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

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

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

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

Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Puget Sound Energy, Inc.	**End of** 2019/Q4

Report of Independent Auditors

To the Board of Directors and
Management of Puget Sound Energy, Inc.

We have audited the accompanying financial statements of Puget Sound Energy, Inc, which comprise the balance sheets as of December 31, 2019 and 2018, and the related statements of income, of retained earnings, and of cash flows for the years then ended, included on pages 110.0 through 123.42 of the accompanying Federal Energy Regulatory Commission Form No.1.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases described in Note 1. on page 123.1. Management is also responsible for the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

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

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

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Puget Sound Energy, Inc. as of December 31, 2019 and 2018, and the results of its operations and its cash flows for the years then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases described in Note 1.

PricewaterhouseCoopers LLP, 1420 Fifth Avenue, Suite 2800, Seattle, WA 98101
T: (206) 398-3000, F: (206) 398-3100, www.pwc.com/us

Basis of Accounting

We draw attention to Note 1 of the financial statements, which describes the basis of accounting. As described in Note 1 to the financial statements, the financial statements are prepared by Puget Sound Energy, Inc. on the basis of the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than accounting principles generally accepted in the United States of America, to meet the requirements of the Federal Energy Regulatory Commission. Our opinion is not modified with respect to this matter.

Restriction of Use

This report is intended solely for the information and use of the Board of Directors and Management of Puget Sound Energy, Inc. and the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

Emphasis of Matter

As discussed in Note 2 of the financial statements, the Company changed the manner in which it accounts for leases in 2019. Our opinion is not modified in respect to this manner.

PricewaterhouseCoopers LLP

April 17, 2020

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 2019/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* P.O. BOX 97034, Bellevue, WA 98009-9734	
05 Name of Contact Person Stephen J King	06 Title of Contact Person Controller and 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) 456-2008	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Stephen J King	Stephen J King	04/17/2020
02 Title Controller and 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

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	
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	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[ ] Two copies will be submitted

[X] 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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

GENERAL INFORMATION

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

Puget Sound Energy, Inc.
Stephen J King, Controller and Principal Accounting Officer
P.O. BOX 97034
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
Natural 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) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

CONTROL OVER RESPONDENT

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

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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	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	989,799
2	President	Mary K Kipp	252,540
3	Sr. V.P. & Chief Financial Officer	Daniel A. Doyle	521,399
4	Sr. V.P. & Chief Administrative Officer	Marla D. Mellies	382,671
5	Sr. V.P., G.C., & Chief Ethics & Compliance Officer	Steve R. Secrist	459,165
6	V.P. Chief Information Officer	Margaret Hopkins	325,592
7	V.P. Operations & Communications	Andy W. Wappler	307,163
8	Sr. V.P. Operations	Booga K. Glibertson	380,587
9	Sr. V.P. Policy and Energy Supply	David E. Mills	368,616
10	V.P. Regulatory & Government Affiars	Ken Johnson	261,088
11	Controller & Principal Accounting Officier	Stephen J. King	187,763
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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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Scott Armstrong	Washington, DC
2	Steven W. Hooper	Bellevue, WA
3	Kenton Bradbury	London, UK
4	Richard Dinneny	British Columbia
5	Barbara J Gordon	Bellevue, WA
6	Christopher Hind	Canada BC
7	Thomas King	New York, NY
8	Paul McMillian	Toronto, Ontario, Cananda
9	Mary O. McWilliams	Seattle, WA
10	Mary E. Kipp, President	Bellevue, WA
11	Christopher Trumpy	British Columbia
12	Martijn Verwoest	Netherlands
13	Steven Zucchet	London, UK
14	Kimberly Harris, President & CEO	Bellevue, WA
15	Karl Kuchel	New York, NY
16	Andrew Chapman	New York, NY
17	Christopher Leslie	New York, NY
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Schedule Page: 105 Line No.: 3 Column: a

Effective April 17, 2019, Mr. Kenton Bradbury was elected to serve on the Board of Directors of Puget Sound Energy.

Schedule Page: 105 Line No.: 4 Column: a

Effective April 17, 2019, Mr. Richard Dinneny was elected to serve on the Board of Directors of Puget Sound Energy.

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

Effective July 1, 2019, Mr. Thomas King was elected to serve on the Board of Directors of Puget Sound Energy.

Schedule Page: 105 Line No.: 10 Column: a

Effective August 30, 2019, Ms. Mary Kipp was appointed President of Puget Sound Energy. On January 3, 2020, Ms. Mary Kipp, assumed additional role of Chief Executive Officer of the Companies upon Ms. Kimberly Harris' retirement.

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

Effective April 17, 2019, Mr. Martijn Verwoest was elected to serve on the Board of Directors of Puget Sound Energy.

Schedule Page: 105 Line No.: 13 Column: a

Effective April 17, 2019, Mr. Stephen Zucchet was elected to serve on the Board of Directors of Puget Sound Energy.

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

Effective August 30, 2019, Ms. Kimberly Harris voluntarily resigned her position as President, while retaining her role as Chief Executive Officer throughout 2019.

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

Mr. Karl Kuchel, director on the Boards of Directors of Puget Sound Energy, Inc tendered his resignation from the Company effective on April 17, 2019.

Schedule Page: 105 Line No.: 16 Column: a

Mr. Andrew Chapman, director on the Boards of Directors of Puget Sound Energy, Inc tendered his resignation from the Company effective on April 17, 2019.

Schedule Page: 105 Line No.: 17 Column: a

Mr. Christopher Leslie, director on the Boards of Directors of Puget Sound Energy, Inc tendered his resignation from the Company effective on April 17, 2019.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

Does the respondent have formula rates? [X] Yes [ ] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff	FERC Docket No. ER12-778-001
2	FERC Electric Tariff Amendment	FERC Docket No. ER18-1249-000
3		Amendment to OATT Schedules
4		7, 8, and 10 to revise depreciation rates.
5		Letter order issued May 19, 2018 accepting tariff
6		revisions.
7		(Accession No. 201803305155).
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Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

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

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

[ ] Yes
[X] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20180601-5313	06/01/2018	ER12-778-001	Informational Filing of Annual Update	FERC Electric Tariff
2	20180529-5249	05/16/2018	ER18-1695-000	Petition for limited waiver of tariff	FERC Electric Tariff
3				Order granting petition issued on Dec.	
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Schedule Page: 1061 Line No.: 1 Column: e

Pursaunt to the PSE OATT formula rate protocols, PSE performs an Annual Update to the formula rate which is filed at FERC. However FERC does not send an approval letter or issue a new docket number for the Annual Update.

Schedule Page: 1061 Line No.: 2 Column: e

In 2018, PSE filed an amendment to the OATT formula rate, amending the depreciation rates. FERC accepted the amendment filing in 2018, effective December 19, 2017.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
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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. 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.

Location (WA)	County	Type	Category	Initial Term	Consideration
Bremerton	Kitsap	Electric	New	10 years	$ -
King County	King	Electric	New	10 years	$ -
Burien	King	Electric & Natural Gas	Expired	-	$ -
King County	King	Natural Gas	Expired	-	$ -

2. None.

3. None.

4. None.

5. None.

6.

Credit Facilities

As of December 31, 2019, no amounts were drawn and outstanding under PSE's credit facility. No letters of credit were outstanding and $176.0 million was outstanding under the commercial paper program. Outside of the credit agreement, PSE had a $2.8 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.

Long Term Debt

On August 2, 2019, PSE filed a new shelf registration statement under which it may issue, up to $1.0 billion aggregate principal amount of senior notes secured by first mortgage bonds. As of the date of this report, $550.0 million was available under the registration. The shelf registration will expire in August 2022.

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, 2019, the earnings available for interest exceeded the required amount.

On August 30, 2019, PSE issued $450.0 million of senior notes at an interest rate of 3.250%. (Filing UE-190700) The notes pay interest semi-annually and are due to mature on September 15, 2049. Proceeds from the sale of the notes were used to repay outstanding short term debt under the Company’s commercial paper program.

7. None.

8. Non-represented employees received on average a 3.29% increase effective March 1, 2019. Employees of the IBEW received a 3.0% salary increase that went into effect January 1, 2019. Employees of the UA received a 3.0% salary increase that went into effect October 1, 2019. The estimated annual effect of these changes is $9.2 million. The current contracts with the IBEW and UA will expire March 31, 2020 and September 30, 2021, respectively.

9. Legal Proceedings:

Regulation and Rates

General Rate Case Filing

PSE filed a GRC with the Washington Commission on June 20, 2019, requesting an overall increase in electric and natural gas rates of 6.9% and 7.9% respectively. PSE requested a return on equity of 9.8% with an overall rate of return of 7.62%. In addition to the traditional areas of focus (revenue requirements, cost allocation, rate design and cost of capital), the Company completed an attrition study and included a portion of the attrition revenue requirement in the overall request in order address the expected regulatory lag in the rate year. Additionally, as the non-plant related excess deferred taxes that resulted from the Tax Cuts and Jobs Act (TCJA) remained outstanding from PSE's Expedited Rate Filing (ERF) as discussed below, PSE requested in its GRC to pass back the amounts over four years. On September 17, 2019, PSE filed a supplemental filing in the GRC, which provided updates as discussed in our original filing, but did not impact the requested overall electric and natural gas rate increases, return on equity or overall rate of return as originally filed. On January 15, 2020, PSE filed rebuttal testimony which included a reduction to the requested return on equity to 9.5%, which decreased the rate of return to 7.48%. The requested rate increase for both electric and natural gas remained at 6.9% and 7.9%, respectively. For both electric and natural gas PSE did not originally request its full attrition adjustment; therefore, the decrease in return on equity led to a reduction in the electric rate increase of only $1.5 million and did not have an impact on the natural gas rate increase.

Expedited Rate Filing Rate Adjustment

On November 7, 2018, PSE filed an expedited rate filing (ERF) with the Washington Commission. The filing requested to change rates associated with PSE's delivery and fixed production costs. It did not include variable power costs, purchased gas costs or natural gas pipeline replacement program costs, which are recovered in separate mechanisms. The filing was based on historical test year costs and rate base, and followed the reporting requirements of a Commission Basis Report, as defined by the Washington Administrative Code, but used end of period rate base and certain annualizing adjustments. It did not include any forward-looking or pro-forma adjustments. Included in the filing was a reduction to the overall authorized rate of return from 7.6% to 7.49% to recognize a reduction in debt costs associated with recent debt activity. PSE requested an overall increase in electric rates of $18.9 million annually, which is a 0.9% increase, and an overall increase in natural gas rates of $21.7 million annually, which is a 2.7% increase.

On January 22, 2019, all parties in the proceeding reached an agreement on settlement terms that resolved all issues in the filing. The settlement agreement was filed on January 30, 2019. The parties agreed to a $21.5 million for natural gas and no rate increase for electric which became effective March 1, 2019. As is discussed below, these rates include the offsetting effect of passing back to customers plant related excess deferred income taxes that resulted from the TCJA, using the average rate assumption method (ARAM) amounts to arrive at the settlement rate changes.

The settlement agreement provides for the pass back of plant related excess deferred income taxes that resulted from the TCJA using the ARAM methodology based on 2018 amounts beginning March 1, 2019, in the amount of $6.1 million for natural gas customers and $25.9 million for electric customers. The settlement agreement left the determination for the regulatory treatment of the remaining items related to the TCJA, listed below, to PSE's next GRC, filed June 20, 2019:

1) excess deferred taxes for non-plant-related book/tax differences for periods prior to March 1, 2019,
2) the deferred balance associated with the over-collection of income tax expense for the period January 1 through April 30, 2018 (the time period that encompasses the effective date of the TCJA to May 1, 2018, the effective date of the TCJA rate change); and
3) the turnaround of plant related excess deferred income taxes using the ARAM method for the period from January 2018 through February 2019, the rate effective date for the ERF.

The agreement provides that PSE may defer the depreciation expense associated with PSE's ongoing investment in its advanced metering infrastructure (AMI) investment and may defer the return on the AMI investment that was included in the test year of the filing. The agreement preserves the parties' rights to argue whether or not these deferrals should be recovered in the Company's 2019 GRC. The rate of return adopted in the settlement for reporting and deferral purposes is 7.49% . On February 21, 2019, the Washington Commission approved the settlement with one condition: PSE must pass back the deferred balance associated with the tax over-collection of $34.6 million for the period from January 1, 2018, through April 30, 2018, over a one-year period which began May 1, 2019.

Washington Commission Tax Deferral Filing

The TCJA was signed into law in December 2017. As a result of this change, PSE re-measured its deferred tax balances under the new corporate tax rate. PSE filed an accounting petition on December 29, 2017, requesting deferred accounting treatment for the impacts of tax reform. The requested deferral accounting treatment resulted in the tax rate change being captured in the deferred income tax balance with an offset to the regulatory liability for deferred income taxes for GAAP purposes. Additionally, on March 30, 2018, PSE filed for a rate change for electric and natural gas customers associated with TCJA to reflect the decrease in the federal corporate income tax rate from 35.0% to 21.0%. The overall impact of the rate change, based on the annual period from May 2018 through April 2019, is a revenue decrease of $72.9 million, or 3.4%, for electric and $23.6 million, or 2.7%, for natural gas and became effective May 1, 2018, by operation of law.

The March 30, 2018, rate change filing did not address excess deferred taxes or the deferred balance associated with the over-collection of income tax expense of $34.6 million for the period January 1 through April 30, 2018 (the time period that encompasses the effective date of the TCJA through May 1, 2018, the effective date of the rate change). The $34.6 million tax over-collection decreased PSE's revenue and increased the regulatory liability for a refund to customers.

As a result of the Washington Commission's final order in the ERF, the excess deferred taxes associated with non-plant-related book/tax differences and the treatment of the excess deferred taxes associated with plant related book/tax differences from January 1, 2019, through February 28, 2019, was addressed in PSE’s GRC, which was filed on June 20, 2019. The Washington Commission also required in the ERF order that PSE pass back the deferred balance associated with the tax over-collection for the period from January 1, 2018, through April 30, 2018, as discussed above, over a one-year period which began May 1, 2019.

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 assist in mitigating the impact of weather on operating revenue and net income. Since July 2013, 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 most residential, commercial and industrial customers to mitigate the effects of abnormal weather, conservation impacts and changes in usage patterns per customer. As a result, these electric and natural gas revenues are recovered on a per customer basis regardless of actual consumption levels. PSE's 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 from, or refund to, customers the difference between allowed decoupling revenue and the corresponding actual revenue during the following May to April time period.

On December 5, 2017, the Washington Commission approved PSE’s request within the 2017 GRC to extend the decoupling mechanism with several changes to the methodology that took effect on December 19, 2017. Electric and natural gas delivery revenues continue to be recovered on a per customer basis and electric fixed production energy costs are now decoupled and recovered on the basis of a fixed monthly amount. The allowed decoupling revenue for electric and natural gas customers will no longer increase annually each January 1 as occurred prior to December 19, 2017. Approved revenue per customer costs can only be changed in a GRC or ERF. Approved electric fixed production energy costs can also be changed in a power cost only rate case (PCORC). Other changes to the decoupling methodology approved by the Washington Commission include regrouping of electric and natural gas non-residential customers and the exclusion of certain electric schedules from the decoupling mechanism going forward. The rate test, which limits the amount of revenues PSE can collect in its annual filings, increased from 3.0% to 5.0% for natural gas customers but will remain at 3.0% for electric customers. The decoupling mechanism will be reviewed again in PSE’s first rate case filed in or after 2021, or in a separate proceeding, if appropriate. PSE’s decoupling mechanism over- and under- collections will still be collectible or refundable after this effective date even if the decoupling mechanism is not extended.

On February 21, 2019, the Washington Commission approved the multi-party settlement agreement which was filed within PSE’s ERF filing. As part of this settlement agreement, electric and natural gas allowed delivery revenue per customer was updated to reflect changes in the approved revenue requirement. For electric, there were no changes to the annual allowed fixed power cost revenue. The changes took effect on March 1, 2019.

On December 31, 2019, PSE performed an analysis to determine if electric and natural gas decoupling revenue deferrals would be collected from customers within 24 months of the annual period, per ASC 980. If not, for GAAP purposes only, PSE would need to record a reserve against the decoupling revenue and regulatory asset balance. Once the reserve is probable of collection within 24 months from the end of the annual period, the reserve can be recognized as decoupling revenue. The analysis indicated that electric and natural gas deferred revenue will be collected within 24 months of the annual period; therefore, no adjustment was booked to 2019 decoupling revenue. The previously unrecognized decoupling deferrals of $0.8 million and $20.8 million at December 31, 2018, and December 31, 2016, were recognized as decoupling revenue in the year ended December 31, 2019, and December 31, 2017, respectively.

Power Cost Adjustment Mechanism

PSE currently has a PCA mechanism that provides for the deferral of power costs that vary from the "power cost baseline" level of power costs. The "power cost baseline" levels are set, in part, based on normalized assumptions about weather and hydroelectric conditions. Excess power costs or savings are apportioned between PSE and its customers pursuant to the graduated scale set forth in the PCA mechanism and will trigger a surcharge or refund when the cumulative deferral trigger is reached.

Effective January 1, 2017, the following graduated scale is used in the PCA mechanism:

	Company's Share		Customers' Share	
Annual Power Cost Variability	Over	Under	Over	Under
Over or Under Collected by up to $17 million	100 %	100 %	— %	— %
Over or Under Collected by between $17 million - $40 million	35	50	65	50
Over or Under Collected beyond $40 + million	10	10	90	90

In September 2016, PSE filed an accounting petition with the Washington Commission which requested deferral of the variances, either positive or negative, between the fixed costs previously recovered in the PCA and the revenue received to cover the allowed fixed costs. The deferral period requested was January 1, 2017, through December 31, 2017, when rates were to go into effect from PSE's 2017 GRC. In November 2016, the Washington Commission issued Order No. 01 approving PSE's accounting petition. With the final determination in PSE's GRC, this deferral ceased with the rate effective date of December 19, 2017.

For the year ended December 31, 2019, in its PCA mechanism, PSE under recovered its allowable costs by $67.2 million of which $36.0 million was apportioned to customers and $1.0 million of interest was accrued on the deferred customer balance. This compares to an under recovery of allowable costs of $3.5 million for the year ended December 31, 2018, of which no amounts were apportioned to customers and accrued $0.2 million of interest on the total deferred customer balance. Power costs have been higher than the allowed base line in 2019 which has led to an increase in the PCA deferral causing a higher under-collection compared to the prior year. Actual power costs were higher than baseline rates in 2018 also but by a narrower margin, resulting in lower under-collection. Power prices increased during 2019 as compared to the prior year due to: (i) Cold weather in February and early March, which drove regional loads and demand for power up; (ii) Westcoast pipeline capacity limitations, which contributed to higher natural gas and power prices; (iii) An outage on a transmission line, which contributed to a liquidity crisis at Mid-C and resulted in high market power prices; and (iv) The relative prices of natural gas and power, which reduced the supply of natural gas-fired generation and increased the demand for market power, increasing prices.

Purchased Gas Adjustment

For the year ended December 31, 2018, PSE had a beginning PGA payable balance of $16.1 million, incurred actual natural gas costs of $319.3 million, of which $292.0 million was recovered through rates. The difference between actual and allowed costs, less interest $1.3 million, resulted in a PGA receivable of $9.9 million. For the year ended December 31, 2019, PSE had incurred actual natural gas costs of $406.2 million, of which $289.9 million was recovered through rates. The difference between actual and allowed costs, plus interest of $6.6 million, resulted in a PGA receivable of $132.8 million.

On April 25, 2019, the Washington Commission approved PSE's request for an out-of-cycle change to PGA rates with the rate change taking effect May 1, 2019. The out-of-cycle PGA filing was needed to begin amortizing a large PGA commodity deferral balance that had grown due to higher than projected commodity costs during the 2018/19 winter. These higher than projected commodity costs were primarily due to an October 9, 2018, rupture and subsequent explosion on Westcoast Pipeline which is one of the major pipelines feeding PSE's distribution system. The pipeline was repaired in October 2018, however supply capacity on the pipeline was limited over the 2018/19 winter leading to higher prices. February weather was also much colder than normal which also increased the demand for natural gas. The amortization period will be from May 2019 through April 2020.

On October 24, 2019, the Washington Commission approved PSE's request for November 2019 PGA rates, with the rate change taking effect on November 1, 2019. As part of that filing, PSE requested PGA rates increase annual revenue by $17.8 million, while the new tracker rates increased by annual revenue of $100.6 million; this was in addition to continuing the collection on the remaining balance of $54.0 million from the out-of-cycle PGA. The tracker rates include deferral balances for the three separate amounts: (i) $114.4 million of under collected commodity balances deferred in February and March; (ii) a $10.8 million balance of over-collected commodity costs for the 2018 PGA, and (iii) a $4.1 million remaining balance from the $54.7 million credit to customers, caused by the 2017 over-collection, established in the 2018 tracker. The high commodity deferral balances for winter months through March 2019 were the result of three noteworthy events last winter experienced by PSE: the Enbridge pipeline rupture, unusually low temperatures in February and March, and a compressor failure in February at the Jackson Prairie storage facility. Additionally, to reduce customer impact, as part of the approved PGA filing, PSE will be collecting $114.4 million commodity deferrals and related interest over a two year period, instead of the historic one year period, from November 2019 through October 2021.

Get to Zero Depreciation Deferral

On April 10, 2019, PSE filed an accounting petition with the Washington Commission, requesting authorization to defer depreciation expense associated with Get To Zero (GTZ) projects that were placed in service after June 30, 2018. The GTZ project consists of a number of short-lived technology upgrades. The depreciation expense associated with the GTZ projects with lives of 10 years or less that were placed in service after June 30, 2018, were deferred beginning May 1 per the petition request. For the year ended December 31, 2019, PSE deferred $21.7 million of depreciation expense for GTZ. In addition to the deferral of depreciation expense, PSE had also requested to defer carrying charges on the GTZ deferral, to be calculated utilizing the Company's currently authorized after tax rate of return, or 6.89% per the 2018 ERF. For the year ended December 31, 2019, PSE deferred $0.5 million of carrying charges on the deferral. The GTZ accounting petition was consolidated with PSE's 2019 GRC and is currently being reviewed by the Washington Commission. If authorized, both the GTZ depreciation and interest on the deferral will be begin amortizing over three years in May 2020

Storm Damage Deferral Accounting

The Washington Commission issued a GRC order that defined deferrable storm events and provided that costs in excess of the annual cost threshold may be deferred for qualifying storm damage costs that meet the modified Institute of Electrical and Electronics Engineers outage criteria for system average interruption duration index. For the year ended December 31, 2019, PSE incurred $39.3 million in storm-related electric transmission and distribution system restoration costs, of which the Company deferred $0.4 million and $28.5 million as regulatory assets related to storms that occurred in 2018 and 2019, respectively. This compares to $25.4 million incurred in storm-related electric transmission and distribution system restoration costs for the year ended December 31, 2018, of which the Company deferred $3.3 million and $11.9 million as regulatory assets related to storms that occurred in 2017 and 2018, respectively. Under the December 5, 2017, Washington Commission order regarding PSE's GRC, the following changes to PSE's storm deferral mechanism were approved: (i) the cumulative annual cost threshold for deferral of storms under the mechanism increased from $8.0 million to $10.0 million effective January 1, 2018; and (ii) qualifying events where the total qualifying cost is less than $0.5 million will not qualify for deferral and these costs will also not count toward the $10.0 million annual cost threshold.

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. In accordance with 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 $41.8 million for natural gas and $8.7 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, 2019, the Company's share of future remediation costs is estimated to be approximately $31.6 million. The Company's deferred electric environmental costs are $13.7 million and $14.1 million at December 31, 2019 and 2018, respectively, net of insurance proceeds. The Company's deferred natural gas environmental costs are $54.8 million and $62.2 million at December 31, 2019 and 2018, respectively, net of insurance proceeds. In the 2017 GRC, the Company had its third party recoveries and remediation costs incurred as of September 30, 2016, net of a portion of insurance, approved for amortization and inclusion in rates, effective December 19, 2017.

Litigation

From time to time, the Company is involved in litigation or legislative rulemaking proceedings relating to its operations in the normal course of business. The following is a description of pending proceedings that are material to PSE's operations:

Colstrip

PSE has a 50% ownership interest in Colstrip Units 1 and 2 and a 25% interest in each of Colstrip Units 3 and 4. In March 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. In July 2016, PSE reached a settlement with the Sierra Club to dismiss all of the Clean Air Act allegations against the Colstrip Generating Station, which was approved by the court in September 2016. As part of the settlement that was signed by all Colstrip owners, Colstrip 1 and 2 owners, PSE and Talen Energy Corporation (Talen), agreed to retire the two oldest units (Units 1 and 2) at Colstrip in eastern Montana no later than July 1, 2022. Depreciation rates were updated in the GRC effective December 19, 2017, where PSE's depreciation increased for Colstrip Units 1 and 2 to recover plant costs to the expected shutdown date. Additionally, PSE has accelerated the depreciation of Colstrip Units 3 and 4, per the terms of the GRC settlement, to December 31, 2027. The GRC also repurposed PTCs and hydro-related treasury grants to recover unrecovered plant costs and to fund and recover decommissioning and remediation costs for Colstrip Units 1 through 4.

Consistent with a June 2019 announcement, Talen permanently shut down Units 1 and 2 at the end of the year due to operational losses associated with the Units. Colstrip Units 1 and 2 were retired effective December 31, 2019. The Washington Clean Energy Transition Act requires the Washington Commission to provide recovery of the investment, decommissioning, and remediation costs associated with the facilities that are not recovered through the repurposed PTC's and hydro-related treasury grants. The full scope of decommissioning activities and costs may vary from the estimates that are available at this time.

On December 10, 2019, PSE announced its intention to sell its interest in Colstrip Unit 4 to NorthWestern Energy for $1. Under this agreement, PSE would retain its obligation to fund 25% of the environmental remediation and decommissioning costs associated with Unit 4 during PSE's operation. The agreement is subject to approval by the Washington Commission and the Montana Public Service Commission. Additionally, PSE has agreed to enter into a power purchase agreement with NorthWestern Energy for 90 MW through 2025 to facilitate the transition, and sell a portion of its dedicated Colstrip transmission system, conditioned upon regulatory approval. PSE expects external parties to intervene on the contingent purchase agreement for Colstrip Unit 4. For accounting purposes, management has evaluated the applicable held for sale criteria as of December 31, 2019, and determined that these criteria were not met. As such, Unit 4 is classified as Electric Utility Plant on the balance sheet, see Note 6, "Utility Plant," to the consolidated financial statements included in Item 8 of this report.

Regional Haze Rule

In January 2017, the EPA published revisions to the Regional Haze Rule. Among other things, these revisions delayed new Regional Haze review from 2018 to 2021, however the end date will remain 2028. In January 2018, the EPA announced that it was reconsidering certain aspects of these revisions and PSE is unable to predict the outcome. Challenges to the 2017 Regional Haze Revision Rule are pending in abeyance in the U.S. Court of Appeals for the D.C. Circuit, pending resolution of the EPA's reconsideration of the rule.

Clean Air Act 111(d)/EPA Affordable clean Energy Rule

In June 2014, the EPA issued a proposed Clean Power Plan (CPP) rule under Section 111(d) of the Clean Air Act designed to regulate GHG emissions from existing power plants. The proposed rule includes state-specific goals and guidelines for states to develop plans for meeting these goals. The EPA published a final rule in October 2015. In March 2017, then EPA Administrator, Scott Pruitt, signed a notice of withdrawal of the proposed CPP federal plan and model trading rules and, in October 2017, the EPA proposed to repeal the CPP rule.

In August 2018, the EPA proposed the Affordable Clean Energy (ACE) rule, pursuant to Section 111(d) of the Clean Air Act.. The ACE rule was finalized in June 2019, and establishes emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired plants. Compliance plans under ACE are due July 2020, and compliance generally required by July 2024. PSE is evaluating the final ACE rule to determine its impact on operations pending the outcome of the proposed Colstrip Unit 4 sale to NorthWestern Energy.

Washington Clean Air Rule

The CAR was adopted in September 2016, in Washington State and attempts to reduce greenhouse gas emissions from "covered entities" located within Washington State. Included under the new rule are large manufacturers, petroleum producers and natural gas utilities, including PSE. The CAR sets a cap on emissions associated with covered entities, which decreases over time approximately 5.0% every three years. Entities must reduce their carbon emissions, or purchase emission reduction units (ERUs), as defined under the rule, from others.

In September 2016, PSE, along with Avista Corporation, Cascade Natural Gas Corporation and NW Natural, filed a lawsuit in the U.S. District Court for the Eastern District of Washington challenging the CAR. In September 2016, the four companies filed a similar challenge to the CAR in Thurston County Superior Court. In March 2018, the Thurston County Superior Court invalidated the CAR. The Department of Ecology appealed the Superior Court decision in May 2018. As a result of the appeal, direct review to the Washington State Supreme Court was granted and oral argument was held on March 16, 2019. In January 2020, the Washington Supreme Court affirmed that CAR is not valid for "indirect emitters" meaning it does not apply to the sale of natural gas for use by customers. The court ruled, however, that the rule can be severed and is valid for direct emitters including electric utilities with permitted air emission sources, but remanded the case back to the Thurston County to determine which parts of the rule survive. Meanwhile, the federal court litigation has been held in abeyance pending resolution of the state case.

10. Related Party Transactions

Tacoma LNG Facility

In August 2015, PSE filed a proposal with the Washington Commission to develop an LNG facility at the Port of Tacoma. Currently under construction at the Port of Tacoma, the facility is expected to be operational in 2021. The Tacoma LNG facility is designed to provide peak-shaving services to PSE's natural gas customers. By storing surplus natural gas, PSE is able to meet the requirements of peak consumption. LNG will also provide fuel to transportation customers, particularly in the marine market. On January 24, 2018, Puget Sound Clean Air Agency (PSCAA) determined a Supplemental Environmental Impact Statement (SEIS) was necessary in order to rule on the air quality permit for the facility. As a result of requiring a SEIS, the Company's construction schedule was impacted. PSE received the SEIS which concluded the LNG facility would result in a net decrease in GHG emissions providing, in part, that the natural gas for the facility was sourced from British Columbia or Alberta. On December 10, 2019, the PSCAA approved the Notice of Construction permit, a decision which has been appealed to the Washington Pollution Control Hearings Board by each of the Puyallup Tribe of Indians and nonprofit law firm Earthjustice.

Pursuant to an order by the Washington Commission, PSE will be allocated approximately 43.0% of common capital and operating costs, consistent with the regulated portion of the Tacoma LNG facility. The remaining 57.0% of common capital and operating costs of the Tacoma LNG facility will be allocated to Puget LNG. Per this allocation of costs, $199.9 million and $165.6 million of construction work in progress related to Puget LNG's portion of the Tacoma LNG facility is reported in the Puget Energy "Other property and investments" financial statement line item as of December 31, 2019, and December 31, 2018, respectively. Additionally, $1.2 million, $2.0 million, and $0.3 million of operating costs are reported in the Puget Energy "Non-utility expense and other" financial statement line item in 2019, 2018, and 2017, respectively. Additionally, $162.8 million and $130.8 million of construction work in progress related to PSE's portion of the Tacoma LNG facility is reported in the PSE "Utility plant - Natural gas plant" financial statement line item as of December 31, 2019, and December 31, 2018, respectively, as PSE is a regulated entity.

11. Reserved.

12. None.

13.

<u>Changes of Ownership</u>:

In April, 2019, funds managed by Macquarie Infrastructure Partners Inc. completed the sale of a 43.99% ownership stake in

Washington state utility Puget Sound Energy Inc. to a group of investors.
Under the transaction, the two existing investors Alberta Investment Management Corp. and British Columbia Investment Management Corp. increased their interests in Puget Holdings LLC (which is the parent company of Puget Sound Energy) to 13.6% and 20.9%, respectively. OMERS Infrastructure Management Inc., which invests on behalf the pension fund for the province of Ontario's municipal employees, acquired a 23.9% stake and Dutch pension fund Pggm Coöperatie U.A. bought a 10% stake. The Canada Pension Plan Investment Board retained its 31.6% interest, becoming Puget Sound Energy's largest single stakeholder.

Washington state utilities regulators approved the deal in March 2019. The Federal Energy Regulatory Commission approved the sale in November 2018.

The parties closed the transaction on April 17. (FERC docket EC18-152, UTC docket U-180680).

<u>Changes of Directors or Certain Officers:</u>

Effective April 17, 2019, the sole shareholders of Puget Energy, Inc. and Puget Sound Energy, Inc. (together, the “Companies”) appointed and elected Stephen Zucchet, Kenton Bradbury, Richard Dinneny and Martijn Verwoest to the Boards of Directors of the Companies (the “Boards”). Andrew Chapman, Karl Kuchel and Christopher Leslie, who served as representatives of the Companies’ Macquarie affiliated investors on the Boards, resigned from the Boards effective the same day.

Mr. Zucchet is a managing director at Ontario Municipal Employees Retirement System Infrastructure Management (“OMERS”) and is also currently a board member of Oncor and Bruce Power Inc and previously served as chief operating officer at Enwave Energy. Mr. Bradbury is a managing director at OMERS and is currently responsible for OMERS investments with a focus on the Americas. Prior to joining OMERS in 2015, Mr. Bradbury served as a director at Infracapital, the infrastructure investment arm of M&G Investments, and was senior vice president of Infrastructure and Regulation at e.on in Germany. Messrs. Zucchet and Bradbury were selected by OMERS and pursuant to the Amended and Restated Bylaws of each of the Companies, will serve as Owner Directors on their respective Boards of Directors. Messrs. Zucchet and Bradbury will not receive any director compensation from the Companies for their services as Owner Directors on the Boards, but will be reimbursed for out-of-pocket expenses. Any compensation received by Messrs. Zucchet and Bradbury for their services on the Companies’ Boards is a function of their respective employment arrangement with OMERS.

Mr. Dinneny is the Senior Portfolio Manager, Infrastructure and Renewable Resources for British Columbia Investment Management Corporation (“bcIMC”), where he has responsibility for all aspects of investing in infrastructure transactions. He is a member of the board of managers of Cleco Group LLC, Cleco Corporate Holdings LLC, and Cleco Power LLC, and is a director of Vier Gas Services GmbH & Co. KG, Essen, the owner of Open Grid Europe, Germany’s leading natural gas transport company. Mr. Dinneny was selected by bcIMC and pursuant to the Amended and Restated Bylaws of each of the Companies, will serve as Owner Directors on their respective Boards of Directors. Mr. Dinneny will not receive any director compensation from the Companies for his services as an Owner Director on the Boards, but will be reimbursed for out-of-pocket expenses. Any compensation received by Mr. Dinneny for his services on the Companies’ Boards is a function of his employment arrangement with bcIMC.

Mr. Verwoest is a Senior Director for global energy and utilities investments within the infrastructure team at Stichting Pensioenfonds Zorg en Welzijn (“PGGM”), and is a member of their Infrastructure Investment Committee. Prior to this role, he worked on investments across the broader infrastructure spectrum, including regulated utilities, midstream, conventional and renewable generation, toll roads and public-private partnership. He joined the infrastructure team in 2007, helping to develop their investment strategy and build their in-house direct investing capabilities. From 2001 to 2007, he worked in PGGM’s public equity department. Mr. Verwoest was selected by PGGM and pursuant to the Amended and Restated Bylaws of each of the Companies, will serve as Owner Directors on their respective Boards of Directors. Mr. Verwoest will not receive any director compensation from the Companies for his services as an Owner Director on the Boards, but will be reimbursed for out-of-pocket expenses. Any compensation received by Mr. Verwoest for his services on the Companies’ Boards is a function of his employment arrangement with PGGM.

As part of its ongoing succession planning efforts, on July 1, 2019, Puget Sound Energy, Inc. and Puget Energy, Inc. (together, the “Companies”) announced that Mary E. Kipp has been appointed to serve as President of the Company. Ms. Kipp will report to Kimberly J. Harris, the Company’s Chief Executive Officer, who voluntarily resigned her position as President. It is anticipated that

Ms. Kipp will begin her service on August 30, 2019.

In addition, it is anticipated that Ms. Kipp will assume the additional role of Chief Executive Officer of the Companies upon Ms. Harris' expected retirement in January 2020.

Prior to her appointment as President, Ms. Kipp, 51, served as the President, Chief Executive Officer and director of El Paso Electric Company ("El Paso") since May 2017. Prior to that, she served as Chief Executive Officer and director of El Paso from December 2015 to May 2017, President of El Paso from 2014 to 2015, Senior Vice President, General Counsel and Chief Compliance Officer of El Paso from 2010 to 2014, Vice President – Legal and Chief Compliance Officer from 2009 to 2010, and Assistant General Counsel and Director of FERC Compliance for El Paso from 2007 to 2009. Prior to joining El Paso, Ms. Kipp served as a senior attorney in the Federal Energy Regulatory Commission's Office of Enforcement in Washington D.C.

Effective July 1, 2019, the sole shareholders of Puget Energy, Inc. and Puget Sound Energy, Inc. (together, the "Companies") appointed and elected Thomas King to the Boards of Directors of the Companies (the "Boards"). The Boards have not yet determined the board committee or committees, if any, on which Mr. King will serve.

Mr. King currently serves as Operating Executive of AEA Investors LP ("AEA"), a private equity firm, which position he has held since 2017. Prior to joining AEA in 2017, Mr. King served as Senior Advisor to IFM Investors, an investor-owned fund manager, from 2015 to 2019, as an Operating Executive at Palladium Equity Partners from 2015 to 2017, and was Chairman and President of National Grid Corporation from 2007 to 2015. Mr. King also serves as the Executive Chairman of Entregado Group, a holding company of electric utility service providers, as a director of Peak Reliability and was previously on the Board of Directors of EnergySavvy Inc.

Mr. King was selected by CPP Investment Board (USRE II) Inc. ("CPPIB") and pursuant to the Amended and Restated Bylaws of each of the Companies, will serve as an Owner Director on their respective Boards.

