washington	Various Washington				19
PSE OATT	Various Washington	Various Washington				20
PSE OATT	Various Washington	Various Washington				21
PSE OATT	Various Washington	Various Washington				22
PSE OATT	Various Washington	Various Washington				23
PSE OATT	Various Washington	Various Washington				24
PSE OATT	Various Washington	Various Washington				25
PSE OATT	Various Washington	Various Washington				26
PSE OATT	John Day, COB	John Day, COB				27
PSE OATT	Various Washington	Various Washington				28
PSE OATT	John Day, COB	John Day, COB				29
PSE OATT	Various Washington	Various Washington				30
PSE OATT	John Day, COB	John Day, COB				31
PSE OATT	Various Washington	Various Washington				32
PSE OATT	Various Washington	Various Washington				33
PSE OATT	Custer Substation	Enterprise Sub				34
			18,649	**9,521,013**	**9,521,013**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
						1
						2
PSE OATT	Rocky Reach 115KV Sw	Air Liquide		76,170	76,170	3
PSE OATT	Rocky Reach 115KV Sw	Air Products		44,434	44,434	4
PSE OATT	Rocky Reach 115KV Sw	AMCOR Rigid Plastics		39,230	39,230	5
PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Orch		14,106	14,106	6
PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Roed		17,130	17,130	7
PSE OATT	Rocky Reach 115KV Sw	Boeing		521,272	521,272	8
PSE OATT	Rocky Reach 115KV Sw	BP Westcoast Product		707,518	707,518	9
PSE OATT	Rocky Reach 115KV Sw	Intel		16,352	16,352	10
PSE OATT	Rocky Reach 115KV Sw	Equilon Refinery		328,123	328,123	11
PSE OATT	Rocky Reach 115KV Sw	Tesoro		245,872	245,872	12
						13
PSE OATT	Rocky Reach 115KV Sw	Air Liquide				14
PSE OATT	Rocky Reach 115KV Sw	Air Products				15
PSE OATT	Rocky Reach 115KV Sw	AMCOR Rigid Plastics				16
PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Orch				17
PSE OATT	Rocky Reach 115KV Sw	Boeing				18
PSE OATT	Rocky Reach 115KV Sw	BP Westcoast Product				19
PSE OATT	Rocky Reach 115KV Sw	Intel				20
PSE OATT	Rocky Reach 115KV Sw	Equilon Refinery				21
PSE OATT	Rocky Reach 115KV Sw	Tesoro				22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			18,649	**9,521,013**	**9,521,013**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
332,297			332,297	1
		600	600	2
9,644		600	10,244	3
2,337		600	2,937	4
		4,576	4,576	5
				6
217,766		215,627	433,393	7
95,828		174,833	270,661	8
53,345		68,148	121,493	9
680,138		212,004	892,142	10
62,180		32,506	94,686	11
43,785		51,513	95,298	12
183,134		95,223	278,357	13
325,400		342,246	667,646	14
				15
		-72,434	-72,434	16
		-80,600	-80,600	17
		-33,578	-33,578	18
		-7,698	-7,698	19
		-9,238	-9,238	20
		-7,698	-7,698	21
		-135,229	-135,229	22
				23
898,509		387,694	1,286,203	24
2,113,432		799,413	2,912,845	25
1,369,148		826,476	2,195,624	26
1,080,029		2,114,355	3,194,384	27
374,855		121,276	496,131	28
731,954		325,389	1,057,343	29
-29		-1	-30	30
41,250		79,156	120,406	31
				32
				33
				34
17,227,272	**498,931**	**8,748,176**	**26,474,379**	

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.
26,560		7,126	33,686	1
117,540		14,680	132,220	2
84,635		8,314	92,949	3
2,733,382		264,117	2,997,499	4
779,177		644,148	1,423,325	5
35		39	74	6
				7
		-712,217	-712,217	8
				9
	2		2	10
	5,606	477	6,083	11
	16	9	25	12
	3,529	1,479	5,008	13
	63,845	25,624	89,469	14
	3,056	1,272	4,328	15
	8,336	3,373	11,709	16
	4	2	6	17
	236,826	101,674	338,500	18
	42,798	15,570	58,368	19
	1,775	835	2,610	20
	9,688	3,342	13,030	21
	80,012	68,592	148,604	22
	37,587	17,694	55,281	23
	364	31	395	24
	171	75	246	25
	1,836	810	2,646	26
	22	5	27	27
	2,313	1,066	3,379	28
	1,145	346	1,491	29
				30
		-3	-3	31
		-8,793	-8,793	32
		-754	-754	33
		-7	-7	34
17,227,272	**498,931**	**8,748,176**	**26,474,379**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		-2	-2	1
		-14	-14	2
		-13	-13	3
		-6	-6	4
		-1,880	-1,880	5
		-14	-14	6
		-51	-51	7
		-20	-20	8
		-6,956	-6,956	9
		-3,079	-3,079	10
		-475	-475	11
		-6	-6	12
		-17	-17	13
		-258	-258	14
		-19,833	-19,833	15
		-4,724	-4,724	16
		-48,348	-48,348	17
		-411	-411	18
		-66	-66	19
		-19	-19	20
		-27	-27	21
		-1,134	-1,134	22
		-1,154	-1,154	23
		-9	-9	24
		-149	-149	25
		-17	-17	26
		-8	-8	27
		-8	-8	28
		-6,288	-6,288	29
		-6,762	-6,762	30
		-38	-38	31
		-1	-1	32
		-45	-45	33
		-406	-406	34
17,227,272	**498,931**	**8,748,176**	**26,474,379**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
				1
				2
180,645		265,037	445,682	3
92,679		338,530	431,209	4
90,473		-22,276	68,197	5
36,345		-58,078	-21,733	6
41,452		-14,014	27,438	7
1,375,834		463,288	1,839,122	8
1,651,233		1,042,078	2,693,311	9
44,508		-244,155	-199,647	10
771,455		776,613	1,548,068	11
586,317		401,750	988,067	12
				13
		-953	-953	14
		-666	-666	15
		-666	-666	16
		-701	-701	17
		-10,359	-10,359	18
		-13,489	-13,489	19
		-441	-441	20
		-4,631	-4,631	21
		-3,987	-3,987	22
				23
		-27,151	-27,151	24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
17,227,272	**498,931**	**8,748,176**	**26,474,379**	

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

Contract expires with three years written notice.

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

Grandfathered Exchange and Transfer Agreement where power from Seattle City Light's (SCL) Tolt River South Fork project is transferred from Puget Sound Energy's Stillwater switching station to SCL's Bothell substation.

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

Grandfathered Exchange and Transfer Agreement where power from Seattle City Light's (SCL) Tolt River South Fork project is transferred from Puget Sound Energy's Stillwater switching station to SCL's Bothell substation.

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

Grandfathered Exchange and Transfer Agreement for service to Snohomish County PUD's Goldbar substation.

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

Grandfathered Exchange and Transfer Agreement for service to Snohomish County PUD's Goldbar substation.

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

Use of facilities charges.

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

Contract expires with two years written notice.

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

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Hilton Lake substation.

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

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Hilton Lake substation.

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

Use of facilities charges.

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

Contract expires with two years written notice.

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

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Olympic Pipe substation.

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

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Olympic Pipe substation.

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

Use of facilities charges.

Schedule Page: 328 Line No.: 5 Column: d

Use of facilities on pre-888 contract with Baldi substation.
Contract expires every 10 years but is automatically renewed unless otherwise requested.

Schedule Page: 328 Line No.: 5 Column: e

Grandfathered Transfer Agreement with the City of Tacoma where Puget Sound Energy transfers transmission and energy to Tacoma's North Fork Well Field Complex.

Schedule Page: 328 Line No.: 5 Column: h

Grandfathered Transfer Agreement with the City of Tacoma where Puget Sound Energy transfers transmission and energy to Tacoma's North Fork Well Field Complex.

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

Use of facilities charges.

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

Full title of the FERC rate is PSE OATT 10th Revised Colume No.7

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

Billing demand is based on monthly peak consistent with Puget Sound Energy's OATT.

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

Includes ancillary services, Washington State Tax, facilities fees, loss return charges and imbalance amounts.

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

Billing demand is based on monthly peak consistent with Puget Sound Energy’s OATT.

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

Includes ancillary services, Washington's State Tax, facilities fees, loss return charges and imbalance amounts.

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

Billing demand is based on monthly peak consistent with Puget Sound Energy’s OATT.

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

Includes ancillary services, Washington's State Tax, facilities fees, loss return charges and imbalance amounts.

Schedule Page: 328 Line No.: 10 Column: h

Billing demand is based on monthly peak consistent with Puget Sound Energy’s OATT.

Schedule Page: 328 Line No.: 10 Column: m

Includes ancillary services, Washington's State Tax, facilities fees, loss return charges and imbalance amounts.

Schedule Page: 328 Line No.: 11 Column: h

Billing demand is based on monthly peak consistent with Puget Sound Energy’s OATT.

Schedule Page: 328 Line No.: 11 Column: m

Includes ancillary services, Washington's State Tax, facilities fees, loss return charges and imbalance amounts.

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

Billing demand is based on monthly peak consistent with Puget Sound Energy’s OATT.

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

Includes ancillary services, Washington's State Tax, facilities fees, loss return charges and imbalance amounts.

Schedule Page: 328 Line No.: 13 Column: h

Billing demand is based on monthly peak consistent with Puget Sound Energy’s OATT.

Schedule Page: 328 Line No.: 13 Column: m

Includes ancillary services, Washington's State Tax, facilities fees, loss return charges and imbalance amounts.

Schedule Page: 328 Line No.: 14 Column: h

Billing demand is based on monthly peak consistent with Puget Sound Energy’s OATT.

Schedule Page: 328 Line No.: 14 Column: m

Includes ancillary services, Washington's State Tax, facilities fees, loss return charges and imbalance amounts.

Schedule Page: 328 Line No.: 16 Column: m

Prior period adjustment of distribution facilities fees.

Schedule Page: 328 Line No.: 17 Column: m

Prior period adjustment of distribution facilities fees.
Also includes prior period billings.

Schedule Page: 328 Line No.: 18 Column: m

Prior period adjustment of distribution facilities fees.

Schedule Page: 328 Line No.: 19 Column: m

Prior period adjustment of distribution facilities fees.

Schedule Page: 328 Line No.: 20 Column: m

Prior period adjustment of distribution facilities fees.

Schedule Page: 328 Line No.: 21 Column: m

Prior period adjustment of distribution facilities fees.

Schedule Page: 328 Line No.: 22 Column: m

Prior period adjustment of distribution facilities fees.

Schedule Page: 328 Line No.: 24 Column: d

Contract expires August 1,2020.

Schedule Page: 328 Line No.: 24 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328 Line No.: 25 Column: d

Powerex LFP 225 MW

Includes three contracts with the following end dates:

25 MW - October 1, 2017
100 MW - September 1, 2018
100 MW - September 1, 2019

Schedule Page: 328 Line No.: 25 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328 Line No.: 26 Column: d

Contract expires June 1, 2016

Schedule Page: 328 Line No.: 26 Column: m

Includes ancillary services, Washtington State Tax and loss return charges.

Schedule Page: 328 Line No.: 27 Column: a

Long-Term point-to-point transmission resale.

Schedule Page: 328 Line No.: 27 Column: d

Contract expires October 1,2020.

Schedule Page: 328 Line No.: 27 Column: m

Includes ancillary services, Washington State Tax, loss return charges and imbalance amounts.

Schedule Page: 328 Line No.: 28 Column: d

Contract expires December 1,2016.

Schedule Page: 328 Line No.: 28 Column: m

Includes ancillary services, Washington State Tax, loss return charges and imbalance amounts.

Schedule Page: 328 Line No.: 29 Column: d

Contract expires October 1, 2017.

Schedule Page: 328 Line No.: 29 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328 Line No.: 30 Column: d

Contract expires October 1,2020.

Schedule Page: 328 Line No.: 30 Column: h

90 MW long-term contract resold to Powerex.

Schedule Page: 328 Line No.: 30 Column: m

Includes ancillary services and Washington State Tax.

Schedule Page: 328 Line No.: 31 Column: d

Contract expires with one year written notice.

Schedule Page: 328 Line No.: 31 Column: m

Includes ancillary services, Washington State Tax, loss return charges and imbalance amounts.

Schedule Page: 328.1 Line No.: 1 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 2 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 3 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 4 Column: m

Includes ancillary services, Washington State Tax and loss return charges.

Schedule Page: 328.1 Line No.: 5 Column: m

Includes ancillary services, Washington State Tax, loss return charges and imbalance amounts. Also includes unreserved use penalty charges.

Schedule Page: 328.1 Line No.: 6 Column: k

Unreserved use penalty charge.

Schedule Page: 328.1 Line No.: 6 Column: m

Unreserved use penalty charge.

Schedule Page: 328.1 Line No.: 8 Column: m

Refund of ancillary service charges incorrectly billed to Shell Energy North America in prior years. The charges to Shell Energy North America were reversed and billed correctly to other transmission customers in the second quarter of 2015.

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

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 12 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 13 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 14 Column: a

Macquarie Energy, LLC is an affiliate of Puget Sound Energy.

Schedule Page: 328.1 Line No.: 14 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 15 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 16 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 17 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 18 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 19 Column: m

Includes ancillary services, Washington State Tax and loss return charges.

Schedule Page: 328.1 Line No.: 20 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 21 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 22 Column: m

Includes ancillary services, Washington State Tax, loss return charges and imbalance amounts. Also, incluses the unreserved use penalty charges.

Schedule Page: 328.1 Line No.: 23 Column: m

Includes ancillary services and Washington State Tax. Also, includes unreserved use penalty charges.

Schedule Page: 328.1 Line No.: 24 Column: m

Includes ancillary services and Washington State Tax.

Schedule Page: 328.1 Line No.: 25 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 26 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 27 Column: m

Includes ancillary services, Washington State Tax and loss return charges.

Schedule Page: 328.1 Line No.: 28 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 29 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 31 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.1 Line No.: 32 Column: m

Distribution of prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.1 Line No.: 33 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.1 Line No.: 34 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 1 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 2 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 3 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 4 Column: m

Correction of December 2014 loss return charges.

Schedule Page: 328.2 Line No.: 5 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 6 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 7 Column: a

Maquarie Energy, LLC is an affiliate of Puget Sound Energy.

Schedule Page: 328.2 Line No.: 7 Column: m

Correction of December 2014 loss return charges.

Schedule Page: 328.2 Line No.: 8 Column: a

Maquarie Energy, LLC is an affiliate of Puget Sound Energy.

Schedule Page: 328.2 Line No.: 8 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 9 Column: m

Correction of December 2014 loss return charges.

Schedule Page: 328.2 Line No.: 10 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 11 Column: m

Correction of December 2014 loss return charges.

Schedule Page: 328.2 Line No.: 12 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 13 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 14 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 15 Column: m

Correction of December 2014 loss return charges.

Schedule Page: 328.2 Line No.: 16 Column: m

Correction of December 2014 loss return charges.

Schedule Page: 328.2 Line No.: 17 Column: m

Distribution of prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.2 Line No.: 18 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 19 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 20 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 21 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 22 Column: m

Distribution of prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.2 Line No.: 23 Column: m

Distribution from prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.2 Line No.: 24 Column: m

Distribution from prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 25 Column: m

Distribution from prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 26 Column: m

Distribution from prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.2 Line No.: 27 Column: m

Correction of December 2014 loss return charges.

Schedule Page: 328.2 Line No.: 28 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 29 Column: m

Correction of December 2014 loss return charges.

Schedule Page: 328.2 Line No.: 30 Column: m

Distribution from prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 31 Column: m

Correction of December 2014 loss return charges.

Schedule Page: 328.2 Line No.: 32 Column: m

Distribution from prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 33 Column: m

Distribution from prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.2 Line No.: 34 Column: m

Distribution from prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.3 Line No.: 3 Column: d

Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.3 Line No.: 3 Column: f

Full name of the point of receipt is Rocky Reach 115KV switchyeard.

Schedule Page: 328.3 Line No.: 3 Column: m
Includes ancillary services, Washington State Tax and imbalance amounts.

Schedule Page: 328.3 Line No.: 4 Column: d
Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.3 Line No.: 4 Column: m
Includes ancillary services, Washington State Tax and imbalance amounts.

Schedule Page: 328.3 Line No.: 5 Column: d
Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.3 Line No.: 5 Column: m
Includes ancillary services, Washington State Tax and imbalance amounts.

Schedule Page: 328.3 Line No.: 6 Column: d
Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.3 Line No.: 6 Column: m
Includes ancillary services, Washington State Tax and imbalance amounts.

Schedule Page: 328.3 Line No.: 7 Column: d
Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.3 Line No.: 7 Column: m
Includes ancillary services, Washington State Tax and imbalance amounts.

Schedule Page: 328.3 Line No.: 8 Column: d
Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.3 Line No.: 8 Column: m
Includes ancillary services, Washington State Tax and imbalance amounts.

Schedule Page: 328.3 Line No.: 9 Column: d
Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.3 Line No.: 9 Column: m
Includes ancillary services, Washington State Tax and imbalance amounts.

Schedule Page: 328.3 Line No.: 10 Column: d
Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.3 Line No.: 10 Column: m
Includes ancillary services, Washington State Tax and imbalance amounts.

Schedule Page: 328.3 Line No.: 11 Column: d
Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.3 Line No.: 11 Column: m
Includes ancillary services, Washington State Tax and imbalance amounts.

Schedule Page: 328.3 Line No.: 12 Column: d
Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 449.

Schedule Page: 328.3 Line No.: 12 Column: m
Includes ancillary services, Washington State Tax and imbalance amounts.

Schedule Page: 328.3 Line No.: 14 Column: m

Distribution of prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.3 Line No.: 15 Column: m

Distribution of prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.3 Line No.: 16 Column: m

Distribution of prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.3 Line No.: 17 Column: m

Distribution of prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.3 Line No.: 18 Column: m

Distribution of prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.3 Line No.: 19 Column: m

Distribution of prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.3 Line No.: 20 Column: m

Distribution of prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.3 Line No.: 21 Column: m

Distribution of prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.3 Line No.: 22 Column: m

Distribution of prior year unreserved use penalty and imbalance penalty charges.

Schedule Page: 328.3 Line No.: 24 Column: m

Reversal of December 2014 duplicate entry done in error for $(24,151) and $(2,901) payment error that was corrected in second quarter of 2015.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Pwr Admin	LFP			18,793,458		2,389,488	21,182,946
2	Bonneville Pwr Admin	LFP	20,367,198	20,367,198	63,832,703		9,434,005	73,266,708
3	Bonneville Pwr Admin	SFP			81,432		18,792	100,224
4	Bonneville Pwr Admin	NF	12,685	12,685	51,030		4,142	55,172
5	Bonneville Pwr Admin	OS	160	160			3,599	3,599
6	Bonneville Pwr Admin	OS					162,252	162,252
7	Bonneville Pwr Admin	OS					5,781,700	5,781,700
8	Bonneville Pwr Admin	OS					7,777,102	7,777,102
9	Bonneville Pwr Admin	OS					-14,961	-14,961
10	Bonneville Pwr Admin	AD					339,428	339,428
11	Arizona Public Services	NF	1	1		7		7
12	Avista Corp	NF	351	351		2,025		2,025
13	Chelan County PUD No. 1	OLF	2,299,343	2,299,343			4,035,800	4,035,800
14	EDFT Trading NA, LLC	OS					-182,937	-182,937
15	Grant County PUD No. 2	OS					140,952	140,952
16	Iberdrola Renewables	LFP	400	400	705,200		316	705,516
	TOTAL		25,161,891	25,161,891	84,421,135	25,348	26,211,871	110,658,354

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Iberdrola Renewables	OS					-111,066	-111,066
2	Idaho Power Company	NF	67	67		311		311
3	Idaho Power Company	OS					-187,620	-187,620
4	Idaho Power Company	AD					3	3
5	Klickitat PUD	LFP	1,498,666	1,498,666			1,534,068	1,534,068
6	Klondike Wind Power III	OS					444,000	444,000
7	Los Angeles Water & Pwr	NF	1	1		12		12
8	Morgan Stanley CG	OS					-974,857	-974,857
9	Nevada Power	NF	69	69		508		508
10	NextEra Energy Pwr Mktg	OS					-144,565	-144,565
11	Northwestern Energy	SFP	18,705	18,705	80,936		4,209	85,145
12	Northwestern Energy	NF	50,706	50,706	219,787		11,243	231,030
13	Northwestern Energy	OS					424,542	424,542
14	Northwestern Energy	AD					-25,144	-25,144
15	Pacificorp	NF	2	2		17		17
16	Pacificorp	OS					-398,951	-398,951
	TOTAL		25,161,891	25,161,891	84,421,135	25,348	26,211,871	110,658,354

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Pacificorp	AD					-10	-10
2	Portland General Elec	LFP	874,267	874,267	642,989			642,989
3	Portland General Elec	SFP	19,338	19,338	13,600			13,600
4	Portland General Elec	NF	19,932	19,932		22,468		22,468
5	Portland General Elec	AD					-31,764	-31,764
6	Powerex	OS					-3,029,800	-3,029,800
7	Powerex	AD					-1,882	-1,882
8	Rainbow Energy Mrktng	OS					-500	-500
9	Seattle City Light Mrkg	OS					-1,050	-1,050
10	Shell Energy	OS					-19,306	-19,306
11	Snohomish Co. PUD No. 1	OS					64,515	64,515
12	Tacoma Power	OS					-17,775	-17,775
13	The Energy Authority	OS					-468,737	-468,737
14	TransAlta Energy Mrktng	OS					354,414	354,414
15	TransAlta Energy Mrktng	OS					-1,199,822	-1,199,822
16	TransAlta Energy Mrktng	AD					41,522	41,522
	TOTAL		25,161,891	25,161,891	84,421,135	25,348	26,211,871	110,658,354

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Whatcom Co PUD #1	OS					26,892	26,892
2	Whatcom Co PUD #1	AD					29,634	29,634
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		25,161,891	25,161,891	84,421,135	25,348	26,211,871	110,658,354

Name of Respondent Puget Sound Energy, Inc.	This Report is: (1) __ An Original (2) X A Resubmission	Date of Report (Mo, Da, Yr) 09/27/2016	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 332 Line No.: 1 Column: b

Includes a contract with an end date of August 2018 and a contract wth several tables with end dates ranging from February 2016 to June 2037.

Schedule Page: 332 Line No.: 1 Column: c

Total MWh's for BPA firm transmission is calculated to be 20,367,198. The reporting does not split the MWh's amongst the long-term firm contracts for the Mid-Columbia projects, the other long-term firm contracts and the short-term firm contracts so the entire 20,367,198 is reported with the other long-term firm contracts on line 2.

Schedule Page: 332 Line No.: 1 Column: e

Fixed transmission capacity charges that are related to the contracts for the Mid-Columbia projects.

Schedule Page: 332 Line No.: 1 Column: g

Ancillary services.

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

Includes a contract with a calculated end date of mid-2017 and a contract with several tables with end dates ranging from June 2016 to August 2028.

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

Total MWh's for BPA firm transmission is calculated to be 20,367,198. The reporting does not split the MWh's amongst the long-term firm contracts for the Mid-Columbia projects, the other long-term firm contracts and the short-term firm contracts so the entire 20,367,198 is reported with the other long-term firm contracts on line 2.

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

Fixed transmission capacity charges other than those related to the Mid-Columbia projects.

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

Charges are for ancillary services including all spin and supplemental spin reserves. There are spin and supplemental spin reserves for both firm and non-firm transmission but the reporting only shows it in total so reported all of the reserves with the firm transmission "other" charges on line 2.

The amount also includes regulatory entries done to record interest PSE received on a transmission deposit as customer interest via credits to transmission expense.

Schedule Page: 332 Line No.: 3 Column: c

Total MWh's for BPA firm transmission is calculated to be 20,367,198. The reporting does not split the MWh's amongst the long-term firm contracts for the Mid-Columbia projects, the other long-term firm contracts and the short-term firm contracts so the entire 20,367,198 is reported with the other long-term firm contracts on line 2.

Schedule Page: 332 Line No.: 3 Column: g

Ancillary services.

There are spin and supplemental spin reserves for both firm and non-firm transmission but the reporting only shows it in total so reported all of the reserves with the firm transmission "other" charges on line 2.

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

Ancillary services.

There are spin and supplemental spin reserves for both firm and non-firm transmission but the reporting only shows it in total so reported all of the reserves with the firm transmission "other" charges on line 2.

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

NWPP reserve sharing.

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

NWPP reserve sharing.

Schedule Page: 332 Line No.: 6 Column: g

Use of facilities charges and operation and maintenance charges.

Schedule Page: 332 Line No.: 7 Column: g

Intertie charges and capacity rights charges.

Schedule Page: 332 Line No.: 8 Column: g

Wind integration charges and generator imbalance charges.

Schedule Page: 332 Line No.: 9 Column: g

Transmission deposit interest to be returned to Puget Sound Energy Customers.

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

Prior period adjustments of:

Prior year NF transmission charges	$ 390
Prior years LFP transmission charges	150,176
Prior year 3rd AC costs	60,231
Prior years spinning and supplemental reserves	128,631
	$ 339,428

Schedule Page: 332 Line No.: 13 Column: b

Contract end date is October 31, 2031.

Schedule Page: 332 Line No.: 13 Column: g

Use of facilities charges.

Schedule Page: 332 Line No.: 14 Column: g

Reimbursement from EDFT Tranding NA, LLC for use of PSE capacity on Bonneville Power Administration lines.

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

Use of transmission facilities charges.

Schedule Page: 332 Line No.: 16 Column: b

Contract end date is February 2016.

Schedule Page: 332 Line No.: 16 Column: g

Ancillary services.

Schedule Page: 332.1 Line No.: 1 Column: g

Reimbursement from Iberdrola Renewables for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.1 Line No.: 3 Column: g

Reimbursement from Idaho Power Company for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.1 Line No.: 4 Column: g

Adjustment of prior year NF transmission costs.

Schedule Page: 332.1 Line No.: 5 Column: b

Contract end date is June 2032.

Schedule Page: 332.1 Line No.: 5 Column: g

Actual cost capacity charges.

Schedule Page: 332.1 Line No.: 6 Column: g

Wind integration charges.

Schedule Page: 332.1 Line No.: 8 Column: g

Reimbursement from Morgan Stanley Capital Group for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.1 Line No.: 10 Column: g

Reimbursement from NextEra Energy Power Marketing for use of PSE capacity on Bonneville

Power Administration lines.

Schedule Page: 332.1 Line No.: 11 Column: g

Ancillary services.

Schedule Page: 332.1 Line No.: 12 Column: g

Ancillary services.

Schedule Page: 332.1 Line No.: 13 Column: g

Use of facilities charges.

Schedule Page: 332.1 Line No.: 14 Column: g

Adjustment of prior year use of facilities charges.

Schedule Page: 332.1 Line No.: 16 Column: g

Reimbursement from Pacificorp for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.2 Line No.: 1 Column: g

Unreserved use credit distribution from Pacificorp.

Schedule Page: 332.2 Line No.: 2 Column: b

Contract end date is January 2017.

Schedule Page: 332.2 Line No.: 5 Column: g

Adjustment of prior year transmission charges.

Schedule Page: 332.2 Line No.: 6 Column: g

Reimbursement from Powerex Corporation for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.2 Line No.: 7 Column: g

Adjustment of prior year reimbursement from Powerex Corporation for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.2 Line No.: 8 Column: g

Reimbursement from Rainbow Energy Marketing for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.2 Line No.: 9 Column: g

Reimbursement from Seattle City Light Marketing for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.2 Line No.: 10 Column: g

Reimbursement from Shell Energy for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.2 Line No.: 11 Column: g

Beverly Park Substation annual use charge paid to Snohomish County PUD.

Schedule Page: 332.2 Line No.: 12 Column: g

Reimbursement from Tacoma Power for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.2 Line No.: 13 Column: g

Reimbursement from The Energy Authority for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.2 Line No.: 14 Column: g

Ancillary services.