14. None.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	15,854,140,158	15,375,856,926
3	Construction Work in Progress (107)	200-201	591,198,562	550,466,420
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		16,445,338,720	15,926,323,346
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	6,192,635,006	6,013,978,491
6	Net Utility Plant (Enter Total of line 4 less 5)		10,252,703,714	9,912,344,855
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)		10,252,703,714	9,912,344,855
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)		2,983,185	3,200,905
19	(Less) Accum. Prov. for Depr. and Amort. (122)		20,713	20,713
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	26,955,155	24,740,583
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)		51,453,007	49,502,086
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		20,188,091	20,175,526
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		7,681,161	2,512,359
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		109,239,886	100,110,746
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		43,543,104	34,727,116
36	Special Deposits (132-134)		17,175,665	14,058,058
37	Working Fund (135)		3,712,154	3,991,806
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		91,410	546,625
40	Customer Accounts Receivable (142)		220,795,792	187,008,727
41	Other Accounts Receivable (143)		90,809,156	140,877,616
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		8,293,320	8,408,670
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		3,805,084	8,535,302
45	Fuel Stock (151)	227	15,762,779	19,826,388
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	115,555,118	116,613,588
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	32,795	277,440
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	335,928	22,556

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	-208,479	-456,332
55	Gas Stored Underground - Current (164.1)		34,945,592	31,860,027
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		76,243	65,133
57	Prepayments (165)		40,207,822	35,275,821
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)		224,656,494	205,285,105
62	Miscellaneous Current and Accrued Assets (174)		1,306,156	0
63	Derivative Instrument Assets (175)		31,307,186	49,019,225
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		7,681,161	2,512,359
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)		827,935,518	836,613,172
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		26,542,709	26,727,401
70	Extraordinary Property Losses (182.1)	230a	121,893,612	118,330,539
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	44,325,180	0
72	Other Regulatory Assets (182.3)	232	412,199,577	444,071,714
73	Prelim. Survey and Investigation Charges (Electric) (183)		52,940	21,333
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)		70,201	190,335
78	Miscellaneous Deferred Debits (186)	233	205,430,089	187,854,739
79	Def. Losses from Disposition of Utility Plt. (187)		86,136	168,103
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		40,177,287	42,377,721
82	Accumulated Deferred Income Taxes (190)	234	1,196,021,909	1,276,161,014
83	Unrecovered Purchased Gas Costs (191)		132,766,288	9,921,988
84	Total Deferred Debits (lines 69 through 83)		2,179,565,928	2,105,824,887
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		13,378,099,610	12,963,548,224

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	end of 2019/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	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	3,014,096,691	2,804,096,691
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	771,480,383	642,598,308
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-20,292,289	-19,756,868
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)	-188,476,903	-190,884,863
16	Total Proprietary Capital (lines 2 through 15)		4,048,678,291	3,707,923,677
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	4,373,860,000	3,923,860,000
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)		13,364,139	6,849,516
24	Total Long-Term Debt (lines 18 through 23)		4,360,495,861	3,917,010,484
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		175,138,666	789,154
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		1,561,500	-225,000
29	Accumulated Provision for Pensions and Benefits (228.3)		93,392,467	101,089,892
30	Accumulated Miscellaneous Operating Provisions (228.4)		116,685,343	140,915,093
31	Accumulated Provision for Rate Refunds (229)		0	34,578,500
32	Long-Term Portion of Derivative Instrument Liabilities		12,692,651	11,094,245
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		177,019,252	180,489,049
35	Total Other Noncurrent Liabilities (lines 26 through 34)		576,489,879	468,730,933
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		176,000,000	379,297,000
38	Accounts Payable (232)		361,508,286	506,308,451
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		422,022	183,621
41	Customer Deposits (235)		32,362,304	42,029,654
42	Taxes Accrued (236)	262-263	99,611,547	116,841,727
43	Interest Accrued (237)		48,918,273	43,950,570
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		2,389,097	7,377,211
48	Miscellaneous Current and Accrued Liabilities (242)		41,570,159	24,929,141
49	Obligations Under Capital Leases-Current (243)		16,531,463	525,359
50	Derivative Instrument Liabilities (244)		26,121,263	57,755,823
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		12,692,651	11,094,245
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		792,741,763	1,168,104,312
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		95,530,623	93,054,782
57	Accumulated Deferred Investment Tax Credits (255)	266-267	0	0
58	Deferred Gains from Disposition of Utility Plant (256)		1,412,065	1,674,794
59	Other Deferred Credits (253)	269	255,311,849	313,584,370
60	Other Regulatory Liabilities (254)	278	1,071,933,845	1,088,713,709
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)		1,943,729,915	1,998,720,901
64	Accum. Deferred Income Taxes-Other (283)		231,775,519	206,030,262
65	Total Deferred Credits (lines 56 through 64)		3,599,693,816	3,701,778,818
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		13,378,099,610	12,963,548,224

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	3,391,632,576	3,293,830,865		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,751,167,612	1,664,295,805		
5	Maintenance Expenses (402)	320-323	168,501,630	173,363,458		
6	Depreciation Expense (403)	336-337	470,613,251	450,723,964		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	7,703,704	7,859,026		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	121,035,219	86,037,315		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	11,737,268	11,656,401		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		31,893,438	35,645,161		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		17,366,545	21,433,427		
13	(Less) Regulatory Credits (407.4)		75,940,513	33,645,163		
14	Taxes Other Than Income Taxes (408.1)	262-263	331,568,910	335,917,730		
15	Income Taxes - Federal (409.1)	262-263	64,226,432	54,348,132		
16	- Other (409.1)	262-263	570,874	437,582		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	262,037,296	223,098,926		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	239,898,093	193,749,349		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)		729,404	729,404		
21	Losses from Disp. of Utility Plant (411.7)		81,967	81,967		
22	(Less) Gains from Disposition of Allowances (411.8)		981	4,419		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		3,837,179	3,716,812		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,925,772,334	2,840,487,371		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		465,860,242	453,343,494		

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
2,516,261,884	2,443,083,188	875,370,692	850,747,677			2
						3
1,313,659,877	1,218,665,540	437,507,735	445,630,265			4
141,849,803	146,329,474	26,651,827	27,033,984			5
345,727,153	333,758,359	124,886,098	116,965,605			6
7,533,981	7,708,442	169,723	150,584			7
83,314,999	59,676,651	37,720,220	26,360,664			8
11,737,268	11,656,401					9
31,893,438	35,645,161					10
						11
8,763,271	12,780,372	8,603,274	8,653,055			12
64,670,416	33,645,163	11,270,097				13
232,335,156	234,352,537	99,233,754	101,565,193			14
30,838,206	22,590,030	33,388,226	31,758,102			15
570,874	251,525		186,057			16
219,283,109	177,018,210	42,754,187	46,080,716			17
190,762,694	138,110,502	49,135,399	55,638,847			18
						19
755,389	755,389	-25,985	-25,985			20
-8,354	-8,354	90,321	90,321			21
981	4,419					22
						23
3,611,963	3,557,679	225,216	159,133			24
2,174,921,264	2,091,466,554	750,851,070	749,020,817			25
341,340,620	351,616,634	124,519,622	101,726,860			26

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Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		465,860,242	453,343,494		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,149,128	501,689		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		379,840	363,014		
33	Revenues From Nonutility Operations (417)		27,564,187	39,203,175		
34	(Less) Expenses of Nonutility Operations (417.1)		40,474,706	44,832,238		
35	Nonoperating Rental Income (418)		47,472	41,250		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-535,421	-541,432		
37	Interest and Dividend Income (419)		11,431,257	6,407,864		
38	Allowance for Other Funds Used During Construction (419.1)		15,801,744	17,190,558		
39	Miscellaneous Nonoperating Income (421)		-668,191	27,336,459		
40	Gain on Disposition of Property (421.1)		63,751	67,090		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		13,999,381	45,011,401		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		60,141	61,557		
46	Life Insurance (426.2)		-1,698,847	-1,763,633		
47	Penalties (426.3)		907,062	447,169		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		5,829,260	6,511,722		
49	Other Deductions (426.5)		-374,787	-9,128,046		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		4,722,829	-3,871,231		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	641,738	434,470		
53	Income Taxes-Federal (409.2)	262-263	-46,133,494	-35,064,733		
54	Income Taxes-Other (409.2)	262-263				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-1,512,293	1,773,037		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277				
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)		-47,004,049	-32,857,226		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		56,280,601	81,739,858		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		217,516,084	209,707,869		
63	Amort. of Debt Disc. and Expense (428)		2,314,664	2,183,068		
64	Amortization of Loss on Reaquired Debt (428.1)		2,200,434	2,244,801		
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)					
68	Other Interest Expense (431)		21,746,828	17,479,096		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		14,558,843	13,695,291		
70	Net Interest Charges (Total of lines 62 thru 69)		229,219,167	217,919,543		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		292,921,676	317,163,809		
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)		292,921,676	317,163,809		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		613,815,928	448,721,521
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Stranded taxes to RE due to tax reform			27,333,181
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			27,333,181
10	License Hydro Project Excess Earnings		-1,436,618	(6,228,008)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-1,436,618	(6,228,008)
16	Balance Transferred from Income (Account 433 less Account 418.1)		293,457,097	317,705,240
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	Dividends Declared			
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Dividends Declared		-164,575,021	(173,716,006)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-164,575,021	(173,716,006)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		741,261,386	613,815,928
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

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)		30,218,997	28,782,380
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		30,218,997	28,782,380
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		771,480,383	642,598,308
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-19,756,868	(19,215,435)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-535,421	(541,433)
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		-20,292,289	(19,756,868)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	292,921,676	317,163,809
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	545,619,345	535,046,680
5	Amortization of		
6	Utility Plant Adjustments	11,737,268	11,656,401
7	Property Losses	31,893,438	35,645,161
8	Deferred Income Taxes (Net)	20,607,295	31,142,231
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	794,067	15,941,390
11	Net (Increase) Decrease in Inventory	-4,805,124	-12,620,970
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-130,816,693	108,982,873
14	Net (Increase) Decrease in Other Regulatory Assets	-227,270,664	-117,733,917
15	Net Increase (Decrease) in Other Regulatory Liabilities	27,958,487	-10,070,155
16	(Less) Allowance for Other Funds Used During Construction	15,801,744	17,190,558
17	(Less) Undistributed Earnings from Subsidiary Companies	-535,421	458,568
18	Other (provide details in footnote):	71,157,764	98,672,790
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	624,530,536	996,177,167
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-935,070,312	-1,027,696,687
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	-15,801,744	-17,190,558
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-919,268,568	-1,010,506,129
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	13,301,696	156,046
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-2,750,000	
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):	-4,000,050	1,941,409
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-912,716,922	-1,008,408,674
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	443,151,000	594,750,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		49,834,000
67	Other (provide details in footnote):	14,561,350	9,107,370
68	Investment from Parent Company	210,000,000	
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	667,712,350	653,691,370
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		-450,000,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77			
78	Net Decrease in Short-Term Debt (c)	-203,297,000	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-164,575,021	-173,716,006
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	299,840,329	29,975,364
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	11,653,943	17,743,857
87			
88	Cash and Cash Equivalents at Beginning of Period	52,776,980	35,033,123
89			
90	Cash and Cash Equivalents at End of period	64,430,923	52,776,980

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

Other components of operating cash flows	**Q4 2019**	**Q4 2018**
Other Long-Term Assets	(14,678,515)	(3,537,618)
Other Long-Term Liabilities	22,019,783	54,210,428
Conservation Amortization	96,570,844	111,713,736
Pension Funding	(18,000,000)	(18,000,000)
Net Unrealized (Gain) Loss on Derivative Transactions	3,574,274	(41,661,501)
Amortization of TCJA Over Collection	(19,697,351)	-
Prepayment and Other	1,368,729	(4,052,255)
Total	71,157,764	98,672,790

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Other components of investing cash flows	**Q4 2019**	**Q4 2018**
Life Insurance Premiums	-	1,955,409
Renewable energy credits	-	(14,000)
Future BPA transmission rights	(4,000,050)	-
Total	(4,000,050)	1,941,409

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

Other components of financing cash flows	**Q4 2019**	**Q4 2018**
Debt issue (redemption costs) costs	(1,187,773)	(6,389,086)
Refundable cash received for customer construction projects	16,311,015	16,137,161
Lease Financing Activity	(561,893)	(640,705)
Total	14,561,349	9,107,370

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, 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 approximately 6,000 square miles, primarily in the Puget Sound region.

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 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.

Other Property and Investments

The costs of other property and investments (i.e., non-utility) 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. Replacements 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

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 annual depreciation provision stated as a percent of a depreciable electric utility plant was 3.4% and 3.3% in 2019 and 2018, respectively; depreciable natural gas utility plant was 2.8% in both 2019 and 2018; and depreciable common utility plant was 7.3% and 7.1% in 2019 and 2018, respectively. The cost of removal is collected from PSE's customers through depreciation expense and any excess is recorded as a regulatory liability.

Tacoma LNG Facility

In August 2015, PSE filed a proposal with the Washington Commission to develop an LNG facility at the Port of Tacoma. Currently under construction at the Port of Tacoma, the facility is expected to be operational in 2021. The Tacoma LNG facility is designed to provide peak-shaving services to PSE's natural gas customers. By storing surplus natural gas, PSE is able to meet the requirements of peak consumption. LNG will also provide fuel to transportation customers, particularly in the marine market. On January 24, 2018, Puget Sound Clean Air Agency (PSCAA) determined a Supplemental Environmental Impact Statement (SEIS) was necessary in order to rule on the air quality permit for the facility. As a result of requiring a SEIS, the Company's construction schedule was impacted. PSE received the SEIS which concluded the LNG facility would result in a net decrease in GHG emissions providing, in part, that the natural gas for the facility was sourced from British Columbia or Alberta. On December 10, 2019, the PSCAA approved the Notice of Construction permit, a decision which has been appealed to the Washington Pollution Control Hearings Board by each of the Puyallup Tribe of Indians and nonprofit law firm Earthjustice.

Pursuant to an order by the Washington Commission, PSE will be allocated approximately 43.0% of common capital and operating costs, consistent with the regulated portion of the Tacoma LNG facility. For PSE, construction work in progress of $162.8 million and $130.8 million related to PSE's portion of the Tacoma LNG facility is reported in the "Utility plant - Natural gas plant" financial statement line item as of December 31, 2019, and December 31, 2018, respectively, as PSE is a regulated entity.

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 carrying amounts of cash and cash equivalents are reported at cost and approximate fair value, due to the short-term maturity.

Restricted Cash

Restricted cash amounts are primarily represent cash posted as collateral for derivative contracts as well as funds required to be set aside for contractual obligations related to transmission and generation facilities.

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. The Company 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 LNG held in storage for future sales. The Company records these items at the lower of cost or net realizable value 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 or losses 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. 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 when amortization periods extend longer than one year. For further details regarding regulatory assets and liabilities, see Note 3, "Regulation and Rates".

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; the AFUDC debt portion is credited to interest expense, while the AFUDC equity portion is credited to other income. Cash inflow related to AFUDC does not occur until these charges are reflected in rates. The current AFUDC rate authorized by the Washington Commission for natural gas and electric utility plant additions through December 18, 2017, was 7.77%. Effective December 19, 2017, with the Washington Commission order, the new AFUDC rate authorized is 7.60%.

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 Federal Energy Regulatory Commission (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. Revenue from retail sales is billed based on tariff rates approved by the Washington Commission. 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 tariff rate schedule to estimate the unbilled revenues by customer.

PSE collected Washington State excise taxes (which are a component of general retail customer rates) and municipal taxes totaling $236.5 million and $239.3 million for 2019 and 2018, respectively. The Company 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.

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 and gross margin erosion due to weather and 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. Revenue is recognized under this program when deemed collectible 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. On December 5, 2017, the Washington Commission approved PSE’s request within the 2017 general rate case (GRC) to extend the decoupling mechanism with some changes to the methodology that took effect on December 19, 2017. The rate test which limits the amount of revenues PSE can collect in its annual filings increased from 3.0% to 5.0% for natural gas customers but will remain at 3.0% for electric customers. The Company will not record any decoupling revenue that is expected to take longer than 24 months to collect following the end of the annual period in which the revenues would have otherwise been recognized. Once determined to be collectible within 24 months, any previously non-recognized amounts will be recognized. 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 balance for allowance for doubtful accounts at December 31, 2019, and 2018, was $8.3 million and $8.4 million, respectively.

Self-Insurance

PSE is self-insured for storm damage and certain environmental contamination associated with current operations 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. Under the December 5, 2017, Washington Commission order regarding PSE's GRC, the cumulative annual cost threshold for deferral of storms under the mechanism increased from $8.0 million to $10.0 million effective January 1, 2018. 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.

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.

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 electric operating revenue and are included in the PCA mechanism.

Accounting for Derivatives

ASC 815, "Derivatives and Hedging" (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 natural gas related derivatives due to the PGA mechanism. 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 and presented net of long-term liabilities on the balance sheet.

Leases

PSE determines if an arrangement is, or contains, a lease at inception of the contract. If the arrangement is, or contains a lease, PSE assesses whether the lease is operating or financing for income statement and balance sheet classification. Operating and Finance leases are included in utility plant, other current liabilities, and other deferred credits in our consolidated balance sheets.

ROU assets represent the right to use an underlying asset for the lease term, and consist of the amount of the initial measurement of the lease liability, any lease payments made to the lessor at or before the commencement date, minus any lease incentives received, and any initial direct costs incurred by the lessee. Lease liabilities represent our obligation to make lease payments arising from the lease and are measured at present value of the lease payments not yet paid, discounted using the discount rate for the lease at commencement. As most of PSE's leases do not provide an implicit interest rate, PSE uses the incremental borrowing rate based on the information available at commencement date in determining the present value of lease payments. For fleet, IT and wind farm leases, this rate is applied using a portfolio approach. The lease terms may include options to extend or terminate the lease when it is reasonably certain that PSE will exercise that option. On the statement of income, operating leases are generally accounted for under a straight-line expense model, while finance leases, which were previously referred to as capital leases, are generally accounted for under a financing model. Consistent with the previous lease guidance, however, the standard allows rate-regulated utilities to recognize expense consistent with the timing of recovery in rates.

PSE has lease agreements with lease and non-lease components. Non-lease components comprise common area maintenance and utilities, and are accounted for separately from lease components.

Subsequent Events

On January 21, 2020, the first Coronavirus case in the United States was confirmed in Washington State, followed by the first virus-related death on February 29, 2020, also in Washington in the Company's service territory. On March 3, 2020, the Mayor of Seattle declared a state of emergency in response to the Coronavirus outbreak and increasing death toll. Local companies, PSE included, instructed employees to work remotely if at all possible. Governor Jay Inslee subsequently banned gatherings of more than 50 people in multiple counties, required all restaurants and bars be closed except for take-out and deliveries, and cancelled all schools through April 24, 2020. President Trump declared a national emergency on March 13, 2020, as a result of the outbreak. On March 23, 2020, Governor Jay Inslee issued a Stay at Home – Stay Healthy Order throughout Washington State by prohibiting all people in Washington State from leaving their homes or participating in social, spiritual and recreational gatherings of any kind regardless of the number of participants, and all non-essential businesses in Washington State from conducting business. On April 6, 2020, Governor Jay Inslee ordered all Washington schools closed for the school year. The situation continues to be dynamic, with potential increases and extensions to these restrictions anticipated.

The Company responded to the extraordinary event, implementing a number of changes intended to protect customers, employees, and the communities in our service territory. These include not disconnecting customers for non-payment, receiving Commission approval to waive late fees, and filing a motion with the Commission to waive the statutory deadline for the Company's General Rate Case for up to 60 days, from May 20, 2020, until July 20, 2020. This is expected to impact financial results for the Company in 2020, but does not impact any balances or estimates in the 2019 Financial Statements. The extent of the 2020 impact is not currently known nor estimable.

The Company evaluates events or transactions that occur after the balance sheet date but before the financial statements are issued for potential recognition or disclosures in the financial statements. The Company has evaluated subsequent events through the date the financial statements were filed with the FERC, and no additional disclosures are required.

(2) New Accounting Pronouncements

Recently Adopted Accounting Guidance

Lease Accounting

In February 2016, the FASB issued ASU 2016-02, *"Leases (Topic 842)"*. The FASB issued this ASU to increase transparency and comparability among organizations by recognizing right-of-use lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. To meet that objective, the FASB amended the FASB ASC and created Topic 842, Leases. ASU 2016-02 requires lessees to recognize the following for all leases (with the exception of short-term leases) at the commencement date: (i) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (ii) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. The income statement recognition is similar to existing lease accounting and is based on lease classification. Under the new guidance, lessor accounting is largely unchanged.

In January 2018, the FASB issued ASU 2018-01, *"Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842"*. In connection with the FASB's transition support efforts, the amendments in this update provide an optional transition practical expedient to not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current guidance in Topic 840. An entity that elects this practical expedient should evaluate new or modified land easements under Topic 842 upon adoption. Land easements (also commonly referred to as rights of way) represent the right to use, access, or cross another entity's land for a specified purpose. The Company elected this practical expedient.

In July 2018, the FASB issued both ASU 2018-10 and ASU 2018-11, *"Leases (Topic 842): Codification Improvements"* and *"Leases (Topic 842): Targeted Improvements"*. These ASUs provide entities with both clarification on existing guidance issued in ASU 2016-02, as well as an additional transition method to adopt the new leasing standard. Under the new transition method, the entity initially applies the new standard at the adoption date by recognizing a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. Consequently, an entity's reporting for the comparative periods presented in the financial statements will continue to be in accordance with Topic 840. The Company has elected to adopt the standard using this new modified transition method.

In preparation for adoption of the standard, the Company assembled a project team that met bi-weekly to make key accounting assessments and perform pre-implementation controls related to the scoping and completeness of existing leases. Additionally, the Company implemented a new leasing system and drafted accounting policies including discount rate, variable pricing, power purchase agreements, and election of practical expedients. In addition to the land easement practical expedient, the Company has elected the practical expedient package.

These amendments are effective for financial statements issued for fiscal years beginning after December 15, 2018, including interim periods within those fiscal years. The Company has adopted ASU 2016-02 as of January 1, 2019, which resulted in the recognition of right-of-use asset and lease liabilities that have not previously been recorded and are material to the balance sheet. Under FERC Docket AI-19-1-000, operating leases are not required to be capitalized and reported in the balance sheet accounts established for capital leases. However, a jurisdictional entity is permitted to implement the ASU's guidance to report operating leases with a lease term in excess of 12 months as right of use assets, with corresponding lease obligations, in the balance sheet accounts established for capital leases. Accordingly the Company's operating leases are recognized on the balance sheet in Account 101.1 (Property Under Capital Leases), Account 227 (Obligations Under Capital Leases- Noncurrent), and Account 243 (Obligations Under Capital Leases — Current). Adoption of the standard did not have a material impact on the income statement. The financial impact as of the date of adoption was not materially different than what has been disclosed as of December 31, 2019, in Note 8, "Leases".

Internal-Use Software

In August 2018, the FASB issued ASU 2018-15, *"Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract"*. These amendments align the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software (and hosting arrangements that include an internal-use software license). The accounting for the service element of a hosting arrangement that is a service contract is not affected by these amendments. While the standard requires that the capitalized implementation costs be reported on the balance sheet in the same manner as a prepayment and the related amortization expense in the same expense line item on the income statement as the expense for the associated cloud computing arrangement, the Company capitalizes implementation costs associated with cloud computing arrangements as a utility plant asset and amortizes the costs in a consistent manner in accordance with FERC Docket Number AI90-1-000.

The amendments in this update are effective for public business entities for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years. Early adoption of the amendments in this update is permitted, including adoption in any interim period, for all entities. The amendments in this update should be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. The Company adopted this update prospectively in 2019 for implementation costs incurred in hosting arrangements and application of the amendment did not have a material impact on the consolidated financial statements.

Accounting Standards Issued but Not Yet Adopted

Credit Losses

In June 2016, the FASB issued ASU 2016-13, "*Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments"*. The amendments in the update change how entities account for credit losses on receivables and certain other assets. The guidance requires use of a current expected loss model, which may result in earlier recognition of credit losses than under previous accounting standards. ASU 2016-13 is effective for interim and annual periods beginning on or after December 15, 2019. The Company has analyzed its financial instruments within the scope of the guidance and does not expect a material impact to the consolidated financial statements..

Fair Value Measurement

In August 2018, the FASB issued ASU 2018-13, *"Fair Value Measurement (Topic 820): Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement"*. The guidance in ASU No. 2018-13 eliminates such disclosures as the amount of and reasons for transfers between Level 1 and Level 2 of the fair value hierarchy. The amendments in ASU No. 2018-13 add new disclosure requirements for Level 3 measurements. ASU No. 2018-13 is effective for fiscal years beginning after December 15, 2019, and interim periods within those fiscal years, with early adoption permitted for any eliminated or modified disclosures. Certain disclosures in ASU No. 2018-13 are required to be applied on a retrospective basis and others on a prospective basis. As the amendment contemplates changes in disclosures only, it will have no material impact on the Company's results of operations, cash flows, or consolidated balance sheet.

(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.

The net regulatory assets and liabilities at December 31, 2019, and 2018, included the following:

Puget Sound Energy	Remaining Amortization Period	December 31,	
(Dollars in Thousands)		2019	2018
Storm damage costs electric	1 to 4 years	$ 121,894	$ 118,331
Chelan PUD contract initiation	11.8 years	83,875	90,964
Environmental remediation	(a)	68,486	76,345
Lower Snake River	17.4 years	62,899	67,021
Decoupling deferrals and interest	Less than 2 years	43,509	65,779
Baker Dam licensing operating and maintenance costs	N/A	56,427	55,607
Deferred Washington Commission AFUDC	30 years	57,553	52,029
Property tax tracker	Less than 2 years	22,442	45,621
Unamortized loss on reacquired debt	2 to 48 years	40,177	42,378
Energy conservation costs	(a)	25,272	30,701
Get to zero depreciation expense deferral	N/A	22,148	—
Advanced metering infrastructure	(a)	14,845	—
Generation plant major maintenance, excluding Colstrip	3 to 10 years	12,744	15,027
PGA deferral of unrealized losses on derivative instruments	N/A	—	14,739
White River relicensing and other costs	1 year	6,399	12,966
Mint Farm ownership and operating costs	5.3 years	10,318	12,319
PGA receivable	2 years	132,766	9,922
Snoqualmie licensing operating and maintenance costs	N/A	7,442	7,407
Colstrip major maintenance	0.0 years	2,929	6,841
PCA mechanism	N/A	41,745	4,735
Colstrip common property	4.4 years	3,188	3,903
Ferndale	0.0 years	—	3,316
Various other regulatory assets	(a)	10,474	14,583
Total PSE regulatory assets		$ 847,532	$ 750,534
Deferred income taxes (d)	N/A	(946,936)	(976,582)
Cost of removal	(b)	(469,922)	(424,727)
Treasury grants	18 years	(101,981)	(168,884)
Production tax credits	(c)	(85,323)	(93,616)
Gain on Sale Shuffleton	N/A	(12,483)	—

Microsoft special contract regulatory liability	N/A	(12,661)	—
Repurposed production tax credits	N/A	(23,171)	—
Accumulated provision for rate refunds	N/A	—	(34,579)
Total decoupling liability	Less than 2 years	(8,500)	(13,758)
Various other regulatory liabilities	(a)	(15,573)	(10,316)
Total PSE regulatory liabilities		(1,676,550)	(1,722,462)
PSE net regulatory assets (liabilities)		$ (829,018)	$ (971,928)

(a) Amortization periods vary depending on timing of underlying transactions.

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

Amortize as PTCs are utilized by PSE on its tax return.

For additional information, see Note 13,"Income Taxes".

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 $469.9 million and $424.7 million in 2019 and 2018, respectively, for the cost of removal of utility plant. These amounts are collected from PSE's customers through depreciation rates.

General Rate Case Filing

PSE filed a GRC with the Washington Commission on June 20, 2019, requesting an overall increase in electric and natural gas rates of 6.9% and 7.9% respectively. PSE requested a return on equity of 9.8% with an overall rate of return of 7.62%. In addition to the traditional areas of focus (revenue requirements, cost allocation, rate design and cost of capital), the Company completed an attrition study and included a portion of the attrition revenue requirement in the overall request in order address the expected regulatory lag in the rate year. Additionally, as the non-plant related excess deferred taxes that resulted from the Tax Cuts and Jobs Act (TCJA) remained outstanding from PSE's Expedited Rate Filing (ERF) as discussed below, PSE requested in its GRC to pass back the amounts over four years. On September 17, 2019, PSE filed a supplemental filing in the GRC, which provided updates as discussed in our original filing, but did not impact the requested overall electric and natural gas rate increases, return on equity or overall rate of return as originally filed. On January 15, 2020, PSE filed rebuttal testimony which included a reduction to the requested return on equity to 9.5%, which decreased the rate of return to 7.48%. The requested rate increase for both electric and natural gas remained at 6.9% and 7.9%, respectively. For both electric and natural gas PSE did not originally request its full attrition adjustment; therefore, the decrease in return on equity led to a reduction in the electric rate increase of only $1.5 million and did not have an impact on the natural gas rate increase.

In January 2017, PSE filed its GRC with the Washington Commission. The GRC filing included a required plan to address Colstrip Units 1 and 2 closures, requested that electric energy supply fixed costs be included in PSE's decoupling mechanism, and contained requests for two new mechanisms to address regulatory lag. The Washington Commission entered a final order accepting the multi-party settlement agreement and determined the contested issues in the case on December 5, 2017, and new rates became effective December 19, 2017. The settlement agreement provided for a weighted cost of capital of 7.6%, or 6.55% after-tax, and a capital structure of 48.5% in common equity with a return on equity of 9.5%. The settlement also resulted in a combined electric tariff change that resulted in a net increase of $20.2 million, or 0.9%, annually, and a combined natural gas tariff change that resulted in a net decrease of $35.5 million, or 3.8%, annually.

The 2017 GRC also re-purposed the benefit of hydro-related treasury grants to fund and recover decommissioning and remediation costs for Colstrip Units 1 and 2.

The Company responded to the COVID-19 situation, in part, by implementing a number of changes intended to protect customers, employees, and the communities in our service territory. These include not disconnecting customers for non-payment, receiving Commission approval to waive late fees, and filing a motion with the Commission to waive the statutory deadline for the Company's General Rate Case for up to 60 days, from May 20, 2020, until July 20, 2020. This is expected to impact financial results for the Company in 2020, but does not impact any balances or estimates in the 2019 Financial Statements. The extent of the 2020 impact is not currently known nor estimable.

Expedited Rate Filing Rate Adjustment

On November 7, 2018, PSE filed an expedited rate filing (ERF) with the Washington Commission. The filing requested to change rates associated with PSE's delivery and fixed production costs. It did not include variable power costs, purchased gas costs or natural gas pipeline replacement program costs, which are recovered in separate mechanisms. The filing was based on historical test year costs and rate base, and followed the reporting requirements of a Commission Basis Report, as defined by the Washington Administrative Code, but used end of period rate base and certain annualizing adjustments. It did not include any forward-looking or pro-forma adjustments. Included in the filing was a reduction to the overall authorized rate of return from 7.6% to 7.49% to recognize a reduction in debt costs associated with recent debt activity. PSE requested an overall increase in electric rates of $18.9 million annually, which is a 0.9% increase, and an overall increase in natural gas rates of $21.7 million annually, which is a 2.7% increase.

On January 22, 2019, all parties in the proceeding reached an agreement on settlement terms that resolved all issues in the filing. The settlement agreement was filed on January 30, 2019. The parties agreed to a $21.5 million for natural gas and no rate increase for electric which became effective March 1, 2019. As is discussed below, these rates include the offsetting effect of passing back to customers plant related excess deferred income taxes that resulted from the TCJA, using the average rate assumption method (ARAM) amounts to arrive at the settlement rate changes.

The settlement agreement provides for the pass back of plant related excess deferred income taxes that resulted from the TCJA using the ARAM methodology based on 2018 amounts beginning March 1, 2019, in the amount of $6.1 million for natural gas customers and $25.9 million for electric customers. The settlement agreement left the determination for the regulatory treatment of the remaining items related to the TCJA, listed below, to PSE's next GRC, filed June 20, 2019:

1) excess deferred taxes for non-plant-related book/tax differences for periods prior to March 1, 2019,

the deferred balance associated with the over-collection of income tax expense for the period January 1 through April 30, 2018 (the time period that encompasses the effective date of the TCJA to May 1, 2018, the effective date of the TCJA rate change); and

the turnaround of plant related excess deferred income taxes using the ARAM method for the period from January 2018 through February 2019, the rate effective date for the ERF.

The agreement provides that PSE may defer the depreciation expense associated with PSE's ongoing investment in its advanced metering infrastructure (AMI) investment and may defer the return on the AMI investment that was included in the test year of the filing. The agreement preserves the parties' rights to argue whether or not these deferrals should be recovered in the Company's 2019 GRC. The rate of return adopted in the settlement for reporting and deferral purposes is 7.49% . On February 21, 2019, the Washington Commission approved the settlement with one condition: PSE must pass back the deferred balance associated with the tax over-collection of $34.6 million for the period from January 1, 2018, through April 30, 2018, over a one-year period which began May 1, 2019.

Washington Commission Tax Deferral Filing

The TCJA was signed into law in December 2017. As a result of this change, PSE re-measured its deferred tax balances under the new corporate tax rate. PSE filed an accounting petition on December 29, 2017, requesting deferred accounting treatment for the impacts of tax reform. The requested deferral accounting treatment resulted in the tax rate change being captured in the deferred income tax balance with an offset to the regulatory liability for deferred income taxes for GAAP purposes. Additionally, on March 30, 2018, PSE filed for a rate change for electric and natural gas customers associated with TCJA to reflect the decrease in the federal corporate income tax rate from 35.0% to 21.0%. The overall impact of the rate change, based on the annual period from May 2018 through April 2019, is a revenue decrease of $72.9 million, or 3.4%, for electric and $23.6 million, or 2.7%, for natural gas and became effective May 1, 2018, by operation of law.

The March 30, 2018, rate change filing did not address excess deferred taxes or the deferred balance associated with the over-collection of income tax expense of $34.6 million for the period January 1 through April 30, 2018 (the time period that encompasses the effective date of the TCJA through May 1, 2018, the effective date of the rate change). The $34.6 million tax over-collection decreased PSE's revenue and increased the regulatory liability for a refund to customers.

As a result of the Washington Commission's final order in the ERF, the excess deferred taxes associated with non-plant-related book/tax differences and the treatment of the excess deferred taxes associated with plant related book/tax differences from January 1, 2019, through February 28, 2019, was addressed in PSE’s GRC, which was filed on June 20, 2019. The Washington Commission also required in the ERF order that PSE pass back the deferred balance associated with the tax over-collection for the period from January 1, 2018, through April 30, 2018, as discussed above, over a one-year period which began May 1, 2019.

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 assist in mitigating the impact of weather on operating revenue and net income. Since July 2013, 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 most residential, commercial and industrial customers to mitigate the effects of abnormal weather, conservation impacts and changes in usage patterns per customer. As a result, these electric and natural gas revenues are recovered on a per customer basis regardless of actual consumption levels. PSE's 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 from, or refund to, customers the difference between allowed decoupling revenue and the corresponding actual revenue during the following May to April time period.

On December 5, 2017, the Washington Commission approved PSE’s request within the 2017 GRC to extend the decoupling mechanism with several changes to the methodology that took effect on December 19, 2017. Electric and natural gas delivery revenues continue to be recovered on a per customer basis and electric fixed production energy costs are now decoupled and recovered on the basis of a fixed monthly amount. The allowed decoupling revenue for electric and natural gas customers will no longer increase annually each January 1 as occurred prior to December 19, 2017. Approved revenue per customer costs can only be changed in a GRC or ERF. Approved electric fixed production energy costs can also be changed in a power cost only rate case (PCORC). Other changes to the decoupling methodology approved by the Washington Commission include regrouping of electric and natural gas non-residential customers and the exclusion of certain electric schedules from the decoupling mechanism going forward. The rate test, which limits the amount of revenues PSE can collect in its annual filings, increased from 3.0% to 5.0% for natural gas customers but will remain at 3.0% for electric customers. The decoupling mechanism will be reviewed again in PSE’s first rate case filed in or after 2021, or in a separate proceeding, if appropriate. PSE’s decoupling mechanism over- and under- collections will still be collectible or refundable after this effective date even if the decoupling mechanism is not extended.

On February 21, 2019, the Washington Commission approved the multi-party settlement agreement which was filed within PSE’s ERF filing. As part of this settlement agreement, electric and natural gas allowed delivery revenue per customer was updated to reflect changes in the approved revenue requirement. For electric, there were no changes to the annual allowed fixed power cost revenue. The changes took effect on March 1, 2019.

On December 31, 2019, PSE performed an analysis to determine if electric and natural gas decoupling revenue deferrals would be collected from customers within 24 months of the annual period, per ASC 980. If not, for GAAP purposes only, PSE would need to record a reserve against the decoupling revenue and regulatory asset balance. Once the reserve is probable of collection within 24 months from the end of the annual period, the reserve can be recognized as decoupling revenue. The analysis indicated that electric and natural gas deferred revenue will be collected within 24 months of the annual period; therefore, no adjustment was booked to 2019 decoupling revenue. The previously unrecognized decoupling deferral of $0.8 million at December 31, 2018, was recognized as decoupling revenue in the year ended December 31, 2019.

Power Cost Adjustment Mechanism

PSE currently has a PCA mechanism that provides for the deferral of power costs that vary from the “power cost baseline” level of power costs. The “power cost baseline” levels are set, in part, based on normalized assumptions about weather and hydroelectric conditions. Excess power costs or savings are apportioned between PSE and its customers pursuant to the graduated scale set forth in the PCA mechanism and will trigger a surcharge or refund when the cumulative deferral trigger is reached.

Effective January 1, 2017, the following graduated scale is used in the PCA mechanism:

	Company’s Share		Customers' Share	
Annual Power Cost Variability	Over	Under	Over	Under
Over or Under Collected by up to $17 million	100 %	100 %	— %	— %
Over or Under Collected by between $17 million - $40 million	35	50	65	50
Over or Under Collected beyond $40 + million	10	10	90	90

In September 2016, PSE filed an accounting petition with the Washington Commission which requested deferral of the variances, either positive or negative, between the fixed costs previously recovered in the PCA and the revenue received to cover the allowed fixed costs. The deferral period requested was January 1, 2017, through December 31, 2017, when rates were to go into effect from PSE's 2017 GRC. In November 2016, the Washington Commission issued Order No. 01 approving PSE’s accounting petition. With the final determination in PSE’s GRC, this deferral ceased with the rate effective date of December 19, 2017.

For the year ended December 31, 2019, in its PCA mechanism, PSE under recovered its allowable costs by $67.2 million of which $36.0 million was apportioned to customers and $1.0 million of interest was accrued on the deferred customer balance. This compares to an under recovery of allowable costs of $3.5 million for the year ended December 31, 2018, of which no amounts were apportioned to customers and accrued $0.2 million of interest on the total deferred customer balance. Power costs have been higher than the allowed base line in 2019 which has led to an increase in the PCA deferral causing a higher under-collection compared to the prior year. Actual power costs were higher than baseline rates in 2018 also but by a narrower margin, resulting in lower under-collection. Power prices increased during 2019 as compared to the prior year due to: (i) Cold weather in February and early March, which drove regional loads and demand for power up; (ii) Westcoast pipeline capacity limitations, which contributed to higher natural gas and power prices; (iii) An outage on a transmission line, which contributed to a liquidity crisis at Mid-C and resulted in high market power prices; and (iv) The relative prices of natural gas and power, which reduced the supply of natural gas-fired generation and increased the demand for market power, increasing prices.

Purchased Gas Adjustment

For the year ended December 31, 2018, PSE had a beginning PGA payable balance of $16.1 million, incurred actual natural gas costs of $319.3 million, of which $292.0 million was recovered through rates. The difference between actual and allowed costs, less interest $1.3 million, resulted in a PGA receivable of $9.9 million. For the year ended December 31, 2019, PSE had incurred actual natural gas costs of $406.2 million, of which $289.9 million was recovered through rates. The difference between actual and allowed costs, plus interest of $6.6 million, resulted in a PGA receivable of $132.8 million.

On April 25, 2019, the Washington Commission approved PSE’s request for an out-of-cycle change to PGA rates with the rate change taking effect May 1, 2019. The out-of-cycle PGA filing was needed to begin amortizing a large PGA commodity deferral balance that had grown due to higher than projected commodity costs during the 2018/19 winter. These higher than projected commodity costs were primarily due to an October 9, 2018, rupture and subsequent explosion on Westcoast Pipeline which is one of the major pipelines feeding PSE’s distribution system. The pipeline was repaired in October 2018, however supply capacity on the pipeline was limited over the 2018/19 winter leading to higher prices. February weather was also much colder than normal which also increased the demand for natural gas. The amortization period will be from May 2019 through April 2020.

On October 24, 2019, the Washington Commission approved PSE’s request for November 2019 PGA rates, with the rate change taking effect on November 1, 2019. As part of that filing, PSE requested PGA rates increase annual revenue by $17.8 million, while the new tracker rates increased by annual revenue of $100.6 million; this was in addition to continuing the collection on the remaining balance of $54.0 million from the out-of-cycle PGA. The tracker rates include deferral balances for the three separate amounts: (i) $114.4 million of under collected commodity balances deferred in February and March; (ii) a $10.8 million balance of over-collected commodity costs for the 2018 PGA, and (iii) a $4.1 million remaining balance from the $54.7 million credit to customers, caused by the 2017 over-collection, established in the 2018 tracker. The high commodity deferral balances for winter months through March 2019 were the result of three noteworthy events last winter experienced by PSE: the Enbridge pipeline rupture, unusually low temperatures in February and March, and a compressor failure in February at the Jackson Prairie storage facility. Additionally, to reduce customer impact, as part of the approved PGA filing, PSE will be collecting $114.4 million commodity deferrals and related interest over a two year period, instead of the historic one year period, from November 2019 through October 2021.

Get to Zero Depreciation Deferral

On April 10, 2019, PSE filed an accounting petition with the Washington Commission, requesting authorization to defer depreciation expense associated with Get To Zero (GTZ) projects that were placed in service after June 30, 2018. The GTZ project consists of a number of short-lived technology upgrades. The depreciation expense associated with the GTZ projects with lives of 10 years or less that were placed in service after June 30, 2018, were deferred beginning May 1 per the petition request. For the year ended December 31, 2019, PSE deferred $21.7 million of depreciation expense for GTZ. In addition to the deferral of depreciation expense, PSE had also requested to defer carrying charges on the GTZ deferral, to be calculated utilizing the Company's currently authorized after tax rate of return, or 6.89% per the 2018 ERF. For the year ended December 31, 2019, PSE deferred $0.5 million of carrying charges on the deferral. The GTZ accounting petition was consolidated with PSE's 2019 GRC and is currently being reviewed by the Washington Commission. If authorized, both the GTZ depreciation and interest on the deferral will be begin amortizing over three years in May 2020

Storm Damage Deferral Accounting

The Washington Commission issued a GRC order that defined deferrable storm events and provided that costs in excess of the annual cost threshold may be deferred for qualifying storm damage costs that meet the modified Institute of Electrical and Electronics Engineers outage criteria for system average interruption duration index. For the year ended December 31, 2019, PSE incurred $39.3 million in storm-related electric transmission and distribution system restoration costs, of which the Company deferred $0.4 million and $28.5 million as regulatory assets related to storms that occurred in 2018 and 2019, respectively. This compares to $25.4 million incurred in storm-related electric transmission and distribution system restoration costs for the year ended December 31, 2018, of which the Company deferred $3.3 million and $11.9 million as regulatory assets related to storms that occurred in 2017 and 2018, respectively. Under the December 5, 2017, Washington Commission order regarding PSE's GRC, the following changes to PSE's storm deferral mechanism were approved: (i) the cumulative annual cost threshold for deferral of storms under the mechanism increased from $8.0 million to $10.0 million effective January 1, 2018; and (ii) qualifying events where the total qualifying cost is less than $0.5 million will not qualify for deferral and these costs will also not count toward the $10.0 million annual cost threshold.

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. In accordance with 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 $41.8 million for natural gas and $8.7 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, 2019, the Company's share of future remediation costs is estimated to be approximately $31.6 million. The Company's deferred electric environmental costs are $13.7 million and $14.1 million at December 31, 2019 and 2018, respectively, net of insurance proceeds. The Company's deferred natural gas environmental costs are $54.8 million and $62.2 million at December 31, 2019 and 2018, respectively, net of insurance proceeds. In the 2017 GRC, the Company had its third party recoveries and remediation costs incurred as of September 30, 2016, net of a portion of insurance, approved for amortization and inclusion in rates, effective December 19, 2017.

(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, 2019, approximately $914.2 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 3.0 to 1.0. The common equity ratio, calculated on a regulatory basis, was 48.4% at December 31, 2019, and the EBITDA to interest expense was 5.3 to 1.0 for the twelve months ended December 31, 2019.

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, 2019, PSE was in compliance with all applicable covenants, including those pertaining to the payment of dividends.

(5) Utility Plant

The following table presents electric, natural gas and common utility plant classified by account:

Utility Plant	Estimated Useful Life	Puget Sound Energy December 31,	
(Dollars in Thousands)	(Years)	2019	2018
Distribution plant	20-65	$ 8,185,700	$ 7,722,024
Production plant	12-90	3,743,493	4,104,963
Transmission plant	43-75	1,571,186	1,550,950
General plant	5-75	731,279	718,105
Intangible plant (including capitalized software)[1]	3-50	726,383	652,942
Plant acquisition adjustment	N/A	282,792	282,792
Underground storage	25-60	50,963	48,874
Liquefied natural gas storage	25-60	14,498	14,498

Plant held for future use	N/A		46,385		39,536
Plant not classified	N/A		316,925		239,857
Capital leases, net of accumulated amortization[2]	N/A		184,536		1,315
Less: accumulated provision for depreciation			(6,192,635)		(6,013,978))
Subtotal		$	9,661,505	$	9,361,878
Construction work in progress			591,199		550,466
Net utility plant		$	10,252,704	$	9,912,344

1. *Intangible assets include capitalized software and franchise agreements with useful lives ranging between 3-10 years and 10-50 years, respectively.*

The capital leases balance includes $183.0 million related to the operating lease ROU asset, as discussed in Footnote 1, "Summary of Significant Accounting Policies". At December 31, 2019, and 2018, accumulated amortization of capital leases at PSE was $1.0 million and $1.3 million, respectively.

Jointly owned generating plant service costs are included in utility plant service cost at the Company's ownership share. The Company provides financing for its ownership interest in the jointly owned utility plants. The following tables indicate the Company's percentage ownership and the extent of the Company's investment in jointly owned generating plants in service at December 31, 2019. These amounts are also included in the Utility Plant table above. The Company's share of fuel costs and operating expenses for plant in service are included in the corresponding accounts in the Consolidated Statements of Income.

Puget Sound Energy

Jointly Owned Generating Plants (Dollars in Thousands)	Energy Source (Fuel)	Company's Ownership Share	Plant in Service at Cost		Construction Work in Progress		Accumulated Depreciation	
Colstrip Units 3 & 4	Coal	25.00%	$	582,372	$	—	$	(398,099)
Frederickson 1	Natural Gas	49.85		67,888		—		(17,063)
Jackson Prairie	Natural Gas	33.34		50,963		119		(22,578)
Tacoma LNG	Natural Gas	various		—		162,820		—

In June 2019, Talen, the plant operator of Colstrip 1&2, announced a plan to shut down as of December 31, 2019. The Company retired Colstrip 1&2 from Utility Plant and transferred the unrecovered plant amount of $126.5 million to regulatory assets. Consistent with the GRC settlement in 2017, monetization of the PTCs will fund the following: (i) Colstrip Community Transition Fund, (ii) unrecovered Colstrip plant and (iii) incurred decommissioning and remediation costs for Colstrip. At December 31, 2019, the unrecovered plant for Colstrip 1&2 was fully offset with PTCs.

Asset Retirement Obligation

The Company has recorded liabilities for steam generation sites, combustion turbine generation sites, wind generation sites, distribution and transmission poles, natural gas mains, and leased facilities where disposal is governed by ASC 410 "Asset Retirement and Environmental Obligations" (ARO).

On April 17, 2015, the 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 ruling requires the Company to perform an extensive study on the effects of coal ash on the environment and public health. The 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.

The CCR rule and two new legal agreements which include a consent decree with the Sierra Club and a settlement agreement with the Sierra Club and the National Wildlife Federation in 2016 make significant changes to the Company's Colstrip operations and those changes were reviewed by the Company and the plant operator in 2015 and 2016. PSE had previously recognized a legal obligation in 2003 under the EPA rules to dispose of coal ash material at Colstrip.

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.

For the twelve months ended December 31, 2019, the Company reviewed the estimated remediation costs at Colstrip and increased the Colstrip ARO liability by $4.2 million for Colstrip Units 1 and 2 and $0.5 million for Colstrip Units 3 and 4. The 2019 increase to the Colstrip ARO liability are primarily due to accelerated timing of activities due to the closure of Colstrip Units 1 and 2 at the end of 2019. For the twelve months ended December 31, 2018, the company reduced the Colstrip ARO liability by $11.0 million for Colstrip Units 1 and 2, and increased $1.8 million for Colstrip Units 3 and 4. The 2018 change to the Colstrip ARO liability is primarily based on the plant site remedy report approved by the Montana Department of Environmental Quality. For the twelve months ended December 31, 2019 and 2018, the Company also recorded the Colstrip relief of liability of $12.4 million and $4.8 million, respectively. In addition, the Company recorded Tacoma LNG facility ARO liability of $3.0 million and $2.7 million for PSE as of December 31, 2019 and December 31, 2018, respectively. The 2019 increase to the Tacoma LNG facility ARO liability is primarily due to continued construction of the plant.

Puget Sound Energy	December 31,	
(Dollars in Thousands)	2019	2018
Asset retirement obligation at beginning of the period	$ 180,489	$ 188,934
New asset retirement obligation recognized in the period	—	501
Relief of liability	(12,449)	(4,750)
Revisions in estimated cash flows	3,405	(9,876)
Accretion expense	5,574	5,680
Asset retirement obligation at end of period[1]	$ 177,019	$ 180,489

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, 2019:

1 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

The following table presents outstanding long-term debt principal amounts and due dates as of 2019 and 2018:

(Dollars in Thousands)			December 31,	
Series	Type	Due	2019	2018
Puget Sound Energy:				
5.500%	Promissory Note[1]	2020	$ —	$ 2,412
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	425,000
4.223%	Senior Secured Note	2048	600,000	600,000
3.250%	Senior Secured Note	2049	450,000	—
4.700%	Senior Secured Note	2051	45,000	45,000
*	Debt discount, issuance cost and other	*	(37,718)	(31,412)
Total PSE long-term debt			4,336,142	3,894,860

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1 Not Applicable.

1. 5.500% Promissory Note in the amount of $2.4 million was classified on the Balance Sheet as a current maturity of long-term debt as of August 12, 2019.

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, 2019, 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

On August 2, 2019, PSE filed a new shelf registration statement under which it may issue, up to $1.0 billion aggregate principal amount of senior notes secured by first mortgage bonds. As of the date of this report, $550.0 million was available under the registration. The shelf registration will expire in August 2022.

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, 2019, the earnings available for interest exceeded the required amount.

On March 5, 2018, PSE commenced a tender offer and related consent solicitation to purchase any and all of the outstanding $250.0 million 6.974% Series A Enhanced Junior Subordinated Notes due June 1, 2067. Holders of the notes received $1,005 per $1,000 principal amount of notes plus accrued and unpaid interest for notes tendered and accepted by the early tender payment deadline of March 16, 2018. Holders of notes tendered after the early tender payment deadline, but prior to the tender offer expiration on April 2, 2018, were to receive the tender offer consideration of $975 per $1,000 of principal amount of the notes plus accrued but unpaid interest. A total of $193.4 million in principal amount of notes were tendered by the early payment deadline and no notes were tendered after the early payment deadline. On March 20, 2018, $194.9 million was paid to the holders of the tendered notes. This amount included the principal, early tender consideration and accrued interest up to, but not including March 20, 2018.

Concurrently with the tender offer, PSE solicited consents from a majority (in principal amount) of the holders of PSE's 6.274% Senior Notes due March 15, 2037 to terminate the replacement capital covenant granted to the holders of those notes. The termination of the covenant was necessary because it included restrictions related to repurchases, redemptions and repayments of the 6.974% Series A Enhanced Junior Subordinated Notes. PSE received consents from holders of 87.7% of the 6.274% Senior Notes and paid a consent fee totaling $2.6 million to those holders on March 19, 2018.

On March 28, 2018, PSE issued a notice of redemption, effective April 27, 2018, for the remaining $56.6 million principal amount of the 6.974% Series A Enhanced Junior Subordinated Notes. The notes were redeemed at a price equal to 100% of their principal amount plus accrued and unpaid interest up to, but excluding the redemption date.

On June 4, 2018, PSE issued $600.0 million of 30-year Senior Notes under its senior note indenture at an interest rate of 4.223% with a maturity date of June 15, 2048. The proceeds from the issuance were used to pay the principal and accrued interest on the Company's $200.0 million Secured Notes that matured on June 15, 2018, outstanding commercial paper borrowings of $348.0 million and other general corporate expenses.

On August 30, 2019, PSE issued $450.0 million of senior notes at an interest rate of 3.250%. The notes pay interest semi-annually and are due to mature on September 15, 2049. Proceeds from the sale of the notes were used to repay outstanding short term debt under the Company's commercial paper program.

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)	2020	2021	2022	2023	2024	Thereafter	Total
Maturities of:							
PSE	$ —	$ —	$ —	$ —	$ —	$ 4,373,860	$ 4,373,860
Total long-term debt	$ —	$ —	$ —	$ —	$ —	$ 4,373,860	$ 4,373,860

(7) Liquidity Facilities and Other Financing Arrangements

As of December 31, 2019, and 2018, PSE had $176.0 million and $379.3 million in short-term debt outstanding, respectively. PSE's weighted-average interest rate on short-term debt, including borrowing rate, commitment fees and the amortization of debt issuance costs, during 2019 and 2018 was 3.4% and 3.4%, respectively. As of December 31, 2019, PSE had several committed credit facilities that are described below.

Puget Sound Energy

Credit Facility

In October 2017, PSE entered into a new $800.0 million credit facility which consolidates the two previous facilities into a single, smaller facility. All other features including fees, interest rate options, letter of credit, same day swingline borrowings, financial covenant and accordion feature remain substantially the same. The credit facility includes a swingline feature allowing same day availability on borrowings up to $75.0 million. The credit facility also has an expansion feature which, upon the banks' approval, would increase the total size of the facility to $1.4 billion. On September 25, 2019, with no changes to the size, terms or conditions, the maturity of the unsecured revolving credit facility was extended for one year. The facility now matures in October 2023.

The credit agreement is syndicated among numerous lenders and contains usual and customary affirmative and negative covenants that, among other things, places limitations on PSE's ability to transact with affiliates, make asset dispositions and investments or permit liens to exist. The credit agreement also contains 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, 2019, PSE was in compliance with all applicable covenant ratios.

The credit agreement provides PSE with the ability to borrow at different interest rate options. The credit agreement allows PSE to borrow at the bank's prime rate or to make floating rate advances at the 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 facility. 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, 2019, no amounts were drawn and outstanding under PSE's credit facility. No letters of credit were outstanding and $176.0 million was outstanding under the commercial paper program. Outside of the credit agreement, PSE had a $2.8 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

In 2006, 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%. As of December 31, 2019, there was no outstanding balance under the Note.

(8) Leases

PSE has operating leases for buildings for corporate offices and operations, real estate for operating facilities and the PSE and PLNG LNG facility, land for our wind farms, and vehicles for PSE’s fleet. The finance leases are for office printers. The leases have remaining lease terms of less than a year to 50 years. PSE's ROU assets and lease liabilities include options to extend leases when it is reasonably certain that PSE will exercise that option.

During the fourth quarter of 2019, PSE became reasonably certain to exercise an option to extend its lease at the Port of Tacoma for an additional 25 years as a result of the approval of the Notice of Construction permit for the Tacoma LNG facility. This remeasurement resulted in an increase of the Operating lease right-of-use asset and Operating lease liabilities of $14.7 million.

The components of lease cost were as follows:

Puget Sound Energy	Year Ended December 31,
(Dollars in Thousands)	2019
Finance lease cost:	
Amortization of right-of-use asset	$ 562
Interest on lease liabilities	40
Total finance lease cost	$ 602

Operating lease cost	$	19,639

Supplemental cash flow information related to leases was as follows:

Puget Sound Energy		Year Ended December 31,
(Dollars in Thousands)		2019
Cash paid for amounts included in the measurement of lease liabilities:		
Operating cash flow for operating leases	$	14,104
Investing cash flow for operating leases		5,535
Operating cash flow for finance leases		40
Financing cash flow for finance leases		562
Non-cash disclosure upon commencement of new lease		
Right-of-use assets obtained in exchange for new operating lease liabilities	$	5,976
Right-of-use assets obtained in exchange for new finance lease liabilities		745
Non-cash disclosure upon modification of existing lease		
Modification of operating lease right-of-use assets	$	14,712

Supplemental balance sheet information related to leases was as follows:

Puget Sound Energy		
(Dollars in Thousands)		At December 31,
Operating Leases		2019
Operating lease right-of-use asset	$	183,048
Operating leases liabilities current		15,862
Operating lease liabilities long-term		174,327
Total Operating lease liabilities:	$	190,189
Finance Leases		
Common Plant	$	1,488
Other current liabilities		669
Other deferred credits		811
Total finance lease liabilities	$	1,480
Weighted Average Remaining Lease Term		
Operating leases		19.24 Years

Finance leases	2.76 Years
Weighted Average Discount Rate	
Operating leases	3.59 %
Finance leases	2.98 %

The following tables summarize the Company's estimated future minimum lease payments as of December 31, 2019, and December 31, 2018, respectively:

Maturities of lease liabilities (Dollars in Thousands)	Future Minimum Lease Payments	
At December 31,	Operating Leases	Finance Leases
2020	$ 22,500	$ 643
2021	22,527	508
2022	21,856	279
2023	21,415	98
2024	20,690	—
Thereafter	160,410	—
Total lease payments	$ 269,398	$ 1,528
Less imputed interest	(79,209)	(48)
Total net present value	$ 190,189	$ 1,480

Maturities of lease liabilities (Dollars in Thousands)	Future Minimum Lease Payments	
At December 31,	Operating Leases	Finance Leases
2019	$ 20,635	$ 495
2020	20,704	446
2021	20,630	311
2022	20,202	82
2023	19,223	—
Thereafter	132,889	—
Total lease payments	$ 234,283	$ 1,334

PSE adopted ASU 2016-02 and elected the modified transition method practical expedient. Consequently, comparative period disclosures are presented in accordance with ASC 840. For further details see Note 2, "New Accounting Pronouncements". Operating lease expense, which includes both cancellable and non-cancellable leases, net of sublease receipts are presented in the following table.

(Dollars in Thousands)	Operating Lease Expense
Year Ended December 31,	
2018	$ 34,093

(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 hedging strategy includes a risk-responsive component for the core natural gas portfolio, which utilizes quantitative risk-based measures with defined objectives to balance both portfolio risk and hedge costs.

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. Currently, the Company does not apply cash flow hedge accounting, and therefore records all mark-to-market gains or losses through earnings.

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.

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

Puget Sound Energy	Year Ended December 31,					
(Dollars in Thousands)	Volumes (millions)		Assets[1]		Liabilities[2]	
	2019	2018	2019	2018	2019	2018
Electric portfolio derivatives	*	*	$ 19,933	$ 33,287	$ 17,504	$ 27,284
Natural gas derivatives (MMBtus)[3]	316	337	11,375	15,732	8,617	30,472
Total derivative contracts			$ 31,308	$ 49,019	$ 26,121	$ 57,756
Current			23,626	46,507	13,428	46,661
Long-term			7,682	2,512	12,693	11,095
Total derivative contracts			$ 31,308	$ 49,019	$ 26,121	$ 57,756

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

Balance sheet classification: Current and Long-term Unrealized loss on derivative instruments.

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.

1 *Electric portfolio derivatives consist of electric generation fuel of 229.3 million One Million British Thermal Units (MMBtus) and purchased electricity of 10.4 million megawatt hours (MWhs) at December 31, 2019, and 194.8 million MMBtus and 6.6 million MWhs at December 31, 2018.*

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 natural gas and electric contracts; and North American Energy Standards Board (NAESB) agreements, which standardize physical natural 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 the 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. For further details regarding the fair value of derivative instruments, see Note 10, "Fair Value Measurements".

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

Puget Sound Energy

December 31, 2019

(Dollars in Thousands)	Gross Amount Recognized in the Consolidated Balance Sheet[1]	Gross Amounts Offset in the Consolidated Balance Sheet	Net of Amounts Presented in the Consolidated Balance Sheet	Gross Amounts Not Offset in the Consolidated Balance Sheet		
				Commodity Contracts[2]	Cash Collateral Received/Pledged	Net Amount
Assets:						
Energy derivative contracts	$ 31,308	$ —	$ 31,308	$ (14,922)	$ —	$ 16,386
Liabilities:						
Energy derivative contracts	26,121	—	26,121	(14,922)	2,000	13,199

Puget Sound Energy

December 31, 2018

(Dollars in Thousands)	Gross Amount Recognized[1]	Gross Amounts Offset in the Consolidated Balance Sheet	Net of Amounts Presented in the Consolidated Balance Sheet	Gross Amounts Not Offset in the Consolidated Balance Sheet		
				Commodity Contracts[2]	Cash Collateral Received/Pledged	Net Amount
Assets						
Energy Derivative Contracts	$ 49,019	$ —	$ 49,019	$ (25,388)	$ —	$ 23,631
Liabilities						
Energy Derivative Contracts	57,756	—	57,756	(25,388)	—	32,368

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

Balance sheet classification: Current and Long-term Unrealized loss on derivative instruments.

The following tables present the effect and locations of the realized and unrealized gains (losses) of the Company's derivatives recorded on the statements of income:

Puget Sound Energy (Dollars in Thousands)	Location	2019	2018
Gas for Power Derivatives:			
Unrealized	Unrealized gain (loss) on derivative instruments, net	16,970	23,186
Realized	Electric generation fuel	10,828	26,222
Power Derivatives:			
Unrealized	Unrealized gain (loss) on derivative instruments, net	(20,544)	18,476
Realized	Purchased electricity	48,686	12,240
Total gain (loss) recognized in income on derivatives		$ 55,940	$ 80,124

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, and exposure monitoring and mitigation.

The Company monitors counterparties for significant swings in credit default rates, credit rating changes by external rating agencies, ownership changes or 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, 2019, approximately 95.0% of the Company's energy portfolio exposure, excluding normal purchase normal sale (NPNS) transactions, is with counterparties that are rated investment grade by rating agencies and 5.0% are either rated below investment grade or not rated by rating agencies. The Company assesses credit risk internally for counterparties that are not rated by the major rating agencies.

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, 2019, 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 period. The majority of the Company's derivative contracts are with financial institutions and other utilities operating within the Western Electricity Coordinating Council. PSE also transacts power futures contracts on the Intercontinental Exchange (ICE), and natural gas contracts on the ICE NGX exchange platform. Execution of contracts on ICE requires the daily posting of margin calls as collateral through a futures and clearing agent. As of December 31, 2019, PSE had cash posted as collateral of $14.8 million related to contracts executed on the ICE platform. Also, as of December 31, 2019, PSE has a $1.0 million letter of credit posted as collateral as a condition of transacting on the ICE NGX exchange. PSE did not trigger any collateral requirements with any of its counterparties during the twelve months ended December 31, 2019, nor were any of PSE's counterparties required to post collateral resulting from credit rating downgrades.

The following table presents the aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position and the amount of additional collateral the Company could be required to post:

Puget Sound Energy	December 31,					
(Dollars in Thousands)	2019			2018		
Contingent Feature	Fair Value[1] Liability	Posted Collateral	Contingent Collateral	Fair Value[1] Liability	Posted Collateral	Contingent Collateral
Credit rating[2]	$ 6,110	$ —	$ 6,110	$ 574	$ —	$ 574
Requested credit for adequate assurance	5,253	—	—	18,495	—	—
Forward value of contract[3]	—	14,827	N/A	—	—	—
Total	$ 11,363	$ 14,827	$ 6,110	$ 19,069	$ —	$ 574

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.*

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.

Collateral requirements may vary, based on changes in the forward value of underlying transactions relative to contractually defined collateral thresholds.

(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 as 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.

The Company considers its electric and natural gas contracts as Level 2 derivative instruments as such contracts are commonly traded as over-the-counter forwards with indirectly observable price quotes. 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. Management's assessment is 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 used to value Level 2 commodity contracts with the actual prices of commodity contracts entered into during the most recent quarter.

Assets and Liabilities with Estimated Fair Value

The carrying values of cash and cash equivalents, restricted cash, and short-term debt as reported on the balance sheet are reasonable estimates of their fair value due to the short-term nature of these instruments and are classified as Level 1 in the fair value hierarchy. The carrying value of other investments of $51.5 million and $49.5 million at December 31, 2019, and 2018, respectively, are included in "Other property and investments" on the balance sheet. These values are also reasonable estimates of their fair value and classified as Level 2 in the fair value hierarchy as they are valued based on market rates for similar transactions.

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's credit spreads as inputs, interpolating to the maturity date of each issue. The carrying values and estimated fair values were as follows:

Puget Sound Energy		December 31, 2019		December 31, 2018	
(Dollars in Thousands)	Level	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial liabilities:					
Long-term debt (fixed-rate), net of discount[1]	2	$ 4,336,142	$ 5,571,818	$ 3,894,860	$ 4,574,611
Total		$ 4,336,142	$ 5,571,818	$ 3,894,860	$ 4,574,611

1. *The carrying value includes debt issuances costs of $24.4 million and $24.6 million for December 31, 2019, and 2018, respectively, which are not included in fair value.*

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:

Puget Sound Energy	Fair Value December 31, 2019			Fair Value December 31, 2018		
(Dollars in Thousands)	Level 2	Level 3	Total	Level 2	Level 3	Total
Assets:						
Electric Derivative Instruments	$ 19,282	$ 651	$ 19,933	$ 28,765	$ 4,522	$ 33,287
Gas Derivative Instruments	9,852	1,523	11,375	12,247	3,485	15,732
Total derivative assets	$ 29,134	$ 2,174	$ 31,308	$ 41,012	$ 8,007	$ 49,019
Liabilities:						
Electric Derivative Instruments	$ 13,474	$ 4,030	$ 17,504	$ 24,124	$ 3,160	$ 27,284
Gas Derivative Instruments	8,376	241	8,617	28,660	1,812	30,472
Total derivative liabilities	$ 21,850	$ 4,271	$ 26,121	$ 52,784	$ 4,972	$ 57,756

Puget Sound Energy Level 3 Roll-Forward Net Asset(Liability)	2019			2018		
(Dollars in Thousands)	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Balance at beginning of period	$ 1,362	$ 1,673	$ 3,035	$ 1,098	$ 1,923	$ 3,021
Changes during period						
Realized and unrealized energy derivatives:						
Included in earnings[1]	3,558	—	3,558	34,604	—	34,604
Included in regulatory assets / liabilities	—	3,151	3,151	—	6,075	6,075
Settlements[2]	(11,265)	(4,708)	(15,973)	(33,067)	(7,197)	(40,264)
Transferred into Level 3	4,390	(398)	3,992	(1,987)	—	(1,987)
Transferred out Level 3	(1,424)	1,564	140	714	872	$ 1,586
Balance at end of period	$ (3,379)	$ 1,282	$ (2,097)	$ 1,362	$ 1,673	$ 3,035

1. Income Statement classification: 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 $(3.2) million and $1.1 million for the years ended December 31, 2019 and 2018, respectively.

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, 2019 and 2018. 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, 2019:

Puget Sound Energy Energy	Fair Value				Range		
(Dollars in Thousands)	Assets[1]	Liabilities[1]	Valuation Technique	Unobservable Input	Low	High	Weighted
Electricity	$ 651	$ 4,030	Discounted cash flow	Power Prices (per MWh)	$ 9.00	$ 43.85	$ 33.99
Natural Gas	$ 1,523	$ 241	Discounted cash flow	Natural Gas Prices (per MMBtu)	$ 1.25	$ 3.18	$ 2.47

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, 2019, 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 $2.5 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 $21.7 million and $20.7 million for the years 2019 and 2018, 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:

1. For employees under the Cash Balance retirement plan formula, PSE will match 100% of an employee's contribution up to 6.0% of plan compensation each paycheck, and will make an additional year-end contribution equal to 1.0% of base pay.

For employees grandfathered under the Final Average Earning retirement plan formula, PSE will match 55.0% of an employee's contribution up to 6.0% of plan compensation each paycheck.

Non-represented and UA-represented employees hired on or after January 1, 2014 along with IBEW-represented employees hired on or after December 12, 2014, will have access to the 401(k) plan. The two contribution sources from PSE are below:

1. 401(k) Company Matching: For non-represented, UA-represented and IBEW-represented employees PSE will match: 100% match on the first 3.0% of pay contributed and 50.0% match on the next 3.0% of pay contributed, such that an employee who contributes 6.0% of pay will receive 4.5% of pay in company match. Company matching will be immediately vested.

Company Contribution: For UA-represented employees will receive an annual company contribution of 4.0% of eligible pay placed in the Cash Balance retirement plan. Non-represented and IBEW-represented employees will receive an annual company contribution of 4.0% of eligible pay, placed either in the Investment Plan 401(k) plan or in PSE's Cash Balance retirement plan. Non-represented and IBEW-represented employees will make a one-time election within 30 days of hire and direct that PSE put the 4.0% contribution either into the 401(k) plan or into an account in the Cash Balance retirement plan. The Company's 4.0% contribution will vest after three years of service.

(12) Retirement Benefits

PSE has a defined benefit pension plan (Qualified Pension Benefits) covering a substantial majority 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 UA represented employees will receive annual pay contributions of 4.0% of eligible pay each year in the cash balance formula plan of the defined benefit pension. Starting January 1, 2014, for non-represented employees, and December 12, 2014 for employees represented by the IBEW, participants will receive annual employer contributions of 4.0% of eligible pay each year in the cash balance formula of the defined benefit pension or 401k plan account. Those employees receiving contributions in the cash balance formula plan also receive interest credits, which are at least 1.0% per quarter. When an employee with a vested cash balance formula benefit leaves PSE, they will have annuity and lump sum options for distribution. PSE also has a non-qualified Supplemental Executive Retirement Plan (SERP) for certain key senior management employees that closed to new participants in 2019. PSE has an officer restoration benefit for new officers who join PSE or are promoted beginning in 2019, such that company contributions under PSE's applicable tax-qualified plan, which otherwise would have been earned if not for IRS limitations, are credited to an account with the Deferred Compensation Plan.

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. On June 11, 2019, the Welfare Benefits Committee approved the termination of the Plan effective December 31, 2019, and the creation of a Retiree Health Reimbursement Account (HRA) Plan effective January 1, 2020. No eligible individual may become a participant or covered dependent in the Plan on or after January 1, 2020, and no benefits will be payable under insurance contracts or the Plan on or after January 1, 2020. Effective January 1, 2020, assets in the 401(h) account will be allocated to the Retiree HRA instead of the Plan to cover the Company's portion of premiums for health benefits for retiree and their beneficiaries.

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, 2019, and 2018:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2019	2018	2019	2018	2019	2018
Change in benefit obligation:						

Benefit obligation at beginning of period	$ 677,643	$ 700,481	$ 55,708	$ 55,754	$ 10,636	$ 11,454
Amendments	—	—	—	1,446	9,049	—
Service cost	22,656	22,757	1,023	847	61	69
Interest cost	28,913	27,303	2,314	2,120	410	444
Curtailment Loss / (Gain)	—	—	—	—	(7,486)	—
Actuarial loss (gain)	84,272	(29,067)	6,756	1,122	(287)	(379)
Benefits paid	(36,740)	(42,662)	(2,801)	(5,581)	(982)	(1,037)
Medicare part D subsidy received	—	—	—	—	226	85
Administrative expense	(2,439)	(1,169)	—	—	—	—
Benefit obligation at end of period	$ 774,305	$ 677,643	$ 63,000	$ 55,708	$ 11,627	$ 10,636

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2019	2018	2019	2018	2019	2018
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 640,242	$ 704,360	$ —	$ —	$ 5,960	$ 7,138
Actual return on plan assets	133,939	(38,379)	—	—	1,006	(395)
Employer contribution	18,000	18,000	2,801	5,581	305	254
Benefits paid	(36,740)	(42,662)	(2,801)	(5,581)	(982)	(1,037)
Administrative expense	(2,399)	(1,077)	—	—	—	—
Fair value of plan assets at end of period	$ 753,042	$ 640,242	$ —	$ —	$ 6,289	$ 5,960
Funded status at end of period	$ (21,263)	$ (37,401)	$ (63,000)	$ (55,708)	$ (5,338)	$ (4,676)

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2019	2018	2019	2018	2019	2018
Amounts recognized in Consolidated Balance Sheet consist of:						
Noncurrent assets	$ —	$ —	$ —	$ —	$ —	$ —
Current liabilities	—	—	(22,604)	(6,249)	(308)	(332)
Noncurrent liabilities	(21,263)	(37,401)	(40,396)	(49,459)	(5,030)	(4,344)
Net assets (liabilities)	$ (21,263)	$ (37,401)	$ (63,000)	$ (55,708)	$ (5,338)	$ (4,676)

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2019	2018	2019	2018	2019	2018
Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:						
Projected benefit obligation	$ 774,305	$ 677,643	$ 63,000	$ 55,708	$ 11,627	$ 10,636
Accumulated benefit obligation	762,838	668,469	59,988	51,031	11,604	10,557
Fair value of plan assets	753,042	640,242	—	—	6,289	5,960

The following tables summarize PSE's pension benefit amounts recognized in AOCI for the years ended December 31, 2019, and 2018:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2019	2018	2019	2018	2019	2018
Amounts recognized in Accumulated Other Comprehensive Income consist of:						
Net loss (gain)	$ 217,502	$ 229,819	$ 16,473	$ 11,450	$ (364)	$ (3,857)
Prior service cost (credit)	(3,086)	(4,659)	1,276	1,609	—	—
Total	$ 214,416	$ 225,160	$ 17,749	$ 13,059	$ (364)	$ (3,857)

The following tables summarize PSE's net periodic benefit cost for the years ended December 31, 2019 and 2018:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2019	2018	2019	2018	2019	2018
Components of net periodic benefit cost:						
Service cost	$ 22,656	$ 22,757	$ 1,023	$ 847	$ 61	$ 69 69
Interest cost	28,913	27,303	2,314	2,120	410	444
Expected return on plan assets	(50,267)	(50,240)	—	—	(393)	(472)
Amortization of prior service cost (credit)	(1,573)	(1,573)	333	44	—	—
Amortization of net loss (gain)	12,877	14,917	1,733	2,069	(562)	(556)
Net periodic benefit cost	$ 12,606	$ 13,164	$ 5,403	$ 5,080	$ (484)	$ (515) (515)

The following tables summarize PSE's benefit obligations recognized in other comprehensive income (OCI) for the years ended

December 31, 2019, and 2018:

Puget Sound Energy	Qualified Pension Benefit		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2019	2018	2019	2018	2019	2018
Other changes (pre-tax) in plan assets and benefit obligations recognized in other comprehensive income:						
Net loss (gain)	$ 559	$ 59,460	$ 6,756	$ 1,122	$ (900)	$ 488
Amortization of net (loss) gain	(12,877)	(14,917)	(1,733)	(2,069)	562	556
Settlements, mergers, sales, and closures	—	—	—	(737)	3,832	—
Prior service cost (credit)	—	—	—	1,446	—	—
Amortization of prior service (cost) credit	1,573	1,573	(333)	(44)	—	—
Total change in other comprehensive income for year	$ (10,745)	$ 46,116	$ 4,690	$ (282)	$ 3,494	$ 1,044

The estimated net (loss) gain and prior service cost (credit) for the pension plans that will be amortized from AOCI into net periodic benefit cost in 2020 by PSE include a $18.6 million net loss and a $1.6 million credit, respectively. The estimated net (loss) gain and prior service cost (credit) for the SERP that will be amortized from AOCI into net periodic benefit cost in 2020 is a $2.6 million net loss and a $0.3 million net loss, respectively. The estimated net (loss) gain and prior service cost (credit) for the other postretirement plans that will be amortized from AOCI into net periodic benefit cost in 2020 is a net loss of $0.2 million.

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, 2020, are expected to be at least $18.0 million, $22.6 million and $0.1 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	2019	2018	2019	2018	2019	2018
Discount rate	3.35 %	4.40 %	3.35 %	4.40 %	3.35 %	4.40 %
Rate of compensation increase	4.50	4.50	4.50	4.50	4.50	4.50
Medical trend rate[1]	—	—	—	—	N/A	7.60
Benefit Cost Assumptions						
Discount rate	4.40	4.40	4.40	4.40	4.40	4.40
Return on plan assets	7.50	7.50	—	—	7.00	7.00
Rate of compensation increase	4.50	4.50	4.50	4.50	4.50	4.50
Medical trend rate[1]	—	—	—	—	N/A	7.60

1. *As of December 31, 2019, PSE terminated the previous group retiree medical plan and created an HRA. As a result, medical inflation is no longer applicable*

in accounting for the related benefit obligation.

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 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)	2020	2021	2022	2023	2024	2025-2029
Qualified Pension total benefits	$ 45,000	$ 45,200	$ 46,200	$ 47,900	$ 48,800	$ 253,400
SERP Pension total benefits	22,604	1,940	5,792	3,663	6,290	21,283
Other Benefits total with Medicare Part D subsidy	843	826	972	937	901	4,053
Other Benefits total without Medicare Part D subsidy	1,055	1,007	972	937	901	4,053

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	—	9	15
Non-U.S. equity	10	25	30

Fixed income	15	25	30
Real estate	—	—	10
Absolute return	5	10	15
Cash	—	—	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: (i) how investment allocation decisions are made, including the factors that are pertinent to an understanding of investment policies and strategies; (ii) major categories of plan assets; (iii) inputs and valuation techniques used to measure the fair value of plan assets; (iv) effect of fair value measurements using significant unobservable inputs (Level 3) on changes in plan assets for the period; and (v) 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, 2019, and 2018:

	Recurring Fair Value Measures			Recurring Fair Value Measures		
	December 31, 2019			December 31, 2018		
(Dollars in Thousands)	Level 1	Level 2	Total	Level 1	Level 2	Total
Assets:						
Mutual Funds	$ 91,658	$ —	$ 91,658	$ 103,661	$ —	$ 103,661
Common Stock	224,146	—	224,146	177,949	—	177,949
Government Securities	34,916	—	34,916	—	—	—
Corporate Bonds	—	—	—	—	—	—
Cash and cash equivalents	—	150	150	—	702	702
Subtotal	$ 350,720	$ 150	$ 350,870	$ 281,610	$ 702	$ 282,312
Investments measured at NAV[1]			401,668			356,586
Net (payable) receivable			505			1,345
Total assets			$ 753,043			$ 640,243

1. *In accordance with ASU 2015-07, "Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (or Its Equivalent)", certain investments that are measured at NAV per share (or its equivalent) are not classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the line items presented in the statement of net assets available for benefits. Investments measured at NAV primarily consist of common/collective trust funds and two partnerships held as of December 31, 2019, and 2018.*

Mesirow Institutional Multi-Strategy Fund Partnership, L.P. utilizes a combination of long and short strategies through investments in investment funds. The major strategy allocations of the investment funds include (1) Investments in debt obligations of public and private entities; typically, in financial duress, and (2) Investments in equity positions on a global basis utilizing fundamental analysis.