Schedule Page: 332.2 Line No.: 15 Column: g

Reimbursement from TransAlta Energy Marketing for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.2 Line No.: 16 Column: g

Adjustment of prior year ancillary services.

Schedule Page: 332.3 Line No.: 1 Column: g

Interconnection losses charges.

Schedule Page: 332.3 Line No.: 2 Column: g

Prior year interconnection losses charges.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	761,336
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Board of Director Fees & Expenses	681,071
7	Western Electric Coordinator Council Dues	2,398,209
8	Other Memebership Dues	184,347
9	Communication Services	127,907
10	Treasury Fees & Expenses	195,777
11	Misc General Expense - Electric	88,522
12	State/Fed Govt Related Industry Expenses	29,001
13		
14		
15		
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46	TOTAL	4,466,170

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			8,119,336		8,119,336
2	Steam Production Plant	21,634,131	631,705			22,265,836
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	15,010,699		1,179,413		16,190,112
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	67,545,541	309,375			67,854,916
7	Transmission Plant	32,791,199	58,541			32,849,740
8	Distribution Plant	94,436,729	53,699			94,490,428
9	Regional Transmission and Market Operation					
10	General Plant	14,490,456				14,490,456
11	Common Plant-Electric	14,143,797	117,517	19,863,455		34,124,769
12	TOTAL	260,052,552	1,170,837	29,162,204		290,385,593

B. Basis for Amortization Charges

Account	Category	Basis for Amortization
404	Leasehold Improvements	Life of Lease or life of asset, whichever is shorter
404	Computer Software	Original estimated useful life
404	Franchise	Life of franchise
404	Snoqualmie License Costs	40 Years (Life of new license)
404	Baker License Costs	50 Years (Life of new license)

***Note: Page 337 is published every fifth year beginning with report year 1971 and when depreciation studies are published. Most recently PSE published Page 337 in 2011 and next one is due in 2016.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
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Schedule Page: 336 Line No.: 7 Column: b

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 336 Line No.: 7 Column: f

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 336 Line No.: 8 Column: b

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Schedule Page: 336 Line No.: 8 Column: f

Revision due to reclass of Generation Interconnection Facility (GIF) from distribution plant to transmission plant.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	WUTC Filing Fee	4,219,027		4,219,027	
2					
3	Federal Fees:				
4	Upper & Lower Baker Project	1,491,871		1,491,871	
5	Snoqualmie 1 & 2 Project	151,064		151,064	
6	Annual Power License Fees	21,646		21,646	
7					
8	Other Charges:				
9	Ferc Regulatory Legal Fees		107,514	107,514	
10	Ferc Regulatory Misc Fees		16,003	16,003	
11	State Regulatory Legal Fees		42,130	42,130	
12	2013 Transmission Rate Case		59,954	59,954	
13	2015 PCORC		2,930	2,930	
14	Annual Ferc Legal Fees		663,951	663,951	
15	Annual Ferc Misc Fees		67,616	67,616	
16	WUTC Misc Legal Fees		387,225	387,225	
17	2016 General Rate Case Legal Fees		81,057	81,057	
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46	TOTAL	5,883,608	1,428,380	7,311,988	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
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.
	928	4,219,027					1
							2
							3
	928	1,491,871					4
	928	151,064					5
	928	21,646					6
							7
							8
	928	107,514					9
	928	16,003					10
	928	42,130					11
	928	59,954					12
	928	2,930					13
	928	731,567					14
							15
	928	387,225					16
	928	81,057					17
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		7,311,988					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	19,362,805		
4	Transmission	6,314,045		
5	Regional Market			
6	Distribution	14,128,749		
7	Customer Accounts	11,246,595		
8	Customer Service and Informational	1,376,684		
9	Sales	264,990		
10	Administrative and General	27,137,358		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	79,831,226		
12	Maintenance			
13	Production	5,316,224		
14	Transmission	2,444,207		
15	Regional Market			
16	Distribution	13,654,419		
17	Administrative and General	273,111		
18	TOTAL Maintenance (Total of lines 13 thru 17)	21,687,961		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	24,679,029		
21	Transmission (Enter Total of lines 4 and 14)	8,758,252		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	27,783,168		
24	Customer Accounts (Transcribe from line 7)	11,246,595		
25	Customer Service and Informational (Transcribe from line 8)	1,376,684		
26	Sales (Transcribe from line 9)	264,990		
27	Administrative and General (Enter Total of lines 10 and 17)	27,410,469		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	101,519,187	1,099,344	102,618,531
29	Gas			
30	Operation			
31	Production-Manufactured Gas	144,985		
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	324,020		
34	Storage, LNG Terminaling and Processing	516,276		
35	Transmission			
36	Distribution	19,259,484		
37	Customer Accounts	7,678,001		
38	Customer Service and Informational	998,129		
39	Sales	7,405		
40	Administrative and General	12,428,024		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	41,356,324		
42	Maintenance			
43	Production-Manufactured Gas	13		
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	268,430		
47	Transmission			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	5,090,606		
49	Administrative and General	362,217		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	5,721,266		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	144,998		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	324,020		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	784,706		
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	24,350,090		
58	Customer Accounts (Line 37)	7,678,001		
59	Customer Service and Informational (Line 38)	998,129		
60	Sales (Line 39)	7,405		
61	Administrative and General (Lines 40 and 49)	12,790,241		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	47,077,590	509,800	47,587,390
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	148,596,777	1,609,144	150,205,921
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	41,312,261	447,366	41,759,627
69	Gas Plant	19,935,878	215,884	20,151,762
70	Other (provide details in footnote):	16,137,130	174,748	16,311,878
71	TOTAL Construction (Total of lines 68 thru 70)	77,385,269	837,998	78,223,267
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,555,479	27,673	2,583,152
74	Gas Plant	2,404,450	26,038	2,430,488
75	Other (provide details in footnote):	891,311	9,652	900,963
76	TOTAL Plant Removal (Total of lines 73 thru 75)	5,851,240	63,363	5,914,603
77	Other Accounts (Specify, provide details in footnote):	22,815,172	247,064	23,062,236
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95	TOTAL Other Accounts	22,815,172	247,064	23,062,236
96	TOTAL SALARIES AND WAGES	254,648,458	2,757,569	257,406,027

Schedule Page: 354 Line No.: 77 Column: a

Other Accounts	Direct Payroll Distribution	Allocation of Payroll Charged for Clearing Accounts	Total
121 Non Utility Property	148,302	1,606	149,908
163 Store Expense	3,842,167	41,607	3,883,774
182 Regulatory Asset	14,216,031	153,944	14,369,975
185 Temporary Facilities	13,709	148	13,857
186 Misc. Deferred Debits	3,146,887	34,077	3,180,964
Misc. 400 Accounts	1,398,392	15,143	1,413,535
143 Accts Receivable Misc.	28,192	305	28,497
Prelim Survey OG 183	107	1	108
Misc. 200 Accounts	7,289	80	7,369
Jackson Prairie Joint Venture - Capital - PSE Share	14,096	153	14,249
Jackson Prairie Joint Venture - Expense - PSE Share	0	0	0
TOTAL	22,815,172	247,064	23,062,236

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 and Accumulated Provision for Depreciation:

Account	Description	Book Value 12/31/2015	Accumulated Provision for Depreciation & Amortization
302	Franchises	$ 25,744	$ 5,078
303	Software Development	157,639,021	53,783,492
389	Land and Land Rights	24,026,081	1,416,182
390	Structures and Improvements	126,110,173	71,412,325
391	Office Furniture and Equipment	69,719,487	30,783,140
392	Transportation Equipment	6,542,554	4,146,136
393	Stores Equipment	92,576	32,375
394	Tools/Shop/Garage Equipment	1,263,589	388,938
396	Power Operated Equipment	405,180	871,236
397	Communication Equipment	83,162,968	27,534,772
398	Miscellaneous Equipment	1,041,117	584,738
399	Other Tangible Property	892,594	304,500
Total Common Plant in Service		$ 470,921,084	$ 191,262,912

Common plant balances are not allocated to Electric or Gas departments.

3. Common expense allocated to Electric and Gas departments:

Account	Description	Total	Allocated to Electric	Allocated to Gas	Allocation Basis
403	Depreciation	$ 20,632,820	$ 14,164,431	$ 6,468,389	(D)
403.1	ARO Depreciation	171,433	117,689	53,744	(D)
404	Amortization of LTD Term Plant	28,976,594	19,892,432	9,084,162	(D)
901	Customer Accounting and Collection Supervision	287,284	167,142	120,142	(A)
902	Meter Reading	577,697	359,732	217,965	(B)
903	Customer Records and Collections	30,357,325	17,661,892	12,695,433	(A)
905	Miscellaneous Customer Accounts	3,945	2,295	1,650	(A)
908	Customer Assistance	1,434,637	834,672	599,965	(A)
909	Informational and Instructional Advertising	1,238,093	720,323	517,770	(A)
910	Miscellaneous Customer Service and Information	151,062	87,888	63,174	(A)
920	Administrative and General Salaries	36,803,967	25,265,923	11,538,044	(D)

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.

921	Office Supplies	4,730,848	3,247,727	1,483,121	(D)
922	Administrative Expense Transferred	(260,667)	178,948)	(81,719)	(D)
923	Outside Services Employed	7,952,974	5,459,716	2,493,258	(D)
924	Property Insurance	616,064	375,737	240,327	(C)
925	Injuries and Damages	4,804,386	2,795,192	2,009,194	(A)
926	Employee Pension and Benefits	12,537,359	8,724,748	3,812,611	(E)
928	Regulatory Commission	677,007	464,765	212,242	(D)
930.1	General Advertising	24,058	16,516	7,542	(D)
930.2	Miscellaneous General	1,952,488	1,340,383	612,105	(D)
931	Rents	10,670,613	7,325,376	3,345,237	(D)
935	Maintenance of General Plant	14,864,736	10,204,641	4,660,095	(D)
Total Expenses		$ 179,204,723	$ 119,050,272	$ 60,154,451	

(A) 12 Month Average Number of Customers
(B) Joint Meter Reading Customers
(C) Non-Production Plant
(D) 4-Factor Allocator (25% each: customer counts, direct labor O&M, classified plant and T&D expense excluding labor) Electric: 68.65%, and Gas: 31.35%
(E) Direct Labor

4. Docket UE-960195 of the Washington Utilities and Transportation Commission, dated February 5, 1997.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) ☐ An Original (2) ☒ A Resubmission	09/27/2016	End of 2015/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)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
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45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

Line No.	Type of Ancillary Service (a)	Amount Purchased for the Year — Usage - Related Billing Determinant: Number of Units (b)	Unit of Measure (c)	Dollars (d)	Amount Sold for the Year — Usage - Related Billing Determinant: Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch				75,407	MW	4,864,662
2	Reactive Supply and Voltage				21,066	MW	278,967
3	Regulation and Frequency Response				4,521	MW	2,192,185
4	Energy Imbalance	33,102	MWh	1,099,100	-48,545	MWh	36,975
5	Operating Reserve - Spinning	46,200	MWh	510,635	4,673	MW	959,102
6	Operating Reserve - Supplement	46,200	MWh	468,336	4,673	MW	956,187
7	Other	6,292	MW	7,633,920	-11,146	MWh	379,593
8	Total (Lines 1 thru 7)	131,794		9,711,991	50,649		9,667,671

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

Schedule 1 purchases can be broken down as follows:

Number of Units	Unit of measure	Dollars
116,096	MW	$ 18,287,551
12,624	MWh	9,342
		$ 18,296,893

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

Units for column e lines 1, 2, 3, 5, and 6 have been calculated to a normalized MW/month based on the dollars billed since actual billings are based on a number of different units (kW/year, kW/month, kW/week, kW/day, and kWh.)

Schedule Page: 398 Line No.: 2 Column: b

Schedule 2 purchases can be broken down as follows:

Number of Units	Unit of measure	Dollars
61,755	MW	$ 49,944
12,624	MWh	-
		$ 49,944

The units include reactive supply and voltage received from Bonneville Power Administration for which the rate is currently zero.

Schedule Page: 398 Line No.: 2 Column: e

Units for column e lines 1, 2, 3, 5, and 6 have been calculated to a normalized MW/month based on the dollars billed since actual billings are based on a number of different units (kW/year, kW/month, kW/week, kW/day, and kWh.)

Schedule Page: 398 Line No.: 3 Column: e

Sales can be broken down as follows:

Schedule 3 - Units: 3,829 MW Dollars: $ 442,250
Schedule 13 - Units: 692 MW Dollars: $1,749,935

Units for column e lines 1, 2, 3, 5, and 6 have been calculated to a normalized MW/month based on the dollars billed since actual billings are based on a number of different units (kW/year, kW/month, kW/week, kW/day, and kWh.)

Schedule Page: 398 Line No.: 5 Column: e

Units for column e lines 1, 2, 3, 5, and 6 have been calculated to a normalized MW/month based on the dollars billed since actual billings are based on a number of different units (kW/year, kW/month, kW/week, kW/day, and kWh.)

Schedule Page: 398 Line No.: 6 Column: e

Units for column e lines 1, 2, 3, 5, and 6 have been calculated to a normalized MW/month based on the dollars billed since actual billings are based on a number of different units (kW/year, kW/month, kW/week, kW/day, and kWh.)

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

Wind integration charges.