Grosvenor Institutional Partners Fund, L.P invests substantially all of the fund assets available in the Grosvenor Master Fund, a Cayman Islands exempted company *which is sponsored, managed and has the same investment objective as the Partnership fund. In addition to the Master Fund, investments are made primarily in offshore investment funds, investment partnerships, and pooled investment vehicles; collectively referred to as Portfolio Funds, which generally implement "nontraditional" or "alternative" investment strategies.*

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 December 31, 2019			Recurring Fair Value Measures December 31, 2018		
(Dollars in Thousands)	Level 1	Level 2	Total	Level 1	Level 2	Total
Assets:						
Mutual fund[1]	$ 6,201	$ —	$ 6,201	$ 5,910	$ —	$ 5,910
Investments measured at NAV[2]			88			50
Total assets			$ 6,289			$ 5,960

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, 2019, and 2018.*

In accordance with ASU 2015-07, "Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities that Calculate Net Asset Value per Share (or Its Equivalent)", certain investments are measured at NAV per share (or its equivalent) are not classified in the fair value hierarchy. The fair value amounts presented in this table are intended to permit reconciliation of the fair value hierarchy to the line items presented in the statement of net assets available for benefits. Investments measured at NAV consist of a common/collective trust fund as of December 31, 2019, and 2018.

(13) Income Taxes

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

Puget Sound Energy	Year Ended December 31,	
(Dollars in Thousands)	2019	2018
Charged to operating expenses:		
Current:		
Federal	$ 18,093	$ 19,283
State	570	438
Deferred:		
Federal	20,628	30,979
State	—	—
Total income tax expense	$ 39,291	$ 50,700

The following reconciliation compares pre-tax book income at the federal statutory rate of 21.0% in 2019 and 2018 to the actual income tax expense in the Statements of Income:

Puget Sound Energy	Year Ended December 31,	
(Dollars in Thousands)	2019	2018
Income taxes at the statutory rate	$ 69,735	$ 77,251
Increase (decrease):		
Utility plant differences[1]	$ (23,025)	$ (25,871)
AFUDC, net	(4,462)	(4,173)
Executive Compensation	2,596	4,439
Treasury grant amortization	(7,870)	(4,861)
Tax reform	—	—
Other–net	2,317	3,915
Total income tax expense	$ 39,291	$ 50,700
Effective tax rate	11.8%	13.8%

1. *Utility plant differences include the reversal of excess deferred taxes using the average rate assumption method in the amount of $27.6 million and $29.8 million in 2019, and 2018, respectively.*

The Company's net deferred tax liability at December 31, 2019, and 2018, is composed of amounts related to the following types of temporary differences:

Puget Sound Energy	At December 31,	
(Dollars in Thousands)	2019	2018
Utility plant and equipment	$ 1,943,730	$ 1,998,721
Other, net deferred tax liabilities	50,095	25,880
Subtotal deferred tax liabilities	1,993,825	2,024,601
Net regulatory liability for income taxes	(946,936)	(976,582)
Production tax credit carryforward	(67,405)	(121,616)
Subtotal deferred tax assets	(1,014,341)	(1,098,198)
Total net deferred tax liabilities	$ 979,484	$ 926,403

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. PSE's PTC carryforwards expire from 2033 through 2036. Net operating losses generated in 2018 and thereafter have no expiration date. No valuation allowance has been provided for PTC or net operating loss carryforwards.

Federal Income Tax Law Changes

On December 22, 2017, President Trump signed into law legislation referred to as the TCJA. Substantially all of the provisions of the TCJA are effective for taxable years beginning after December 31, 2017. The TCJA includes significant changes to the Internal Revenue Code of 1986 (as amended, the Code), including amendments which significantly change the taxation of business entities and includes specific provisions related to regulated public utilities including PSE. The most significant change that impacts the Company included in the TCJA is the reduction in the corporate federal income tax rate from 35.0% to 21.0% and the limitation of deductibility of executive compensation. The specific provisions related to regulated public utilities in the TCJA generally allow for the continued deductibility of interest expense, the elimination of full expensing for tax purposes of certain property acquired after December 31, 2017, and continues normalization requirements for accelerated depreciation benefits.

Under GAAP, specifically ASC Topic 740, Income Taxes, the tax effects of changes in tax laws must be recognized in the period in which the law is enacted and deferred tax assets and liabilities are to be re-measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. The change in deferred taxes is recorded as either an offset to a regulatory asset or liability and is subject to approval by the Washington Commission.

Upon enactment of the TCJA, the Company re-measured its deferred tax assets and liabilities based upon the TCJA's 21.0% percent corporate federal income tax rate. The corporate tax rate change for PSE is captured in the deferred tax balance with an offset to the regulatory liability for deferred income taxes. As a result of tax reform, the balance was a liability of $1,012.3 million. Since PSE is in a net regulatory liability position with respect to these income tax matters, PSE netted the regulatory asset for deferred income taxes against the regulatory liability for deferred income taxes. Under the normalization requirements continued by the TCJA, $919.8 million of the net regulatory liability related to certain accelerated tax depreciation benefits is to be reversed over the remaining lives of the related assets using ARAM. The remainder of the net regulatory liability of $91.9 million is available for PSE and the Washington Commission regulatory process to determine how the amounts will be refunded to customers. PSE requested to delay the impact of tax reform in an accounting petition which was filed with the Washington Commission on December 29, 2017. For further details regarding PSE's ERF and Accounting Petition, see Note 3, "Regulation and Rates". In 2019 and 2018, the Company reversed excess deferred taxes for plant-related items using ARAM in the amount of $27.6 million and $29.8 million, respectively.

The staff of the US Securities and Exchange Commission (SEC) has recognized the complexity of reflecting the impacts of the TCJA and on December 22, 2017, issued guidance in Staff Accounting Bulletin 118 (SAB 118). The guidance clarifies accounting for income taxes under ASC 740 if information is not yet available or complete and provides for up to a one year period in which to complete the required analysis and accounting (the measurement period). The Company completed the required analysis and accounting for the effects of the TCJA's enactment and did not identify any additional adjustments required.

Unrecognized Tax Benefits

The Company accounts for uncertain tax positions 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.

FERC Policy Statement

The following disclosure is provided pursuant to the FERC Policy Statement PL 19-2-000. The Company records its accumulated deferred taxes in FERC Accounts 190, 282, and 283. Based on the Company's estimate of the amount of deferred income taxes that would be used in setting customer rates in the future, it recorded an increase in its net regulatory liability for deferred income taxes of approximately $1,083.8 million, resulting in a regulatory liability for deferred income taxes of $1,012.3 million in FERC Account 254. At remeasurement, the Company did not change its regulated balances in its FERC 190, 282, or 283 Accounts.

Table 1: Change to ADIT balances at Remeasurement by FERC Account

Jurisdiction	FERC 190	FERC 282	FERC 283	FERC 182	FERC 254
FERC	$0	$0	$0	$0	$0

State	$0	$0	$0	$0	$0
Regulated Balance	**$0**	**$0**	**$0**	**$0**	**$0**
FAS109	$1,012.3	$0	$71.5	($71.5)	($1,012.3)
GAAP Balance	**$1,012.3**	**$0**	**$71.5**	**($71.5)**	**($1,012.3)**

The excess ADIT in each FERC account is summarized in Table 2, below.

Table 2: Excess ADIT balances at Remeasurement

Jurisdiction	**FERC 190**	**FERC 282**	**FERC 283**
FERC	$4.9	($90.7)	($3.1)
State	$11.2	($724.7)	($51.8)
Regulated Balance	**$16.1**	**($815.4)**	**($54.9)**
Protected	none	($53.0)	none
Unprotected	$16.1	($762.4)	($54.9)
Reversal Period	Subject to future WUTC order	Average rate assumption method	Subject to future WUTC order
FERC account	FERC 410	FERC 411	FERC 411

At remeasurement, the Company had EDIT of $854.3 million of which $762.4 million was protected and $91.9 million was unprotected.

The reversal of the excess ADIT in FERC Accounts 190 and 283 will be determined by the WUTC in the Company's next general rate case. The reversal of the excess ADIT in FERC Account 282 has already begun under the average rate assumption method as provided in the WUTC's order in the Company's EFT filing. For more detail on the inclusion of excess ADIT in rates, see Footnote 3, "Regulation and Rates".

As of December 31, 2019, and 2018, the Company had no material unrecognized tax benefits. As a result, no interest or penalties were accrued for unrecognized tax benefits during the year.

The Company has open tax years from 2016 through 2019. The Company classifies interest as interest expense and penalties as other expense in the financial statements.

(14) Litigation

From time to time, the Company is involved in litigation or legislative rulemaking proceedings relating to its operations in the normal course of business. The following is a description of pending proceedings that are material to PSE's operations:

Colstrip

PSE has a 50% ownership interest in Colstrip Units 1 and 2 and a 25% interest in each of Colstrip Units 3 and 4. In March 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. In July 2016, PSE reached a settlement with the Sierra Club to dismiss all of the Clean Air Act allegations against the Colstrip Generating Station, which was approved by the court in September 2016. As part of the settlement that was signed by all Colstrip owners, Colstrip 1 and 2 owners, PSE and Talen Energy Corporation (Talen), agreed to retire the two oldest units (Units 1 and 2) at Colstrip in eastern Montana no later than July 1, 2022. Depreciation rates were updated in the GRC effective December 19, 2017, where PSE's depreciation increased for Colstrip Units 1 and 2 to recover plant costs to the expected shutdown date. Additionally, PSE has accelerated the depreciation of Colstrip Units 3 and 4, per the terms of the GRC settlement, to December 31, 2027. The GRC also repurposed PTCs and hydro-related treasury grants to recover unrecovered plant costs and to fund and recover decommissioning and remediation costs for Colstrip Units 1 through 4.

Consistent with a June 2019 announcement, Talen permanently shut down Units 1 and 2 at the end of the year due to operational losses associated with the Units. Colstrip Units 1 and 2 were retired effective December 31, 2019. The Washington Clean Energy Transition Act requires the Washington Commission to provide recovery of the investment, decommissioning, and remediation costs associated with the facilities that are not recovered through the repurposed PTC's and hydro-related treasury grants. The full scope of decommissioning activities and costs may vary from the estimates that are available at this time.

On December 10, 2019, PSE announced its intention to sell its interest in Colstrip Unit 4 to NorthWestern Energy for $1. Under this agreement, PSE would retain its obligation to fund 25% of the environmental remediation and decommissioning costs associated with Unit 4 during PSE's operation. The agreement is subject to approval by the Washington Commission and the Montana Public Service Commission. Additionally, PSE has agreed to enter into a power purchase agreement with NorthWestern Energy for 90 MW through 2025 to facilitate the transition, and sell a portion of its dedicated Colstrip transmission system, conditioned upon regulatory approval. PSE expects external parties to intervene on the contingent purchase agreement for Colstrip Unit 4. For accounting purposes, management has evaluated the applicable held for sale criteria as of December 31, 2019, and determined that these criteria were not met. As such, Unit 4 is classified as Electric Utility Plant on the balance sheet, see Note 5, "Utility Plant,".

Regional Haze Rule

In January 2017, the EPA published revisions to the Regional Haze Rule. Among other things, these revisions delayed new Regional Haze review from 2018 to 2021, however the end date will remain 2028. In January 2018, the EPA announced that it was reconsidering certain aspects of these revisions and PSE is unable to predict the outcome. Challenges to the 2017 Regional Haze Revision Rule are pending in abeyance in the U.S. Court of Appeals for the D.C. Circuit, pending resolution of the EPA's reconsideration of the rule.

Clean Air Act 111(d)/EPA Affordable clean Energy Rule

In June 2014, the EPA issued a proposed Clean Power Plan (CPP) rule under Section 111(d) of the Clean Air Act designed to regulate GHG emissions from existing power plants. The proposed rule includes state-specific goals and guidelines for states to develop plans for meeting these goals. The EPA published a final rule in October 2015. In March 2017, then EPA Administrator, Scott Pruitt, signed a notice of withdrawal of the proposed CPP federal plan and model trading rules and, in October 2017, the EPA proposed to repeal the CPP rule.

In August 2018, the EPA proposed the Affordable Clean Energy (ACE) rule, pursuant to Section 111(d) of the Clean Air Act.. The ACE rule was finalized in June 2019, and establishes emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired plants. Compliance plans under ACE are due July 2020, and compliance generally required by July 2024. PSE is evaluating the final ACE rule to determine its impact on operations pending the outcome of the proposed Colstrip Unit 4 sale to NorthWestern Energy.

Washington Clean Air Rule

The CAR was adopted in September 2016, in Washington State and attempts to reduce greenhouse gas emissions from "covered entities" located within Washington State. Included under the new rule are large manufacturers, petroleum producers and natural gas utilities, including PSE. The CAR sets a cap on emissions associated with covered entities, which decreases over time approximately 5.0% every three years. Entities must reduce their carbon emissions, or purchase emission reduction units (ERUs), as defined under the rule, from others.

In September 2016, PSE, along with Avista Corporation, Cascade Natural Gas Corporation and NW Natural, filed a lawsuit in the U.S. District Court for the Eastern District of Washington challenging the CAR. In September 2016, the four companies filed a similar challenge to the CAR in Thurston County Superior Court. In March 2018, the Thurston County Superior Court invalidated the CAR. The Department of Ecology appealed the Superior Court decision in May 2018. As a result of the appeal, direct review to the Washington State Supreme Court was granted and oral argument was held on March 16, 2019. In January 2020, the Washington Supreme Court affirmed that CAR is not valid for "indirect emitters" meaning it does not apply to the sale of natural gas for use by customers. The court ruled, however, that the rule can be severed and is valid for direct emitters including electric utilities with permitted air emission sources, but remanded the case back to the Thurston County to determine which parts of the rule survive. Meanwhile, the federal court litigation has been held in abeyance pending resolution of the state case.

(15) Commitments and Contingencies

For the year ended December 31, 2019, approximately 10.2% of the Company's energy output was obtained at an average cost of approximately $0.033 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 substantially through 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)	2019	2018
PUD contract costs	$ 87,135	$ 80,165

As of December 31, 2019, 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 2020 Costs	2020 Debt Service Costs	Interest included in 2020 Debt Service Costs	Debt Outstanding
Chelan County PUD:							
Rock Island Project	2031	25.0 %	156	$ 34,180	$ 11,499	$ 5,681	$ 96,956
Rocky Reach Project	2031	25.0	325	31,190	4,940	2,129	33,317
Douglas County PUD:							
Wells Project[1]	2028	27.1	228	43,004	—	—	—
Grant County PUD:							
Priest Rapids Development	2052	0.6	6	1,831	1,085	586	12,793
Wanapum Development	2052	0.6	7	1,831	1,085	586	12,793
Total			722	$ 112,036	$ 18,609	$ 8,982	$ 155,859

1. *In March 2017, PSE entered a new PPA with Douglas County PUD for Wells Project output that begins upon expiration of the existing contract on August 31, 2018, and continues through September 30, 2028.*

The following table summarizes the Company's estimated payment obligations for power purchases from the Columbia River projects, electric portfolio contracts and electric wholesale market transactions. These contracts have varying terms and may include escalation and termination provisions.

(Dollars in Thousands)	2020	2021	2022	2023	2024	Thereafter	Total
Columbia River projects	$ 121,680	$ 111,125	$ 103,879	$ 103,377	$ 102,976	$ 609,912	$ 1,152,949
Electric portfolio contracts	263,940	300,795	302,838	307,888	315,593	969,383	2,460,437
Electric wholesale market transactions	188,822	24,901	3,190	—	—	—	216,913
Total	$ 574,442	$ 436,821	$ 409,907	$ 411,265	$ 418,569	$ 1,579,295	$ 3,830,299

Total purchased power contracts provided the Company with approximately 12.5 million, 14.1 million and 14.5 million MWhs of firm energy at a cost of approximately $550.6 million and $508.2 million for the years 2019 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 1 year to 25 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage. The Company incurred demand charges for 2019 for firm transportation, storage and peaking services for its natural gas customers of $125.1 million. The Company incurred demand charges in 2019 for firm transportation and storage services for the natural gas supply for its combustion turbines in the amount of $51.2 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 CER (Canadian Energy Regulator) currently authorized rates, which are subject to change.

Natural Gas Supply and Demand Charge Obligations (Dollars in Thousands)	2020	2021	2022	2023	2024	Thereafter	Total
Natural gas portfolio contracts	$ 273,263	$ 196,806	$ 178,208	$ 148,165	$ 82,509	$ —	$ 878,951
Firm transportation service	176,741	173,133	172,190	161,508	116,842	828,136	1,628,550
Firm storage service	8,954	4,503	3,014	853	140	213	17,677
Total	$ 458,958	$ 374,442	$ 353,412	$ 310,526	$ 199,491	$ 828,349	$2,525,178

Service Contracts

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

Service Contract Obligations	2020	2021	2022	2023	2024	Thereafter	Total

(Dollars in Thousands)							
Energy production service contracts	$ 28,474	$ 29,219	$ 29,923	$ 30,645	$ 31,400	$ 141,817	$ 291,478
Automated meter reading system	43,971	44,849	45,526	46,218	46,926	96,149	323,639
Total	$ 72,445	$ 74,068	$ 75,449	$ 76,863	$ 78,326	$ 237,966	$ 615,117

Other Commitments and Contingencies

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

(16) Related Party Transactions

The Company identified no material related party transactions during the year ended December 31, 2019 and December 31, 2018.

(17) 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, 2019 and 2018, respectively:

Puget Sound Energy 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 treasury interest rate swaps	Total
Balance at December 31, 2017	$ (121,867)	$ (5,039)	$ (126,906)
Other comprehensive income (loss) before reclassifications	(48,802)	—	(48,802)
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	11,772	385	12,157
Reclassification of stranded taxes to retained earnings due to tax reform	(26,233)	(1,100)	(27,333)
Net current-period other comprehensive income (loss)	(63,263)	(715)	(63,978)
Balance at December 31, 2018	$ (185,130)	$ (5,754)	$ (190,884)
Other comprehensive income (loss) before reclassifications	(8,096)	—	(8,096)
Amounts reclassified from accumulated other comprehensive income (loss), net of tax	10,118	385	10,503
Net current-period other comprehensive income (loss)	2,022	385	2,407
Balance at December 31, 2019	$ (183,108)	$ (5,369)	$ (188,477)

Details about the reclassifications out of AOCI (loss) for the years ended December 31, 2019 and 2018, respectively, are as follows:

Puget Sound Energy

(Dollars in Thousands)

Details about accumulated other comprehensive income (loss) components	Affected line item in the statement where net income (loss) is presented	Amount reclassified from accumulated other comprehensive income (loss) 2019	2018
Net unrealized gain (loss) and prior service cost on pension plans:			
Amortization of prior service cost	(a)	$ 1,240	$ 1,529
Amortization of net gain (loss)	(a)	(14,048)	(16,430)
	Total before tax	$ (12,808)	$ (14,901)
	Tax (expense) or benefit	2,690	3,129
	Net of tax	$ (10,118)	$ (11,772)
Net unrealized gain (loss) on treasury interest rate swaps:			
Interest rate contracts	Interest expense	(487)	(487)
	Tax (expense) or benefit	102	102
	Net of Tax	$ (385)	$ (385)
Total reclassification for the period	Net of Tax	$ (10,503)	$ (12,157)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year		(121,865,358)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income		(140,102,830)		
3	Preceding Quarter/Year to Date Changes in Fair Value		76,822,038		
4	Total (lines 2 and 3)		(63,280,792)		
5	Balance of Account 219 at End of Preceding Quarter/Year		(185,146,150)		
6	Balance of Account 219 at Beginning of Current Year		(185,146,150)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income		10,118,075		
8	Current Quarter/Year to Date Changes in Fair Value		(8,095,354)		
9	Total (lines 7 and 8)		2,022,721		
10	Balance of Account 219 at End of Current Quarter/Year		(183,123,429)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(5,038,694)		(126,904,052)	[redacted]	
2	(700,019)		(140,802,849)		
3			76,822,038		
4	(700,019)		(63,980,811)	317,163,809	253,182,998
5	(5,738,713)		(190,884,863)	[redacted]	
6	(5,738,713)		(190,884,863)		
7	385,239		10,503,314		
8			(8,095,354)		
9	385,239		2,407,960	292,921,676	295,329,636
10	(5,353,474)		(188,476,903)	[redacted]	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	15,023,503,671	9,850,884,909
4	Property Under Capital Leases	184,535,890	
5	Plant Purchased or Sold		
6	Completed Construction not Classified	316,923,426	198,014,565
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	15,524,962,987	10,048,899,474
9	Leased to Others		
10	Held for Future Use	46,385,496	39,011,262
11	Construction Work in Progress	591,198,562	300,627,395
12	Acquisition Adjustments	282,791,675	282,791,675
13	Total Utility Plant (8 thru 12)	16,445,338,720	10,671,329,806
14	Accum Prov for Depr, Amort, & Depl	6,192,635,006	4,199,965,864
15	Net Utility Plant (13 less 14)	10,252,703,714	6,471,363,942
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	5,727,879,898	3,994,415,717
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	318,097,388	58,892,426
22	Total In Service (18 thru 21)	6,045,977,286	4,053,308,143
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation	162,425	162,425
29	Amortization		
30	Total Held for Future Use (28 & 29)	162,425	162,425
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	146,495,295	146,495,295
33	Total Accum Prov (equals 14) (22,26,30,31,32)	6,192,635,006	4,199,965,863

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/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
4,136,788,563				1,035,830,199	3
				184,535,890	4
					5
95,366,539				23,542,322	6
					7
4,232,155,102				1,243,908,411	8
					9
7,374,234					10
229,862,918				60,708,249	11
					12
4,469,392,254				1,304,616,660	13
1,618,544,390				374,124,752	14
2,850,847,864				930,491,908	15
					16
					17
1,601,931,073				131,533,108	18
					19
					20
16,613,317				242,591,645	21
1,618,544,390				374,124,753	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
1,618,544,390				374,124,753	33

Schedule Page: 200 Line No.: 4 Column: b

The Company has adopted ASU 2016-02 as of January 1, 2019, which resulted in the recognition of right-of-use asset and lease liabilities that have not previously been recorded and are material to the balance sheet. Under FERC Docket AI-19-1-000, operating leases are not required to be capitalized and reported in the balance sheet accounts established for capital leases. However, a jurisdictional entity is permitted to implement the ASU's guidance to report operating leases with a lease term in excess of 12 months as right of use assets, with corresponding lease obligations, in the balance sheet accounts established for capital leases. Accordingly the Company’s operating leases are recognized on the balance sheet in Account 101.1 (Property Under Capital Leases), Account 227 (Obligations Under Capital Leases- Noncurrent), and Account 243 (Obligations Under Capital Leases — Current). Adoption of the standard did not have a material impact on the income statement. The financial impact as of the date of adoption was not materially different than what has been disclosed as of December 31, 2019, in Note 8, "Leases".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year: Amortization (d)	Changes during Year: Other Reductions (Explain in a footnote) (e)	Balance End of Year (f)	Line No.
			1
			2
			3
			4
			5
			6
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			9
			10
			11
			12
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			22

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	114,202	
3	(302) Franchises and Consents	58,363,422	1,278,188
4	(303) Miscellaneous Intangible Plant	82,537,015	11,382,224
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	141,014,639	12,660,412
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	3,794,975	
9	(311) Structures and Improvements	178,794,230	2,702,489
10	(312) Boiler Plant Equipment	713,967,406	-853,762
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	345,233,071	2,154,168
13	(315) Accessory Electric Equipment	49,453,732	890,188
14	(316) Misc. Power Plant Equipment	15,898,577	22
15	(317) Asset Retirement Costs for Steam Production	90,820,081	4,690,074
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,397,962,072	9,583,179
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	7,084,999	3,804,376
28	(331) Structures and Improvements	166,252,369	189,967
29	(332) Reservoirs, Dams, and Waterways	358,984,696	1,256,105
30	(333) Water Wheels, Turbines, and Generators	130,239,359	-79,523
31	(334) Accessory Electric Equipment	45,906,968	
32	(335) Misc. Power PLant Equipment	16,076,507	332,882
33	(336) Roads, Railroads, and Bridges	5,045,062	
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	729,589,960	5,503,807
36	D. Other Production Plant		
37	(340) Land and Land Rights	16,016,762	
38	(341) Structures and Improvements	131,543,499	125,419
39	(342) Fuel Holders, Products, and Accessories	25,859,528	319,678
40	(343) Prime Movers		
41	(344) Generators	1,575,106,678	8,475,829
42	(345) Accessory Electric Equipment	153,219,160	1,111,432
43	(346) Misc. Power Plant Equipment	20,594,641	192,977
44	(347) Asset Retirement Costs for Other Production	53,575,909	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,975,916,177	10,225,335
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	4,103,468,209	25,312,321

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Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	59,888,823	-3,545,816
49	(352) Structures and Improvements	12,203,052	
50	(353) Station Equipment	659,825,364	50,703,558
51	(354) Towers and Fixtures	92,200,007	
52	(355) Poles and Fixtures	396,542,783	9,428,859
53	(356) Overhead Conductors and Devices	317,098,187	3,818,811
54	(357) Underground Conduit	1,210,859	
55	(358) Underground Conductors and Devices	36,956,731	
56	(359) Roads and Trails	1,916,220	389,920
57	(359.1) Asset Retirement Costs for Transmission Plant	4,471,521	-2,080,139
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,582,313,547	58,715,193
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	40,668,097	65,785
61	(361) Structures and Improvements	8,102,681	
62	(362) Station Equipment	471,366,229	12,323,149
63	(363) Storage Battery Equipment	1,101,221	108,532
64	(364) Poles, Towers, and Fixtures	394,068,682	22,124,714
65	(365) Overhead Conductors and Devices	470,354,756	49,401,284
66	(366) Underground Conduit	742,386,101	39,173,843
67	(367) Underground Conductors and Devices	982,990,157	79,600,284
68	(368) Line Transformers	499,516,821	22,815,060
69	(369) Services	189,025,800	3,628,059
70	(370) Meters	187,245,608	57,033,274
71	(371) Installations on Customer Premises		228,919
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	57,241,160	2,900,560
74	(374) Asset Retirement Costs for Distribution Plant	2,342,551	892,444
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	4,046,409,864	290,295,907
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	5,116,918	
87	(390) Structures and Improvements	72,979,268	-2,308,873
88	(391) Office Furniture and Equipment	20,605,311	5,766,432
89	(392) Transportation Equipment	11,203,022	275,856
90	(393) Stores Equipment	170,597	
91	(394) Tools, Shop and Garage Equipment	14,283,962	1,924,864
92	(395) Laboratory Equipment	7,819,786	727,910
93	(396) Power Operated Equipment	4,825,233	247,821
94	(397) Communication Equipment	93,796,486	3,872,626
95	(398) Miscellaneous Equipment	277,392	37,221
96	SUBTOTAL (Enter Total of lines 86 thru 95)	231,077,975	10,543,857
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)	231,077,975	10,543,857
100	TOTAL (Accounts 101 and 106)	10,104,284,234	397,527,690
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)	10,104,284,234	397,527,690

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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
1,178,326			58,463,284		3
22,022,738		143,712	72,040,213		4
23,201,064		143,712	130,617,699		5
					6
					7
1,006,168		-62	2,788,745		8
45,206,121			136,290,598		9
186,363,853			526,749,791		10
					11
66,657,465			280,729,774		12
13,749,241			36,594,679		13
8,308,547			7,590,052		14
50,629,164			44,880,991		15
371,920,559		-62	1,035,624,630		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			10,889,375		27
			166,442,336		28
347,783			359,893,018		29
1,041,132			129,118,704		30
15,986			45,890,982		31
28,914			16,380,475		32
			5,045,062		33
					34
1,433,815			733,659,952		35
					36
			16,016,762		37
			131,668,918		38
36,332			26,142,874		39
					40
11,499,858			1,572,082,649		41
769,581			153,561,011		42
			20,787,618		43
			53,575,909		44
12,305,771			1,973,835,741		45
385,660,145		-62	3,743,120,323		46

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
3,624		3,561,326	59,900,709		48
			12,203,052		49
5,648,337			704,880,585		50
88,577			92,111,430		51
727,682			405,243,960		52
486,292			320,430,706		53
			1,210,859		54
			36,956,731		55
			2,306,140		56
			2,391,382		57
6,954,512		3,561,326	1,637,635,554		58
					59
		-634	40,733,248		60
			8,102,681		61
2,430,629			481,258,749		62
			1,209,753		63
2,595,788			413,597,608		64
4,180,610			515,575,430		65
1,277,915			780,282,029		66
7,011,349			1,055,579,092		67
3,614,731			518,717,150		68
227,764			192,426,095		69
12,820,403			231,458,479		70
			228,919		71
					72
26,128			60,115,592		73
			3,234,995		74
34,185,317		-634	4,302,519,820		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		-21,388	5,095,530		86
2,763,738			67,906,657		87
1,858,424			24,513,319		88
335,200			11,143,678		89
			170,597		90
506,949			15,701,877		91
313,326			8,234,370		92
328,929			4,744,125		93
487,805			97,181,307		94
			314,613		95
6,594,371		-21,388	235,006,073		96
					97
					98
6,594,371		-21,388	235,006,073		99
456,595,409		3,682,954	10,048,899,469		100
					101
					102
					103
456,595,409		3,682,954	10,048,899,469		104

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
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42					
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44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	DISTRIBUTION E3600 - AUTUMN GLEN SUBSTATION LAND	3/30/2009	1/31/2021	770,620
3	DISTRIBUTION E3600 - BAINBRIDGE SUBSTATION LAND	2/28/2009	1/1/2029	618,393
4	DISTRIBUTION E3600 - BEL-RED SUBSTATION LAND	12/31/2009	1/31/2022	2,184,108
5	DISTRIBUTION E3600 - BETHEL SUBSTATION LAND	12/31/2005	1/31/2025	710,313
6	DISTRIBUTION E3600 - BUCKLEY SUBSTATION LAND	1/5/2009	12/31/2022	488,523
7	DISTRIBUTION E3600 - CARPENTER SUBSTATION LAND	4/28/2009	1/31/2029	1,041,420
8	DISTRIBUTION E3890 - CLYDE HILL SUBSTATION LAND	10/1/2014	1/31/2024	397,742
9	DISTRIBUTION E3600 - JENKINS CREEK SUBSTATION LAND	10/30/2009	10/25/2022	1,000,290
10	DISTRIBUTION E3600 - KENDALL SUBSTATION LAND	1/31/2010	1/31/2025	353,720
11	DISTRIBUTION E3600 - LAKE HOLMS SUBSTATION LAND	1/1/2012	1/31/2021	912,413
12	DISTRIBUTION E3600 - MITIGATION LAND GOPHER	12/31/2018	9/20/2020	2,177,759
13	DISTRIBUTION E3600 - PLUM STREET SUBSTATION LAND	2/28/2014	1/31/2025	305,608
14	TRANSMISSION E3500 - BPA KITSAP NAVAL TRANS PLANT	12/31/1992	1/1/2020	436,566
15	TRANSMISSION E3501 -BPA KITSAP NAVAL YARD TRANS	1/21/2016	12/31/2022	460,720
16	TRANSMISSION E3500 -HAZELWOOD SUBSTATION - LAND	1/31/2014	1/1/2022	460,994
17	TRANSMISSION E3500 -HOFFMAN SWITCHING STATION DISTR	3/31/2005	1/31/2021	714,663
18	TRANSMISSION E3557 / E3567 -SAINT CLAIR - PLEASANT	1/31/2014	1/31/2029	1,870,639
19	TRANSMISSION E3507 -SO. BREMERTON-BANGOR LAND	9/4/2007	12/31/2025	1,005,331
20	INTANGIBLE E303 - GREEN DIRECT-SW.CN.3YR	12/31/2018	4/30/2020	340,638
21	Other Property:			
22	OTHER PROPERTY (less than $250,000)			517,256
23				
24	Land and Rights: (continued)			
25	INTANGIBLE E303 - LOWER SNAKE RIVER WIND	3/31/2014	12/31/2020	22,243,546
26				
27				
28				
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34				
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42				
43				
44				
45				
46				
47	Total			39,011,262

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	ADMS-Distribution Management System	13,967,001
2	AMI Project	1,135,941
3	Bainbridge Project	4,751,494
4	Baker Project	34,917,178
5	Berrydale-Krain Transmission Line Project	1,368,731
6	Bremerton-Bangor Project	1,455,918
7	Eastside Transmission Project	79,386,243
8	Fredonia Project	15,063,668
9	Greenwater Tap Project	1,395,653
10	Lakeside-Ardmore Project	1,013,979
11	Other Misc. Work Orders	2,411,762
12	Phantom Lake - Lake Hills Project	4,846,005
13	Residential Electric Vehicle Project	1,000,315
14	Sammamish-Moorlands Project	8,416,037
15	Sedro-Bellingham Project	3,582,799
16	Skookumchuck Wind Farm Project	3,712,582
17	Woodland - St Clair Project	3,092,616
18		
19	CWIP less than $1,000,000 each - Electric Distribution	77,821,389
20	CWIP less than $1,000,000 each - Electric Transmission	18,362,334
21	CWIP less than $1,000,000 each - Electric General Plant & Intangibles	11,545,334
22	CWIP less than $1,000,000 each - Electric Generation	10,616,927
23	WSDOT	763,489
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	300,627,395

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	3,996,939,491	3,996,777,066	162,425	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	326,659,699	326,659,699		
4	(403.1) Depreciation Expense for Asset Retirement Costs	7,533,981	7,533,981		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing				
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)	334,193,680	334,193,680		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	430,053,741	430,053,741		
13	Cost of Removal	24,492,631	24,492,631		
14	Salvage (Credit)	267,269	267,269		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	454,279,103	454,279,103		
16	Other Debit or Cr. Items (Describe, details in footnote):	117,724,074	117,724,074		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	3,994,578,142	3,994,415,717	162,425	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	722,384,927	722,384,927		
21	Nuclear Production				
22	Hydraulic Production-Conventional	200,179,377	200,179,377		
23	Hydraulic Production-Pumped Storage				
24	Other Production	852,190,783	852,190,783		
25	Transmission	544,378,862	544,378,862		
26	Distribution	1,583,879,759	1,583,879,759		
27	Regional Transmission and Market Operation				
28	General	91,564,434	91,564,434		
29	TOTAL (Enter Total of lines 20 thru 28)	3,994,578,142	3,994,578,142		

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

Other debit or Cr. Items includes the transfer of unrecovered plant of $126.5M related to the retirement of Colstrip Units 1&2 to a designated 182.2 account as well as other manual adjustments.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	PUGET WESTERN, INC.	05/31/1960		
2	Common			10,200
3	Retained Earnings			-19,756,868
4	Additional Paid in Capital			44,487,244
5	Subtotal			24,740,576
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
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36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	24,740,576

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
-535,421		-20,292,289		3
2,750,000		47,237,244		4
2,214,579		26,955,155		5
				6
				7
				8
				9
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2,214,579		26,955,155		42

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	19,826,388	15,762,779	
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)	94,863,106	99,932,988	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	9,404,016	3,821,990	Electric & Gas
8	Transmission Plant (Estimated)	819,033	571,263	Electric & Gas
9	Distribution Plant (Estimated)	8,863,340	9,104,743	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	2,664,093	2,124,134	Electric & Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	116,613,588	115,555,118	Electric & Gas
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	277,440	32,795	Electric & Gas
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	-456,332	-208,479	Electric & Gas
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	136,261,084	131,142,213	

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

These accounts are primarily from damage claims, miscellaneous projects for customers at the customer's premises, and various other merchandising materials.

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

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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/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)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	52,955.00	22,556	9,030.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Purchased: Vitol	10,000.00	157,800		
10	Purchased: Morgan Stanley	10,000.00	172,500		
11	Transfer: Talen MT	-3,150.00			
12	Initial Allocation to PSE				
13					
14					
15	Total	16,850.00	330,300		
16					
17	Relinquished During Year:				
18	Charges to Account 509	18.00			
19	Other:				
20		1,113.00	16,928		
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	68,674.00	335,928	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	5,120.00			
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA	398.00			
39	Cost of Sales				
40	Balance-End of Year	4,722.00			
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)		10		
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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/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.

2021		2022		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
9,034.00		9,029.00		229,679.00		309,727.00	22,556	1
								2
								3
								4
								5
								6
								7
								8
						10,000.00	157,800	9
						10,000.00	172,500	10
				10,650.00		7,500.00		11
				3,686.00		3,686.00		12
								13
								14
				14,336.00		31,186.00	330,300	15
								16
								17
						18.00		18
								19
						1,113.00	16,928	20
								21
								22
								23
								24
								25
								26
								27
								28
9,034.00		9,029.00		244,015.00		339,782.00	335,928	29
								30
								31
								32
								33
								34
								35
						5,120.00		36
								37
						398.00		38
								39
						4,722.00		40
								41
								42
							10	43
								44
								45
								46

Schedule Page: 228 Line No.: 11 Column: a

Talen MT (previously, PPL Montana) is the operator and co-owner of the Colstrip Generating Facility.

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

The following table reflects 2019 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	12/31/18 Estimated Balance of Withheld Allowances Years 2009-2025	Estimated EPA Withheld Allowances Sold During 2019	12/31/19 Estimated Balance of Withheld Allowances Years 2009-2025
Colstrip Unit 1	1,269	163	1,106
Colstrip Unit 2	1,243	162	1,081
Colstrip Unit 3	735	41	694
Colstrip Unit 4	1,873	32	1,841
	5,120	398	4,722

Schedule Page: 228 Line No.: 43 Column: c

2019 proceeds from sales of allowances withheld by the Environmental Protection Agency were as follows:

Plant	2019 Proceeds
Colstrip Unit 1	4
Colstrip Unit 2	4
Colstrip Unit 3	1
Colstrip Unit 4	1
Total Proceeds	$ 10

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/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)	2020 No. (d)	2020 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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/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.

2021		2022		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
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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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/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	2012 Storm	45,531,109		407	9,061,380	36,469,729
2	2014 Storm	1,406,044		407	1,406,044	
3	2015 Storm	24,158,235		407	14,855,492	9,302,743
4	2016 Storm	10,437,020				10,437,020
5	2017 Storm Excess Costs	12,707,858				12,707,858
6	2017 Storm Recovery	12,215,519				12,215,519
7	2018 Storm Excess Costs	11,874,754	372,516			12,247,270
8	2019 Storm Excess Costs		28,513,473			28,513,473
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL	118,330,539	28,885,989		25,322,916	121,893,612

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Colstrip 1&2 Unrecovered Plant		126,549,623			126,549,623
22	Contra PTCs Monetized for Unrec P		-82,224,443			-82,224,443
23						
24						
25						
26						
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43						
44						
45						
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48						
49	TOTAL		44,325,180			44,325,180

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

The 2010 storm deferral cost was over-amortized beginning in 2016, and the over-amortized balance was approved by WUTC Dockets UE-170033 and UG-170034 to be applied to offset the remaining balances first on the 2006 storm deferral cost, and then any remaining credit be applied to the 2012 storm deferral cost. This caused a credit of ($5,386,340) to reduce the 2012 storm deferral cost. Additionally, the WUTC approved amortization of the remaining 2012 storm deferral cost over a period of 6 years, beginning in December 2017.

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

The 2017 General Rate Case on Dockets UE-170033 and UG-170034 was approved by the WUTC to amortize 2010-2017 storm deferral costs over a 4 year period, beginning in December 2017. The storms were to be amortized at a total monthly rate of $1,355,128, with a prorated amortization of $518,093 occuring in December 2017. The storm deferrals are to be amortized in order of occurrence, beginning with the 2014 storm deferral cost.

Schedule Page: 230 Line No.: 3 Column: a

The 2017 General Rate Case on Dockets UE-170033 and UG-170034 was approved by the WUTC to amortize 2010-2017 storm deferral costs over a 4 year period, beginning in December 2017. The storms were to be amortized at a total monthly rate of $1,355,128. The storm deferrals are to be amortized in order of occurrence, beginning with the 2014 storm deferral cost. The 2014 storm deferral amortization was completed in February of 2019, at which time the 2015 storm deferral amortization began at a prorated amount of $1,304,212 for February.

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

Colstrip units 1&2 have been shut down with an effective date of 12/31/2019 which will be considered the retirement date. All assets related to Colstrip units 1&2 have been retired in PowerPlant, and transferred to a 182.2 account for unrecovered plant. The balance will remain in this account until the WUTC authorizes the amortization over a defined period of time.

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

Colstrip units 1&2 have been shut down with an effective date of 12/31/2019 which will be considered the retirement date. All assets related to Colstrip units 1&2 have been retired in PowerPlant, and transferred to a 182.2 account for unrecovered plant. Per the 2017 GRC order, unrecovered plant is recoverable through existing balances of Production Tax Credits (PTC's).

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	n/a				
3					
4					
5					
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21	**Generation Studies**				
22	Grays Harbor System Impact Study	222	186051050		
23	Maria Energy Storage Ph 1&2 FStudy	13,153	186052891		
24	Painter Storage 150MW FStudy	26,869	186052893		
25	Stony Lake 200MW Battery FStudy	18,817	186052896		
26	Kittitas Solar Center FStudy			(12,432)	186054127
27	Maria Energy Storage Ph 1&2 SIS	11,695	186055227		
28	Stony Lake 200MW Battery SIS	18,914	186055229		
29	Painter Storage 150MW SIS	3,079	186055230		
30	Rocky Reach Solar FStudy	1,081	186056550		
31					
32					
33					
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40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Unamortized Energy Conservation Costs	30,700,749	269,351,244	182.3, 908	274,779,743	25,272,250
2	WUTC Deferred AFUDC	52,028,793	8,137,111	406	2,612,609	57,553,295
3	Colstrip 1&2 Western Energy Coal Reserve - 10 years	3,641,810		501, 406	1,076,478	2,565,332
4	Colstrip 3&4 Deferred Depreciation - 17.5 years	761,233		406	138,804	622,429
5	Environmental Remediation Costs	40,025,397	7,088,762	Multiple	16,597,872	30,516,287
6	Property Tax Tracker	45,621,842	58,964,305	408	82,143,844	22,442,303
7	Decoupling Mechanism	66,614,366	97,627,681	Multiple	120,732,918	43,509,129
8	Low Income Home Energy Assistance Program		20,244,794	108, 253	20,244,793	1
9	Power Cost Adjustment Mechanism	4,734,998	43,757,076	557, 419	6,747,098	41,744,976
10	White River Regulatory Asset - 3 years	12,965,655	3,779	182.3, 407	6,570,522	6,398,912
11	Chelan PUD - 20 years	90,963,509		555	7,088,066	83,875,443
12	Mint Farm Deferral - 15 years	17,865,335		407.3	2,885,052	14,980,283
13	Lower Snake River Deferral - 25 years	72,093,361		253, 407.3	4,398,795	67,694,566
14	Ferndale Deferral - 6 years	3,767,014		407.3	3,767,014	
15	Credit Card Fee Deferral - 3 years	2,287,652		182.3, 407	1,426,044	861,608
16	AMI and Electric Vehicle Deferral		14,162,763	Multiple		14,162,763
17						
18						
19						
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44	TOTAL	444,071,714	519,337,515		551,209,652	412,199,577

Schedule Page: 232 Line No.: 1 Column: a

Included in Washington Commission Dockets UE-080389, UG-080390, UE-970686 and UG-120812.

Schedule Page: 232 Line No.: 2 Column: a

Included in Washington Commission Dockets UE-130137, UG-130138, UE-072300 and UG-072301.

Schedule Page: 232 Line No.: 3 Column: a

Included in Washington Commission Dockets UE-111048 and UG-111049. Amortization expired in December 2019.

Schedule Page: 232 Line No.: 4 Column: a

Included in Washington Commission Dockets UE-072300 and UG-072301. Amortization expires in May 2024.

Schedule Page: 232 Line No.: 5 Column: a

Included in Washington Commission Dockets UE-991796, UE-072300, UG-072301, UE-911476, UE-021537, UE-130137 and UG-130138.

Schedule Page: 232 Line No.: 6 Column: a

Included in Washington Commission Dockets UE-111048, UG-111049, and UE -140599 effective May 1, 2014.

Schedule Page: 232 Line No.: 7 Column: a

Included in Washington Commission Dockets UE-170033 and UG-170034.

Schedule Page: 232 Line No.: 8 Column: a

No docket number required.

Schedule Page: 232 Line No.: 9 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.: 10 Column: a

Included in Washington Commission Dockets UE-170033 and UG-170034. New GRC 2017 for White River amortization of 3 years. Effective December 19, 2017 and expires in December 2020.

Schedule Page: 232 Line No.: 11 Column: a

Included in Washington Commission Dockets UE-060266 and UE-060539. Amortization began in November 2011 and expires in October 2031.

Schedule Page: 232 Line No.: 12 Column: a

Included in Washington Commission Docket UE-090704. Amortization began in April 2010 and expires in March 2025.

Schedule Page: 232 Line No.: 13 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 2037.

Schedule Page: 232 Line No.: 14 Column: a

Included in Washington Commission Dockets UE-141141, UE-130617, UE-131230, UE-131099 and UE-130583. Amortization is for 6 years which began November 2013 and expired October 2019.

Schedule Page: 232 Line No.: 15 Column: a

Included in Washington Commission Dockets UE-170033 and UG-170034. PSE sought recovery of the deferral in rates that become effective December 19, 2017 and expires in December 2020.

Schedule Page: 232 Line No.: 16 Column: a

Included in Washington Commission Dockets UE-180899, UG-180900, UE-190129, UE-160799 and UE-180877. Amortization began in March 2019.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Incurred not Report Worker Comp	3,277,997	564,107	186,253	1,793,199	2,048,905
2	Carbon Offset Program	106,533	84,114	253	190,647	
3	Damage Claim	3,453,533	12,523,293	186	11,459,598	4,517,228
4	Clearing Account Charges	-247,490	5,754,925	184,186	326,027	5,181,408
5	FAS133 Net Unrealized	14,739,439	73,470,383	244	88,209,822	
6	Chelan Prepayments - 20 Yrs	6,264,466	141,067	555	528,456	5,877,077
7	Ferndale Maintenance - 12 Yrs	2,044,203		553	240,495	1,803,708
8	Encogen Maintenance - 10 Yrs	8,695,978	18,737	553	1,188,839	7,525,876
9	Environmental Remediation Exp	36,319,509	6,910,771	186,228	5,260,413	37,969,867
10	Real Estate Oper Leases - 7 Yrs	9,774,328	1,273,044	Various	3,498,111	7,549,261
11	FSAS 71 - Snoqualmie License	7,406,855	35,459	253		7,442,314
12	Baker Article	4,927,628	87,920	242	255,783	4,759,765
13	SFAS 71 - Baker License	55,607,319	982,190	253	162,759	56,426,750
14	Colstrip Maintenance - 3 Yrs	6,848,735		Various	3,911,826	2,936,909
15	Montana Comm Transition Fund	712,737		108	712,737	
16	Fredonia Maintenance - 9 Yrs	3,787,620	4,114,304	553	701,148	7,200,776
17	Fredrickson Maintenance - 7 Yrs	4,748,786	11,116	513,553	1,210,542	3,549,360
18	Goldendale Maintenance 4-8 Yrs	2,392,551		514,553	694,250	1,698,301
19	Whitehorn Maintenance - 6 Yrs	2,285,414	5,361	186,553	494,595	1,796,180
20	Mint Farm Maintenance - 3-7 Yrs	2,023,150		513,553	970,982	1,052,168
21	Sumas Maintenance - 11 Yrs	3,195,444		553	339,138	2,856,306
22	Non-Temp Facility	6,521,470	10,381,696	186	9,117,368	7,785,798
23	Residential Exchange	2,807,590	46,123,381	253	42,533,308	6,397,663
24	GTZ Depreciation		22,148,375	186		22,148,375
25	Minor Items	160,944	22,038,099	186,456	15,292,949	6,906,094
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44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	187,854,739				205,430,089

Schedule Page: 233 Line No.: 8 Column: a

18605081 ENC Unit #3 Main 2017 JR490 - December 2018 ending balance versus amortization schedule discrepancy corrected in 2019.

Schedule Page: 233 Line No.: 10 Column: c

Q4/2019 Revision: Rounded down debit by 1 to fix rounding error.

Schedule Page: 233 Line No.: 17 Column: a

18603041 FRE U2 Hot Gas Inspection JR326 - December 2017 and 2018 ending balance versus amortization schedule discrepancy corrected in 2019.

Schedule Page: 233 Line No.: 18 Column: a

18603011 GLD Stm Tur Inspection 2014 JR329 - December 2017 ending balance versus amortization schedule discrepancy corrected in 2018.

Schedule Page: 233 Line No.: 20 Column: a

18604011 MTF ST FP Ins 2017 JR523 - December 2017 and 2018 ending balance versus amortization schedule discrepancy corrected in 2019.

Schedule Page: 233 Line No.: 21 Column: a

18604021 SUM CT Gen Major Inspection JR493 - December 2018 ending balance versus amortization schedule discrepancy corrected in 2019.

Schedule Page: 233 Line No.: 23 Column: a

2017/Q4 Line 23 was Shelf Registration. Accounts involved have no 2018 activity and were blocked. Line 23 was re-purposed to Residential Exchange which is a new 2018 line item.

Schedule Page: 233 Line No.: 25 Column: a

Q4/2019 Revision: Removed previous line 25 - ROU Assets which actually sits in Plant due to a FERC order issued 2019. Moved line 26 - Minor Items up to Line 25.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	SFAS 109	635,356,819	611,977,826
3	Production Tax Credit	121,616,101	67,404,994
4	Pension and Other Compensation	69,351,222	69,624,102
5	Regulatory Assets	41,983,848	58,549,953
6	Derivative Instruments	12,792,839	10,487,446
7	Other	38,808,916	31,932,404
8	TOTAL Electric (Enter Total of lines 2 thru 7)	919,909,745	849,976,725
9	Gas		
10	SFAS 109	341,225,136	334,958,136
11	Derivative Instruments	6,399,076	2,388,606
12	Pension and Other Compensation	4,033,820	3,905,229
13	Regulatory Assets	2,647,274	1,477,679
14			
15	Other	1,945,963	3,315,534
16	TOTAL Gas (Enter Total of lines 10 thru 15	356,251,269	346,045,184
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,276,161,014	1,196,021,909

Notes

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/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	Total Common	150,000,000		
4				
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CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
85,903,791	859,038					1
						2
85,903,791	859,038					3
						4
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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	3,014,096,691
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40	TOTAL	3,014,096,691

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
2		
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21		
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 7.00% Series B	100,000,000	954,608
5	5.483% Senior Notes Due 06/35	250,000,000	2,460,125
6	6.724% Senior Notes Due 06/36	250,000,000	2,527,628
7	6.274% Senior Notes Due 03/37	300,000,000	2,921,148
8	5.757% Senior Notes Due 10/39	350,000,000	3,557,361
9	5.795% Senior Notes Due 03/40	325,000,000	3,384,066
10	5.464% Senior Notes Due 07/40	250,000,000	2,587,276
11	4.434% Senior Notes Due 11/41	250,000,000	2,592,616
12	4.700% Senior Notes Due 11/51	45,000,000	511,229
13	5.638% Senior Notes Due 04/41	300,000,000	3,071,895
14	5.638% Senior Notes Due 04/41 (D)		15,000
15	4.300% Senior Notes Due 05/45	425,000,000	3,718,750
16	4.300% Senior Notes Due 05/45 (D)		1,912,500
17	4.223% Senior Notes Due 06/48	600,000,000	1,429,461
18	3.250% Senior Notes Due 09/49	450,000,000	6,849,000
19	3.9% Pollution Control Bonds Rev Series 2013A	138,460,000	1,473,301
20	4.0% Pollution Control Bonds Rev Series 2013B	23,400,000	248,243
21	SUBTOTAL	4,356,860,000	43,224,953
22			
23	Bonds assumed which were originally issued by Washington Natural Gas Company		
24			
25	Secured Medium Term Notes - 7.15% Series C	15,000,000	112,500
26	Secured Medium Term Notes - 7.20% Series C	2,000,000	15,000
27	SUBTOTAL	17,000,000	127,500
28			
29			
30			
31			
32			
33	TOTAL	4,373,860,000	43,352,453

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
12/22/97	12/01/27	12/22/97	12/01/27	300,000,000	21,060,000	3
03/09/99	03/09/29	03/09/99	03/09/29	100,000,000	7,000,000	4
05/27/05	06/01/35	05/27/05	06/01/35	250,000,000	13,707,500	5
06/30/06	06/15/36	06/30/06	06/15/36	250,000,000	16,810,000	6
09/18/06	03/15/37	09/18/06	03/15/37	300,000,000	18,822,000	7
09/11/09	10/01/39	09/11/09	10/01/39	350,000,000	20,149,500	8
03/08/10	03/15/40	03/08/10	03/15/40	325,000,000	18,833,750	9
06/29/10	07/15/40	06/29/10	07/15/40	250,000,000	14,410,000	10
11/16/11	11/15/41	11/16/11	11/15/41	250,000,000	11,085,000	11
11/22/11	11/15/51	11/22/11	11/15/51	45,000,000	2,115,000	12
03/25/11	04/15/41	03/25/11	04/15/41	300,000,000	16,914,000	13
						14
05/26/15	05/20/45	05/26/15	05/20/45	425,000,000	18,275,000	15
						16
06/04/18	06/15/48	06/04/18	06/15/48	600,000,000	25,338,000	17
08/30/19	09/15/49	08/30/19	09/15/49	450,000,000	4,956,250	18
05/23/13	03/01/31	05/23/13	03/01/31	138,460,000	5,399,940	19
05/23/13	03/01/31	05/23/13	03/01/31	23,400,000	936,000	20
				4,356,860,000	215,811,940	21
						22
						23
						24
12/20/95	12/19/25	12/20/95	12/19/25	15,000,000	1,072,500	25
12/22/95	12/22/25	12/22/95	12/22/25	2,000,000	144,000	26
				17,000,000	1,216,500	27
						28
						29
						30
						31
						32
				4,373,860,000	217,028,440	33

Schedule Page: 256 Line No.: 27 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).

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)	292,921,676
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	39,290,721
11	Others	271,693,831
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	259,601,255
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	
28	Show Computation of Tax:	
29		
30	Taxable Income	344,304,974
31	Tax @21%	72,304,045
32	PTC	-54,211,107
33	Current Federal Tax	18,092,938
34	Current State Tax	570,873
35	Deferred Tax	20,626,910
36	Total Tax	39,290,721
37		
38		
39		
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43		
44		

Schedule Page: 261   Line No.: 11   Column: b

Line 11 Details:	
Capitalized Interest	14,636,849
Conservation Activity	5,428,499
Decoupling Revenue	22,338,570
Plant Related	180,328,240
Derivative Instruments	3,574,274
Environmental Costs	7,022,602
Non-Deductible Items	5,399,605
Pensions and Other Compensation	8,692,787
Property Tax Rate Tracker	13,662,843
Other Adjustment	10,609,563
Subtotal	271,693,832

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

Line 20 Details:	
Allowance for Funds Used During Construction	(35,885,089)
Electric and Gas Purchase Contracts	(6,943,930)
Regulatory Assets	(175,140,906)
Storm Related Activity	(3,563,073)
Treasury Grant Amortization	(37,477,767)
State Tax Expense	(590,490)
Subtotal	(259,601,255)

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						
2	Income	-504,098		64,226,432	-64,434,806	
3	Employment	492,677		26,211,715	-26,286,045	
4	Other					
5						
6						
7	Property	81,221,084		56,423,457	-75,862,318	1,401,258
8	Excise	18,269,985		118,680,734	-119,972,022	
9	Municipal	16,337,694		120,284,603	-117,842,986	
10	Other	1,024,385		4,668,843	-4,729,045	
11						
12						
13						
14						
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39						
40						
41	TOTAL	116,841,727		390,495,784	-409,127,222	1,401,258

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-712,472		30,838,206			33,388,226	2
418,347		9,363,564			16,848,151	3
						4
						5
						6
63,183,481		58,456,212			-2,032,755	7
16,978,697		82,732,381			35,948,353	8
18,779,311		79,796,782			40,487,821	9
964,183		2,195,100			2,473,743	10
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99,611,547		263,382,245			127,113,539	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
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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11							
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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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
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			48

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	8,246,652	Various	2,130,389	2,362,503	8,478,766
2	SFAS 106 Unfunded Liability	29,662,354	417	14,932,226	19,716,734	34,446,862
3	Low Income Program	18,014,753	Various	32,375,505	41,639,613	27,278,861
4	Sch 85 Line Extension Cost	12,437,441	456	443,958	1,141,507	13,134,990
5	Green Power Tariff	6,059,946	456	885,781	2,486,592	7,660,757
6	Landlord Incentives - 5-11 Yrs	3,221,728	931	4,812,357	10,630,461	9,039,832
7	PTC Deferred Post June '10	60,328,609	407	67,606,962	7,278,351	-2
8	Workers Comp - IBNR	3,295,054	186	1,120,241	173,764	2,348,577
9	Residential Exchange		555	179,319,399	179,319,399	
10	Operating Leases Obligation	9,679,079	186	11,188,792	1,509,713	
11	Decoupling	835,357		835,358		-1
12	LSR License O&M - 25 Yrs	9,454,183	Various	8,652,977	8,235,078	9,036,284
13	Snoqualmie License O&M	7,406,855	186		35,459	7,442,314
14	Ferndale License Misc Def - 6 Yrs	451,086	419	451,086		
15	Baker License Misc Def	55,607,320	186	162,759	982,189	56,426,750
16	Unearned Revenue - 11-20 Yrs	822,251	454	6,377,871	9,127,958	3,572,338
17	Deferred Pole Contact			13,393,802	13,393,802	
18	PGA Unrealized Gain			14,159,921	16,917,277	2,757,356
19	Equity Reserve AMI		419		1,180,824	1,180,824
20	Montana PTC	81,811,275	Various	278,201,467	263,885,948	67,495,756
21	Unclaimed Property	-52,210	131	700,437	850,623	97,976
22	Colstrip 3&4 Final	57,989	131	2,364,859	2,347,840	40,970
23	Mint Farm Misc Def Credit - 15 Yrs	5,546,713	419	884,724		4,661,989
24	Deferred Interchange		555	24,368,677	24,368,677	
25	Tacoma LNG	500,000	131	500,000		
26	Green Direct Liquidated Damages		143	1,903,176	1,903,176	
27	Microsoft Special Contract Regula			23,685,000	23,685,000	
28	Minor Items	197,935	Various	347,138	359,853	210,650
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47	TOTAL	313,584,370		691,804,862	633,532,341	255,311,849

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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (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
							2
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NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	1,398,173,784	7,087,535	60,792,643
3	Gas	600,547,117	8,565,070	9,850,948
4				
5	TOTAL (Enter Total of lines 2 thru 4)	1,998,720,901	15,652,605	70,643,591
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,998,720,901	15,652,605	70,643,591
10	Classification of TOTAL			
11	Federal Income Tax	1,998,720,901	15,652,606	70,643,591
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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
						1,344,468,676	2
						599,261,239	3
							4
						1,943,729,915	5
							6
							7
							8
						1,943,729,915	9
							10
						1,943,729,916	11
							12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Pension related	43,333,659	2,275,369	964,859
4	Storm Damage	42,840,603	12,438,354	11,690,109
5	Derivative Instruments	11,442,698	17,490,419	20,294,760
6	Regulatory Assets	58,637,352	47,891,085	18,121,475
7	Other	12,640,800	5,926,222	708,062
8				
9	TOTAL Electric (Total of lines 3 thru 8)	168,895,112	86,021,449	51,779,265
10	Gas			
11	Pension related	4,374,151	1,162,264	492,852
12	Derivative Instruments	6,399,076	10,844,368	14,854,838
13	Regulatory Assets	25,372,123	5,193,581	11,553,752
14	Other	989,800	1,353,546	
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	37,135,150	18,553,759	26,901,442
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	206,030,262	104,575,208	78,680,707
20	Classification of TOTAL			
21	Federal Income Tax			
22	State Income Tax			
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						44,644,169	3
						43,588,848	4
		various	149,244			8,489,113	5
						88,406,962	6
						17,858,960	7
							8
			149,244			202,988,052	9
							10
						5,043,563	11
						2,388,606	12
						19,011,952	13
						2,343,346	14
							15
							16
						28,787,467	17
							18
			149,244			231,775,519	19
							20
							21
							22
							23

NOTES (Continued)

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	1,196	411.8	971		225
2	Summit Purchase Buyout	2,887,500	456, 495	1,575,000		1,312,500
3	Renewable Energy Credits	1,409,173	Multiple	4,078,006	4,086,280	1,417,447
4	Treasury Grants - Wind Project Expansion	460,141	407.4	11,833,082	12,252,818	879,877
5	PTC Cost Deferral	93,615,823	407.3, 403	11,192,989	2,899,939	85,322,773
6	Decoupling Mechanisms	13,757,924	Multiple	57,523,288	52,265,637	8,500,273
7	Regulatory Liability Tax Reform	976,581,952	Multiple	30,106,772	460,779	946,935,959
8	Microsoft Special Contract Reg Liability		253, 254		12,661,278	12,661,278
9	Green Direct Liquidated Damages		143, 254		2,420,712	2,420,712
10	Gain on Sale Shuffleton - Electric		187, 254		12,482,801	12,482,801
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41	TOTAL	1,088,713,709		116,310,108	99,530,244	1,071,933,845

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

Included in Washington Commission Docket UE-001157. Effective in October 2000, each sale amortizes over ten years from the date of sale. Amortization expires in April 2020 and April 2021.

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

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

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

Included in Washington Commission Dockets UE-111048 and UE-111049 (Schedule 137) effective January 1, 2018. The REC liablility balance is used to offset PTC receivables.

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

Included in Washington Commission Docket UE-120277 "Interest on the unamortized balance of U.S. Treasury Department Grant" and UE-171086 (Schedule 95A) effective January 1, 2018. The updated name is to reflect the liabilities being reviewed which remains the same from previous quarters.

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

Included in Washington Commission Dockets UE-070725, UE-101581, UE-170033, and UG-170034. The REC liability balance is used to offset PTC receivables.

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

Included in Washington Commission Dockets UE-170033 and UG-170034 effective December 19, 2017.

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

PSE re-evaluated it's deferred tax liability in December 2017 due to the 2017 Tax reform and has requested deferral accounting in a petition filed with the WUTC on December 29, 2017.

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

Included in Washington Commission Docket UE-161123 effective July 13, 2017. The Special Contract will have a 20-year initial term with automatic 5-year extension so long as Microsoft does not have any cost-effective alternative to PSE for distribution service, all as set forth in the Special Contract.

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

Shookumchuck Wind Energy Project accural on liquidated damages. The foundation completion of 11 Turbines to be erected has currently been achieved as of December 16, 2019.

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

Included in Washington Commission Docket UE-190606 effective August 29, 2019. On July 16, 2019, PSE filed with WUTC an application seeking a determination that 7.74 acres at its Shuffleton Switching Station Property will no longer be necessary or useful under WAC 480-143-180, and authorization for accounting treatment for the gain on sale will be recorded in FERC Account 254 (Other Regulatory Liabilities).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	1,139,356,243	1,147,259,983
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	861,688,507	885,537,077
5	Large (or Ind.) (See Instr. 4)	107,951,534	114,058,620
6	(444) Public Street and Highway Lighting	18,056,669	18,378,087
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	2,127,052,953	2,165,233,767
11	(447) Sales for Resale	197,298,066	155,673,554
12	TOTAL Sales of Electricity	2,324,351,019	2,320,907,321
13	(Less) (449.1) Provision for Rate Refunds	-14,827,619	24,054,569
14	TOTAL Revenues Net of Prov. for Refunds	2,339,178,638	2,296,852,752
15	Other Operating Revenues		
16	(450) Forfeited Discounts	2,128,526	2,451,377
17	(451) Miscellaneous Service Revenues	11,894,207	12,237,816
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	17,462,763	18,352,788
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	117,042,184	84,129,102
22	(456.1) Revenues from Transmission of Electricity of Others	28,555,566	29,059,353
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	177,083,246	146,230,436
27	TOTAL Electric Operating Revenues	2,516,261,884	2,443,083,188

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	No.
				1
10,756,628	10,497,389	1,025,024	1,010,574	2
				3
8,837,457	8,932,681	130,009	128,845	4
1,161,149	1,189,828	3,343	3,378	5
77,996	77,297	7,315	6,984	6
				7
				8
				9
20,833,230	20,697,195	1,165,691	1,149,781	10
6,653,074	5,384,631	8	8	11
27,486,304	26,081,826	1,165,699	1,149,789	12
				13
27,486,304	26,081,826	1,165,699	1,149,789	14

Line 12, column (b) includes $ 16,271,444 of unbilled revenues.

Line 12, column (d) includes 269,925 MWH relating to unbilled revenues

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

This includes $6,778,860 of transportation revenue

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

This includes $79,908 of transportation revenue

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

This includes $2,931,137 of transportation revenue

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

This includes $3,451,986 of transportation revenue.

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

Amounts Greater than $250,000 - (451) - Misc. Services Revenues

Schedule 87 Tax Surcharge	5,025,946
Temporary Service Charge	1,129,107
Line Extension Revenue	1,103,941
Non-Consumption Utility Tax	303,330
Reconnection Charge	1,187,554
Treble Damages	-
Non-Consumption & Consumption Misc. Service Charges	2,155,028

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

Amounts Greater than $250,000 - (451) - Misc. Services Revenues

Conversion Sch 73 Revenue	$	0
Non-Consumption Utility Tax		305,958
Line Extension Revenue		1,064,858
Temporary Service Charge		1,314,248
Treble Damages		580,062
Reconnection Charge		1,460,925
Non-Consumption & Consumption Misc. Service Charges		2,407,581
Schedule 87 Tax Surcharge		4,541,829

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

Amounts Greater than $250,000 - (456) Other Revenues

Decoupling Revenues	5,022,325
Gain/(Loss) on sales or assignment of Non-core Gas	104,269,151
Electric Over-Earnings	3,290,096
Misc. O&M Revenue	2,479,769
Summit Buyout	1,026,108

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

Amounts Greater than $250,000 - (456) Other Revenues

Decoupling Revenues	1,850,774
Misc. O&M Revenue	262,047
Summit Buyout	1,026,108
Electric Over-Earnings	10,925,933
Gain/(Loss) on sales or assignment of Non-core Gas	
	69.470,812

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/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					
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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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential:					
2	SCH _7E	10,699,108	1,133,452,489	1,025,022	10,438	0.1059
3	SCH_7AE	2,495	217,010	2	1,247,500	0.0870
4	Residential Non-Consumption		-125,429			
5	Residential Unbilled	55,026	5,592,806			0.1016
6	Total	10,756,629	1,139,136,876	1,025,024	10,494	0.1059
7						
8	Commercial:					
9	SCH_8E	254,412	27,682,329	30,257	8,408	0.1088
10	SCH_10E	27,846	2,821,567	13	2,142,000	0.1013
11	SCH_11E	139,301	12,228,754	304	458,227	0.0878
12	SCH_12E	17,042	1,442,569	14	1,217,286	0.0846
13	SCH_24EC	2,337,096	252,303,548	88,470	26,417	0.1080
14	SCH_25EC	2,658,620	263,625,447	7,003	379,640	0.0992
15	SCH_26EC	1,644,826	150,146,244	721	2,281,312	0.0913
16	SCH_29E	14,411	1,058,351	606	23,781	0.0734
17	SCH_31EC	776,235	68,918,425	350	2,217,814	0.0888
18	SCH_35E	4,706	251,425	2	2,353,000	0.0534
19	SCH_43E	122,307	11,613,495	152	804,651	0.0950
20	SCH_46EC	20,988	1,453,215	2	10,494,000	0.0692
21	SCH_49EC	438,503	31,084,354	14	31,321,643	0.0709
22	SCH_55E	2,094	596,210	811	2,582	0.2847
23	SCH_56E	1,781	587,687	843	2,113	0.3300
24	SCH_58E	2,123	435,800	297	7,148	0.2053
25	SCH_59E	79	18,513	29	2,724	0.2343
26	SCH_40EC	221,104	18,576,273	56	3,948,286	0.0840
27	SCH_449EC		833,006	1		
28	SCH_MSOFT		5,945,854	64		
29	Non-Consumption		-150,590			
30	Commercial Unbilled	153,983	9,816,001			0.0637
31	Total	8,837,457	861,288,477	130,009	67,976	0.0975
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	20,833,230	2,126,271,840	0	0	0.1021
42	Total Unbilled Rev.(See Instr. 6)	212,804	15,464,228	0	0	0.0727
43	TOTAL	21,046,034	2,141,736,068	0	0	0.1018

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Industrial:					
2	SCH_24EI	86,130	9,459,285	2,677	32,174	0.1098
3	SCH_25EI	169,427	17,641,303	430	394,016	0.1041
4	SCH_26EI	212,153	20,303,881	90	2,357,256	0.0957
5	SCH_31EI	459,943	40,755,408	119	3,865,067	0.0886
6	SCH_46EI	59,489	4,245,443	4	14,872,250	0.0714
7	SCH_49EI	122,247	8,825,302	5	24,449,400	0.0722
8	SCH_40EI	49,295	3,908,173	3	16,431,667	0.0793
9	SCH_449EI		2,465,791	12		
10	SCH_459EI		465,345	3		
11	Non-Consumption		-1,661			
12	Industrial Unbilled	2,466	-120,058			-0.0487
13	Total	1,161,150	107,948,212	3,343	347,338	0.0930
14						
15	Lighting:					
16	SCH_03E	7	532	1	7,000	0.0760
17	SCH_24EL	11,515	1,313,848	1,124	10,245	0.1141
18	SCH_25EL	1,002	131,827	8	125,250	0.1316
19	SCH_50E	54	5,856	10	5,400	0.1084
20	SCH_51E	1,973	444,062	767	2,572	0.2251
21	SCH_52E	13,116	2,633,149	2,401	5,463	0.2008
22	SCH_53E	38,258	12,075,872	2,854	13,405	0.3156
23	SCH_54E	7,264	668,710	45	161,422	0.0921
24	SCH_57E	3,476	528,137	105	33,105	0.1519
25	Non-Consumption		-79,197			
26	Lighting Unbilled	1,329	175,479			0.1320
27	Total	77,994	17,898,275	7,315	10,662	0.2295
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	20,833,230	2,126,271,840	0	0	0.1021
42	Total Unbilled Rev.(See Instr. 6)	212,804	15,464,228	0	0	0.0727
43	TOTAL	21,046,034	2,141,736,068	0	0	0.1018

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical 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	0.139	0.139	0.139
2	Port of Brownsville	RQ	Sch005	0.141	0.141	0.141
3	City of Des Moines	RQ	Sch005	0.199	0.199	0.199
4	Kingston Port District	RQ	Sch005	0.122	0.122	0.122
5	Kittitas Co PUD	RQ	Sch005	0.024	0.024	0.024
6	City of Oak Harbor	RQ	Sch005	0.131	0.131	0.131
7	Poulsbo Port District	RQ	Sch005	0.095	0.095	0.095
8	Port of Skagit - LaConner Marina	RQ	Sch005	0.077	0.077	0.077
9	Port of Skagit - North Basin	RQ	Sch005	0.149	0.149	0.149
10	Change in Unbilled Revenue	RQ	Sch005			
11	Avangrid Renewables, LLC	AD	FERC #8			
12	Avangrid Renewables, LLC	OS	FERC #8			
13	Avangrid Renewables, LLC	OS	FERC #9			
14	Avista Corp. WWP Division	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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Avista Corp. WWP Division	OS	FERC #8			
2	Avista Corp. WWP Division	OS	FERC #9			
3	BC Hydro	OS	FERC #9			
4	Black Hills Power, Inc.	OS	FERC #8			
5	Bonneville Power Administration	AD	FERC #8			
6	Bonneville Power Administration	AD	FERC #9			
7	Bonneville Power Administration	OS	FERC #8			
8	Bonneville Power Administration	OS	FERC #9			
9	BP Energy Company	OS	FERC #8			
10	Brookfield Energy Marketing LP	OS	FERC #8			
11	Brookfield Renewable Trading and Marke	OS	FERC #8			
12	California ISO	OS	FERC #8			
13	Chelan County PUD	OS	FERC #8			
14	Chelan County PUD	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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Citigroup Energy Inc.	AD	FERC #8			
2	Citigroup Energy Inc.	OS	FERC #8			
3	Clatskanie Peoples Utility District	OS	FERC #8			
4	ConocoPhillips Company	OS	FERC #8			
5	CP Energy Marketing (US) Inc.	OS	FERC #8			
6	EDF Trading N.A., LLC	AD	FERC #8			
7	EDF Trading N.A., LLC	OS	FERC #8			
8	Energy Keepers, Inc.	OS	FERC #8			
9	Eugene Water & Electric Board	OS	FERC #8			
10	Exelon Generation Company LLC	OS	FERC #8			
11	Grant County PUD No.2	AD	FERC #8			
12	Grant County PUD No.2	OS	FERC #9			
13	Gridforce Energy Management, LLC.	AD	FERC #8			
14	Gridforce Energy Management, LLC.	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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Idaho Power Company	OS	FERC #8			
2	Idaho Power Company	OS	FERC #9			
3	Morgan Stanley Capital Group Inc.	AD	FERC #8			
4	Morgan Stanley Capital Group Inc.	OS	FERC #8			
5	NaturEner Power Watch, LLC	AD	FERC #8			
6	NaturEner Power Watch, LLC	OS	FERC #9			
7	Nevada Power Company	OS	FERC #9			
8	NextEra Energy Marketing, LLC	OS	FERC #8			
9	NorthWestern Energy	AD	FERC #8			
10	NorthWestern Energy	OS	FERC #8			
11	NorthWestern Energy	OS	FERC #9			
12	P.U.D. No. 1 of Douglas County	OS	FERC #8			
13	P.U.D. No. 1 of Douglas County	OS	FERC #9			
14	P.U.D. No. 1 of Okanogan 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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	PacifiCorp	AD	FERC #8			
2	PacifiCorp	OS	FERC #8			
3	PacifiCorp	OS	FERC #9			
4	Portland General Electric Company	AD	FERC #8			
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	OS	FERC #8			
11	Sacramento Municipal Utility District	OS	FERC #9			
12	Seattle City Light Marketing	OS	FERC #8			
13	Seattle City Light Marketing	OS	FERC #9			
14	Shell Energy North America (US)	AD	FERC #8			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Shell Energy North America (US)	OS	FERC #8			
2	Snohomish County PUD	OS	FERC #8			
3	Tacoma Power	AD	FERC #8			
4	Tacoma Power	OS	FERC #8			
5	Tacoma Power	OS	FERC #9			
6	The Energy Authority	OS	FERC #8			
7	TransAlta Energy Marketing U.S.	AD	FERC #8			
8	TransAlta Energy Marketing U.S.	OS	FERC #8			
9	TransCanada Energy Sales Ltd.	OS	FERC #8			
10	Turlock Irrigation District	OS	FERC #8			
11	Vitol Inc.	OS	FERC #8			
12	Western Area Power Admin	OS	FERC #9			
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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
810	8,732	28,463	2,823	40,018	1
1,594	15,813	55,999	3,029	74,841	2
1,251	12,506	43,950	2,380	58,836	3
631	7,657	22,182	1,215	31,054	4
172	2,643	6,043		8,686	5
754	8,273	26,486	2,884	37,643	6
587	6,004	20,633	1,598	28,235	7
442	4,826	15,528	824	21,178	8
929	9,392	32,649	4,531	46,572	9
136	-463	4,797		4,334	10
5			-700	-700	11
446,958		12,739,060		12,739,060	12
68		2,003		2,003	13
			200	200	14
7,306	75,383	256,730	19,284	351,397	
6,645,768	0	196,942,476	4,193	196,946,669	
6,653,074	**75,383**	**197,199,206**	**23,477**	**197,298,066**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
72,572		3,064,624		3,064,624	1
31		839		839	2
9		319		319	3
700		20,025		20,025	4
-18			-822	-822	5
-2			-6	-6	6
710,874		21,122,444		21,122,444	7
93		3,194		3,194	8
276,166		8,249,807		8,249,807	9
8,400		207,956		207,956	10
4,000		132,456		132,456	11
686,268		21,574,509		21,574,509	12
28,535		1,286,096		1,286,096	13
11		321		321	14
7,306	75,383	256,730	19,284	351,397	
6,645,768	0	196,942,476	4,193	196,946,669	
6,653,074	**75,383**	**197,199,206**	**23,477**	**197,298,066**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			2	2	1
508,676		15,007,949		15,007,949	2
50,086		1,414,177		1,414,177	3
95,250		2,502,258		2,502,258	4
690		24,400		24,400	5
-60			-9,240	-9,240	6
23,663		671,044		671,044	7
3,177		89,078		89,078	8
97,275		3,110,378		3,110,378	9
116,281		4,018,264		4,018,264	10
1			49	49	11
4		40		40	12
2			-211	-211	13
583		20,287		20,287	14
7,306	75,383	256,730	19,284	351,397	
6,645,768	0	196,942,476	4,193	196,946,669	
6,653,074	**75,383**	**197,199,206**	**23,477**	**197,298,066**	

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
36,379		860,822		860,822	1
30		1,036		1,036	2
25			7,975	7,975	3
770,002		22,919,447		22,919,447	4
27			223	223	5
200		5,395		5,395	6
11		268		268	7
5,000		103,234		103,234	8
-17			107	107	9
13,995		440,030		440,030	10
40		804		804	11
9,225		378,800		378,800	12
4		12		12	13
1,430		56,489		56,489	14
7,306	75,383	256,730	19,284	351,397	
6,645,768	0	196,942,476	4,193	196,946,669	
6,653,074	**75,383**	**197,199,206**	**23,477**	**197,298,066**	

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.
			525	525	1
102,379		3,288,448		3,288,448	2
348		11,518		11,518	3
			-1,000	-1,000	4
144,365		4,792,839		4,792,839	5
142		4,901		4,901	6
86			6,740	6,740	7
848,585		21,566,961		21,566,961	8
24,600		752,280		752,280	9
640		5,856		5,856	10
30		981		981	11
118,025		3,430,009		3,430,009	12
3		54		54	13
			360	360	14
7,306	75,383	256,730	19,284	351,397	
6,645,768	0	196,942,476	4,193	196,946,669	
6,653,074	**75,383**	**197,199,206**	**23,477**	**197,298,066**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
267,046		7,612,436		7,612,436	1
32,585		1,017,925		1,017,925	2
			20	20	3
35,217		1,192,680		1,192,680	4
7		265		265	5
433,561		14,347,129		14,347,129	6
-1			-29	-29	7
612,752		17,449,490		17,449,490	8
32,734		784,117		784,117	9
1,212		49,006		49,006	10
24,800		607,650		607,650	11
3		66		66	12
					13
					14
7,306	75,383	256,730	19,284	351,397	
6,645,768	0	196,942,476	4,193	196,946,669	
6,653,074	**75,383**	**197,199,206**	**23,477**	**197,298,066**	

Schedule Page: 310 Line No.: 1 Column: j

Other charges to municipalities include State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 2 Column: j

Other charges to municipalities include State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 3 Column: j

Other charges to municipalities include State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 4 Column: j

Other charges to municipalities include State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 6 Column: j

Other charges to municipalities include State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 7 Column: j

Other charges to municipalities include State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 8 Column: j

Other charges to municipalities include State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 9 Column: j

Other charges to municipalities include State Public Utility Tax, City Tax and Reactive Demand.