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

Schedule 9 Generator Imbalance is reported in "Other" sales.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

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	6,540			3,675	322	2,210	333	224	
2	February	6,353			3,494	318	2,210	331	237	
3	March	6,163			3,596	326	2,210	31	466	
4	Total for Quarter 1				10,765	966	6,630	695	927	
5	April	5,610			3,091	281	2,210	28	565	
6	May	5,117			2,629	248	2,210	30	256	
7	June	6,224			3,044	338	2,210	632	416	
8	Total for Quarter 2				8,764	867	6,630	690	1,237	
9	July	6,252			3,078	334	2,210	630	354	
10	August	6,186			3,014	332	2,210	630	375	
11	September	5,763			2,599	325	2,210	629	275	
12	Total for Quarter 3				8,691	991	6,630	1,889	1,004	
13	October	5,412			2,854	315	2,210	33	284	
14	November	6,830			3,937	345	2,210	338	279	
15	December	6,807			3,828	330	2,310	339	3,754	
16	Total for Quarter 4				10,619	990	6,730	710	4,317	
17	Total Year to Date/Year				38,839	3,814	26,620	3,984	7,485	

Name of Respondent Puget Sound Energy, Inc.	This Report is: (1) __ An Original (2) X A Resubmission	Date of Report (Mo, Da, Yr) 09/27/2016	Year/Period of Report 2015/Q4

FOOTNOTE DATA

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

NAME OF SYSTEM: WA Area Facilities

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	5,177	2	1800	3,675	322	1,147	33	224	-
2	February	4,990	23	800	3,494	318	1,147	31	237	-
3	March	5,100	4	800	3,596	326	1,147	31	466	-
4	*Total for Quarter*	*15,267*			*10,765*	*966*	*3,441*	*95*	*927*	-
5	April	4,547	15	800	3,091	281	1,147	28	565	-
6	May	4,054	6	800	2,629	248	1,147	30	256	-
7	June	4,861	29	1800	3,044	338	1,147	332	316	-
8	*Total for Quarter*	*13,462*			*8,764*	*867*	*3,441*	*390*	*1,137*	-
9	July	4,889	30	1800	3,078	334	1,147	330	279	-
10	August	4,823	19	1800	3,014	332	1,147	330	275	-
11	September	4,400	11	1700	2,599	325	1,147	329	275	-
12	*Total for Quarter*	*14,112*			*8,691*	*991*	*3,441*	*989*	*829*	-
13	October	4,349	26	1900	2,854	315	1,147	33	284	
14	November	5,467	30	800	3,937	345	1,147	38	279	
15	December	5,444	30	1900	3,828	330	1,247	39	3,754	
16	*Total for Quarter*	*15,260*			*10,619*	*990*	*3,541*	*110*	*4,317*	-
17	**Total for Year**	**58,101**			**38,839**	**3,814**	**13,864**	**1,584**	**7,210**	-

NAME OF SYSTEM: Southern Intertie

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	700			-	-	400	300	-	-
2	February	700			-	-	400	300	-	-
3	March	400			-	-	400	-	-	-
4	*Total for Quarter*	*1,800*			-	-	*1,200*	*600*	-	-
5	April	400			-	-	400	-	-	-
6	May	400			-	-	400	-	-	-
7	June	700			-	-	400	300	100	-
8	*Total for Quarter*	*1,500*			-	-	*1,200*	*300*	*100*	-
9	July	700			-	-	400	300	75	-
10	August	700			-	-	400	300	100	-
11	September	700			-	-	400	300	-	-
12	*Total for Quarter*	*2,100*			-	-	*1,200*	*900*	*175*	-
13	October	400					400	-	-	-
14	November	700					400	300	-	-
15	December	700					400	300	-	-
16	*Total for Quarter*	*1,800*			-	-	*1,200*	*600*	-	-
17	**Total for Year**	**7,200**			-	-	**4,800**	**2,400**	**275**	-

Name of Respondent Puget Sound Energy, Inc.	This Report is: (1) __ An Original (2) X A Resubmission	Date of Report (Mo, Da, Yr) 09/27/2016	Year/Period of Report 2015/Q4

FOOTNOTE DATA

NAME OF SYSTEM: Colstrip

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	663			-	-	663	-	-	-
2	February	663			-	-	663	-	-	-
3	March	663			-	-	663	-	-	-
4	*Total for Quarter*	*1,989*			-	-	*1,989*	-	-	-
5	April	663			-	-	663	-	-	-
6	May	663			-	-	663	-	-	-
7	June	663			-	-	663	-	-	-
8	*Total for Quarter*	*1,989*			-	-	*1,989*	-	-	-
9	July	663			-	-	663	-	-	-
10	August	663			-	-	663	-	-	-
11	September	663			-	-	663	-	-	-
12	*Total for Quarter*	*1,989*			-	-	*1,989*	-	-	-
13	October	663			-	-	663	-	-	-
14	November	663			-	-	663	-	-	-
15	December	663			-	-	663	-	-	-
16	*Total for Quarter*	*1,989*			-	-	*1,989*	-	-	-
17	**Total for Year**	**7,956**			-	-	**7,956**	-	-	-

Footnote A

Day and Hour of Monthly Peak were left blank due to the fact that Network Service plus the Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/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
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	20,509,764
3	Steam	6,438,547			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	6,812
5	Hydro-Conventional	706,231			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	7,666,572
7	Other	5,602,236			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	12,747,014	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	58,417
10	Purchases	16,874,776	27	Total Energy Losses	1,455,855
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	29,697,420
12	Received	488,630			
13	Delivered	413,000			
14	Net Exchanges (Line 12 minus line 13)	75,630			
15	Transmission For Other (Wheeling)				
16	Received	9,521,013			
17	Delivered	9,521,013			
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)	29,697,420			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM: Puget Sound Energy, Inc.

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	2,379,966	210,186	3,866	2	1800
30	February	2,082,130	282,862	3,680	23	0800
31	March	2,340,435	443,619	3,790	4	0800
32	April	2,159,491	413,863	3,279	15	0800
33	May	2,122,056	489,580	2,783	6	0800
34	June	2,181,192	521,548	3,225	29	1800
35	July	2,639,035	867,738	3,286	2	1800
36	August	2,646,939	948,832	3,179	19	1800
37	September	2,490,174	906,688	2,756	11	1700
38	October	2,364,364	654,811	3,001	26	1900
39	November	3,075,961	1,004,886	4,155	30	0800
40	December	3,215,677	921,959	4,047	30	1900
41	TOTAL	29,697,420	7,666,572			

Schedule Page: 401 Line No.: 29 Column: Sys

NAME OF SYSTEM: Point Roberts Transfer Point
2015

Line No.	Month (a)	Total Monthly Energy (MWH) (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (see instr 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
1	January	2,346		5.1	1	0900
2	February	1,806		3.8	28	0810
3	March	1,840		4.0	4	0755
4	**Total**	**5,992**	**0**			
5	April	1,547		3.7	5	0800
6	May	1,246		2.6	3	0835
7	June	1,120		2.2	27	1740
8	**Total**	**3,913**	**0**			
9	July	1,245		2.6	4	1000
10	August	1,255		2.5	2	1800
11	September	1,204		2.9	6	0910
12	**Total**	**3,704**	**0**			
13	October	1,383		2.9	24	0945
14	November	2,107		4.9	28	0850
15	December	2,484		5.4	31	1855
16	**Total**	**5,974**	**0**			
17	**Yr Total**	**19,583**	**0**			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *COLSTRIP 1 & 2* (b)			Plant Name: *COLSTRIP 3 & 4* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor			Semi-Outdoor		
3	Year Originally Constructed	1975			1984		
4	Year Last Unit was Installed	1976			1986		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	377.00			433.50		
6	Net Peak Demand on Plant - MW (60 minutes)	307			370		
7	Plant Hours Connected to Load	8707			8755		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	307			370		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	1			1		
12	Net Generation, Exclusive of Plant Use - KWh	1756858000			2738174000		
13	Cost of Plant: Land and Land Rights	1006168			2789214		
14	Structures and Improvements	43983657			127448455		
15	Equipment Costs	264446116			376075624		
16	Asset Retirement Costs	17408225			18292219		
17	Total Cost	326844166			524605512		
18	Cost per KW of Installed Capacity (line 17/5) Including	866.9607			1210.1627		
19	Production Expenses: Oper, Supv, & Engr	109179			89157		
20	Fuel	35800968			44189012		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4371928			2884144		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	241929			214168		
26	Misc Steam (or Nuclear) Power Expenses	4866215			3663617		
27	Rents	31816			50358		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	1005850			656053		
30	Maintenance of Structures	1531514			1069915		
31	Maintenance of Boiler (or reactor) Plant	7492296			5175716		
32	Maintenance of Electric Plant	2351271			1598983		
33	Maintenance of Misc Steam (or Nuclear) Plant	1198891			825541		
34	Total Production Expenses	59001857			60416664		
35	Expenses per Net KWh	0.0336			0.0221		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal			Coal		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons			Tons		
38	Quantity (Units) of Fuel Burned	1095057	0	0	1718605	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8415	0	0	8704	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	29.668	0.000	0.000	22.701	0.000	0.000
41	Average Cost of Fuel per Unit Burned	32.693	0.000	0.000	25.712	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.943	0.000	0.000	1.477	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.020	0.000	0.000	0.016	0.000	0.000
44	Average BTU per KWh Net Generation	10490.210	0.000	0.000	10926.068	0.000	0.000

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: *MINT FARM* (b)			Plant Name: *SUMAS* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor			Outdoor		
3	Year Originally Constructed	2007			1993		
4	Year Last Unit was Installed	2007			1993		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	319.00			145.00		
6	Net Peak Demand on Plant - MW (60 minutes)	297			127		
7	Plant Hours Connected to Load	7224			5796		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	297			127		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	18			17		
12	Net Generation, Exclusive of Plant Use - KWh	1701035900			601052900		
13	Cost of Plant: Land and Land Rights	1194000			795165		
14	Structures and Improvements	11425636			4390654		
15	Equipment Costs	91024042			77098286		
16	Asset Retirement Costs	0			0		
17	Total Cost	103643678			82284105		
18	Cost per KW of Installed Capacity (line 17/5) Including	324.9018			567.4766		
19	Production Expenses: Oper, Supv, & Engr	69200			288629		
20	Fuel	46796174			17456192		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	81628			522301		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2738866			1989828		
26	Misc Steam (or Nuclear) Power Expenses	15657			0		
27	Rents	289580			108021		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	18101			13447		
30	Maintenance of Structures	80758			164528		
31	Maintenance of Boiler (or reactor) Plant	493840			295969		
32	Maintenance of Electric Plant	3408339			733702		
33	Maintenance of Misc Steam (or Nuclear) Plant	113924			17207		
34	Total Production Expenses	54106067			21589824		
35	Expenses per Net KWh	0.0318			0.0359		
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	11733184	0	0	4660228	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1071900	0	0	1071900	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.988	0.000	0.000	3.746	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.988	0.000	0.000	3.746	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.721	0.000	0.000	3.495	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.028	0.000	0.000	0.029	0.000	0.000
44	Average BTU per KWh Net Generation	7393.613	0.000	0.000	8310.914	0.000	0.000

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Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *FREDONIA 1&2* (b)			Plant Name: *FREDONIA 3&4* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor			Outdoor		
3	Year Originally Constructed	1984			2001		
4	Year Last Unit was Installed	1984			2001		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	258.20			117.80		
6	Net Peak Demand on Plant - MW (60 minutes)	207			107		
7	Plant Hours Connected to Load	1109			716		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	207			107		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	4			4		
12	Net Generation, Exclusive of Plant Use - KWh	113691100			47603800		
13	Cost of Plant: Land and Land Rights	1502988			0		
14	Structures and Improvements	3782846			1252681		
15	Equipment Costs	50843054			59921897		
16	Asset Retirement Costs	0			0		
17	Total Cost	56128888			61174578		
18	Cost per KW of Installed Capacity (line 17/5) Including	217.3853			519.3088		
19	Production Expenses: Oper, Supv, & Engr	145042			137728		
20	Fuel	6406882			2165061		
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	380344			282759		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	38937			12864		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	17152			0		
30	Maintenance of Structures	64281			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	1375916			424161		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	8428554			3022573		
35	Expenses per Net KWh	0.0741			0.0635		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas	Oil		Gas	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF	Bbl		MCF	Bbl	
38	Quantity (Units) of Fuel Burned	1439957	938	0	427533	706	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1071900	139500	0	1071900	139500	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.370	0.000	0.000	4.862	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.370	122.220	0.000	4.862	122.220	0.000
42	Average Cost of Fuel Burned per Million BTU	4.077	20.860	0.000	4.536	20.860	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.055	0.434	0.000	0.044	0.248	0.000
44	Average BTU per KWh Net Generation	13607.795	20808.548	0.000	9697.751	11874.843	0.000

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Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

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

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

Plant Name: *ENCOGEN* (d)			Plant Name: *FREDERICKSON 1* (e)			Plant Name: *GOLDENDALE* (f)			Line No.
Combined Cycle			Combined Cycle			Combined Cycle			1
Outdoor			Outdoor			Outdoor			2
1993			2002			2004			3
1993			2002			2004			4
176.40			137.00			284.30			5
165			136			278			6
2623			5067			7040			7
0			0			0			8
165			136			278			9
0			0			0			10
15			0			16			11
297657600			623181113			1498666000			12
1051000			699814			1288140			13
8865614			6178023			36462321			14
150980494			63403182			286440395			15
0			443797			0			16
160897108			70724816			324190856			17
912.1151			516.2395			1140.3125			18
387739			1397196			47646			19
9663785			14730947			39493420			20
0			0			0			21
374201			0			219301			22
0			0			0			23
0			0			0			24
1798959			785263			4082476			25
8950			30541			12365			26
59757			91157			244389			27
0			0			0			28
20864			466253			35749			29
63976			274829			209309			30
551179			491445			307987			31
544589			716837			2871530			32
42194			67251			54478			33
13516193			19051719			47578650			34
0.0454			0.0306			0.0317			35
Gas	Oil		Gas			Gas			36
MCF	Bbl		MCF			MCF			37
2529824	295	0	4156601	0	0	10062858	0	0	38
1071900	140000	0	1071900	0	0	1071900	0	0	39
3.817	0.000	0.000	3.544	0.000	0.000	3.925	0.000	0.000	40
3.817	23.520	0.000	3.544	0.000	0.000	3.925	0.000	0.000	41
3.561	4.000	0.000	3.306	0.000	0.000	3.661	0.000	0.000	42
0.032	0.045	0.000	0.024	0.000	0.000	0.026	0.000	0.000	43
9114.952	11174.799	0.000	7149.543	0.000	0.000	7197.319	0.000	0.000	44