Schedule Page: 310 Line No.: 11 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections	Total
MWH	5	0	0	5
Amount	$137	($837)	$0	($700)

Schedule Page: 310 Line No.: 14 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections	Total
MWH	0	0	0	0
Amount	$200	$0	$0	$200

Schedule Page: 310.1 Line No.: 5 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections	Total
MWH	(18)	0	0	(18)
Amount	($744)	($80)	$2	($822)

Schedule Page: 310.1 Line No.: 6 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections	Total
MWH	0	0	(2)	(2)
Amount	$0	$0	($6)	($6)

Schedule Page: 310.1 Line No.: 10 Column: a

Brookfield Energy Marketing (BMLP) became Brookfield Renewable Trading and Marketing (BRTM) effective October 1, 2019.

Schedule Page: 310.1 Line No.: 11 Column: a

Brookfield Energy Marketing (BMLP) became Brookfield Renewable Trading and Marketing (BRTM) effective October 1, 2019.

Schedule Page: 310.2 Line No.: 1 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections	Total
MWH	0	0	0	0
Amount	$0	$0	$2	$2

Schedule Page: 310.2 Line No.: 6 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections *	Total
MWH	0	0	(60)	(60)
Amount	$0	$0	($9,240)	($9,240)

*Correction of March 2019 transaction made in December 2019 after EQR refiling. Deemed immaterial, so no second refiling was made.

Schedule Page: 310.2 Line No.: 11 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections	Total
MWH	1	0	0	1
Amount	$49	$0	$0	$49

Schedule Page: 310.2 Line No.: 13 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections	Total
MWH	2	0	0	2
Amount	$87	($298)	$0	($211)

Schedule Page: 310.3 Line No.: 3 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections *	Total
MWH	0	(35)	60	25
Amount	$0	($2,125)	$10,100	$7,975

*Correction of March 2019 transaction made in December 2019 after EQR refiling. Deemed immaterial, so no second refiling was made.

Schedule Page: 310.3 Line No.: 5 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections	Total
MWH	27	0	0	27
Amount	$701	($478)	$0	$223

Schedule Page: 310.3 Line No.: 9 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections	Total
MWH	(17)	0	0	(17)
Amount	$107	$0	$0	$107

Schedule Page: 310.4 Line No.: 1 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections	Total
MWH	0	0	0	0
Amount	$525	$0	$0	$525

Schedule Page: 310.4 Line No.: 4 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections	Total
MWH	0	0	0	0
Amount	$0	($1,000)	$0	($1,000)

Schedule Page: 310.4 Line No.: 7 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections	Total
MWH	86	0	0	86
Amount	$6,740	$0	$0	$6,740

Schedule Page: 310.4 Line No.: 14 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections	Total
MWH	0	0	0	0
Amount	$200	$160	$0	$360

Schedule Page: 310.5 Line No.: 3 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections	Total
MWH	0	0	0	0
Amount	$0	$20	$0	$20

Schedule Page: 310.5 Line No.: 7 Column: j

	Prior Period (2018) Adjustments	Post Period (2020) Adjustments	EQR Corrections	Total
MWH	(1)	0	0	(1)
Amount	($29)	$0	$0	($29)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,345,911	1,705,460
5	(501) Fuel	94,983,743	79,334,192
6	(502) Steam Expenses	10,513,412	9,075,849
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,806,882	1,790,939
10	(506) Miscellaneous Steam Power Expenses	10,493,096	11,281,399
11	(507) Rents	24,198	71,114
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	119,167,242	103,258,953
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,868,541	1,708,415
16	(511) Maintenance of Structures	1,957,038	1,786,439
17	(512) Maintenance of Boiler Plant	14,045,708	13,792,263
18	(513) Maintenance of Electric Plant	7,058,869	9,151,401
19	(514) Maintenance of Miscellaneous Steam Plant	3,353,819	3,636,763
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	28,283,975	30,075,281
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	147,451,217	133,334,234
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	2,032,967	2,191,353
45	(536) Water for Power		
46	(537) Hydraulic Expenses	3,392,829	3,603,020
47	(538) Electric Expenses	250,971	234,879
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,823,961	2,591,277
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	7,500,728	8,620,529
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	190,186	328,603
54	(542) Maintenance of Structures	351,293	328,234
55	(543) Maintenance of Reservoirs, Dams, and Waterways	419,922	520,395
56	(544) Maintenance of Electric Plant	1,107,383	1,300,141
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,485,637	4,053,077
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	5,554,421	6,530,450
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	13,055,149	15,150,979

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	4,270,611	3,158,357
63	(547) Fuel	187,880,093	124,839,938
64	(548) Generation Expenses	12,036,694	10,960,994
65	(549) Miscellaneous Other Power Generation Expenses	4,023,936	5,198,887
66	(550) Rents	6,167,238	6,931,080
67	TOTAL Operation (Enter Total of lines 62 thru 66)	214,378,572	151,089,256
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	516,853	656,043
70	(552) Maintenance of Structures	978,519	754,814
71	(553) Maintenance of Generating and Electric Plant	30,074,646	29,404,802
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	670,988	842,726
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	32,241,006	31,658,385
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	246,619,578	182,747,641
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	559,286,807	496,710,087
77	(556) System Control and Load Dispatching	123,404	109,272
78	(557) Other Expenses	-21,388,429	17,679,051
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	538,021,782	514,498,410
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	945,147,726	845,731,264
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,701,249	2,519,400
84			
85	(561.1) Load Dispatch-Reliability	85,035	152,208
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,625,328	1,612,805
87	(561.3) Load Dispatch-Transmission Service and Scheduling	670,141	548,215
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	2,914,429	2,417,054
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	1,572,656	2,280,012
92	(561.8) Reliability, Planning and Standards Development Services	87,714	102,621
93	(562) Station Expenses	1,235,002	1,374,172
94	(563) Overhead Lines Expenses	291,575	340,841
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	121,674,523	115,807,778
97	(566) Miscellaneous Transmission Expenses	2,952,511	2,740,905
98	(567) Rents	462,594	372,875
99	TOTAL Operation (Enter Total of lines 83 thru 98)	136,272,757	130,268,886
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	53,697	80,644
102	(569) Maintenance of Structures	5,291	1,877
103	(569.1) Maintenance of Computer Hardware	35	
104	(569.2) Maintenance of Computer Software	178,304	125,706
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,884,698	3,008,944
108	(571) Maintenance of Overhead Lines	7,321,785	6,637,104
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	78,942	124,119
111	TOTAL Maintenance (Total of lines 101 thru 110)	9,522,752	9,978,394
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	145,795,509	140,247,280

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	2,828,108	2,675,136
135	(581) Load Dispatching	1,603,559	1,710,998
136	(582) Station Expenses	2,240,360	1,777,553
137	(583) Overhead Line Expenses	2,577,803	2,571,367
138	(584) Underground Line Expenses	4,481,910	4,555,493
139	(585) Street Lighting and Signal System Expenses	4,408	142,212
140	(586) Meter Expenses	2,529,507	1,704,988
141	(587) Customer Installations Expenses	3,574,238	3,314,701
142	(588) Miscellaneous Expenses	10,194,399	12,068,387
143	(589) Rents	1,501,277	1,317,139
144	TOTAL Operation (Enter Total of lines 134 thru 143)	31,535,569	31,837,974
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	567,073	541,270
147	(591) Maintenance of Structures		-5
148	(592) Maintenance of Station Equipment	1,367,269	1,486,799
149	(593) Maintenance of Overhead Lines	34,816,830	34,730,225
150	(594) Maintenance of Underground Lines	9,900,645	12,006,811
151	(595) Maintenance of Line Transformers	107,940	171,037
152	(596) Maintenance of Street Lighting and Signal Systems	2,003,455	1,958,092
153	(597) Maintenance of Meters	580,259	519,037
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of lines 146 thru 154)	49,343,471	51,413,266
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	80,879,040	83,251,240
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	129,197	130,944
160	(902) Meter Reading Expenses	12,300,425	11,224,995
161	(903) Customer Records and Collection Expenses	23,579,145	23,118,231
162	(904) Uncollectible Accounts	14,594,914	18,742,716
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	50,603,681	53,216,886

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	99,686,489	115,366,839
169	(909) Informational and Instructional Expenses	2,523,745	3,056,500
170	(910) Miscellaneous Customer Service and Informational Expenses	201	893
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	102,210,435	118,424,232
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	649,824	805,415
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	649,824	805,415
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	51,395,112	48,105,340
182	(921) Office Supplies and Expenses	9,505,816	8,547,055
183	(Less) (922) Administrative Expenses Transferred-Credit	23,278,644	21,363,036
184	(923) Outside Services Employed	10,889,883	10,996,650
185	(924) Property Insurance	4,830,519	4,710,219
186	(925) Injuries and Damages	6,404,903	4,956,899
187	(926) Employee Pensions and Benefits	29,646,355	31,216,294
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	8,596,791	7,358,825
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	76,114	
192	(930.2) Miscellaneous General Expenses	8,237,224	5,413,039
193	(931) Rents	7,138,619	6,812,985
194	TOTAL Operation (Enter Total of lines 181 thru 193)	113,442,692	106,754,270
195	Maintenance		
196	(935) Maintenance of General Plant	16,780,773	16,564,426
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	130,223,465	123,318,696
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,455,509,680	1,364,995,013

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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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	AD				
2	3 Bar G Wind Turbine #3 LLC	LU				
3	Avista Corp. WWP Division	OS				
4	Avista Nichols Pump	EX				
5	Powerex (Point Roberts)	LF				
6	BIO ENERGY (Washington) LLC	LU				
7	Black Creek Hydro	LU				
8	Black Hills Power	OS				
9	Bloks Evergreen Dairy	LU				
10	BP Energy Co.	OS				
11	Bonneville Power Admistration	AD				
12	Bonneville Power Admistration	OS				
13	British Columbia Transmission Corp	OS				
14	Brookfield Energy Marketing LP	OS				
	Total					

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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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	California ISO - EIM Purchases	OS				
2	California ISO	OS				
3	Cascade Community Solar	LU				
4	Chelan County PUD #1	OS				
5	Chelan PUD - Rock Island and Rocky Reh	AD				
6	Chelan PUD - Rock Island and Rocky Reh	LF				
7	Citigroup Energy (Financial)	OS				
8	Citigroup Energy Inc	AD				
9	Citigroup Energy Inc	OS				
10	Clatskanie PUD	AD				
11	Clatskanie PUD	OS				
12	Conoco, Inc.	OS				
13	CP Energy Marketing (Epcor)	OS				
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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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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	Douglas County PUD #1	AD				
2	Douglas County PUD #1	OS				
3	Douglas PUD - Wells Project	LF				
4	Edaleen Dairy, LLC	LU				
5	EDF Trading (Financial)	OS				
6	EDF Trading NA LLC	AD				
7	EDF Trading NA LLC	OS				
8	Electron Hydro, LLC	LU				
9	Emerald City Renewables, LLC	LU				
10	Energy Keepers Inc.	AD				
11	Eugene Water & Electric	AD				
12	Eugene Water & Electric	OS				
13	Exelon Generation Co LLC	OS				
14	Farm Power Lynden LLC	LU				
	Total					

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	Farm Power Rexville LLC	LU				
2	Grant County PUD #2	OS				
3	Grant PUD - Priest Rapids Project	AD				
4	Grant PUD - Priest Rapids Project	LF				
5	Gridforce Energy Management, LLC.	OS				
6	Iberdrola Renewables (PPM Energy)	OS				
7	Idaho Power Company	AD				
8	Idaho Power Company	OS				
9	Ikea U.S. West, Inc.	AD				
10	Ikea U.S. West, Inc.	LU				
11	Island Community Solar	LU				
12	Iberdrola Renewables (Klondike Wind P)	AD				
13	Iberdrola Renewables (Klondike Wind P)	LU				
14	Knudsen Wind Turbine#1	LU				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	Koma Kulshan Associates	LU				
2	Lake Washington School District #414	LU				
3	Lower Baker Test Power					
4	Morgan Stanley CG	AD				
5	Morgan Stanley CG	OS				
6	Morgan Stanley CG (Financial)	OS				
7	NextEra Energy Power Marketing	OS				
8	Puget Sound Hydro (Nooksack)	LU				
9	Northwestern Energy	AD				
10	Northwestern Energy	OS				
11	Okanogan PUD	OS				
12	Pacific Gas & Elec - Exchange	EX				
13	Pacificorp	AD				
14	Pacificorp	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Portland General Electric	AD				
2	Portland General Electric	OS				
3	Powerex Corp.	AD				
4	Powerex Corp.	OS				
5	Public Service of Colorado	OS				
6	Rainbow Energy Marketing	AD				
7	Rainbow Energy Marketing	OS				
8	Rainer BioGas	LU				
9	Residential Exchange	AD				
10	Sacramento Municipal	OS				
11	Seattle City Light Marketing	OS				
12	Shell Energy (Coral Pwr)	AD				
13	Shell Energy (Coral Pwr)	OS				
14	Skookumchuck Hydro	LU				
	Total					

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

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1	Smith Creek Hydro	LU				
2	Snohomish County PUD #1	AD				
3	Snohomish County PUD #1	OS				
4	Swauk Wind LLC	LU				
5	Kingdom Energy Products (Sygitowicz)	AD				
6	Tacoma Power	AD				
7	Tacoma Power	OS				
8	Tenaska Power Services Co.	OS				
9	The Energy Authority	AD				
10	The Energy Authority	OS				
11	Transalta Centralia Generation LLC	LF				
12	TransAlta Energy Marketing	AD				
13	TransAlta Energy Marketing	OS				
14	TransCanada Energy Sales Ltd	OS				
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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1	Turlock Irrigation District	OS				
2	Twin Falls Hydro	LU				
3	Van Dyk S Holsteins	LU				
4	VanderHaak Dairy Digester	LU				
5	Vitol Inc.	OS				
6	South Fork II Associates(Weeks Falls)	LU				
7	Wells Fargo (Financial)	OS				
8	RECs Retired for RPS	OS				
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
(g)	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
-63					-7,312	-7,312	1
195				23,705		23,705	2
146,486				6,312,667		6,312,667	3
	30,837			735,574		735,574	4
20,445				1,206,392		1,206,392	5
8				703		703	6
8,033				744,217		744,217	7
400				90,000		90,000	8
69				4,571		4,571	9
977,532				37,326,565		37,326,565	10
					2,415	2,415	11
563,166				15,021,257		15,021,257	12
13							13
2,500				170,819		170,819	14
15,771,178	443,837	850,531		605,567,194	-46,280,387	559,286,807	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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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.
844,255				15,627,771		15,627,771	1
44,649				2,314,039		2,314,039	2
30				1,993		1,993	3
107,113				4,871,141		4,871,141	4
							5
1,784,269				23,933,339	32,787,286	56,720,625	6
				-4,549,112		-4,549,112	7
-43					-2,047	-2,047	8
1,339,338				44,614,853		44,614,853	9
9					387	387	10
3,005				75,973		75,973	11
18,025				999,016		999,016	12
20,804				1,082,731		1,082,731	13
		437,531					14
15,771,178	443,837	850,531		605,567,194	-46,280,387	559,286,807	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
-153					-5,279	-5,279	1
17,028				476,309		476,309	2
812,102				30,186,428		30,186,428	3
3,546				328,510		328,510	4
				-54,016		-54,016	5
-74					-4,203	-4,203	6
532,207				19,600,134		19,600,134	7
143,654				9,476,857		9,476,857	8
31,113				2,915,702		2,915,702	9
-993					-77,345	-77,345	10
					200	200	11
10,165				242,411		242,411	12
96,790				4,600,968		4,600,968	13
4,062				492,771		492,771	14
15,771,178	443,837	850,531		605,567,194	-46,280,387	559,286,807	

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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MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
5,308				643,917		643,917	1
7				295		295	2
					157,385	157,385	3
45,806				70,675		70,675	4
10				367		367	5
370,310				20,868,674		20,868,674	6
871					29,249	29,249	7
15,025				349,765		349,765	8
					-61	-61	9
72				4,727		4,727	10
62				5,752		5,752	11
					21,794	21,794	12
112,955				7,562,695		7,562,695	13
56				6,824		6,824	14
15,771,178	443,837	850,531		605,567,194	-46,280,387	559,286,807	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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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.
29,784				2,449,201		2,449,201	1
270				25,051		25,051	2
							3
							4
326,121				22,969,344		22,969,344	5
				-61,352		-61,352	6
3,259				410,893		410,893	7
22,783				2,110,607		2,110,607	8
-9					-387	-387	9
12,621				390,860		390,860	10
3,262				90,671		90,671	11
	413,000	413,000					12
					34	34	13
47,439				1,696,511		1,696,511	14
15,771,178	443,837	850,531		605,567,194	-46,280,387	559,286,807	

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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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)	
-93					-2,676	-2,676	1
104,874				4,637,617		4,637,617	2
							3
212,740				18,257,680		18,257,680	4
163,704				6,016,891		6,016,891	5
57					4,816	4,816	6
12,575				1,407,106		1,407,106	7
4,297				454,347		454,347	8
					-79,186,637	-79,186,637	9
4				111		111	10
191,487				4,109,766		4,109,766	11
					4,360	4,360	12
540,432				23,385,109		23,385,109	13
2,326				245,974		245,974	14
15,771,178	443,837	850,531		605,567,194	-46,280,387	559,286,807	

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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.
89				9,422		9,422	1
-216					-7,452	-7,452	2
26,148				508,045		508,045	3
10,224				947,183		947,183	4
414					23,922	23,922	5
					600	600	6
123,895				3,931,663		3,931,663	7
834				144,340		144,340	8
-75					-2,172	-2,172	9
742,942				26,717,182		26,717,182	10
3,327,138				169,929,047		169,929,047	11
-439					-17,264	-17,264	12
1,686,810				105,136,781		105,136,781	13
625				110,075		110,075	14
15,771,178	443,837	850,531		605,567,194	-46,280,387	559,286,807	

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

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

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

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,400				40,829		40,829	1
52,656				3,949,376		3,949,376	2
1,559				164,866		164,866	3
4,285				519,749		519,749	4
23,376				1,422,651		1,422,651	5
9,413				705,960		705,960	6
				-45,762,760		-45,762,760	7
				108,419		108,419	8
							9
							10
							11
							12
							13
							14
15,771,178	443,837	850,531		605,567,194	-46,280,387	559,286,807	

Schedule Page: 326 Line No.: 1 Column: a
Prior Period Adjustment
Schedule Page: 326 Line No.: 2 Column: a
Contract Expires Dec, 2029
Schedule Page: 326 Line No.: 5 Column: a
Contract Expires Sep, 2022
Schedule Page: 326 Line No.: 6 Column: a
Contract Expires Dec, 2021
Schedule Page: 326 Line No.: 7 Column: a
Contract Expires Dec, 2021
Schedule Page: 326 Line No.: 9 Column: a
Contract Expires Dec, 2031
Schedule Page: 326 Line No.: 11 Column: a
Prior Period Adjustment
Schedule Page: 326 Line No.: 12 Column: a
Contract Expires Sep, 2029
Schedule Page: 326.1 Line No.: 3 Column: a
Contract Expires Dec, 2026
Schedule Page: 326.1 Line No.: 5 Column: a
Prior Period Adjustment
Schedule Page: 326.1 Line No.: 6 Column: a
Contract Expires Oct, 2031
Schedule Page: 326.1 Line No.: 7 Column: a
Power Financial Hedging Transactions
Schedule Page: 326.1 Line No.: 8 Column: a
Prior Period Adjustment
Schedule Page: 326.1 Line No.: 10 Column: a
Prior Period Adjustment
Schedule Page: 326.2 Line No.: 1 Column: a
Prior Period Adjustment
Schedule Page: 326.2 Line No.: 3 Column: a
Contract Expires Sep, 2021
Schedule Page: 326.2 Line No.: 4 Column: a
Contract Expires Dec, 2021
Schedule Page: 326.2 Line No.: 5 Column: a
Power Financial Hedging Transactions
Schedule Page: 326.2 Line No.: 6 Column: a
Prior Period Adjustment
Schedule Page: 326.2 Line No.: 8 Column: a
Contract Expires Nov, 2024
Schedule Page: 326.2 Line No.: 9 Column: a
Contract Expires Dec, 2029
Schedule Page: 326.2 Line No.: 10 Column: a
Prior Period Adjustment
Schedule Page: 326.2 Line No.: 11 Column: a
Prior Period Adjustment
Schedule Page: 326.2 Line No.: 14 Column: a
Contract Expires Dec, 2019
Schedule Page: 326.3 Line No.: 1 Column: a
Contract Expires Dec, 2021
Schedule Page: 326.3 Line No.: 3 Column: a

Prior Period Adjustment

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

Contract Expires Apr, 2052

Schedule Page: 326.3 Line No.: 7 Column: a

Prior Period Adjustment

Schedule Page: 326.3 Line No.: 9 Column: a

Prior Period Adjustment

Schedule Page: 326.3 Line No.: 10 Column: a

Contract Expires Dec, 2031

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

Contract Expires Dec, 2021

Schedule Page: 326.3 Line No.: 12 Column: a

Prior Period Adjustment

Schedule Page: 326.3 Line No.: 13 Column: a

Contract Expires Nov, 2027

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

Contract Expires Dec, 2029

Schedule Page: 326.4 Line No.: 1 Column: a

Contract Expires Mar, 2037

Schedule Page: 326.4 Line No.: 2 Column: a

Contract Expires Dec, 2021

Schedule Page: 326.4 Line No.: 4 Column: a

Prior Period Adjustment

Schedule Page: 326.4 Line No.: 6 Column: a

Power Financial Hedging Transactions

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

Contract Expires Dec, 2021

Schedule Page: 326.4 Line No.: 9 Column: a

Prior Period Adjustment

Schedule Page: 326.4 Line No.: 13 Column: a

Prior Period Adjustment

Schedule Page: 326.5 Line No.: 1 Column: a

Prior Period Adjustment

Schedule Page: 326.5 Line No.: 3 Column: a

Prior Period Adjustment

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

Prior Period Adjustment

Schedule Page: 326.5 Line No.: 8 Column: a

Contract Expires Dec, 2020

Schedule Page: 326.5 Line No.: 9 Column: a

Residential Exchange

Schedule Page: 326.5 Line No.: 12 Column: a

Prior Period Adjustment

Schedule Page: 326.5 Line No.: 14 Column: a

Contract Expires Dec, 2020

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

Contract Expires Dec, 2020

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

Prior Period Adjustment

Schedule Page: 326.6 Line No.: 4 Column: a

Contract Expires Dec, 2021

Schedule Page: 326.6 Line No.: 5 Column: a

Prior Period Adjustment

Schedule Page: 326.6 Line No.: 6 Column: a

Prior Period Adjustment

Schedule Page: 326.6 Line No.: 9 Column: a

Prior Period Adjustment

Schedule Page: 326.6 Line No.: 11 Column: a

Contract Expires Dec, 2025

Schedule Page: 326.6 Line No.: 12 Column: a

Prior Period Adjustment

Schedule Page: 326.7 Line No.: 2 Column: a

Contract Expires Mar, 2025

Schedule Page: 326.7 Line No.: 3 Column: a

Contract Expires Dec, 2020

Schedule Page: 326.7 Line No.: 4 Column: a

Contract Expires Dec, 2021

Schedule Page: 326.7 Line No.: 6 Column: a

Contract Expires Nov, 2022

Schedule Page: 326.7 Line No.: 7 Column: a

Power Financial Hedging Transactions

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	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 Administration	Bonneville Power Admin	City of Blaine	FNO
8	Bonneville Power Administration	Bonneville Power Admin	City of Sumas	FNO
9	Bonneville Power Administration	Bonneville Power Admin	Kittitas County PUD	FNO
10	Bonneville Power Administration	Bonneville Power Admin	Orcas Power & Light	FNO
11	Bonneville Power Administration	Bonneville Power Admin	Tanner Electric Cooperative	FNO
12	Bonneville Power Administration	Bonneville Power Admin	Tanner Electric Cooperative	FNO
13	Bonneville Power Administration	Bonneville Power Admin	Tanner Electric Cooperative	FNO
14	Bonneville Power Administration	Bonneville Power Admin	Port of Seattle and Various	FNO
15				
16	Morgan Stanley Capital	Various	Various	LFP
17	Powerex	Various	Various	LFP
18	Powerex	Various	Various	LFP
19	Powerex	Various	Various	LFP
20	Powerex	Various	Various	LFP
21	Sierra Pacific Industries	Various	Various	LFP
22	TransAlta Energy	Various	Various	LFP
23	Vantage Wind Energy LLC- Invenergy	Various	Various	LFP
24	Whatcom County PUD	Whatcom County PUD	Whatcom County PUD	LFP
25				
26	Avangrid Renewables, LLC	Various	Various	SFP
27	Powerex	Various	Various	SFP
28	Powerex	Various	Various	SFP
29	Shell Energy North America	Various	Various	SFP
30	Sierra Pacific Industries	Various	Various	SFP
31	Snohomish County PUD	Various	Various	SFP
32	TransAlta Energy	Various	Various	SFP
33				
34	Avista	Various	Various	NF
	TOTAL			

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Brookfield Energy Marketing, LP	Various	Various	NF
2	Brookfield Renewables	Various	Various	NF
3	Avangrid Renewables, LLC	Various	Various	NF
4	Macquarie Energy, LLC	Various	Various	NF
5	Morgan Stanley Capital	Various	Various	NF
6	Portland General Electric	Various	Various	NF
7	Powerex	Various	Various	NF
8	Powerex	Various	Various	NF
9	Seattle City Light Marketing	Various	Various	NF
10	Shell Energy North America	Various	Various	NF
11	Shell Energy North America	Various	Various	NF
12	Sierra Pacific Industries	Various	Various	NF
13	Snohomish County PUD	Various	Various	NF
14	Tacoma Power	Various	Various	NF
15	The Energy Authority	Various	Various	NF
16	TransAlta Energy	Various	Various	NF
17	TransAlta Energy	Various	Various	NF
18	Turlock Irrigation District	Various	Various	NF
19				
20	Transportation Customers			
21	Air Liquide	Various	Air Liquide	FNO
22	Air Products	Various	Air Products	FNO
23	AMCOR Rigid Plastics USA	Various	AMCOR Rigid Plastics USA	FNO
24	Bellingham Cold Storage - Orchard	Various	Bellingham Cold Storage - Orchar	FNO
25	Bellingham Cold Storage - Roeder	Various	Bellingham Cold Storage - Roeder	FNO
26	Boeing	Various	Boeing	FNO
27	BP Westcoast Products	Various	BP Westcoast Products	FNO
28	Center Drive Owners	Various	Center Drive Owners	FNO
29	DBINTC, LLC	Various	DBINTC, LLC	FNO
30	Shell Oil Products (Equilon)	Various	Shell (Equilon)	FNO
31	Tesoro	Various	Tesoro	FNO
32				
33	Air Liquide	Various	Air Liquide	AD
34	Air Products	Various	Air Products	AD
	TOTAL			

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.
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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)
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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	AMCOR Rigid Plastics USA	Various	AMCOR Rigid Plastics USA	AD
2	Avangrid Renewables, LLC	Various	Various	AD
3	Avista	Various	Various	AD
4	Bellingham Cold Storage - Orchard	Various	Bellingham Cold Storage - Orchar	AD
5	Boeing	Various	Various	AD
6	Bonneville Power Administration	Various	Various	AD
7	BP Westcoast Products	Various	BP Westcoast Products	AD
8	Brookfield Energy Marketing, LP	Various	Various	AD
9	DBINTC, LLC	Various	Various	AD
10	Macquarie Energy, LLC	Various	Various	AD
11	Morgan Stanley Capital	Various	Various	AD
12	Powerex	Various	Various	AD
13	Seattle City Light	Various	Various	AD
14	Shell Energy North America	Various	Various	AD
15	Shell Oil Products (Equilon)	Various	Shell (Equilon)	AD
16	Snohomish County PUD	Various	Various	AD
17	Tesoro	Various	Tesoro	AD
18	The Energy Authority	Various	Various	AD
19	TransAlta Energy	Various	Various	AD
20	Tacoma Power	Various	Various	AD
21	Watcom County PUD	Watcom County PUD	Watcom County PUD	AD
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
FRS #155	Stillwater Substn	Bothell Substation		29,379	29,379	1
FRS #60	Beverly Park Substn	Goldbar Substation				2
FRS #28	Beverly Park Substn	Hilton Lake Substn		75,145	75,145	3
FRS #28	Beverly Park Substn	Olympic Pipe Substn		11,116	11,116	4
FRS #62	Starwood Substation	Baldi Substation				5
						6
PSE OATT	Custer Substation	Blaine&Semiahmo Sub		82,464	82,464	7
PSE OATT	Bellingham Substn	City of Sumas Sub		34,159	34,159	8
PSE OATT	White River Substn	Teanaway Substation		19,108	19,108	9
PSE OATT	Murray Bellingham	Fidalgo Substation		223,202	223,202	10
PSE OATT	Maple Valley Substn	Ames Lake Tap		21,810	21,810	11
PSE OATT	Olympia Substation	Luhr Beach Tap		14,253	14,253	12
PSE OATT	Maple Valley Substn	North Bend Substn		36,329	36,329	13
PSE OATT	Various	Sea Tac Airport		146,074	146,074	14
						15
PSE OATT	John Day, COB	John Day, COB	100	876,000	876,000	16
PSE OATT	John Day, COB	John Day, COB	225	1,875,460	1,875,460	17
PSE OATT	Various Washington	Various Washington				18
PSE OATT	Various Washington	Various Washington	90	788,400	788,400	19
PSE OATT	Various Washington	Various Washington	88	580,888	580,888	20
PSE OATT	Various Washington	Various Washington	15	131,400	131,400	21
PSE OATT	John Day, COB	John Day, COB	75	655,800	655,800	22
PSE OATT	Various Washington	Various Washington				23
PSE OATT	Custer Substation	Enterprise Sub	2	17,520	17,520	24
						25
PSE OATT	John Day, COB	John Day, COB	1,400	95,800	95,800	26
PSE OATT	John Day, COB	John Day, COB	6	144	144	27
PSE OATT	Various Washington	Various Washington	3,826	136,268	136,268	28
PSE OATT	Various Washington	Various Washington	161	5,784	5,784	29
PSE OATT	Various Washington	Various Washington	36	26,280	26,280	30
PSE OATT	Various Washington	Various Washington	1,886	48,342	48,342	31
PSE OATT	John Day, COB	John Day, COB	50	1,200	1,200	32
						33
PSE OATT	John Day, COB	John Day, COB		3,617	3,617	34
			7,960	**8,180,917**	**8,180,917**	

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
PSE OATT	John Day, COB	John Day, COB		2,205	2,205	1
PSE OATT	John Day, COB	John Day, COB		3,026	3,026	2
PSE OATT	John Day, COB	John Day, COB		360	360	3
PSE OATT	John Day, COB	John Day, COB		31,869	31,869	4
PSE OATT	John Day, COB	John Day, COB		1,803	1,803	5
PSE OATT	John Day, COB	John Day, COB		6,082	6,082	6
PSE OATT	John Day, COB	John Day, COB		7,854	7,854	7
PSE OATT	Various Washington	Various Washington		26,775	26,775	8
PSE OATT	John Day, COB	John Day, COB		629	629	9
PSE OATT	John Day, COB	John Day, COB		68,119	68,119	10
PSE OATT	Various Washington	Various Washington		12,780	12,780	11
PSE OATT	Various Washington	Various Washington		24	24	12
PSE OATT	Various Washington	Various Washington		3,851	3,851	13
PSE OATT	Various Washington	Various Washington		3,005	3,005	14
PSE OATT	John Day, COB	John Day, COB		13,459	13,459	15
PSE OATT	John Day, COB	John Day, COB		4,098	4,098	16
PSE OATT	Various Washington	Various Washington		55	55	17
PSE OATT	John Day, COB	John Day, COB		285	285	18
						19
						20
PSE OATT	Rocky Reach 115KV Sw	Air Liquide		73,777	73,777	21
PSE OATT	Rocky Reach 115KV Sw	Air Products		52,266	52,266	22
PSE OATT	Rocky Reach 115KV Sw	AMCOR Rigid Plastics		39,735	39,735	23
PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Orch		17,540	17,540	24
PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Roed		15,414	15,414	25
PSE OATT	Rocky Reach 115KV Sw	Boeing		443,163	443,163	26
PSE OATT	Rocky Reach 115KV Sw	BP Westcoast Product		792,585	792,585	27
PSE OATT	Rocky Reach 115KV Sw	Center Drive Owners		2,744	2,744	28
PSE OATT	Rocky Reach 115KV Sw	DBINTC, LLC				29
PSE OATT	Rocky Reach 115KV Sw	Equilon Refinery		336,965	336,965	30
PSE OATT	Rocky Reach 115KV Sw	Tesoro		284,507	284,507	31
						32
PSE OATT	Rocky Reach 115KV Sw	Air Liquide				33
PSE OATT	Rocky Reach 115KV Sw	Air Products				34
			7,960	**8,180,917**	**8,180,917**	

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
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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	Various Washington	Various Washington				3
PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Orch				4
PSE OATT	Various Washington	Various Washington				5
PSE OATT	Various Washington	Various Washington				6
PSE OATT	Rocky Reach 115KV Sw	BP Westcoast Product				7
PSE OATT	Various Washingto	Various Washingto				8
PSE OATT	Rocky Reach 115KV Sw	DBINTC, LLC				9
PSE OATT	Various Washington	Various Washington				10
PSE OATT	Various Washington	Various Washington				11
PSE OATT	Various Washington	Various Washington				12
PSE OATT	Various Washington	Various Washington				13
PSE OATT	Various Washington	Various Washington				14
PSE OATT	Various Washington	Various Washington				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	Custer Substation	Enterprise Sub				21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			7,960	**8,180,917**	**8,180,917**	

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
332,297			332,297	1
		600	600	2
8,793		600	9,393	3
1,530		600	2,130	4
		4,576	4,576	5
				6
292,724		275,949	568,673	7
112,029		199,688	311,717	8
79,208		68,247	147,455	9
932,918		308,772	1,241,690	10
83,587		46,299	129,886	11
64,353		62,316	126,669	12
216,525		116,974	333,499	13
425,326		365,339	790,665	14
				15
1,151,340		355,412	1,506,752	16
2,453,583		681,475	3,135,058	17
		72,548	72,548	18
2,178,263		2,079,907	4,258,170	19
1,580,031		629,031	2,209,062	20
363,113		197,523	560,636	21
861,629		330,409	1,192,038	22
412		16	428	23
48,415		19,882	68,297	24
				25
156,185		91,035	247,220	26
223		12	235	27
429,297		46,550	475,847	28
19,328		7,785	27,113	29
72,623		34,383	107,006	30
154,743		57,239	211,982	31
2,165		117	2,282	32
				33
	7,957	2,499	10,456	34
17,905,593	**447,569**	**10,202,404**	**28,555,566**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	3,512	1,513	5,025	1
	4,440	1,749	6,189	2
	650	675	1,325	3
	59,084	10,741	69,825	4
	3,227	1,869	5,096	5
	8,475	3,924	12,399	6
	20,225	7,853	28,078	7
	94,132	26,149	120,281	8
	1,346	803	2,149	9
	122,264	61,456	183,720	10
	46,989	42,595	89,584	11
	11,731	12,676	24,407	12
	17,686	8,726	26,412	13
	13,329	4,378	17,707	14
	23,004	11,474	34,478	15
	9,010	3,760	12,770	16
	149	23	172	17
	359	227	586	18
				19
				20
207,768		123,454	331,222	21
123,045		78,886	201,931	22
105,461		101,210	206,671	23
48,406		30,348	78,754	24
44,016		27,482	71,498	25
1,409,368		1,010,018	2,419,386	26
2,190,379		1,303,405	3,493,784	27
9,424		10,024	19,448	28
		2,452	2,452	29
948,452		694,416	1,642,868	30
798,634		569,674	1,368,308	31
				32
		-42	-42	33
		-41	-41	34
17,905,593	**447,569**	**10,202,404**	**28,555,566**	

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.
		-33	-33	1
		-84	-84	2
		-6	-6	3
		-30	-30	4
		-381	-381	5
		-490	-490	6
		-519	-519	7
		-28	-28	8
		-3	-3	9
		-22	-22	10
		-691	-691	11
		-1,922	-1,922	12
		-2	-2	13
		-74	-74	14
		-262	-262	15
		-23	-23	16
		-178	-178	17
		-1	-1	18
		-492	-492	19
		-3	-3	20
		-12	-12	21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
17,905,593	**447,569**	**10,202,404**	**28,555,566**	

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.

Name of Respondent Puget Sound Energy, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report 2019/Q4

FOOTNOTE DATA

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 FERC Electric Tariff of Puget Sound Energy, Inc. filed with the Federal Energy Regulatory Commission, Open Access Transmission Tariff.

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, and loss return charges.

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 State tax, facilities fees, and loss return charges.

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 State tax, facilities fees, and loss return charges.

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 State tax, and loss return charges.

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 State tax, and loss return charges.

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 State tax, facilities fees, and loss return charges.

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 State tax, and loss return charges.

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 State tax, facilities fees, and loss return charges.

Schedule Page: 328 Line No.: 16 Column: d
Contract expires August 1, 2020.

Schedule Page: 328 Line No.: 16 Column: m
Includes ancillary services and loss return charges.