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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: *FERNDALE* (d)	Plant Name: *WHITEHORN* (e)	Plant Name: *FREDERICKSON* (f)	Line No.
Combined Cycle	Gas Turbine	Gas Turbine	1
Outdoor	Outdoor	Outdoor	2
1994	1981	1981	3
1994	1981	1981	4
280.00	169.20	177.80	5
253	149	149	6
4240	1461	1584	7
0	0	0	8
253	149	149	9
0	0	0	10
0	4	6	11
868466832	38733300	39935400	12
0	364590	785528	13
6498588	848293	2651946	14
122420793	33725263	36591876	15
1030922	0	0	16
129950303	34938146	40029350	17
464.1082	206.4902	225.1370	18
884230	190751	39087	19
27183544	2968760	2990294	20
0	0	0	21
726909	0	0	22
0	0	0	23
0	0	0	24
1838458	524014	673813	25
0	0	0	26
168093	17766	18480	27
0	0	0	28
4945	41140	20135	29
4901	196864	74546	30
436320	0	0	31
1533904	639149	858099	32
317547	0	0	33
33098851	4578444	4674454	34
0.0381	0.1182	0.1171	35

(d) Gas	(d) Oil	(d)	(e) Gas	(e) Oil	(e)	(f) Gas	(f) Oli	(f)	Line No.
Gas	Oil		Gas	Oil		Gas	Oli		36
MCF	Bbl		MCF	Bbl		MCF	Bbl		37
6951070	142	0	668926	1093	0	759191	40	0	38
1071900	140800	0	1071900	140100	0	1071900	139100	0	39
3.908	66.510	0.000	4.292	89.460	0.000	3.934	0.000	0.000	40
3.908	138.352	0.000	4.292	89.460	0.000	3.934	96.602	0.000	41
3.646	23.395	0.000	4.004	15.203	0.000	3.670	16.535	0.000	42
0.031	0.207	0.000	0.075	0.214	0.000	0.075	0.136	0.000	43
8580.255	8835.885	0.000	18732.700	14083.712	0.000	20391.933	8227.101	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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: *WILD HORSE* (d)			Plant Name: *HOPKINS RIDGE* (e)			Plant Name: *LOWER SNAKE RIVER* (f)			Line No.
Wind Turbine			Wind Turbine			Wind Turbine			1
Outdoor			Outdoor			Outdoor			2
2006			2005			2012			3
2009			2008			2012			4
273.00			157.00			343.00			5
273			157			343			6
0			0			0			7
0			0			0			8
0			0			0			9
0			0			0			10
7			5			5			11
608885750			364779478			741767960			12
8131854			0			203682			13
15081341			3399075			31416966			14
419226701			172007985			654946786			15
6385603			2879075			5087745			16
448825499			178286135			691655179			17
1644.0494			1135.5805			2016.4874			18
427648			375502			449704			19
0			0			0			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
547450			534504			850337			25
0			0			0			26
2589350			772716			2677410			27
0			0			0			28
178475			98007			77591			29
37065			16589			21883			30
0			0			0			31
4404469			1865641			7722942			32
0			0			0			33
8184457			3662959			11799867			34
0.0134			0.0100			0.0159			35
									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.: 5 Column: b

Jointly owned. Amount represents 50% of rated capacity of 754,000 KW.

Schedule Page: 402 Line No.: 5 Column: c

Jointly owned. Amount represents 25% of rated capacity of 1,734,000 KW.

Schedule Page: 403 Line No.: 5 Column: e

Jointly owned. Amount represents PSE's 49.85% share.

Schedule Page: 402 Line No.: 11 Column: b

Plant is operated by Talen Montana, LLC. Total number of Talen Montana employees at Colstrip at the end of 2015 was 361. There was also one PSE employee. All of the employees work at both Colstrip 1&2 and Colstrip 3&4.

Schedule Page: 402 Line No.: 11 Column: c

Plant is operated by Talen Montana, LLC. Total number of Talen Montana employees at Colstrip at the end of 2015 was 361. There was also one PSE employee. All of the employees work at both Colstrip 1&2 and Colstrip 3&4.

Schedule Page: 403 Line No.: 11 Column: e

Facility is operated by Atlantic Power Corporation. There are no PSE employees.

Schedule Page: 403.1 Line No.: -1 Column: e

Peak load plant.

Schedule Page: 403.1 Line No.: -1 Column: f

Peak load plant.

Schedule Page: 402.1 Line No.: 1 Column: c

This is a cogeneration plant.

Schedule Page: 403.1 Line No.: 11 Column: d

Ferndale is operated by NAES Corporation for Puget Sound Energy.

Schedule Page: 402.2 Line No.: -1 Column: b

Peak load plant.

Schedule Page: 402.2 Line No.: -1 Column: c

Peak load plant.

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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. 2150 Plant Name: LOWER BAKER (b)	FERC Licensed Project No. 2150 Plant Name: UPPER BAKER (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1925	1959
4	Year Last Unit was Installed	2013	1959
5	Total installed cap (Gen name plate Rating in MW)	115.00	104.80
6	Net Peak Demand on Plant-Megawatts (60 minutes)	109	91
7	Plant Hours Connect to Load	8,480	7,027
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	118	110
10	(b) Under the Most Adverse Oper Conditions	83	90
11	Average Number of Employees	27	27
12	Net Generation, Exclusive of Plant Use - Kwh	308,611,200	278,749,550
13	Cost of Plant		
14	Land and Land Rights	3,126,431	2,001,428
15	Structures and Improvements	35,253,454	15,612,654
16	Reservoirs, Dams, and Waterways	115,558,769	119,603,565
17	Equipment Costs	66,037,629	14,081,423
18	Roads, Railroads, and Bridges	1,588,316	2,648,182
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	221,564,599	153,947,252
21	Cost per KW of Installed Capacity (line 20 / 5)	1,926.6487	1,468.9623
22	Production Expenses		
23	Operation Supervision and Engineering	621,903	775,742
24	Water for Power	0	0
25	Hydraulic Expenses	1,342,379	1,593,320
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	1,013,167	760,511
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	106,706	63,079
31	Maintenance of Reservoirs, Dams, and Waterways	234,331	41,136
32	Maintenance of Electric Plant	77,222	154,075
33	Maintenance of Misc Hydraulic Plant	1,631,375	1,791,464
34	Total Production Expenses (total 23 thru 33)	5,027,083	5,179,327
35	Expenses per net KWh	0.0163	0.0186

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 09/27/2016	Year/Period of Report End of 2015/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2493 Plant Name: SNOQUALMIE 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
1898			3
2013			4
54.40	0.00	0.00	5
54	0	0	6
8,281	0	0	7
			8
50	0	0	9
50	0	0	10
19	0	0	11
118,870,558	0	0	12
			13
554,274	0	0	14
113,253,490	0	0	15
115,206,004	0	0	16
101,543,559	0	0	17
795,238	0	0	18
0	0	0	19
331,352,565	0	0	20
6,091.0398	0.0000	0.0000	21
			22
199,248	0	0	23
0	0	0	24
319,202	0	0	25
305,827	0	0	26
892,096	0	0	27
0	0	0	28
0	0	0	29
233,756	0	0	30
257,881	0	0	31
1,612,147	0	0	32
405,023	0	0	33
4,225,180	0	0	34
0.0355	0.0000	0.0000	35

Schedule Page: 406 Line No.: 9 Column: b

Estimated amount.

Schedule Page: 406 Line No.: 9 Column: c

Estimated amount.

Schedule Page: 406 Line No.: 9 Column: d

Estimated amount.

Schedule Page: 406 Line No.: 10 Column: b

Estimated amount.

Schedule Page: 406 Line No.: 10 Column: c

Estimated amount.

Schedule Page: 406 Line No.: 10 Column: d

Estimated amount.

Schedule Page: 406 Line No.: 11 Column: b

There were a total of 54 employees at Baker. They work at both Upper Baker and Lower Baker so split the total number between the two.

Schedule Page: 406 Line No.: 11 Column: c

There were a total of 54 employees at Baker. They work at both Upper Baker and Lower Baker so split the total number between the two.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/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. 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)	

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. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
			6
			7
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			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	INTERNAL COMBUSTION					
2	Crystal Mountain	1969	2.75	2.7	293,680	2,791,394
3						
4						
5						
6						
7						
8						
9						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

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

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
1,015,052	105,866	62,326	33,799	Diesel	1,828	2
						3
						4
						5
						6
						7
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						9
						10
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						45
						46

Schedule Page: 410 Line No.: 2 Column: e

Generation is in kWh.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	3rd Ac Trans Line		500.00	500.00				
2	Broadview S Y	Townsend A Line	500.00	500.00	SCST	133.40		1
3	Broadview S Y	Townsend B Line	500.00	500.00	SCST	133.40		1
4	Colstrip 3	Switch Yard	500.00	500.00	SCST	0.40		1
5	Colstrip 4	Switch Yard	500.00	500.00	SCST	0.40		1
6	Colstrip SY	Broadview A Line	500.00	500.00	SCST	112.70		1
7	Colstrip SY	Broadview B Line	500.00	500.00	SCST	115.90		1
8	500 Kv Tot							
9	Bpa Covington	Berrydale	230.00	230.00	DCST,SCST	4.06		2
10	Bpa Covington	White River #2	230.00	230.00	DCST	9.25		1
11	Bpa Custer	Portal Way	230.00	230.00	WHF	0.06		1
12	Bpa Maple Valley	Talbot #1	230.00	230.00	SCST	0.18		1
13	Bpa Maple Valley	Talbot #2	230.00	230.00	SCST	0.15		1
14	Bpa Monroe	Novelty Hill	230.00	230.00	SCST, DCST	0.27		1
15	Bpa Olympia	Saint Clair	230.00	230.00	DCST	3.62		2
16	Bpa Shelton	South Bremerton	230.00	230.00	WHF	0.80		1
17	Cascade	White River	230.00	230.00	SCST, WHF	68.99		1
18	Christopher	O'Brien #4	230.00	230.00	DCST	4.75		1
19	Colstrip 1	Switch Yard	230.00	230.00	SCST	0.40		1
20	Colstrip 2	Switch Yard	230.00	230.00	SCST	0.40		1
21	Dodge Junction	Phalen Gulch	230.00	230.00	WHF	5.22		2
22	Freddy/Epcor	Bpa South Tacoma #1	230.00	230.00	UG CABLE	0.97		1
23	Horse Ranch Tap	Bpa Monroe Snohomish	230.00	230.00	WHF, SCST	3.48		1
24	North Intertie		230.00	230.00				
25	Phalen Gulch	BPA Central Ferry	230.00	230.00	WHF	2.08		2
26	Poison Spring	Wind Ridge	230.00	230.00	HF2	4.10		1
27	Rocky Ridge	Cascade	230.00	230.00	WHF, SCST	57.29		1
28	Saint Clair	Bpa South Tacoma	230.00	230.00	DCST	3.62		2
29	Sammamish	Bpa Maple Valley #1	230.00	230.00	DCST, SCST	8.14		1
30	Sammamish	Novelty Hill #2	230.00	230.00	DCST, SCST	7.91		1
31	SCL Bothell	Sammamish	230.00	230.00	WHF	13.28		1
32	Sedro Woolley	Bpa Bellingham	230.00	230.00	WHF	0.11		1
33	Sedro Woolley	Horseranch	230.00	230.00	SCST	38.95		1
34	Sedro Woolley	March Point	230.00	230.00	SWP, DCST	23.07		1
35	Sedro Woolley	SCL Bothell	230.00	230.00	WHF	49.04		1
36					TOTAL	2,605.54		44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Sedro Woolley Tap		230.00	230.00	WHF	0.17		1
2	Talbot	Berrydale #3	230.00	230.00	DCST	15.78		2
3	Talbot	O'Brien #3	230.00	230.00	DCST	7.22		2
4	Wanapum	Wind Ridge	230.00	230.00	RHES-MOD,P	21.11		1
5	Wild Horse	Poison Spring	230.00	230.00	HF2	4.52		1
6	230 KV Tot							
7	115 KV Tot					1,672.88		
8	55 KV Tot					77.47		
9	ARO as per FAS 143							
10								
11								
12								
13								
14								
15								
16								
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18								
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21								
22								
23								
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25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	2,605.54		44

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)	
								1
4-795 ACSR								2
4-795 ACSR								3
2-2250 ACSR								4
2-2250 ACSR								5
4-795 ACSR								6
4-795 ACSR								7
	1,753,427	114,939,906	116,693,333					8
2-1590 ACSS								9
2-1272 ACSR								10
795 ACSR								11
2-1780 ACSR								12
2-1780 ACSR								13
1780 ACSR								14
1590 ACSS								15
1590 ACSR								16
1272 ACSR								17
1272 ACSR								18
1272 ACSR								19
1272 ACSR								20
2-1272 ACSR								21
1750 KCML								22
1272 ACSR								23
								24
2-1590 ACSR								25
1272 ACSR								26
1272 ACSR								27
1590 ACSS								28
1780 ACSR								29
1780 ACSR								30
1590 ACSS								31
1.6" AACTW								32
2-795 ACSR								33
2-397.5 ACSR								34
2-795 ACSR								35
	38,979,840	714,187,852	753,167,692					36

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 ACSR								1
2-1590 ACSR								2
2-1272 ACSR								3
2-1272 ACSR								4
1272 ACSR								5
	8,010,308	192,381,796	200,392,104					6
	28,968,212	384,470,447	413,438,659					7
	247,893	18,936,036	19,183,929					8
		3,459,667	3,459,667					9
								10
								11
								12
								13
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								27
								28
								29
								30
								31
								32
								33
								34
								35
	38,979,840	714,187,852	753,167,692					36

Schedule Page: 422 Line No.: 1 Column: a

Facilities are solely owned by the Bonneville Power Administration. Respondent has secured a life-of facilities capacity ownership interest and will be responsible for its share of plant costs and expenses.

Schedule Page: 422 Line No.: 2 Column: a

Facilities are jointly owned with Pennsylvania Power and Light, Avista, Portland General Electric, and Pacificorp. Plant costs and expenses reflect the respondent's share.

Schedule Page: 422 Line No.: 3 Column: a

Same as footnote immediately above.

Schedule Page: 422 Line No.: 4 Column: a

Same as footnote immediately above.

Schedule Page: 422 Line No.: 5 Column: a

Same as footnote immediately above.

Schedule Page: 422 Line No.: 6 Column: a

Same as footnote immediately above.

Schedule Page: 422 Line No.: 7 Column: a

Same as footnote immediately above.

Schedule Page: 422 Line No.: 22 Column: a

Facilities are jointly owned with Epcor, Canada. Plant cost and expenses reflect the respondent's share.

Schedule Page: 422 Line No.: 24 Column: a

Facilities are solely owned by the Bonneville Power Administration. Respondent has secured a life-of facilities capacity ownership interest and will be responsible for its share of plant costs and expenses.

Schedule Page: 422.1 Line No.: 7 Column: a

Type of support structure is SP-W, WHF, Steel Tower, and single Wood.

Schedule Page: 422.1 Line No.: 9 Column: a

Asset retirement cost per FAS 143 was added in 2005.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION		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 lines were added.						
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43							
44	TOTAL						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage KV (Operating) (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
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ALDERTON PIERCE	TU	230.00	115.00	13.20
2	BERRYDALE SOUTH KING	TU	230.00	115.00	13.20
3	BPA BELLINGHAM	TU	230.00	115.00	13.20
4	CASCADE KITTITAS	TU	230.00	115.00	34.50
5	CASCADE KITTITAS	TU	230.00	34.50	
6	DODGE JUNCTION GARFIELD	TU	230.00	34.50	
7	FREDONIA SKAGIT	TU	230.00	13.20	
8	GOLDENDALE GOLDENDALE	TU	230.00	18.00	13.80
9	MARCH POINT SKAGIT	TU	230.00	115.00	13.20
10	NOVELTY HILL NORTH KING	TU	230.00	115.00	13.20
11	O'BRIEN SOUTH KING	TU	230.00	115.00	13.20
12	MINT FARM LONGVIEW	TU	230.00	18.00	
13	MINT FARM LONGVIEW	TU	230.00	13.80	
14	PHALEN GULCH GARFIELD	TU	230.00	34.50	
15	PORTAL WAY WHATCOM	TU	230.00	115.00	13.20
16	SAMMAMISH NORTH KING	TU	230.00	115.00	13.20
17	SEDRO WOOLLEY SKAGIT	TU	230.00	115.00	13.20
18	SOUTH BREMERTON SOUTH PENNISULA	TU	230.00	115.00	13.20
19	ST CLAIR THURSTON	TU	230.00	115.00	13.20
20	TALBOT HILL CENTRAL KING	TU	230.00	115.00	13.20
21	TONO THURSTON	TU	525.00	115.00	13.20
22	WHITE RIVER TRANSM. EAST PIERCE	TU	230.00	115.00	13.20
23	WILD HORSE WIND FARM STATION KITTITAS	TU	230.00	34.50	
24	WIND RIDGE KITTITAS	TU	230.00	115.00	13.20
25	TOTAL TRANSMISSION STATIONS		5815.00	2041.00	246.30
26					
27	AIRPORT THURSTON	DU	115.00	12.50	
28	ALGER SKAGIT	DU	115.00	12.50	
29	ALPAC SOUTH KING	DU	115.00	12.50	
30	ANACORTES SKAGIT	DU	115.00	12.50	
31	ARCO NORTH FERNDALE	DU	115.00	12.50	
32	ARCO SOUTH FERNDALE	DU	115.00	12.50	
33	ARCO CENTRAL FERNDALE	DU	115.00	12.50	
34	ARDMORE REDMOND	DU	115.00	12.50	
35	ASBURY SOUTH KING	DU	115.00	12.50	
36	AVONDALE REDMOND	DU	115.00	12.50	
37	BAKER RIVER LOWER SKAGIT	DU	115.00	13.80	
38	BAKER RIVER SW. SKAGIT	DU	115.00	34.50	
39	BAKER RIVER SW. SKAGIT	DU	34.50	12.50	
40	BAKER RIVER UPPER SKAGIT	DU	115.00	13.80	

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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	BAKER RIVER UPPER SKAGIT	DU	12.50	2.40	
2	BAKERVIEW WHATCOM	DU	115.00	12.50	
3	BARNES LAKE THURSTON	DU	115.00	12.50	
4	BELLIS WHATCOM	DU	115.00	12.50	
5	BELMORE SOUTH WEST KING	DU	115.00	12.50	
6	BERTHUSEN WHATCOM	DU	115.00	12.50	
7	BIG ROCK SKAGIT	DU	115.00	12.50	
8	BIRCH BAY WHATCOM	DU	115.00	12.50	
9	BLACKBURN	DU	115.00	12.50	
10	BLACK DIAMOND SOUTH EAST KING	DU	115.00	12.50	
11	BLAINE WHATCOM	DU	115.00	12.50	
12	BLUMAER THURSTON	DU	115.00	12.50	
13	BONNEY LAKE EAST PIERCE	DU	115.00	12.50	
14	BOW LAKE SOUTH WEST KING	DU	115.00	12.50	
15	BREMERTON SOUTH PENNISULA	DU	115.00	12.50	
16	BRIDLE TRAILS CENTRAL KING	DU	115.00	12.50	
17	BRIGHTWATER IPS NORTH KING	DU	115.00	4.00	
18	BRITTON WHATCOM	DU	115.00	12.50	
19	BROOKS HILL ISLAND	DU	115.00	12.50	
20	BUCKLEY EAST PIERCE	DU	55.00	12.50	
21	BUCKLIN HILL NORTH PENNISULA	DU	115.00	12.50	
22	BURLINGTON SKAGIT	DU	115.00	12.50	
23	BURROWS BAY SKAGIT	DU	115.00	12.50	
24	CAMBRIDGE SOUTH KING	DU	115.00	12.50	
25	CAPITOL THURSTON	DU	115.00	12.50	
26	CAROLINA WHATCOM	DU	115.00	12.50	
27	CEDARHURST EAST PIERCE	DU	115.00	12.50	
28	CENTER CENTRAL KING	DU	115.00	13.09	
29	CENTER CENTRAL KING	DU	115.00	13.09	
30	CENTRAL KITSAP NORTH PENNISULA	DU	115.00	12.50	
31	CHAMBERS THURSTON	DU	115.00	12.50	
32	CHICO SOUTH PENNISULA	DU	115.00	12.50	
33	CHICO SOUTH PENNISULA	DU	34.50	12.50	
34	CHRISTENSENS CORNER NORTH PENNISULA	DU	115.00	12.50	
35	CHRISTOPHER AUBURN	DU	115.00	12.50	
36	CLAY CREEK SOUTH EAST KING	DU	55.00	7.20	
37	CLE ELUM KITTITAS	DU	115.00	34.50	
38	CLOVER VALLEY ISLAND	DU	115.00	12.50	
39	CLYDE HILL CENTRAL KING	DU	115.00	12.50	
40	CLYMER KITTITAS	DU	115.00	12.50	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	COLLEGE CENTRAL KING	DU	115.00	12.50	
2	COTTAGE BROOK NORTH KING	DU	115.00	12.50	
3	COUPEVILLE ISLAND	DU	115.00	12.50	
4	CRESCENT HARBOR ISLAND	DU	115.00	13.00	
5	CRESTWOOD NORTH KING	DU	115.00	12.50	
6	CRYSTAL MOUNTAIN GEN. SE KING	DU	34.50	12.50	
7	CRYSTAL MOUNTAIN GEN. SE KING	DU	12.50	4.16	
8	CUMBERLAND SE KING	DU	115.00	12.50	
9	CUSTER WHATCOM	DU	115.00	12.50	
10	DECATUR THURSTON	DU	115.00	12.50	
11	DES MOINES SOUTH WEST KING	DU	115.00	12.50	
12	DIERINGER EAST PIERCE	DU	115.00	12.50	
13	DUPONT EAST PIERCE	DU	115.00	12.50	
14	DUVALL NORTH KING	DU	115.00	12.50	
15	EARLINGTON SOUTH KING	DU	115.00	12.50	
16	EAST PORT ORCHARD SOUTH PENNISULA	DU	115.00	12.50	
17	EAST VALLEY SOUTH KING	DU	115.00	12.50	
18	EASTGATE CENTRAL KING	DU	115.00	12.50	
19	EASTON KITTITAS	DU	115.00	12.50	
20	EDGEWOOD EAST PIERCE	DU	115.00	12.50	
21	ELD INLET THURSTON	DU	115.00	12.50	
22	ELECTRON GEN. EAST PIERCE	DU	115.00	2.40	
23	ELECTRON HEIGHTS EAST PIERCE	DU	55.00	12.50	
24	ELECTRON HEIGHTS EAST PIERCE	DU	115.00	55.00	
25	ELECTRON HEIGHTS EAST PIERCE	DU	55.00	2.40	
26	ELLINGSON SOUTH EAST KING	DU	115.00	12.50	
27	ENCOGEN GEN. WHATCOM	DU	115.00	13.80	
28	ENCOGEN GEN. WHATCOM	DU	115.00	13.80	
29	ENUMCLAW SOUTH EAST KING	DU	115.00	12.50	
30	EVERGREEN NORTH KING	DU	115.00	12.50	
31	FABER ISLAND	DU	115.00	12.50	
32	FACTORIA CENTER KING	DU	115.00	12.50	
33	FAIRCHILD EAST PIERCE	DU	115.00	12.50	
34	FAIRWOOD CENTRAL KING	DU	115.00	12.50	
35	FALCON SOUTH KING	DU	115.00	12.50	
36	FALL CITY EAST KING	DU	115.00	12.50	
37	FERNWOOD SOUTH PENNISULA	DU	115.00	12.50	
38	FOSS CORNER	DU	115.00		
39	FOUR CORNERS SOUTH EAST KING	DU	115.00	12.50	
40	FRAGARIA SOUTH PENNISULA	DU	115.00	12.50	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	FREDERICKSON GEN STATION E PIERCE	DU	115.00	13.20	
2	FREDERICKSON GEN STATION E PIERCE	DU	12.50	4.20	
3	FREDERICKSON GEN STATION E PIERCE	DU	12.50		
4	FREDERICKSON GEN STATION E PIERCE	DU	115.00	6.60	
5	FREDONIA SKAGIT	DU	115.00	13.20	
6	FREDONIA SKAGIT	DU	115.00	12.50	13.20
7	FREELAND ISLAND	DU	115.00	12.50	
8	FREEWAY SOUTH WEST KING	DU	115.00	12.50	
9	FRIENDLY GROVE THURSTON	DU	115.00	13.09	
10	FRUITLAND EAST PIERCE	DU	115.00	12.50	
11	GAGES SKAGIT	DU	115.00	12.50	
12	GARDELLA EAST PIERCE	DU	115.00	12.50	
13	GLACIER WHATCOM	DU	55.00	12.50	
14	GLENCARIN SOUTH KING	DU	115.00	12.50	
15	GOODES CORNER EAST KING	DU	115.00	12.50	
16	GRADY SOUTH KING	DU	115.00	12.50	
17	GRAVELLY LAKE EAST PIERCE	DU	115.00	12.50	
18	GREENBANK ISLAND	DU	115.00	12.50	
19	GREENWATER SOUTH EAST KING	DU	55.00	13.90	
20	GREENWATER SOUTH EAST KING	DU	34.50	12.50	
21	GRIFFIN THURSTON	DU	115.00	12.50	
22	HAMILTON SKAGIT	DU	115.00	12.50	
23	HANNEGAN WHATCOM	DU	115.00	12.50	
24	HAPPY VALLEY WHATCOM	DU	115.00	12.50	
25	HARVEST SOUTH KING	DU	115.00	12.50	
26	HAWKS PRAIRIE THURSTON	DU	115.00	13.09	
27	HAZELWOOD CENTRAL KING	DU	115.00	12.50	
28	HEMLOCK EAST PIERCE	DU	115.00	12.50	
29	HICKOX SKAGIT	DU	115.00	12.50	
30	HIGHLANDS CENTRAL KING	DU	115.00	12.50	
31	HILLCREST ISLAND	DU	115.00	12.50	
32	HOBART SOUTH EAST KING	DU	115.00	12.50	
33	HOLDEN EAST PIERCE	DU	115.00	12.50	
34	HOLLYWOOD NORTH KING	DU	115.00	12.50	
35	HOPKINS RIDGE WIND FARM Columbia Cnty	DU	115.00	34.50	
36	HOUGHTON NORTH KING	DU	115.00	12.50	
37	HYAK EAST KING	DU	115.00	12.50	
38	INGLEWOOD NORTH KING	DU	115.00	12.50	
39	JOHNSON HILL THURSTON	DU	115.00	12.50	
40	JUANITA NORTH KING	DU	115.00	12.50	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	KAPOWSIN EAST PIERCE	DU	115.00	12.50	
2	KENDALL WHATCOM	DU	115.00	12.50	55.00
3	KENILWORTH NORTH KING	DU	115.00	12.50	
4	KENMORE NORTH KING	DU	115.00	12.50	
5	KENT SOUTH KING	DU	115.00	12.50	
6	KINGSTON	DU	115.00	12.50	
7	KITTITAS	DU	115.00	12.50	
8	KITTS CORNER SOUTHWEST KING	DU	115.00	12.50	
9	KLAHANIE EAST KING	DU	230.00	12.50	
10	KNOBLE EAST PIERCE	DU	115.00	12.50	
11	KRAIN CORNER SOUTH EAST KING	DU	115.00	55.00	
12	LABOUNTY WHATCOM	DU	115.00	12.50	
13	LACEY THURSTON	DU	115.00	12.50	
14	LAKE HILLS CENTRAL KING	DU	115.00	12.50	
15	LAKE LEOTA NORTH KING	DU	115.00	12.50	
16	LAKE LOUISE WHATCOM	DU	115.00	12.50	
17	LAKE MCDONALD EAST KING	DU	115.00	12.50	
18	LAKE MERIDIAN SOUTH KING	DU	115.00	12.50	
19	LAKE TAPPS EAST PIERCE	DU	55.00	12.50	
20	LAKE WILDERNESS SOUTH KING	DU	115.00	12.50	
21	LAKE YOUNGS SOUTH KING	DU	115.00	12.50	
22	LAKOTA SOUTHWEST KING	DU	115.00	12.50	
23	LANGLEY ISLAND	DU	115.00	12.50	
24	LAUREL WHATCOM	DU	115.00	13.09	
25	LEA HILL SOUTHEAST KING	DU	115.00	12.50	
26	LIQUID AIR SOUTH KING	DU	115.00	4.20	
27	LOCHLEVEN CENTRAL KING	DU	115.00	13.09	
28	LONG LAKE SOUTH PENNISULA	DU	115.00	12.50	
29	LONGMIRE THURSTON	DU	115.00	12.50	
30	LUHR BEACH THURSTON	DU	115.00	12.50	
31	LYNDEN WHATCOM	DU	115.00	12.50	
32	M STREET SOUTH EAST KING	DU	115.00	12.50	
33	MANCHESTER SOUTH PENNISULA	DU	115.00	12.50	
34	MANHATTAN SOUTHWEST KING	DU	115.00	12.50	
35	MAPLEWOOD CENTRAL KING	DU	115.00	12.50	
36	MARCH POINT COGEN SKAGIT	DU	115.00	13.80	
37	MARINE VIEW SOUTHWEST KING	DU	115.00	12.50	
38	MCALLISTER SPRINGS THURSTON	DU	115.00	12.50	
39	MCKENZIE WHATCOM	DU	115.00	12.50	
40	MCKINLEY THURSTON	DU	115.00	12.50	