Schedule Page: 328 Line No.: 17 Column: d
Powerex LFP 225 MW

Includes three contracts with the following end dates:

25 MW – October 1, 2022
100 MW – September 1, 2023
100 MW – September 1, 2019

Schedule Page: 328 Line No.: 17 Column: m
Includes ancillary services and loss return charges.
Schedule Page: 328 Line No.: 18 Column: m
Washington State tax and loss charges related to re-direct reservations into Washington..
Schedule Page: 328 Line No.: 19 Column: a
Long-Term point-to-point transmission resale.
Schedule Page: 328 Line No.: 19 Column: d
Contract expires on October 1, 2020.
Schedule Page: 328 Line No.: 19 Column: m
Includes ancillary services, Washington State tax and loss return charges.
Schedule Page: 328 Line No.: 20 Column: d
Contract expires on April 1, 2024.
Schedule Page: 328 Line No.: 20 Column: m
Includes ancillary services and loss return charges.
Schedule Page: 328 Line No.: 21 Column: d
Contract expires on December 1, 2021.
Schedule Page: 328 Line No.: 21 Column: m
Includes ancillary services, Washington State tax and loss return charges.
Schedule Page: 328 Line No.: 22 Column: d
Contract expires on October 1, 2022 (25MW) and January 1, 2022 (50MW).
Schedule Page: 328 Line No.: 22 Column: m
Includes ancillary services and loss return charges.
Schedule Page: 328 Line No.: 23 Column: d
Contract expires on October 1, 2020.
Schedule Page: 328 Line No.: 23 Column: m
Includes ancillary services and Washington State tax.
Schedule Page: 328 Line No.: 24 Column: d
Contract expires with one year written notice.
Schedule Page: 328 Line No.: 24 Column: m
Includes ancillary services, Washington State tax and loss return charges.
Schedule Page: 328 Line No.: 26 Column: m
Includes ancillary services and loss return charges.
Schedule Page: 328 Line No.: 27 Column: m
Ancillary services.
Schedule Page: 328 Line No.: 28 Column: m
Includes ancillary services, Washington State tax and loss return charges.
Schedule Page: 328 Line No.: 29 Column: m
Includes ancillary services, Washington State tax and loss return charges.
Schedule Page: 328 Line No.: 30 Column: m
Includes ancillary services, Washington State tax and loss return charges.
Schedule Page: 328 Line No.: 31 Column: m
Includes ancillary services, Washington State tax and loss return charges.
Schedule Page: 328 Line No.: 32 Column: m
Ancillary services.
Schedule Page: 328 Line No.: 34 Column: m
Includes ancillary services and loss return charges.
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 and loss return charges.

Schedule Page: 328.1 Line No.: 5 Column: m
Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 6 Column: m
Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 7 Column: m
Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 8 Column: m
Includes ancillary services, Washington State tax, unreserved use charges and loss return charges.

Schedule Page: 328.1 Line No.: 9 Column: m
Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 10 Column: m
Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 11 Column: m
Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328.1 Line No.: 12 Column: m
Unreserved use charges.

Schedule Page: 328.1 Line No.: 13 Column: m
Includes ancillary services, Washington State tax, unreserved use charges and loss return charges.

Schedule Page: 328.1 Line No.: 14 Column: m
Includes ancillary services, Washington State tax 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 Washington State tax.

Schedule Page: 328.1 Line No.: 18 Column: m
Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 21 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: 328.1 Line No.: 21 Column: f
Full name of the point of receipt is Rocky Reach 115KV Switchyard.

Schedule Page: 328.1 Line No.: 21 Column: m
Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328.1 Line No.: 22 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: 328.1 Line No.: 22 Column: m
Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328.1 Line No.: 23 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: 328.1 Line No.: 23 Column: m
Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328.1 Line No.: 24 Column: d
Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 459.

Schedule Page: 328.1 Line No.: 24 Column: m
Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328.1 Line No.: 25 Column: d
Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 459.

Schedule Page: 328.1 Line No.: 25 Column: m
Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328.1 Line No.: 26 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: 328.1 Line No.: 26 Column: m
Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328.1 Line No.: 27 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: 328.1 Line No.: 27 Column: m
Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328.1 Line No.: 28 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: 328.1 Line No.: 28 Column: m
Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328.1 Line No.: 29 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: 328.1 Line No.: 29 Column: m
Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328.1 Line No.: 30 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: 328.1 Line No.: 30 Column: m
Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328.1 Line No.: 31 Column: d
Customer takes retail wheeling service under the Washington State Utilities and Transportation Commission's special retail wheeling access program under Schedule 459.

Schedule Page: 328.1 Line No.: 31 Column: m
Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328.1 Line No.: 33 Column: m
Distrubution 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

Distribution of prior year unreserved use penalty 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: m

Distribution of prior year unreserved use penalty charges.

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

Distribution of prior year unreserved use penalty 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

Distribution of prior year unreserved use penalty 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

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 16 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 17 Column: m

Distribution of prior year unreserved use 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.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin	LFP			21,046,146		4,513,837	25,559,983
2	Bonneville Power Admin	LFP	5,908,523	5,908,523	63,824,979		12,152,686	75,977,665
3	Bonneville Power Admin	SFP			7,270		941	8,211
4	Bonneville Power Admin	NF	3,891	3,891	34,000	16,459	3,650	54,109
5	Bonneville Power Admin	OS					2,205	2,205
6	Bonneville Power Admin	OS					7,296	7,296
7	Bonneville Power Admin	OS					185,159	185,159
8	Bonneville Power Admin	OS					5,849,033	5,849,033
9	Bonneville Power Admin	OS					6,676,258	6,676,258
10	Bonneville Power Admin	AD					-54,541	-54,541
11	Avista Corp	NF	4,198	4,198		20,898		20,898
12	Avista Corp	OS					-1,400	-1,400
13	Brookfiled Energy Mrktg	OS					-32,954	-32,954
14	Chelan County PUD No. 1	OLF	1,904,130	1,904,130			5,064,853	5,064,853
15	Grant County PUD No. 2	OS					159,552	159,552
16	Grant County PUD No. 2	AD					12,000	12,000
	TOTAL		9,902,897	9,902,897	85,349,472	455,806	35,869,245	121,674,523

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	TRANSFER OF ENERGY Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Iberdrola Renewables	OS					-40,116	-40,116
2	Idaho Power Company	OS					-11,050	-11,050
3	Klickitat County PUD	OLF	1,942,118	1,942,118			1,324,893	1,324,893
4	Klondike Wind Power lll	OS					384,065	384,065
5	Klondike Wind Power lll	AD					2,004	2,004
6	Morgan Stanley CG	OS					-148,535	-148,535
7	NorthWestern Energy	SFP	69,118	69,118	434,045		10,056	444,101
8	NorthWestern Energy	NF	70,475	70,475		417,995	14,493	432,488
9	NorthWestern Energy	OS					81,770	81,770
10	NorthWestern Energy	OS					407,300	407,300
11	Portland General Elec	NF	444	444		454	377	831
12	Powerex Corp	OS					-576,375	-576,375
13	Shell Energy	OS					-10,320	-10,320
14	Tacoma Power	SFP			3,032		-7,567	-4,535
15	The Energy Authority	OS					-164,806	-164,806
16	TransAlta Energy Mrktng	OS					665,118	665,118
	TOTAL		9,902,897	9,902,897	85,349,472	455,806	35,869,245	121,674,523

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	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	TransAlta Energy Mrktng	OS					-633,595	-633,595
2	Whatcom Co PUD #1	OS					5,157	5,157
3	Whatcom Co PUD	AD					19,272	19,272
4	Misc. Adjustment	OS					8,529	8,529
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		9,902,897	9,902,897	85,349,472	455,806	35,869,245	121,674,523

Schedule Page: 332 Line No.: 1 Column: b

Includes a contract with several tables with end dates ranging from February 2021 to June 2037.

Schedule Page: 332 Line No.: 1 Column: c

Total MWh's for BPA firm transmission is calculated to be 5,908,523. The reporting does not split the MWh's amongst the contracts for the long-term firm Mid-Columbia projects, the other long-term firm contracts and the short-term firm contracts, so the entire 5,908,523 is reported with the long-term firm contracs on Line 2.

Schedule Page: 332 Line No.: 1 Column: e

Fixed tranmission capacity charges that are related to the contracts for the Mid-Columbia hydro projects.

Schedule Page: 332 Line No.: 1 Column: g

Ancillary services.

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

Includes a contract with several tables with end dates ranging from February 2020 to August 2028.

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

Total MWh's for BPA firm transmission is calculated to be 5,908,523. The reporting does not split the MWh's amongst the contracts for the long-term firm Mid-Columbia projects, the other long-term firm contracts and the short-term firm contracts, so the entire 5,908,523 is reported with the long-term firm contracs on Line 2.

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

Fixed tranmission capacity charges other than those related to the contracts for the Mid-Columbia hydro 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 that 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 5,908,523. The reporting does not split the MWh's amongst the contracts for the long-term firm Mid-Columbia projects, the other long-term firm contracts and the short-term firm contracts, so the entire 5,908,523 is reported with the long-term firm contracs on Line 2.

Schedule Page: 332 Line No.: 3 Column: g

Ancillary services.

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

Ancillary services.

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

Reserve sharing charges.

Schedule Page: 332 Line No.: 6 Column: g

Use of facilities charges.

Schedule Page: 332 Line No.: 7 Column: g

PSE's share of BPA line repair charges.

Schedule Page: 332 Line No.: 8 Column: g

Intertie charge and capacity rights charges.

Schedule Page: 332 Line No.: 9 Column: g

Wind integration and generator imbalance charges.

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

The total adjustment includes the following true-ups from prior periods:

$	(95,911.00)	- FTC for oversupply

	(925.00)	- Wind integration charges
	42,295.00	- 2018 PNW AC CAO Tru-up (06/19)
$	(54,541.00)	- Total prior periods adjustments

Schedule Page: 332 Line No.: 12 Column: g
Reimbursement from Avista Corp for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332 Line No.: 13 Column: g
Reimbursement from Brookfield Energy Marketing for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332 Line No.: 14 Column: b
Contract end date is October 31, 2031.

Schedule Page: 332 Line No.: 14 Column: g
Use of facilities charges.

Schedule Page: 332 Line No.: 15 Column: g
Use of transmission facilities charges.

Schedule Page: 332 Line No.: 16 Column: g
Prior period adjustment of transmission facilities charges.

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.: 2 Column: g
Reimbursement from Idaho Power Company for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.1 Line No.: 3 Column: b
Contract end date is June 30, 2032.

Schedule Page: 332.1 Line No.: 3 Column: g
Actual cost capacity charges.

Schedule Page: 332.1 Line No.: 4 Column: g
Wind integration charges.

Schedule Page: 332.1 Line No.: 5 Column: g
Adjustment of prior year wind integration charges in September 2019.

Schedule Page: 332.1 Line No.: 6 Column: g
Reimbursement from Morgan Stanley Capital Group for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.1 Line No.: 7 Column: g
Ancillary services.

Schedule Page: 332.1 Line No.: 8 Column: g
Ancillary services.

Schedule Page: 332.1 Line No.: 9 Column: g
Regulation & Frequency response charges and loss return charges.

Schedule Page: 332.1 Line No.: 10 Column: g
Use of facilities charges.

Schedule Page: 332.1 Line No.: 11 Column: g
Ancillary services.

Schedule Page: 332.1 Line No.: 12 Column: g
Reimbursement from Powerex for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.1 Line No.: 13 Column: g
Reimbursement from Shell Energy for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.1 Line No.: 14 Column: g
Ancillary services and energy imbalance charges.

Schedule Page: 332.1 Line No.: 15 Column: g
Reimbursement from The Energy Authority for use of PSE capacity on Bonneville Power

Administration lines.

Schedule Page: 332.1 Line No.: 16 Column: g

Ancillary services - reserves.

Schedule Page: 332.2 Line No.: 1 Column: g

Reimbursement from TransAlta Energy Marketing for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.2 Line No.: 2 Column: g

Interconnection losses charges.

Schedule Page: 332.2 Line No.: 3 Column: g

Prior period adjustment of inconnection losses charges.

Schedule Page: 332.2 Line No.: 4 Column: g

Amount includes $4,029 related to a write-off of the St. Claire transmission credit balance and $4,500 related to PSE fees for application to the PSE TPC.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	790,248
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	Western Electric Coordinator Council Dues	7,500
7	Board of Director Fees and Expenses	605,299
8	Other Membership Dues	545,873
9	Treasury Fees & Expenses	195,624
10	Misc General Expense - Electric	6,086,805
11	State/Fed Govt Related Industry Expenses	5,875
12		
13		
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46	TOTAL	8,237,224

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

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

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant				15,375,157	15,375,157
2	Steam Production Plant	44,350,798	4,144,993			48,495,791
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	19,374,197			1,189,064	20,563,261
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	75,247,263	3,218,716			78,465,979
7	Transmission Plant	35,623,181	94,817			35,717,998
8	Distribution Plant	138,962,831	41,922			139,004,753
9	Regional Transmission and Market Operation					
10	General Plant	13,101,429				13,101,429
11	Common Plant-Electric	19,067,454	33,533		66,750,778	85,851,765
12	TOTAL	345,727,153	7,533,981		83,314,999	436,576,133

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
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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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	WUTC Filing Fee	4,394,186		4,394,186	
2					
3	Federal fees:				
4	Upper & Lower Baker Project	1,432,749		1,432,749	
5	Snoqualmie 1 & 2 Project	130,190		130,190	
6	FERC Regulatory Comm Trading	876,716		876,716	
7					
8	Other Charges:				
9	FERC Regulatory Legal Fees		205,213	205,213	
10	State Regulatory Legal Fees		361,981	361,981	
11	Transmission Rate Case		77,201	77,201	
12	General Rate Case Legal Fees		1,146,028	1,146,028	
13					
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15					
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46	TOTAL	6,833,841	1,790,423	8,624,264	

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.
Electric	928	4,394,186					1
							2
							3
Electric	928	1,432,749					4
Electric	928	130,190					5
Electric	928	876,716					6
							7
							8
Electric	928	205,213					9
Electric	928	361,981					10
Electric	928	77,201					11
Electric	928	1,146,028					12
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		8,624,264					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	Note: No R&D Activity for 2019	
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
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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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	21,886,771		
4	Transmission	7,632,076		
5	Regional Market			
6	Distribution	19,004,394		
7	Customer Accounts	10,455,286		
8	Customer Service and Informational	1,574,208		
9	Sales	513,761		
10	Administrative and General	29,992,617		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	91,059,113		
12	Maintenance			
13	Production	5,365,232		
14	Transmission	1,659,076		
15	Regional Market			
16	Distribution	9,663,691		
17	Administrative and General	229,898		
18	TOTAL Maintenance (Total of lines 13 thru 17)	16,917,897		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	27,252,003		
21	Transmission (Enter Total of lines 4 and 14)	9,291,152		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	28,668,085		
24	Customer Accounts (Transcribe from line 7)	10,455,286		
25	Customer Service and Informational (Transcribe from line 8)	1,574,208		
26	Sales (Transcribe from line 9)	513,761		
27	Administrative and General (Enter Total of lines 10 and 17)	30,222,515		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	107,977,010	9,071	107,986,081
29	Gas			
30	Operation			
31	Production-Manufactured Gas	64,046		
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	1,952,873		
34	Storage, LNG Terminaling and Processing	949,038		
35	Transmission			
36	Distribution	20,217,188		
37	Customer Accounts	7,250,967		
38	Customer Service and Informational	916,048		
39	Sales	-45,173		
40	Administrative and General	13,903,679		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	45,208,666		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	273,905		
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	6,067,381		
49	Administrative and General	154,180		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	6,495,466		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	64,046		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	1,952,873		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	1,222,943		
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	26,284,569		
58	Customer Accounts (Line 37)	7,250,967		
59	Customer Service and Informational (Line 38)	916,048		
60	Sales (Line 39)	-45,173		
61	Administrative and General (Lines 40 and 49)	14,057,859		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	51,704,132	4,344	51,708,476
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	159,681,142	13,415	159,694,557
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	61,722,455	5,185	61,727,640
69	Gas Plant	28,061,025	2,357	28,063,382
70	Other (provide details in footnote):	49,037,985	4,120	49,042,105
71	TOTAL Construction (Total of lines 68 thru 70)	138,821,465	11,662	138,833,127
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,588,074	217	2,588,291
74	Gas Plant	1,565,483	132	1,565,615
75	Other (provide details in footnote):	383,049	32	383,081
76	TOTAL Plant Removal (Total of lines 73 thru 75)	4,536,606	381	4,536,987
77	Other Accounts (Specify, provide details in footnote):	25,887,686	2,175	25,889,861
78				
79				
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	25,887,686	2,175	25,889,861
96	TOTAL SALARIES AND WAGES	328,926,899	27,633	328,954,532

Schedule Page: 354 Line No.: 77 Column: a

Description	Direct Payroll Distribution (b)	Allocation of Payroll Charged to Clearing Accounts (c)	Total (d) (Col-7 + Col8)
121 Non Utility Property	27,634	2	27,636
163 Stores Exp.	3,966,331	333	3,966,664
182 Regulatory Asset	14,088,489	1,184	14,089,673
185 Temporary Facilities	9,594	1	9,595
149 Misc. Deferred Debits	1,149,490	97	1,149,587
186 Misc. Deferred Debits	2,487,627	209	2,487,836
Misc 400 Accounts	1,608,628	135	1,608,763
143 Accts Receivable Misc.	-	-	-
Prelim Survey OG 183	-	-	-
Allocated OG 184	2,549,459	214	2,549,673
Misc 200 Accounts	434	-	434
Jackson Prairie Joint Venture - Capital - PSE Share	-	-	-
Jackson Prairie Joint Venture - Expense - PSE Share	-	-	-
Total	25,887,686	2,175	25,889,861

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 12/31/2019	ACCUMULATED PROVISION FOR DEPR & AMORT
C302	Franchises	416,721	70,979
C303	Software Development	574,521,364	209,369,286
C389	Land and Land Rights	53,483,328	2,442,449
C390	Structures and Improvements	202,908,542	82,341,385
C391	Office Furniture and Equipment	128,434,920	48,490,489
C392	Transportation Equipment	7,022,615	4,916,467
C393	Stores Equipment	92,576	44,116
C394	Tools/Shop/Garage Equipment	1,515,058	1,224,346
C396	Power Operated Equipment	865,676	918,108
C397	Communication Equipment	88,554,565	24,756,070
C398	Miscellaneous Equipment	1,032,220	1,703,052
C399	Other Tangible Property	524,934	52,768
Total Common Plant in Service		1,059,372,520	376,329,515

Common plant balances are not allocated to electric or gas departments.

3. Common expense allocated to Electric and Gas Department:

Account	Description	Total Allocated	Allocated to Electric	Allocated to Gas	Basis
403	Depreciation	28,807,152	19,067,454	9,739,698	(D)
404	Amortization of LTD Term Plant	100,770,980	66,700,312	34,070,668	(D)
901	Customer Accounts and Collection Supervision	222,561	129,197	93,364	(A)
902	Meter Reading Expense	2,297,616	1,429,347	868,269	(B)
903	Customer Records and Collections	36,111,186	20,962,543	15,148,643	(A)
904	Uncollectible Accounts	84,918	56,207	28,711	(D)
908	Customer Assistance	1,169,289	678,773	490,517	(A)
909	Information and Instructional Advertising	2,303,935	1,337,435	966,501	(A)
910	Miscellaneous Customer Services and Information	347	201	146	(A)

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.

912	Common Sales	(152,651)	(88,660)	(63,991)	(A)
920	Administrative and General Salaries	81,395,408	53,875,620	27,519,787	(D)
921	Office Supplies & Expense	2,353,778	1,557,966	795,812	(D)
922	Administrative Expense Transferred	(35,169,428)	(23,278,644)	(11,890,784)	(D)
923	Outside Services Employed	13,377,138	8,854,328	4,522,810	(D)
924	Property Insurance	(18,720)	(11,303)	(7,417)	(C)
925	Injuries & Damages	5,555,202	3,226,461	2,328,741	(A)
928	Regulatory Commission	1,838,174	1,216,687	621,487	(D)
930.1	Common Gen Advertising Exp	595	394	201	(D)
930.2	Miscellaneous General Expense	10,917,128	7,226,047	3,691,081	(D)
931	Rents	10,368,250	6,862,745	3,505,505	(D)
935	Maintenance of General Plant	24,078,329	15,937,446	8,140,883	(D)
Total Expense		156,733,054	99,972,788	56,760,266	

(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: 66.19%, and Gas: 33.81%

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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/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)	9,111,785	10,459,760	15,795,992	17,635,944
3	Net Sales (Account 447)	(7,649,665)	(11,098,045)	(16,101,522)	(21,574,509)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
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45					
46	TOTAL	1,462,120	(638,285)	(305,530)	(3,938,565)

Schedule Page: 397 Line No.: 2 Column: e

	Q1, 2019	Q2, 2019	Q3, 2019	Q4. 2019	YTD 2019
EIM Purchases	$ 8,289,248	$ 1,162,820	$ 4,944,109	$ 1,231,595	$ 15,627,772
Intertie Purchases	822,537	185,155	392,123	608,357	2,008,172
Total by Quarter	**$ 9,111,785**	**$ 1,347,975**	**$ 5,336,232**	**$ 1,839,952**	**$ 17,635,944**

Schedule Page: 397 Line No.: 3 Column: e

	Q1, 2019	Q2, 2019	Q3,2019	Q4, 2019	YTD 2019
EIM Sales	$ (7,649,665)	$ (3,448,196)	$ (5,003,477)	$ (5,472,987)	$ (21,574,325)
Intertie Sales	-	(184)	-	-	(184)
Total by Quarter	**$ (7,649,665)**	**$ (3,448,380)**	**$ (5,003,477)**	**$ (5,472,987)**	**$ (21,574,509)**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

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				85,593	MW	6,073,798
2	Reactive Supply and Voltage				23,911	MW	132,175
3	Regulation and Frequency Response	87,370	MWH	13,619	6,155	MW	2,258,718
4	Energy Imbalance	-160,765	MWH	-39,441,118	-178,738	MWH	-40,172,861
5	Operating Reserve - Spinning	2,189,274	MWH	663,098	6,728	MW	879,294
6	Operating Reserve - Supplement	2,189,274	MWH	553,312	6,728	MW	855,538
7	Other	29,899	MW	5,876,071	12,099	MWH	-183,800
8	Total (Lines 1 thru 7)	4,335,052		-32,335,018	-37,524		-30,157,138

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

Schedule 1 purchases can be broken down as follows:

Number of Units	Unit of measure	Dollars
131,443	MW	$ 23,531,075
5,353	MWh	4,978
		$ 23,536,053

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
69,739	MW	$ 78,746
5,353	MWh	-
		$ 78,746

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

Schedule 3, Units: 4,762 MW, Dollars: $542,662
Schedule 13, Units: 1,393 MW, Dollars: $1,716,057

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

Schedule 9 Generator Imbalance is reported in "Other" sales.

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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: 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	5,145	15	800	3,614	351	1,150	30	363	187
2	February	5,803	6	900	4,243	378	1,150	32	3,158	247
3	March	5,410	5	800	3,881	346	1,150	33	4,034	176
4	Total for Quarter 1				11,738	1,075	3,450	95	7,555	610
5	April	4,531	15	800	2,967	296	1,238	30	243	397
6	May	4,153	1	800	2,614	273	1,238	28	477	305
7	June	4,957	12	1800	3,064	327	1,238	328	231	251
8	Total for Quarter 2				8,645	896	3,714	386	951	953
9	July	4,785	26	1800	2,899	320	1,238	328	866	72
10	August	4,961	5	1800	3,068	325	1,238	330	648	219
11	September	4,692	30	800	2,799	327	1,238	328	231	300
12	Total for Quarter 3				8,766	972	3,714	986	1,745	591
13	October	5,195	30	800	3,577	349	1,238	31	237	368
14	November	5,207	30	1000	3,622	314	1,238	33	237	248
15	December	5,318	26	1800	3,719	327	1,238	34	3,298	337
16	Total for Quarter 4				10,918	990	3,714	98	3,772	953
17	Total Year to Date/Year				40,067	3,933	14,592	1,565	14,023	3,107

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: 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		306	
4	Total for Quarter 1						1,200	600	306	
5	April	400					400		150	
6	May	400					400			
7	June	700					400	300		
8	Total for Quarter 2						1,200	300	150	
9	July	700					400	300		
10	August	700					400	300		
11	September	700					400	300		
12	Total for Quarter 3						1,200	900		
13	October	700					400	300		
14	November	700					400	300		
15	December	700					400	300		
16	Total for Quarter 4						1,200	900		
17	Total Year to Date/Year						4,800	2,700	456	

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: 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					1,989				
5	April	663				663				
6	May	663				663				
7	June	663				663				
8	Total for Quarter 2					1,989				
9	July	663				663				
10	August	663				663				
11	September	663				663				
12	Total for Quarter 3					1,989				
13	October	663				663				
14	November	663				663				
15	December	663				663				
16	Total for Quarter 4					1,989				
17	Total Year to Date/Year					7,956				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: Total

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	6,508			3,614	351	2,213	330	363	187
2	February	7,166			4,243	378	2,213	332	3,158	247
3	March	6,473			3,881	346	2,213	33	4,340	176
4	Total for Quarter 1				11,738	1,075	6,639	695	7,861	610
5	April	5,594			2,967	296	2,301	30	393	397
6	May	5,216			2,614	273	2,301	28	477	305
7	June	6,320			3,064	327	2,301	628	231	251
8	Total for Quarter 2				8,645	896	6,903	686	1,101	953
9	July	6,148			2,899	320	2,301	628	866	72
10	August	6,324			3,068	325	2,301	630	648	219
11	September	6,055			2,799	327	2,301	628	231	300
12	Total for Quarter 3				8,766	972	6,903	1,886	1,745	591
13	October	6,558			3,577	349	2,301	331	237	368
14	November	6,570			3,622	314	2,301	333	237	248
15	December	6,681			3,719	327	2,301	334	3,298	337
16	Total for Quarter 4				10,918	990	6,903	998	3,772	953
17	Total Year to Date/Year				40,067	3,933	27,348	4,265	14,479	3,107

Schedule Page: 400 Line No.: 1 Column: j
Represents the total MWHr of EIM Transfer utilizing ATC (PSE OATT, Attachment O, section 5.3) for the day and hour of the monthly peak.

Schedule Page: 400 Line No.: 2 Column: j
Represents the total MWHr of EIM Transfer utilizing ATC (PSE OATT, Attachment O, section 5.3) for the day and hour of the monthly peak.

Schedule Page: 400 Line No.: 3 Column: j
Represents the total MWHr of EIM Transfer utilizing ATC (PSE OATT, Attachment O, section 5.3) for the day and hour of the monthly peak.

Schedule Page: 400 Line No.: 5 Column: j
Represents the total MWHr of EIM Transfer utilizing ATC (PSE OATT, Attachment O, section 5.3) for the day and hour of the monthly peak.

Schedule Page: 400 Line No.: 6 Column: j
Represents the total MWHr of EIM Transfer utilizing ATC (PSE OATT, Attachment O, section 5.3) for the day and hour of the monthly peak.

Schedule Page: 400 Line No.: 7 Column: j
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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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	20,833,230
3	Steam	6,320,605			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	7,306
5	Hydro-Conventional	712,727			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,645,768
7	Other	6,386,710			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	13,420,042	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	22,324
10	Purchases	15,771,178	27	Total Energy Losses	1,275,898
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	28,784,526
12	Received	443,837			
13	Delivered	850,531			
14	Net Exchanges (Line 12 minus line 13)	-406,694			
15	Transmission For Other (Wheeling)				
16	Received	8,180,917			
17	Delivered	8,180,917			
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)	28,784,526			

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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	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	2,827,523	623,009	3,833	15	800
30	February	2,519,287	275,882	4,498	6	900
31	March	2,606,455	555,379	4,132	4	800
32	April	2,061,849	383,146	3,106	15	800
33	May	1,798,709	218,894	2,732	1	800
34	June	1,962,227	442,525	3,192	12	1800
35	July	2,421,419	808,143	3,026	26	1800
36	August	2,464,797	803,043	3,196	5	1800
37	September	2,275,091	717,875	2,961	30	800
38	October	2,413,681	571,053	3,757	30	800
39	November	2,476,498	481,600	3,786	30	1000
40	December	2,956,995	764,593	3,902	26	1800
41	TOTAL	28,784,531	6,645,142			

Schedule Page: 401 Line No.: 29 Column: Sys

NAME OF SYSTEM: Point Roberts Transfer Point
2019

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)	Day of Month (e)	Hour (f)
1	January	2,320		4.4	15	0800
2	February	2,722		5.7	10	0900
3	March	2,063		4.8	6	0755
4	**Total**	**7,105**	**0**			
5	April	1,478		3.1	13	1000
6	May	1,193		2.7	20	1000
7	June	1,107		2.2	30	1800
8	**Total**	**3,778**	**0**			
9	July	1,222		2.3	7	1000
10	August	1,236		2.4	4	1800
11	September	1,165		2.7	29	0900
12	**Total**	**3,623**	**0**			
13	October	1,664		3.7	30	0700
14	November	1,969		4.8	30	0900
15	December	2,307		4.4	1	0900
16	**Total**	**5,939**	**0**			
17	**Yr Total**	**20,445**	**0**			

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Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *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)	333			417		
7	Plant Hours Connected to Load	6521			8603		
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	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	1734247000			2613392000		
13	Cost of Plant: Land and Land Rights	0			2788745		
14	Structures and Improvements	0			129907504		
15	Equipment Costs	0			403939889		
16	Asset Retirement Costs	50629164			44628027		
17	Total Cost	50629164			581264165		
18	Cost per KW of Installed Capacity (line 17/5) Including	134.2949			1340.8631		
19	Production Expenses: Oper, Supv, & Engr	115813			90098		
20	Fuel	48151884			46831859		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4614529			3006379		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	143147			119206		
26	Misc Steam (or Nuclear) Power Expenses	5931819			4549696		
27	Rents	3195			21003		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	1003458			696028		
30	Maintenance of Structures	576188			1086799		
31	Maintenance of Boiler (or reactor) Plant	4755017			6318637		
32	Maintenance of Electric Plant	2316107			2219531		
33	Maintenance of Misc Steam (or Nuclear) Plant	1420502			903893		
34	Total Production Expenses	69031659			65843129		
35	Expenses per Net KWh	0.0398			0.0252		
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	1132839	0	0	1684768	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8629	0	0	8384	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	43.686	0.000	0.000	25.269	0.000	0.000
41	Average Cost of Fuel per Unit Burned	42.505	0.000	0.000	27.797	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.463	0.000	0.000	1.658	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.028	0.000	0.000	0.018	0.000	0.000
44	Average BTU per KWh Net Generation	11273.214	0.000	0.000	10809.782	0.000	0.000

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

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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)	330			131		
7	Plant Hours Connected to Load	6878			4297		
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	17			13		
12	Net Generation, Exclusive of Plant Use - KWh	1864729560			483612470		
13	Cost of Plant: Land and Land Rights	1194000			795165		
14	Structures and Improvements	11976018			5697005		
15	Equipment Costs	98868964			79930739		
16	Asset Retirement Costs	0			0		
17	Total Cost	112038982			86422909		
18	Cost per KW of Installed Capacity (line 17/5) Including	351.2194			596.0201		
19	Production Expenses: Oper, Supv, & Engr	343061			278240		
20	Fuel	53517028			13045167		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	223878			265342		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2437796			2206463		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	7639			21825		
30	Maintenance of Structures	261472			213418		
31	Maintenance of Boiler (or reactor) Plant	925522			397746		
32	Maintenance of Electric Plant	2425101			925968		
33	Maintenance of Misc Steam (or Nuclear) Plant	119253			5360		
34	Total Production Expenses	60260750			17359529		
35	Expenses per Net KWh	0.0323			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	12455166	0	0	3635482	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1101468	0	0	1101468	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.297	0.000	0.000	3.588	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.297	0.000	0.000	3.588	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.901	0.000	0.000	3.258	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.029	0.000	0.000	0.027	0.000	0.000
44	Average BTU per KWh Net Generation	7357.082	0.000	0.000	8280.116	0.000	0.000

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Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *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)	193			108		
7	Plant Hours Connected to Load	1705			689		
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	5			5		
12	Net Generation, Exclusive of Plant Use - KWh	163441400			30683000		
13	Cost of Plant: Land and Land Rights	1502988			0		
14	Structures and Improvements	3782846			1635069		
15	Equipment Costs	51320367			63307636		
16	Asset Retirement Costs	0			0		
17	Total Cost	56606201			64942705		
18	Cost per KW of Installed Capacity (line 17/5) Including	219.2339			551.2963		
19	Production Expenses: Oper, Supv, & Engr	404362			14243		
20	Fuel	6178197			1946641		
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	1173887			5514		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	3066			753		
30	Maintenance of Structures	148390			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	1973624			92192		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	9881526			2059343		
35	Expenses per Net KWh	0.0605			0.0671		
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	1915517	669	0	219483	357	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1101468	138900	0	1101468	138900	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.184	125.915	0.000	8.677	125.915	0.000
41	Average Cost of Fuel per Unit Burned	3.184	118.319	0.000	8.677	118.319	0.000
42	Average Cost of Fuel Burned per Million BTU	2.891	20.282	0.000	7.878	20.282	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.038	0.085	0.000	0.062	0.200	0.000
44	Average BTU per KWh Net Generation	12983.236	4180.787	0.000	7933.552	9874.970	0.000

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

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

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

Plant Name: *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			315.00			5
167			135			314			6
3006			5284			7098			7
0			0			0			8
165			136			315			9
0			0			0			10
16			0			18			11
400633000			669752000			1942118000			12
1051000			699814			1288140			13
9478994			6178023			37290067			14
154194164			60565889			281946337			15
0			443797			0			16
164724158			67887523			320524544			17
933.8104			495.5294			1017.5382			18
238654			1876076			287256			19
12157461			15954091			50238828			20
0			0			0			21
42921			27729			1476519			22
0			0			0			23
0			0			0			24
2486564			965962			2684076			25
0			11580			0			26
0			0			0			27
0			0			0			28
9681			293455			7639			29
65680			10505			111602			30
464096			307975			369162			31
1450077			826570			1930827			32
63655			19083			509460			33
16978789			20293026			57615369			34
0.0424			0.0303			0.0297			35
Gas	Oil		Gas			Gas			36
Mcf	Bbl		Mcf			Mcf			37
3247349	0	0	4266118	0	0	12510403	0	0	38
1101468	139600	0	1101468	0	0	1101468	0	0	39
3.744	0.000	0.000	3.740	0.000	0.000	4.016	0.000	0.000	40
3.744	0.000	0.000	3.740	0.000	0.000	4.016	0.000	0.000	41
3.399	0.000	0.000	3.395	0.000	0.000	3.646	0.000	0.000	42
0.030	0.000	0.000	0.024	0.000	0.000	0.026	0.000	0.000	43
8928.000	0.000	0.000	7016.019	0.000	0.000	7095.249	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

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

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

Plant Name: *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
		282			131			129	6
		5448			176			75	7
		0			0			0	8
		253			149			149	9
		0			0			0	10
		0			5			6	11
		1047797000			7870300			81365280	12
		0			364590			785528	13
		6594636			1486817			3194161	14
		119413674			36084861			37083026	15
		1030922			0			0	16
		127039232			37936268			41062715	17
		453.7115			224.2096			230.9489	18
		765968			88106			17120	19
		30816988			751234			3237848	20
		0			0			0	21
		856116			0			0	22
		0			0			0	23
		0			0			0	24
		2308928			496084			680033	25
		0			0			0	26
		0			0			0	27
		0			0			0	28
		0			7639			3820	29
		40316			32878			51830	30
		507719			0			0	31
		2002984			1041337			1060261	32
		312613			0			0	33
		37611632			2417278			5050912	34
		0.0359			0.3071			0.0621	35
Gas	Oil		Gas	Oil		Gas	Oil		36
Mcf	Bbl		Mcf	Bbl		Mcf	Bbl		37
7942492	110	0	107671	1312	0	1089095	434	0	38
1101468	140000	0	1101468	139000	0	1101468	139400	0	39
3.878	96.878	0.000	5.854	125.959	0.000	2.934	94.395	0.000	40
3.878	122.941	0.000	5.854	92.215	0.000	2.934	97.359	0.000	41
3.521	20.908	0.000	5.314	15.796	0.000	2.664	16.629	0.000	42
0.029	0.177	0.000	0.086	0.212	0.000	0.039	0.529	0.000	43
8349.938	8463.046	0.000	16246.793	13421.648	0.000	14757.935	31792.508	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	6	5	11
612886218	340498880	714103694	12
8131854	0	203682	13
15120072	3413472	31393624	14
408227956	168511679	654327874	15
22037384	12455466	17350201	16
453517266	184380617	703275381	17
1661.2354	1174.3988	2050.3655	18
409901	335906	332854	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
617164	621527	881459	25
0	0	0	26
2612135	746010	2809093	27
0	0	0	28
139912	117738	72739	29
213997	40721	78489	30
0	0	0	31
6964730	4531891	8029755	32
0	0	0	33
10957839	6393793	12204389	34
0.0179	0.0188	0.0171	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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

Colstrip is operated by Talen Montana, LLC. There are no PSE employees at the plant.

Schedule Page: 402 Line No.: 11 Column: c

Colstrip is operated by Talen Montana, LLC. There are no PSE employees at the plant.

Schedule Page: 403 Line No.: 11 Column: e

Facility is operated by Atlantic Power Corporation. There are no PSE employees.

Schedule Page: 402 Line No.: 17 Column: b

In June 2019, Talen, the plant operator of Colstrip 1&2, announced a plan to shut down as of December 31, 2019. The Company retired Colstrip 1&2 from Utility Plant and transferred the unrecovered amount of $126.5M to regulatory assets effective December 31, 2019.