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1	MCWILLIAMS NORTH PENNISULA	DU	115.00	12.50	
2	MEDINA CENTRAL KING	DU	115.00	12.50	
3	MERCER ISLAND CENTRAL KING	DU	115.00	12.50	
4	MERCERWOOD CENTRAL KING	DU	115.00	12.50	
5	MERIDETH SOUTH EAST KING	DU	115.00	12.50	
6	MIDLAKES CENTRAL KING	DU	115.00	12.50	
7	MIDWAY SOUTH WEST KING	DU	115.00	12.50	
8	MILLER BAY NORTH PENNISULA	DU	115.00	12.50	
9	MIRRORMONT EAST KING	DU	115.00	12.50	
10	MOBILE UNIT #2 SOUTH KING	DU	66.00	12.50	
11	MOBILE UNIT #3 SOUTH KING	DU	115.00	12.50	
12	MOBILE UNIT #4 SOUTH KING	DU	115.00	12.50	
13	MOBILE UNIT #5 SOUTH KING	DU	115.00	12.50	
14	MOBILE UNIT #6 SOUTH KING	DU	115.00	12.50	
15	MOTTMAN THURSTON	DU	115.00	12.50	
16	MOUNT SI NORTH KING	DU	115.00	12.50	
17	MOUNT VERNON SKAGIT	DU	115.00	12.50	
18	MURDEN COVE NORTH PENNISULA	DU	115.00	12.50	
19	NORKIRK NORTH KING	DU	115.00	12.50	
20	NORLUM SKAGIT	DU	115.00	12.50	
21	NORPAC SOUTHKING	DU	115.00	12.50	
22	NORTH BELLEVUE CENTRAL KING	DU	115.00	13.09	
23	NORTH BEND EAST KING	DU	115.00	12.50	
24	NORTH BOTHELL NORTHKING	DU	115.00	12.50	
25	NORTH NORMANDY SOUTHWEST KING	DU	115.00	12.50	
26	NORTHRUP CENTRAL KING	DU	115.00	12.50	
27	NORWAY HILL NORTH KING	DU	115.00	12.50	
28	NUGENTS CORNER WHATCOM	DU	34.50	12.50	
29	NUGENTS CORNER WHATCOM	DU	115.00	34.50	
30	NUGENTS CORNER WHATCOM	DU	12.50	12.50	
31	OLD TOWN WHATCOM	DU	115.00	12.50	
32	OLYMPIA BREWERY THURSTON	DU	115.00	12.50	
33	OLYMPIC ARCO PUMP WHATCOM	DU	115.00	4.20	
34	OLYMPIC AVON SKAGIT	DU	115.00	4.20	
35	OLYMPIC MOBIL WHATCOM	DU	115.00	4.20	
36	OLYMPIC RENTON SOUTH KING	DU	115.00	4.20	
37	OLYMPIA SWITCH	DU	115.00		
38	OLYMPIC VAIL PIPELINE THURSTON	DU	115.00	4.20	
39	OLYMPIC BAYVIEW SKAGIT	DU	115.00	4.36	
40	ORCHARD SOUTH KING	DU	115.00	12.50	

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [ ] An Original (2) [X] A Resubmission	Date of Report (Mo, Da, Yr) 09/27/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ORILLIA SOUTH KING	DU	115.00	12.50	
2	ORTING EAST PIERCE	DU	115.00	12.50	
3	OSCEOLA SOUTH EAST KING	DU	115.00	12.50	
4	OVERLAKE CENTRAL KING	DU	115.00	12.50	
5	PACCAR CENTRAL KING	DU	115.00	12.50	
6	PADILLA BAY PIPELINE SKAGIT	DU	115.00	12.50	
7	PADILLA BAY PIPELINE SKAGIT	DU	12.50	4.16	
8	PANTHER LAKE SOUTH KING	DU	115.00	12.50	
9	PATTERSON THURSTON	DU	115.00	12.50	
10	PEASLEY CANYON SOUTHWEST KING	DU	115.00	12.50	
11	PETHS CORNER SKAGIT	DU	115.00	12.50	
12	PHANTOM LAKE CENTRAL KING	DU	115.00	12.50	
13	PICKERING CENTRAL KING	DU	115.00	12.50	
14	PINE LAKE EAST KING	DU	115.00	12.50	
15	PIPE LAKE SOUTH EAST KING	DU	115.00	12.50	
16	PLATEAU EAST KING	DU	115.00	12.50	
17	PLEASANT GLADE THURSTON	DU	115.00	12.50	
18	PLUM STREET THURSTON	DU	115.00	13.09	
19	PLYMOUTH WHATCOM	DU	115.00	12.50	
20	POINT ROBERTS WHATCOM	DU	25.00	12.50	
21	PORT GAMBLE NORTH PENNISULA	DU	115.00	12.50	
22	PORT MADISON NORTH PENNISULA	DU	115.00	12.50	
23	POULSBO NORTH PENNISULA	DU	115.00	12.50	
24	PRESIDENT PARK CENTRAL KING	DU	115.00	13.09	
25	PRINE THURSTON	DU	115.00	13.09	
26	PRINE THURSTON	DU	115.00	12.50	
27	QUARRY EAST PIERCE	DU	115.00	12.50	
28	RAINIER VIEW THURSTON	DU	115.00	12.50	
29	REDMOND NORTH KING	DU	115.00	12.50	
30	REDONDO SOUTHWEST KING	DU	115.00	12.50	
31	RENTON JUNCTION SOUTH KING	DU	115.00	12.50	
32	RHODES LAKE EAST PIERCE	DU	115.00	12.50	
33	RITA STREET SKAGIT	DU	115.00	12.50	
34	RIVERBEND SKAGIT	DU	115.00	12.50	
35	ROCHESTER THURSTON	DU	115.00	12.50	
36	ROCKY POINT SOUTH PENNISULA	DU	115.00	12.50	
37	ROEDER WHATCOM	DU	115.00	13.09	
38	ROEDER WHATCOM	DU	12.50	4.20	
39	ROLLING HILLS SOUTH KING	DU	115.00	12.50	
40	ROSE HILL CENTRAL KING	DU	115.00	12.50	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SAHALEE NORTH KING	DU	115.00	12.50	
2	SAINT CLAIR THURSTON	DU			
3	SAMMAMISH NORTH KING	DU	115.00	12.50	
4	SCENIC NORTH KING	DU	115.00	12.50	
5	SCHUETT WHATCOM	DU	115.00	12.50	
6	SEATAC SOUTH KING	DU	115.00	13.09	
7	SEHOME WHATCOM	DU	115.00	12.50	
8	SEMIAHMOO WHATCOM	DU	115.00	12.50	
9	SEQUOIA SOUTH KING	DU	115.00	12.50	
10	SERWOLD NORTH PENNISULA	DU	115.00	12.50	
11	SHANNON WHATCOM	DU	34.50	12.50	
12	SHANNON WHATCOM	DU	115.00	34.50	
13	SHAW EAST PIERCE	DU	115.00	12.50	
14	SHERIDAN NORTH PENNISULA	DU	115.00	12.50	
15	SHERWOOD SOUTH EAST KING	DU	115.00	12.50	
16	SHUFFLETON YARD SOUTH KING	DU	55.00	12.50	
17	SHUFFLETON YARD SOUTH KING	DU	34.50	12.50	
18	SHUFFLETON YARD SOUTH KING	DU	12.50	4.20	
19	SHUFFLETON YARD SOUTH KING	DU	12.50	12.50	
20	SHUFFLETON YARD SOUTH KING	DU	12.50	12.50	
21	SHUFFLETON YARD SOUTH KING	DU	115.00	4.20	
22	SHUFFLETON YARD SOUTH KING	DU	115.00	34.50	
23	SHUFFLETON YARD SOUTH KING	DU	115.00	12.50	
24	SHUFFLETON YARD SOUTH KING	DU	115.00	12.50	
25	SILVERDALE NORTH PENNISULA	DU	115.00	12.50	
26	SINCLAIR INLET SOUTH PENNISULA	DU	115.00	12.50	
27	SKYKOMISH NORTH KING	DU	115.00	12.50	
28	SLATER WHATCOM	DU	115.00	12.50	
29	SNOQUALMIE EAST KING	DU	115.00	12.50	
30	SNOQUALMIE (BLACK CREEK GEN)	DU	34.50	12.50	
31	SNOQUALMIE GEN. #1	DU	117.90	6.90	2.00
32	SNOQUALMIE GEN. #2	DU	117.90	7.20	
33	SOMERSET CENTRAL KING	DU	115.00	12.50	
34	SOOS CREEK SOUTH KING	DU	115.00	12.50	
35	SOUTH BELLEVUE CENTRAL KING	DU	115.00	12.50	
36	SOUTH KEYPORT NORTH PENNISULA	DU	115.00	12.50	
37	SOUTH KIRKLAND NORTH KING	DU	115.00	12.50	
38	SOUTH MERCER CENTRAL KING	DU	115.00	12.50	
39	SOUTHWICK THURSTON	DU	115.00	12.50	
40	SOUTHCENTER SOUTH KING	DU	115.00	12.50	

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1	SOUTH WHIDBEY SWITCH ISLAND	DU	115.00		
2	SPANAWAY EAST PIERCE	DU	115.00	12.50	
3	SPIRITBROOK NORTH KING	DU	115.00	12.50	
4	STARWOOD SOUTH KING	DU	115.00	12.50	
5	STATE STREET WHATCOM	DU	115.00	13.09	
6	STERLING NORTH KING	DU	115.00	12.50	
7	STEWART EAST PIERCE	DU	115.00	12.50	
8	SUMAS GEN STATION	DU	115.00	13.80	
9	SUMMIT PARK SKAGIT	DU	115.00	12.50	
10	SUMNER EAST PIERCE	DU	115.00	12.50	
11	SUNRISE EAST PIERCE	DU	115.00	12.50	
12	SWANTOWN ISLAND	DU	115.00	12.50	
13	SWEPTWING SOUTHWEST KING	DU	115.00	12.50	
14	TANGLEWILDE THURSTON	DU	115.00	12.50	
15	TEN MILE WHATCOM	DU	115.00	4.20	
16	TEXACO EAST SKAGIT	DU	115.00	13.80	
17	TEXACO WEST SKAGIT	DU	115.00	13.80	
18	THORP KITTITAS	DU	34.50	12.50	
19	THURSTON THURSTON	DU	115.00	12.50	
20	TILLICUM EAST PIERCE	DU	115.00	12.50	
21	TOLT NORTH KNG	DU	115.00	12.50	
22	TOTEM NORTH KING	DU	115.00	12.50	
23	TRACYTON NORTH PENNISULA	DU	115.00	12.50	
24	UNION HILL EAST KING	DU	115.00	13.09	
25	VALLEY JUNCTION	DU	115.00		
26	VAN WYCK WHATCOM	DU	115.00	12.50	
27	VASHON SOUTH PENNISULA	DU	115.00	12.50	
28	VICTORIA PARK SOUTH KING	DU	115.00	12.50	
29	VIKING WHATCOM	DU	115.00	12.50	
30	VISTA WHATCOM	DU	115.00	12.50	
31	VITULLI NORTH KING	DU	115.00	12.50	
32	WABASH SOUTH EAST KING	DU	55.00	12.50	
33	WAYNE NORTH KING	DU	115.00	12.50	
34	WEST AUBURN SOUTHWEST KING	DU	115.00	12.50	
35	WEST CAMPUS SOUTHWEST KING	DU	115.00	12.50	
36	WEST ISSAQUAH EAST KING	DU	115.00	13.09	
37	WEST OLYMPIA THURSTON	DU	115.00	12.50	
38	WHIDBEY ISLAND OAK HARBOR	DU			
39	WEYERHAEUSER SW KING	DU	115.00	12.50	
40	WEYERHAEUSER WHR BRANCH	DU	55.00	4.16	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WHITEHORN WHATCOM	DU	115.00	13.20	
2	WHITE RIVER TRANSM. EAST PIERCE	DU	115.00	55.00	
3	WHITE RIVER TRANSM. EAST PIERCE	DU	55.00	7.20	
4	WHITEHORN GEN WHATCOM	DU	12.50		
5	WHITEHORN GEN WHATCOM	DU	12.50	0.50	
6	WHITEHORN GEN WHATCOM	DU	12.50	4.20	
7	WILKESON EAST PIERCE	DU	55.00	12.50	
8	WILSON SKAGIT	DU	115.00	12.50	
9	WINSLOW NORTH PENNISULA	DU	115.00	12.50	
10	WOBURN WHATCOM	DU	115.00	12.50	
11	WOLDALE KITTITAS	DU	115.00	12.50	
12	WOODLAND EAST PIERCE	DU	115.00	12.50	
13	YELM THURSTON	DU	115.00	12.50	
14	ZENITH SOUTHWEST KING	DU	115.00	12.50	
15	TOTAL DISTRIBUTION STATIONS		36994.80	4321.79	70.20
16					
17	SUMMARY - TRANSMISSION CAPACITY		5815.00	2041.00	246.30
18	SUMMARY - DISTRIBUTION CAPACITY		36994.80	4321.79	70.20
19	TOTAL		42809.80	6362.79	316.50
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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.
325	1		Static Capacitor	1	21	1
325	1		Static Capacitor	1	42	2
325	1					3
50	1					4
50	1	1				5
200	1		Reactor	1	10	6
210	2					7
365	1					8
325	1		Static Capacitor	1	23	9
325	1		Static Capacitor	1	42	10
650	2		Static Capacitor	1	42	11
215	1					12
160	1					13
200	1		Reactor	1	10	14
325	1					15
650	2		Static Capacitor	2	84	16
650	2		Static Capacitor	2	42	17
325	1					18
325	1		Static Capacitor	1	42	19
650	2		Static Capacitor	1	42	20
533	4					21
650	2		Static Capacitor	1	45	22
390	3		Static Capacitor	8	106	23
325	1		Reactor	1	45	24
8548	35	1		23	596	25
						26
20	1		Static Capacitor	1	4	27
9	1					28
50	2		Static Capacitor	2	6	29
20	1		Static Capacitor	1	5	30
80	2		Static Capacitor	1	24	31
80	2		Static Capacitor	1	24	32
80	2					33
50	2		Static Capacitor	2	10	34
25	1		Static Capacitor	1	5	35
25	1		Static Capacitor	1	5	36
133	2					37
25	1					38
8	1					39
120	3	1				40

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Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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3	3					1
20	1		Static Capacitor	1	5	2
20	1		Static Capacitor	1	5	3
25	1		Static Capacitor	1	5	4
50	2		Static Capacitor	2	9	5
25	1		Static Capacitor	1	5	6
20	1		Static Capacitor	1	5	7
25	1		Static Capacitor	1	2	8
25	1		Static Capacitor	1	5	9
25	1		Static Capacitor	1	2	10
25	1		Static Capacitor	1	5	11
20	1		Static Capacitor	1	2	12
25	1		Static Capacitor	1	5	13
75	3		Static Capacitor	1	5	14
50	2		Static Capacitor	2	10	15
50	2		Static Capacitor	2	11	16
13	1					17
20	1		Static Capacitor	1	5	18
20	1					19
19	2		Static Capacitor	1	2	20
20	1					21
20	1		Static Capacitor	1	5	22
25	1					23
25	1		Static Capacitor	1	5	24
50	2					25
20	1		Static Capacitor	1	5	26
25	1		Static Capacitor	1	5	27
40	1		Static Capacitor	1	6	28
25	1		Static Capacitor	1	6	29
25	1		Static Capacitor	1	2	30
20	1		Static Capacitor	1	5	31
20	1		Static Capacitor	1	5	32
16	2					33
20	1		Static Capacitor	1	5	34
25	1		Static Capacitor	1	5	35
1	2					36
50	1					37
20	1		Static Capacitor	1	5	38
25	1		Static Capacitor	1	5	39
12	1					40

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SUBSTATIONS (Continued)

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25	1		Static Capacitor	1	5	1
25	1		Static Capacitor	1	5	2
20	1					3
25	1		Static Capacitor	1	5	4
25	1		Static Capacitor	1	5	5
8	1		Static Capacitor			6
4	1					7
25	1		Static Capacitor	1	3	8
20	1		Static Capacitor	1	5	9
20	1		Static Capacitor	1	2	10
25	1		Static Capacitor	1	5	11
25	1					12
20	1		Static Capacitor	1	5	13
25	1					14
25	1		Static Capacitor	2	6	15
25	1		Static Capacitor	1	5	16
25	1		Static Capacitor	1	5	17
50	2		Static Capacitor	1	5	18
20	1					19
25	1		Static Capacitor	1	2	20
20	1		Static Capacitor	1	2	21
25	1					22
2	1					23
40	3					24
3	2					25
25	1		Static Capacitor	1	4	26
120	3					27
43	1					28
25	1		Static Capacitor	1	2	29
50	2		Static Capacitor	2	10	30
20	1		Static Capacitor	1	4	31
50	2		Static Capacitor	2	10	32
50	2		Static Capacitor	1	5	33
25	1		Static Capacitor	1	3	34
25	1		Static Capacitor	1	5	35
20	1					36
25	1		Static Capacitor	1	5	37
			Static Capacitor	1	23	38
25	1		Static Capacitor	1	5	39
25	1		Static Capacitor	1	2	40

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170	2					1
2	2					2
3	2					3
		1	Spare GSU			4
110	2					5
75		1	Spare GSU			6
20	1		Static Capacitor	1	5	7
20	1		Static Capacitor	1	5	8
25	1		Static Capacitor	1	5	9
25	1		Static Capacitor	1	5	10
25	1		Static Capacitor	1	5	11
25	1		Static Capacitor	1	5	12
5	1					13
25	1		Static Capacitor	1	5	14
25	1		Static Capacitor	1	5	15
25	1		Static Capacitor	1	5	16
20	1		Static Capacitor	1	5	17
9	1					18
20	1		Static Capacitor	1	5	19
8	1					20
20	1		Static Capacitor	1	5	21
20	1					22
20	1		Static Capacitor	1	2	23
20	1					24
50	2		Static Capacitor	1	5	25
25	1		Static Capacitor	1	2	26
25	1		Static Capacitor	1	3	27
25	1		Static Capacitor	1	5	28
20	1					29
25	1		Static Capacitor	1	5	30
20	1		Static Capacitor	1	3	31
25	1		Static Capacitor	1	2	32
20	1		Static Capacitor	1	2	33
25	1		Static Capacitor	1	5	34
167	2		Static Capacitor	2	29	35
25	1		Static Capacitor	1	5	36
20	1		Static Capacitor	1	5	37
25	1		Static Capacitor	1	5	38
20	1		Static Capacitor	1	5	39
50	2		Static Capacitor	2	10	40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1		Static Capacitor	1	5	1
60	1	1	Static Capacitor	1	2	2
25	1		Static Capacitor	1	5	3
25	1		Static Capacitor	1	5	4
50	2		Static Capacitor	2	8	5
25	1		Static Capacitor	1	5	6
25	1		Static Capacitor	1	5	7
25	1		Static Capacitor	1	5	8
25	1		Static Capacitor	1	5	9
25	1		Static Capacitor	1	5	10
40	1					11
20	1		Static Capacitor	1	5	12
20	1		Static Capacitor	1	4	13
25	1		Static Capacitor	1	5	14
25	1		Static Capacitor	1	5	15
20	1		Static Capacitor	1	5	16
25	1		Static Capacitor	1	5	17
25	1					18
18	1		Static Capacitor	1	2	19
25	1		Static Capacitor	1	5	20
25	1		Static Capacitor	1	5	21
25	1		Static Capacitor	1	5	22
20	1					23
25	1		Static Capacitor	1	5	24
25	1		Static Capacitor	1	3	25
20	2					26
50	2		Static Capacitor	2	12	27
25	1		Static Capacitor	2	10	28
25	1		Static Capacitor	1	5	29
20	1		Static Capacitor	1	2	30
40	2		Static Capacitor	2	10	31
25	1		Static Capacitor	1	5	32
25	1		Static Capacitor	1	2	33
25	1		Static Capacitor	1	5	34
25	1		Static Capacitor	1	5	35
140	3					36
25	1		Static Capacitor	1	5	37
25	1					38
20	1		Static Capacitor	1	5	39
20	1		Static Capacitor	1	5	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

SUBSTATIONS (Continued)

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

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

SUBSTATIONS (Continued)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1		Static Capacitor	1	5	1
			Static Capacitor	1	40	2
25	1		Static Capacitor	1	5	3
4	1					4
20	1					5
50	2					6
25	1		Static Capacitor	1	5	7
25	1		Static Capacitor	1	5	8
25	1		Static Capacitor	1	5	9
25	1		Static Capacitor	1	5	10
8	1					11
25	1			1	5	12
25	1		Static Capacitor	1	5	13
40	1		Static Capacitor	1	5	14
25	1		Static Capacitor	1	5	15
9		1				16
9		1				17
8		1				18
5		1				19
1		7				20
13		1				21
25		1				22
25		3				23
9		1				24
25	1		Static Capacitor	1	5	25
20	1		Static Capacitor	1	5	26
9	1					27
20	1		Static Capacitor	1	5	28
25	1					29
5	1					30
20	1					31
53	1					32
25	1		Static Capacitor	1	5	33
25	1		Static Capacitor	1	5	34
25	1		Static Capacitor	1	5	35
20	1		Static Capacitor	1	4	36
25	1		Static Capacitor	1	5	37
20	1					38
25	1		Static Capacitor	1	5	39
25	1		Static Capacitor	1	5	40

SUBSTATIONS (Continued)

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

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

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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.
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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.
170	2					1
83	3					2
3	3					3
1	2					4
2	2					5
2	2					6
9	1					7
25	1		Static Capacitor	1	5	8
25	1					9
25	1					10
20	1					11
25	1		Static Capacitor	1	2	12
25	1		Static Capacitor	2	26	13
25	1		Static Capacitor	1	5	14
9530	398	21		256	1,438	15
						16
8548	35	1		23	596	17
9530	398	21		256	1,438	18
18078	433	22		279	2,034	19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426 Line No.: 24 Column: i

The act of installing Shunt Reactor is to meet the requirements of Grant County as a condition to connect or intertie onto the transmission system located at Wild Horse. This equipment serves to reduce the wind farm's turbine impact when producing energy during times of low load conditions in the surrounding area. This translates in allowing PSE to produce all the power it can from the wind turbine generation system during these light load conditions but it does not (as a component) add capacity.

Schedule Page: 426 Line No.: 29 Column: a

Safeway Distribution Center leases PSE owned transformer at Alpac (Algona-Pacific / Boeing-Auburn #2) Substation. Service started Novembe 2004.

Schedule Page: 426 Line No.: 31 Column: a

BP West Coast Products leases PSE owned transformer at ARCO North Substation under schedule 449.

Schedule Page: 426 Line No.: 32 Column: a

BP West Cost Products leases PSE owned transformer at ARCO South Substation under schedule 449.

Schedule Page: 426 Line No.: 33 Column: a

BP West Coast Products leases PSE owned transformer at ARCO Central Substation under schedule 449.

Schedule Page: 426.1 Line No.: 17 Column: a

Waste Water Treatment Division - Brightwater leases PSE owned transformer at Brightwater Substation. Expiration 5/21/2020

Schedule Page: 426.1 Line No.: 25 Column: a

State of Washington Admin leases PSE owned transformer at Capitol Substation. Service started November 1972.

Schedule Page: 426.1 Line No.: 38 Column: a

Navy Ault leases PSE owned transformer at Clover Valley Substation. Service started November 1972.

Schedule Page: 426.2 Line No.: 33 Column: a

Benaryoa leases PSE owned transformer at Fairchild Substation. Service started December 2005.

Schedule Page: 426.4 Line No.: 22 Column: a

Replaced August 2015

Schedule Page: 426.4 Line No.: 26 Column: a

Air Liquide Industrial US LP leases PSE owned transformer at Liquid Air Substation

Schedule Page: 426.5 Line No.: 6 Column: a

Replaced December 2015

Schedule Page: 426.5 Line No.: 9 Column: a

BioEngineer leases PSE owned transformer at Mirrormont Substation.

Schedule Page: 426.5 Line No.: 24 Column: a

AT&T leases PSE owned transformer at North Bothell Substation.

Schedule Page: 426.5 Line No.: 33 Column: a

Praxair and Olympic Pipeline lease PSE owned transformers at Olympic Arco Pump Substation. Services started July 1979.

Schedule Page: 426.5 Line No.: 34 Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Avon Substation. Service started April 2004

Schedule Page: 426.5 Line No.: 35 Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Mobil Substation. Service started April 2004.

Schedule Page: 426.5 Line No.: 36 Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Renton Substation. Service started April 2004.

Schedule Page: 426.5 Line No.: 38 Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Vail Substation. Service started April 2004.

Schedule Page: 426.5 Line No.: 39 Column: a

Olympic Pepeline leases PSE owned transformer at Olympic Bayview Substation.

Schedule Page: 426.6 Line No.: 5 Column: a

PACCAR Inc. leases PSE owned transformer at PACCAR Substation. Service started December 1992.

Schedule Page: 426.6 Line No.: 6 Column: a

Olympic Pipeline leases PSE owned transformer at Padilla Bay Substation.

Schedule Page: 426.6 Line No.: 19 Column: a

Replaced August 2015

Schedule Page: 426.6 Line No.: 37 Column: a

Bellingham Cold Storage leases PSE owned transformer at Roeder Substation. Service started May 1967.

Schedule Page: 426.7 Line No.: 3 Column: a

AT&T leases PSE owned transformer at Sammamish Substation. Service started 2010.

Schedule Page: 426.8 Line No.: 6 Column: a

Microsoft leases PSE owned transformer at Sterling Substation. Service started 2010.

Schedule Page: 426.8 Line No.: 15 Column: a

Trans Mountain Pipeline leases PSE owned transformer at Ten Mile Substation. The substation was energized 10/17/08.

Schedule Page: 426.8 Line No.: 16 Column: a

Shell leases PSE owned transformer at Texaco East Substation under Schedule 449.

Schedule Page: 426.8 Line No.: 17 Column: a

Shell leases PSE owned transformer at Texaco West Substation under Schedule 449.

Schedule Page: 426.8 Line No.: 29 Column: a

Western Washington University leases PSE owned transformer at Viking Substation.

Schedule Page: 426.8 Line No.: 31 Column: a

AT&T Wireless and The Seattle Times lease PSE owned transformers at Vitulli Substation. Services started December 2006 and August 1991.

Schedule Page: 426.8 Line No.: 39 Column: a

Weyerhaeuser leases PSE owned transformer at Weyerhaeuser Substation.

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Puget Sound Energy, Inc.	(1) [ ] An Original (2) [X] A Resubmission	09/27/2016	End of 2015/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	General and Administrative Expenses	Puget Energy, Inc.	186	1,770,455
22	General and Administrative Expenses	Puget Equico, LLC	186	27,469
23	General and Administrative Expenses	Puget Western, Inc.	186	651,184
24	General and Administrative Expenses	Puget Intermediate Holdings, Inc.	186	229,809
25	General and Administrative Expenses	Puget Holdings, LLC.	186	718,338
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

Schedule	Page No.