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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Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: LOWER BAKER (b)	FERC Licensed Project No. 0 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)	103	107
7	Plant Hours Connect to Load	8,749	4,397
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	17	17
12	Net Generation, Exclusive of Plant Use - Kwh	263,805,800	262,945,500
13	Cost of Plant		
14	Land and Land Rights	8,314,620	2,001,428
15	Structures and Improvements	35,903,750	16,076,582
16	Reservoirs, Dams, and Waterways	121,168,604	122,991,212
17	Equipment Costs	67,569,228	18,787,665
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)	234,544,518	162,505,069
21	Cost per KW of Installed Capacity (line 20 / 5)	2,039.5175	1,550.6209
22	Production Expenses		
23	Operation Supervision and Engineering	790,878	1,009,547
24	Water for Power	0	0
25	Hydraulic Expenses	1,298,525	1,909,508
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	122,079	665,195
28	Rents	0	0
29	Maintenance Supervision and Engineering	68,033	58,764
30	Maintenance of Structures	95,344	59,732
31	Maintenance of Reservoirs, Dams, and Waterways	54,267	71,016
32	Maintenance of Electric Plant	51,842	231,119
33	Maintenance of Misc Hydraulic Plant	2,049,084	1,007,635
34	Total Production Expenses (total 23 thru 33)	4,530,052	5,012,516
35	Expenses per net KWh	0.0172	0.0191

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Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 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
42	0	0	6
8,745	0	0	7
			8
50	0	0	9
50	0	0	10
18	0	0	11
185,975,900	0	0	12
			13
554,504	0	0	14
114,462,004	0	0	15
115,733,203	0	0	16
105,033,269	0	0	17
808,565	0	0	18
0	0	0	19
336,591,545	0	0	20
6,187.3446	0.0000	0.0000	21
			22
233,950	0	0	23
0	0	0	24
185,988	0	0	25
250,971	0	0	26
1,037,137	0	0	27
0	0	0	28
63,390	0	0	29
196,216	0	0	30
294,639	0	0	31
824,422	0	0	32
428,849	0	0	33
3,515,562	0	0	34
0.0189	0.0000	0.0000	35

Schedule Page: 406   Line No.: 11   Column: b

There was a total of 35 fulltime equivalent 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 was a total of 35 fulltime equivalent 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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/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)	

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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
			8
			9
			10
			11
			12
			13
			14
			15
			16
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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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	INTERNAL COMBUSTION					
2	Crystal Mountain	1969	2.75	2.7	185,520	2,812,124
3						
4						
5						
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Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
1,022,591	60,205	36,610	16,818	Diesel	1,757	2
						3
						4
						5
						6
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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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH (Pole miles) On Structures of Another Line (g)	Number Of Circuits (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		1
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		1
22	Freddy/APC	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		1
26	Poison Spring	Wind Ridge	230.00	230.00	HF2	4.10		1
27	Rocky Reach	Cascade	230.00	230.00	WHF, SCST	57.86		1
28	Saint Clair	Bpa South Tacoma	230.00	230.00	DCST	3.62		1
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	Horse Ranch	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	2,610.54		40

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	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		1
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	White River	Alderton #5	230.00	230.00	SCST, DCST	8.34		1
7	230 KV Tot							
8	115 KV Tot					1,668.97		
9	55 KV Tot					77.47		
10	ARC as per FAS 143							
11								
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29								
30								
31								
32								
33								
34								
35								
36					TOTAL	2,610.54		40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
4-795 ACSR								2
4-795 ACSR								3
2-2250 ACSR								4
2-2250 ACSR								5
4-795 ACSR								6
4-795 ACSR								7
	1,765,339	116,588,697	118,354,036					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
2-1272 ACSR								18
1272 ACSR								19
1272 ACSR								20
2-1272 ACSR								21
1750 KCML								22
1272 ACSR								23
								24
1272 ACSR								25
1272 ACSR								26
2-1590 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
	45,016,947	809,565,458	854,582,405	14,135,640	9,522,752	462,594	24,120,986	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
1590 ACSR								1
2-1590 ACSR								2
2-1272 ACSR								3
2-1272 ACSR								4
1272 ACSR								5
1590 ACSS								6
	13,778,578	222,325,254	236,103,832					7
	29,206,607	448,305,124	477,511,731					8
	266,423	19,955,002	20,221,425					9
		2,391,381	2,391,381					10
								11
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								27
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								30
								31
								32
				14,135,640	9,522,752	462,594	24,120,986	33
								34
								35
	45,016,947	809,565,458	854,582,405	14,135,640	9,522,752	462,594	24,120,986	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 APC (Atlantic Power Corporation). 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) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1							
2							
3							
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5							
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7							
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43							
44	TOTAL						

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
									2
									3
									4
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Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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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	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	BELLINGHAM	DU			
5	BELLIS WHATCOM	DU	115.00	12.50	
6	BELMORE SOUTH WEST KING	DU	115.00	12.50	
7	BERTHUSEN WHATCOM	DU	115.00	12.50	
8	BIG ROCK SKAGIT	DU	115.00	12.50	
9	BIRCH BAY WHATCOM	DU	115.00	12.50	
10	BLACKBURN	DU	115.00	12.50	
11	BLACK DIAMOND SOUTH EAST KING	DU	115.00	12.50	
12	BLAINE WHATCOM	DU	115.00	12.50	
13	BLUMAER THURSTON	DU	115.00	12.50	
14	BONNEY LAKE EAST PIERCE	DU	115.00	12.50	
15	BOW LAKE SOUTH WEST KING	DU	115.00	12.50	
16	BREMERTON SOUTH PENNISULA	DU	115.00	12.50	
17	BRIDLE TRAILS CENTRAL KING	DU	115.00	12.50	
18	BRIGHTWATER IPS NORTH KING	DU	115.00	4.00	
19	BRITTON WHATCOM	DU	115.00	12.50	
20	BROOKS HILL ISLAND	DU	115.00	12.50	
21	BUCKLEY EAST PIERCE	DU	55.00	12.50	
22	BUCKLIN HILL NORTH PENNISULA	DU	115.00	12.50	
23	BURLINGTON SKAGIT	DU	115.00	12.50	
24	BURROWS BAY SKAGIT	DU	115.00	12.50	
25	CAMBRIDGE SOUTH KING	DU	115.00	12.50	
26	CAPITOL THURSTON	DU	115.00	12.50	
27	CAROLINA WHATCOM	DU	115.00	12.50	
28	CEDARHURST EAST PIERCE	DU	115.00	12.50	
29	CENTER CENTRAL KING	DU	115.00	13.09	
30	CENTER CENTRAL KING	DU	115.00	13.09	
31	CENTRAL KITSAP NORTH PENNISULA	DU	115.00	12.50	
32	CHAMBERS THURSTON	DU	115.00	12.50	
33	CHICO SOUTH PENNISULA	DU	115.00	12.50	
34	CHICO SOUTH PENNISULA	DU	34.50	12.50	
35	CHRISTENSENS CORNER NORTH PENNISULA	DU	115.00	12.50	
36	CHRISTOPHER AUBURN	DU	115.00	12.50	
37	CLAY CREEK SOUTH EAST KING	DU	55.00	7.00	
38	CLE ELUM KITTITAS	DU	115.00	34.50	
39	CLOVER VALLEY ISLAND	DU	115.00	12.50	
40	CLYDE HILL CENTRAL KING	DU	115.00	12.50	

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1	CLYMER KITTITAS	DU	115.00	12.50	
2	COLLEGE CENTRAL KING	DU	115.00	12.50	
3	COTTAGE BROOK NORTH KING	DU	115.00	12.50	
4	COUPEVILLE ISLAND	DU	115.00	12.50	
5	CRESCENT HARBOR ISLAND	DU	115.00	13.00	
6	CRESTWOOD NORTH KING	DU	115.00	12.50	
7	CRYSTAL MOUNTAIN GEN. SE KING	DU	34.50	12.50	
8	CRYSTAL MOUNTAIN GEN. SE KING	DU	12.50	4.16	
9	CUMBERLAND SE KING	DU	115.00	12.50	
10	CUSTER WHATCOM	DU	115.00	12.50	
11	DECATUR THURSTON	DU	115.00	12.50	
12	DES MOINES SOUTH WEST KING	DU	115.00	12.50	
13	DIERINGER EAST PIERCE	DU	115.00	12.50	
14	DUPONT EAST PIERCE	DU	115.00	12.50	
15	DUVALL NORTH KING	DU	115.00	12.50	
16	EARLINGTON SOUTH KING	DU	115.00	12.50	
17	EAST PORT ORCHARD SOUTH PENNISULA	DU	115.00	12.50	
18	EAST VALLEY SOUTH KING	DU	115.00	12.50	
19	EASTGATE CENTRAL KING	DU	115.00	12.50	
20	EASTON KITTITAS	DU	115.00	12.50	
21	EDGEWOOD EAST PIERCE	DU	115.00	12.50	
22	ELD INLET THURSTON	DU	115.00	12.50	
23	ELECTRON GEN. EAST PIERCE	DU	115.00	2.40	
24	ELECTRON HEIGHTS EAST PIERCE	DU	55.00	12.50	
25	ELECTRON HEIGHTS EAST PIERCE	DU	115.00	55.00	
26	ELECTRON HEIGHTS EAST PIERCE	DU	55.00	2.40	
27	ELLINGSON SOUTH EAST KING	DU	115.00	12.50	
28	ENCOGEN GEN. WHATCOM	DU	115.00	13.80	
29	ENCOGEN GEN. WHATCOM	DU	115.00	13.80	
30	ENUMCLAW SOUTH EAST KING	DU	115.00	12.50	
31	EVERGREEN NORTH KING	DU	115.00	12.50	
32	FABER ISLAND	DU	115.00	12.50	
33	FACTORIA CENTER KING	DU	115.00	12.50	
34	FAIRCHILD EAST PIERCE	DU	115.00	12.50	
35	FAIRWOOD CENTRAL KING	DU	115.00	12.50	
36	FALCON SOUTH KING	DU	115.00	12.50	
37	FALL CITY EAST KING	DU	115.00	12.50	
38	FERNWOOD SOUTH PENNISULA	DU	115.00	12.50	
39	FOSS CORNER	DU	115.00		
40	FOUR CORNERS SOUTH EAST KING	DU	115.00	12.50	

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			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	FRAGARIA SOUTH PENNISULA	DU	115.00	12.50	
2	FREDERICKSON GEN STATION E PIERCE	DU	115.00	13.20	
3	FREDERICKSON GEN STATION E PIERCE	DU	12.50	4.20	
4	FREDERICKSON GEN STATION E PIERCE	DU	12.50		
5	FREDERICKSON GEN STATION E PIERCE	DU	115.00	6.60	
6	FREDONIA SKAGIT	DU	115.00	12.50	13.20
7	FREDONIA SKAGIT	DU	115.00	12.50	13.20
8	FREELAND ISLAND	DU	115.00	12.50	
9	FREEWAY SOUTH WEST KING	DU	115.00	12.50	
10	FRIENDLY GROVE THURSTON	DU	115.00	13.09	
11	FRUITLAND EAST PIERCE	DU	115.00	12.50	
12	GAGES SKAGIT	DU	115.00	12.50	
13	GARDELLA EAST PIERCE	DU	115.00	12.50	
14	GLACIER WHATCOM	DU	55.00	12.50	
15	GLENCARIN SOUTH KING	DU	115.00	12.50	
16	GOODES CORNER EAST KING	DU	115.00	12.50	
17	GRADY SOUTH KING	DU	115.00	12.50	
18	GRAVELLY LAKE EAST PIERCE	DU	115.00	12.50	
19	GREENBANK ISLAND	DU	115.00	12.50	
20	GREENWATER SOUTH EAST KING	DU	55.00	13.90	
21	GREENWATER SOUTH EAST KING	DU	34.50	12.50	
22	GRIFFIN THURSTON	DU	115.00	12.50	
23	HAMILTON SKAGIT	DU	115.00	12.50	
24	HANNEGAN WHATCOM	DU	115.00	12.50	
25	HAPPY VALLEY WHATCOM	DU	115.00	12.50	
26	HARVEST SOUTH KING	DU	115.00	12.50	
27	HAWKS PRAIRIE THURSTON	DU	115.00	13.09	
28	HAZELWOOD CENTRAL KING	DU	115.00	12.50	
29	HEMLOCK EAST PIERCE	DU	115.00	12.50	
30	HICKOX SKAGIT	DU	115.00	12.50	
31	HIGHLANDS CENTRAL KING	DU	115.00	12.50	
32	HILLCREST ISLAND	DU	115.00	12.50	
33	HOBART SOUTH EAST KING	DU	115.00	12.50	
34	HOLDEN EAST PIERCE	DU	115.00	12.50	
35	HOLLYWOOD NORTH KING	DU	115.00	12.50	
36	HOPKINS RIDGE WIND FARM Columbia Cnty	DU	115.00	34.50	
37	HOUGHTON NORTH KING	DU	115.00	12.50	
38	HYAK EAST KING	DU	115.00	12.50	
39	INGLEWOOD NORTH KING	DU	115.00	12.50	
40	JOHNSON HILL THURSTON	DU	115.00	12.50	

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1	JUANITA NORTH KING	DU	115.00	12.50	
2	KAPOWSIN EAST PIERCE	DU	115.00	12.50	
3	KENDALL WHATCOM	DU	115.00	12.50	55.00
4	KENILWORTH NORTH KING	DU	115.00	12.50	
5	KENMORE NORTH KING	DU	115.00	12.50	
6	KENT SOUTH KING	DU	115.00	12.50	
7	KINGSTON	DU	115.00	12.50	
8	KITTITAS	DU	115.00	12.50	
9	KITTS CORNER SOUTHWEST KING	DU	115.00	12.50	
10	KLAHANIE EAST KING	DU	230.00	12.50	
11	KNOBLE EAST PIERCE	DU	115.00	12.50	
12	KRAIN CORNER SOUTH EAST KING	DU	115.00	55.00	
13	KRAIN CORNER SOUTH EAST KING	DU	115.00	55.00	
14	LABOUNTY WHATCOM	DU	115.00	12.50	
15	LACEY THURSTON	DU	115.00	12.50	
16	LAKE HILLS CENTRAL KING	DU	115.00	12.50	
17	LAKE LEOTA NORTH KING	DU	115.00	12.50	
18	LAKE LOUISE WHATCOM	DU	115.00	12.50	
19	LAKE MCDONALD EAST KING	DU	115.00	12.50	
20	LAKE MERIDIAN SOUTH KING	DU	115.00	12.50	
21	LAKE TAPPS EAST PIERCE	DU	55.00	12.50	
22	LAKE WILDERNESS SOUTH KING	DU	115.00	12.50	
23	LAKE YOUNGS SOUTH KING	DU	115.00	12.50	
24	LAKOTA SOUTHWEST KING	DU	115.00	12.50	
25	LANGLEY ISLAND	DU	115.00	12.50	
26	LAUREL WHATCOM	DU	115.00	13.09	
27	LEA HILL SOUTHEAST KING	DU	115.00	12.50	
28	LIQUID AIR (Airgas) SOUTH KING -	DU	115.00	4.20	
29	LOCHLEVEN CENTRAL KING	DU	115.00	13.09	
30	LONG LAKE SOUTH PENNISULA	DU	115.00	12.50	
31	LONGMIRE THURSTON	DU	115.00	12.50	
32	LUHR BEACH THURSTON	DU	115.00	12.50	
33	LYNDEN WHATCOM	DU	115.00	12.50	
34	M STREET SOUTH EAST KING	DU	115.00	12.50	
35	MANCHESTER SOUTH PENNISULA	DU	115.00	12.50	
36	MANHATTAN SOUTHWEST KING	DU	115.00	12.50	
37	MAPLEWOOD CENTRAL KING	DU	115.00	12.50	
38	MARCH POINT COGEN SKAGIT	DU	115.00	13.80	
39	MARINE VIEW SOUTHWEST KING	DU	115.00	12.50	
40	MAXWELTON ISLAND COUNTY	DU	115.00	13.00	

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1	MCALLISTER SPRINGS THURSTON	DU	115.00	12.50	
2	MCKENZIE WHATCOM	DU	115.00	12.50	
3	MCKINLEY THURSTON	DU	115.00	12.50	
4	MCWILLIAMS NORTH PENNISULA	DU	115.00	12.50	
5	MEDINA CENTRAL KING	DU	115.00	12.50	
6	MERCER ISLAND CENTRAL KING	DU	115.00	12.50	
7	MERCERWOOD CENTRAL KING	DU	115.00	12.50	
8	MERIDETH SOUTH EAST KING	DU	115.00	12.50	
9	MIDLAKES CENTRAL KING	DU	115.00	12.50	
10	MIDWAY SOUTH WEST KING	DU	115.00	12.50	
11	MILLER BAY NORTH PENNISULA	DU	115.00	12.50	
12	MIRRORMONT EAST KING	DU	115.00	12.50	
13	MOBILE UNIT #2 SOUTH KING	DU	66.00	12.50	
14	MOBILE UNIT #3 SOUTH KING	DU	115.00	12.50	
15	MOBILE UNIT #4 SOUTH KING	DU	115.00	12.50	
16	MOBILE UNIT #5 SOUTH KING	DU	115.00	12.50	
17	MOBILE UNIT #6 SOUTH KING	DU	115.00	12.50	
18	MOTTMAN THURSTON	DU	115.00	12.50	
19	MOUNT SI NORTH KING	DU	115.00	12.50	
20	MOUNT SI NORTH KING	DU	230.00	115.00	13.20
21	MOUNT VERNON SKAGIT	DU	115.00	12.50	
22	MURDEN COVE NORTH PENNISULA	DU	115.00	12.50	
23	NORKIRK NORTH KING	DU	115.00	12.50	
24	NORLUM SKAGIT	DU	115.00	12.50	
25	NORPAC SOUTHKING	DU	115.00	12.50	
26	NORTH BELLEVUE CENTRAL KING	DU	115.00	13.09	
27	NORTH BEND EAST KING	DU	115.00	12.50	
28	NORTH BOTHELL NORTHKING	DU	115.00	12.50	
29	NORTH NORMANDY SOUTHWEST KING	DU	115.00	12.50	
30	NORTHRUP CENTRAL KING	DU	115.00	12.50	
31	NORWAY HILL NORTH KING	DU	115.00	12.50	
32	NUGENTS CORNER WHATCOM	DU	34.50	12.50	
33	NUGENTS CORNER WHATCOM	DU	115.00	34.50	
34	NUGENTS CORNER WHATCOM	DU	12.50	12.50	
35	OLD TOWN WHATCOM	DU	115.00	12.50	
36	OLYMPIA BREWERY THURSTON	DU	115.00	12.50	
37	OLYMPIC ARCO PUMP WHATCOM	DU	115.00	4.20	
38	OLYMPIC AVON SKAGIT	DU	115.00	4.20	
39	OLYMPIC MOBIL WHATCOM	DU	115.00	4.20	
40	OLYMPIC RENTON SOUTH KING	DU	115.00	4.20	

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1	OLYMPIA SWITCH	DU	115.00		
2	OLYMPIC VAIL PIPELINE THURSTON	DU	115.00	4.20	
3	OLYMPIC BAYVIEW SKAGIT	DU	115.00	4.36	
4	ORCHARD SOUTH KING	DU	115.00	12.50	
5	ORILLIA SOUTH KING	DU	115.00	12.50	
6	ORTING EAST PIERCE	DU	115.00	12.50	
7	OSCEOLA SOUTH EAST KING	DU	115.00	12.50	
8	OVERLAKE CENTRAL KING	DU	115.00	12.50	
9	PACCAR CENTRAL KING	DU	115.00	12.50	
10	PADILLA BAY PIPELINE SKAGIT	DU	115.00	12.50	
11	PADILLA BAY PIPELINE SKAGIT	DU	12.50	4.16	
12	PANTHER LAKE SOUTH KING	DU	115.00	12.50	
13	PATTERSON THURSTON	DU	115.00	12.50	
14	PEASLEY CANYON SOUTHWEST KING	DU	115.00	12.50	
15	PETHS CORNER SKAGIT	DU	115.00	12.50	
16	PHANTOM LAKE CENTRAL KING	DU	115.00	12.50	
17	PICKERING CENTRAL KING	DU	115.00	12.50	
18	PINE LAKE EAST KING	DU	115.00	12.50	
19	PIPE LAKE SOUTH EAST KING	DU	115.00	12.50	
20	PLATEAU EAST KING	DU	115.00	12.50	
21	PLEASANT GLADE THURSTON	DU	115.00	12.50	
22	PLUM STREET THURSTON	DU	115.00	13.09	
23	PLYMOUTH WHATCOM	DU	115.00	12.50	
24	POINT ROBERTS WHATCOM	DU	25.00	12.50	
25	PORT GAMBLE NORTH PENNISULA	DU	115.00	12.50	
26	PORT MADISON NORTH PENNISULA	DU	115.00	12.50	
27	POULSBO NORTH PENNISULA	DU	115.00	12.50	
28	PRESIDENT PARK CENTRAL KING	DU	115.00	13.09	
29	PRINE THURSTON	DU	115.00	13.09	
30	PRINE THURSTON	DU	115.00	12.50	
31	QUARRY EAST PIERCE	DU	115.00	12.50	
32	RAINIER VIEW THURSTON	DU	115.00	12.50	
33	REDMOND NORTH KING	DU	115.00	12.50	
34	REDONDO SOUTHWEST KING	DU	115.00	12.50	
35	RENTON JUNCTION SOUTH KING	DU	115.00	12.50	
36	RHODES LAKE EAST PIERCE	DU	115.00	12.50	
37	RITA STREET SKAGIT	DU	115.00	12.50	
38	RIVERBEND SKAGIT	DU	115.00	12.50	
39	ROCHESTER THURSTON	DU	115.00	12.50	
40	ROCKY POINT SOUTH PENNISULA	DU	115.00	12.50	

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1	ROEDER WHATCOM	DU	115.00	13.09	
2	ROLLING HILLS SOUTH KING	DU	115.00	12.50	
3	ROSE HILL CENTRAL KING	DU	115.00	12.50	
4	SAHALEE NORTH KING	DU	115.00	12.50	
5	SAINT CLAIR THURSTON	DU			
6	SAMMAMISH NORTH KING	DU	115.00	12.50	
7	SCENIC NORTH KING	DU	115.00	12.50	
8	SCHUETT WHATCOM	DU	115.00	12.50	
9	SEATAC SOUTH KING	DU	115.00	13.09	
10	SEHOME WHATCOM	DU	115.00	12.50	
11	SEMIAHMOO WHATCOM	DU	115.00	12.50	
12	SEQUOIA SOUTH KING	DU	115.00	12.50	
13	SERWOLD NORTH PENNISULA	DU	115.00	12.50	
14	SHANNON WHATCOM	DU	34.50	12.50	
15	SHANNON WHATCOM	DU	115.00	34.50	
16	SHAW EAST PIERCE	DU	115.00	12.50	
17	SHERIDAN NORTH PENNISULA	DU	115.00	12.50	
18	SHERWOOD SOUTH EAST KING	DU	115.00	12.50	
19	SHUFFLETON YARD SOUTH KING	DU	55.00	12.50	
20	SHUFFLETON YARD SOUTH KING	DU	55.00	7.20	
21	SHUFFLETON YARD SOUTH KING	DU	12.50	4.20	
22	SHUFFLETON YARD SOUTH KING	DU	34.50	12.50	
23	SHUFFLETON YARD SOUTH KING	DU	115.00	34.50	
24	SHUFFLETON YARD SOUTH KING	DU	115.00	12.50	
25	SHUFFLETON YARD SOUTH KING	DU	115.00	12.50	
26	SHUFFLETON YARD SOUTH KING	DU	230.00	36.20	
27	SILVERDALE NORTH PENNISULA	DU	115.00	12.50	
28	SINCLAIR INLET SOUTH PENNISULA	DU	115.00	12.50	
29	SKYKOMISH NORTH KING	DU	115.00	12.50	
30	SLATER WHATCOM	DU	115.00	12.50	
31	SNOQUALMIE EAST KING	DU	115.00	12.50	
32	SNOQUALMIE (BLACK CREEK GEN)	DU	34.50	12.50	
33	SNOQUALMIE GEN. #1	DU	117.90	6.90	2.00
34	SNOQUALMIE GEN. #2	DU	117.90	7.20	
35	SOMERSET CENTRAL KING	DU	115.00	12.50	
36	SOOS CREEK SOUTH KING	DU	115.00	12.50	
37	SOUTH BELLEVUE CENTRAL KING	DU	115.00	12.50	
38	SOUTH KEYPORT NORTH PENNISULA	DU	115.00	12.50	
39	SOUTH KIRKLAND NORTH KING	DU	115.00	12.50	
40	SOUTH MERCER CENTRAL KING	DU	115.00	12.50	

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SOUTHWICK THURSTON	DU	115.00	12.50	
2	SOUTHCENTER SOUTH KING	DU	115.00	12.50	
3	SOUTH WHIDBEY SWITCH ISLAND	DU	115.00		
4	SPANAWAY EAST PIERCE	DU	115.00	12.50	
5	SPIRITBROOK NORTH KING	DU	115.00	12.50	
6	SPURGEON CREEK	DU	115.00	12.50	
7	STARWOOD SOUTH KING	DU	115.00	12.50	
8	STATE STREET WHATCOM	DU	115.00	13.09	
9	STERLING NORTH KING	DU	115.00	12.50	
10	STEWART EAST PIERCE	DU	115.00	12.50	
11	SUMAS GEN STATION	DU	115.00	13.80	
12	SUMMIT PARK SKAGIT	DU	115.00	12.50	
13	SUMNER EAST PIERCE	DU	115.00	12.50	
14	SUNRISE EAST PIERCE	DU	115.00	12.50	
15	SWANTOWN ISLAND	DU	115.00	12.50	
16	SWEPTWING SOUTHWEST KING	DU	115.00	12.50	
17	TANGLEWILDE THURSTON	DU	115.00	12.50	
18	TEN MILE WHATCOM	DU	115.00	4.20	
19	TEXACO EAST SKAGIT	DU	115.00	13.80	
20	TEXACO WEST SKAGIT	DU	115.00	13.80	
21	THORP KITTITAS	DU	34.50	12.50	
22	THURSTON THURSTON	DU	115.00	12.50	
23	TILLICUM EAST PIERCE	DU	115.00	12.50	
24	TOLT NORTH KNG	DU	115.00	12.50	
25	TOTEM NORTH KING	DU	115.00	12.50	
26	TRACYTON NORTH PENNISULA	DU	115.00	12.50	
27	UNION HILL EAST KING	DU	115.00	13.09	
28	VALLEY JUNCTION	DU	115.00		
29	VAN WYCK WHATCOM	DU	115.00	12.50	
30	VASHON SOUTH PENNISULA	DU	115.00	12.50	
31	VICTORIA PARK SOUTH KING	DU	115.00	12.50	
32	VIKING WHATCOM	DU	115.00	12.50	
33	VISTA WHATCOM	DU	115.00	12.50	
34	VITULLI NORTH KING	DU	115.00	12.50	
35	WABASH SOUTH EAST KING	DU	55.00	12.50	
36	WAYNE NORTH KING	DU	115.00	12.50	
37	WEST AUBURN SOUTHWEST KING	DU	115.00	12.50	
38	WEST CAMPUS SOUTHWEST KING	DU	115.00	12.50	
39	WEST ISSAQUAH EAST KING	DU	115.00	13.09	
40	WEST OLYMPIA THURSTON	DU	115.00	12.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SUBSTATIONS

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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	WHIDBEY ISLAND OAK HARBOR	DU			
2	WEYERHAEUSER SW KING	DU	115.00	12.50	
3	WEYERHAEUSER WHR BRANCH	DU	55.00	4.16	
4	WHITEHORN WHATCOM	DU	115.00	13.20	
5	WHITE RIVER TRANSM. EAST PIERCE	DU	115.00	55.00	
6	WHITE RIVER TRANSM. EAST PIERCE	DU	55.00	7.20	
7	WHITEHORN GEN WHATCOM	DU	12.50		
8	WHITEHORN GEN WHATCOM	DU	12.50	0.50	
9	WHITEHORN GEN WHATCOM	DU	12.50	4.20	
10	WILKESON EAST PIERCE	DU	55.00	12.50	
11	WILSON SKAGIT	DU	115.00	12.50	
12	WINSLOW NORTH PENNISULA	DU	115.00	12.50	
13	WOBURN WHATCOM	DU	115.00	12.50	
14	WOLDALE KITTITAS	DU	115.00	12.50	
15	WOODLAND EAST PIERCE	DU	115.00	12.50	
16	YELM THURSTON	DU	115.00	12.50	
17	ZENITH SOUTHWEST KING	DU	115.00	12.50	
18	TOTAL DISTRIBUTION STATIONS		37702.30	4526.39	96.60
19					
20	SUMMARY - TRANSMISSION CAPACITY		5815.00	2041.00	246.30
21	SUMMARY - DISTRIBUTION CAPACITY		37702.30	4526.39	96.60
22	TOTAL		43517.30	6567.39	342.90
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
325	1		Static Capacitor	2	42	1
325	1		Static Capacitor	1	42	2
325	1					3
50	1					4
50	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	1	Static Capacitor	1	39	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	84	17
325	1					18
325	1		Static Capacitor	1	84	19
650	2		Static Capacitor	1	42	20
533	3					21
650	2		Static Capacitor	1	45	22
390	3		Static Capacitor	7	66	23
325	1		Reactor	1	45	24
8548	34	1		23	658	25
						26
20	1		Static Capacitor	1	2	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			36
133	2					37
25	1					38
8	1					39
120	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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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.
3	3					1
25	1		Static Capacitor	1	5	2
20	1		Static Capacitor	1	5	3
			Static Capacitor	1	21	4
25	1		Static Capacitor	1	5	5
50	2		Static Capacitor	2	9	6
25	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	2	11
25	1		Static Capacitor	1	5	12
25	1		Static Capacitor	1	2	13
25	1		Static Capacitor	1	2	14
75	3		Static Capacitor	1	5	15
50	2		Static Capacitor	2	12	16
50	2		Static Capacitor	2	11	17
13	1					18
20	1		Static Capacitor	1	5	19
20	1					20
19	2		Static Capacitor	1	2	21
25	1					22
25	1		Static Capacitor	1	5	23
25	1					24
25	1		Static Capacitor	1	5	25
50	2					26
20	1		Static Capacitor	1	5	27
25	1		Static Capacitor	1	2	28
40	1		Static Capacitor	1	6	29
25	1		Static Capacitor	1	6	30
25	1		Static Capacitor	1	2	31
25	1		Static Capacitor	1	5	32
25	1		Static Capacitor	1	2	33
16	2					34
20	1		Static Capacitor	1	5	35
25	1		Static Capacitor	1	5	36
1	1	1				37
50	1					38
20	1		Static Capacitor	1	5	39
25	1		Static Capacitor	1	5	40

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2020	Year/Period of Report End of 2019/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
12	1					1
25	1		Static Capacitor	1	5	2
25	1		Static Capacitor	1	5	3
20	1					4
25	1		Static Capacitor	1	5	5
25	1		Static Capacitor	1	2	6
8	1		Static Capacitor			7
4	1					8
25	1		Static Capacitor	1	2	9
20	1		Static Capacitor	1	5	10
20	1		Static Capacitor	1	5	11
25	1		Static Capacitor	1	5	12
25	1					13
20	1		Static Capacitor	1	5	14
25	1					15
25	1		Static Capacitor	2	10	16
25	1		Static Capacitor	1	5	17
25	1		Static Capacitor	1	5	18
50	2		Static Capacitor	1	5	19
20	1					20
25	1		Static Capacitor	1	5	21
25	1		Static Capacitor	1	2	22
25	1					23
2	1					24
40	3					25
3	2					26
25	1		Static Capacitor	1	4	27
150	3					28
68	1					29
25	1		Static Capacitor	1	5	30
50	2		Static Capacitor	2	10	31
25	1		Static Capacitor	1	5	32
50	2		Static Capacitor	2	10	33
50	2		Static Capacitor	1	5	34
25	1		Static Capacitor	1	3	35
25	1		Static Capacitor	1	5	36
20	1					37
25	1		Static Capacitor	1	2	38
			Static Capacitor	1	23	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.
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25	1		Static Capacitor	1	5	1
170	2					2
2	2					3
3	2					4
			Spare GSU			5
110	2		Spare GSU			6
75			Spare GSU			7
20	1		Static Capacitor	1	2	8
25	1		Static Capacitor	1	5	9
25	1		Static Capacitor	1	5	10
25	1		Static Capacitor	1	2	11
25	1		Static Capacitor	1	5	12
25	1		Static Capacitor	1	5	13
5	1					14
25	1		Static Capacitor	1	5	15
25	1		Static Capacitor	1	2	16
25	1		Static Capacitor	1	2	17
20	1		Static Capacitor	1	5	18
9	1					19
20	1		Static Capacitor	1	5	20
8	1					21
20	1		Static Capacitor	1	2	22
20	1					23
20	1		Static Capacitor	1	5	24
25	1					25
50	2		Static Capacitor	1	5	26
25	1		Static Capacitor	1	5	27
25	1		Static Capacitor	1	5	28
25	1		Static Capacitor	1	5	29
25	1					30
25	1		Static Capacitor	1	6	31
25	1		Static Capacitor	1	5	32
25	1		Static Capacitor	1	2	33
20	1		Static Capacitor	1	2	34
25	1		Static Capacitor	1	5	35
167	2		Static Capacitor	2	22	36
25	1		Static Capacitor	1	5	37
20	1		Static Capacitor	1	5	38
25	1		Static Capacitor	1	5	39
25	1		Static Capacitor	1	5	40

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50	2		Static Capacitor	2	10	1
20	1		Static Capacitor	1	5	2
30	1	1	Static Capacitor	1	2	3
25	1		Static Capacitor	1	5	4
25	1		Static Capacitor	1	5	5
50	2		Static Capacitor	2	8	6
25	1		Static Capacitor	1	5	7
25	1		Static Capacitor	1	5	8
25	1		Static Capacitor	1	5	9
25	1	1	Static Capacitor	1	5	10
25	1		Static Capacitor	1	5	11
40	1					12
28		3				13
20	1		Static Capacitor	1	5	14
25	1		Static Capacitor	1	4	15
25	1		Static Capacitor	1	5	16
25	1		Static Capacitor	1	5	17
20	1		Static Capacitor	1	5	18
25	1		Static Capacitor	1	2	19
25	1					20
18	1		Static Capacitor	1	2	21
25	1		Static Capacitor	1	5	22
25	1		Static Capacitor	1	5	23
25	1		Static Capacitor	1	5	24
20	1					25
25	1		Static Capacitor	1	5	26
25	1		Static Capacitor	1	3	27
20	2					28
50	2		Static Capacitor	2	12	29
25	1		Static Capacitor	1	5	30
25	1		Static Capacitor	1	5	31
25	1		Static Capacitor	1	2	32
40	2		Static Capacitor	2	10	33
25	1		Static Capacitor	1	5	34
25	1		Static Capacitor	1	2	35
25	1		Static Capacitor	1	5	36
25	1		Static Capacitor	1	5	37
140	3					38
25	1		Static Capacitor	1	5	39
25	1		Static Capacitor	1	5	40

SUBSTATIONS (Continued)

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25	1					1
20	1		Static Capacitor	1	5	2
25	1		Static Capacitor	1	5	3
20	1		Static Capacitor	1	5	4
25	1					5
25	1					6
20	1					7
25	1		Static Capacitor	1	5	8
25	1		Static Capacitor	1	5	9
			Static Capacitor	1	39	10
25	1		Static Capacitor	1	5	11
25	1		Static Capacitor	1	5	12
9	1					13
25	1					14
15	1					15
25	1					16
25	1					17
20	1		Static Capacitor	1	5	18
25	1		Static Capacitor	1	5	19
325		1		1	2	20
25	1		Static Capacitor	1	2	21
25	1		Static Capacitor	1	5	22
25	1		Static Capacitor	1	5	23
20	1					24
25	1		Static Capacitor	1	5	25
50	2		Static Capacitor	2	10	26
25	1		Static Capacitor	1	5	27
25	1		Static Capacitor	1	5	28
20	1		Static Capacitor	1	5	29
25	1		Static Capacitor	1	5	30
25	1		Static Capacitor	1	5	31
8	1					32
25	1					33
5	1					34
20	1		Static Capacitor	1	5	35
20	1		Static Capacitor	1	42	36
6	1					37
19	2					38
9	1					39
9	1					40

SUBSTATIONS (Continued)

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			Static Capacitor	1	42	1
6	1					2
6	1					3
25	1		Static Capacitor	1	4	4
25	1		Static Capacitor	1	5	5
25	1		Static Capacitor	1	2	6
20	1		Static Capacitor	1	5	7
25	1					8
50	2		Static Capacitor	2	10	9
9	1					10
4	1					11
25	1		Static Capacitor	1	5	12
20	1		Static Capacitor	1	2	13
25	1		Static Capacitor	1	5	14
20	1		Static Capacitor	1	5	15
25	1		Static Capacitor	1	5	16
25	1		Static Capacitor	1	5	17
25	1		Static Capacitor	1	5	18
25	1		Static Capacitor	1	3	19
25	1		Static Capacitor	1	5	20
25	1		Static Capacitor	1	5	21
25	1		Static Capacitor	1	5	22
25	1					23
19	2					24
20	1		Static Capacitor	1	4	25
25	1		Static Capacitor	1	5	26
25	1					27
25	1		Static Capacitor	1	5	28
25	1		Static Capacitor	1	5	29
20	1		Static Capacitor	1	5	30
9	1					31
25	1		Static Capacitor	1	5	32
50	2		Static Capacitor	2	10	33
25	1		Static Capacitor	1	5	34
50	2		Static Capacitor	2	10	35
25	1		Static Capacitor	1	5	36
20	1					37
20	1		Static Capacitor	1	5	38
40	2		Static Capacitor	1	5	39
50	2					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
25	1		Static Capacitor			2
25	1		Static Capacitor	1	5	3
25	1		Static Capacitor	1	5	4
			Static Capacitor	1	42	5
25	1	1	Static Capacitor	1	5	6
4	1					7
20	1					8
50	2					9
25	1		Static Capacitor	1	5	10
25	1		Static Capacitor	1	5	11
25	1		Static Capacitor	1	5	12
25	1		Static Capacitor	1	5	13
8	1					14
25	1					15
25	1		Static Capacitor	1	2	16
40	1		Static Capacitor	1	5	17
25	1		Static Capacitor	1	5	18
9		1				19
3		1				20
8		1				21
10		2				22
25		1				23
25		8				24
13		1				25
50		1				26
25	1		Static Capacitor	1	5	27
20	1		Static Capacitor	1	2	28
9	1					29
20	1		Static Capacitor	1	5	30
25	1					31
5	1					32
20	1					33
53	1					34
25	1		Static Capacitor	1	5	35
25	1		Static Capacitor	1	4	36
25	1		Static Capacitor	1	5	37
20	1		Static Capacitor	1	4	38
25	1		Static Capacitor	1	5	39
20	1					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	5	2
			Static Capacitor	2	42	3
20	1		Static Capacitor	1	5	4
25	1		Static Capacitor	1	2	5
25	1		Static Capacitor	1	5	6
50	2		Static Capacitor	2	10	7
25	1		Static Capacitor	1	5	8
50	2		Static Capacitor	2	10	9
25	1		Static Capacitor	1	2	10
240	2					11
20	1		Static Capacitor	1	5	12
20	1		Static Capacitor	1	2	13
25	1		Static Capacitor	1	5	14
20	1					15
25	1		Static Capacitor	1	3	16
20	1		Static Capacitor	1	5	17
9	1					18
50	2					19
80	2					20
9	1					21
50	2		Static Capacitor	1	5	22
25	1		Static Capacitor	1	5	23
25	1					24
25	1		Static Capacitor	1	5	25
20	1		Static Capacitor	1	2	26
25	1		Static Capacitor	1	5	27
			Static Capacitor	1	23	28
9	1					29
50	2		Static Capacitor	1	5	30
25	1		Static Capacitor	1	5	31
20	1		Static Capacitor	1	5	32
20	1		Static Capacitor	1	5	33
50	2		Static Capacitor	2	10	34
9	1					35
25	1					36
25	1		Static Capacitor	1	4	37
25	1		Static Capacitor	1	2	38
25	1		Static Capacitor	1	5	39
25	1		Static Capacitor	1	2	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
			Static Capacitor	1	23	1
20	1					2
8	3					3
170	2					4
83	3					5
3	3					6
1	2					7
2	2					8
2	2					9
9	1					10
25	1		Static Capacitor	1	5	11
25	1					12
25	1					13
20	1					14
25	1		Static Capacitor	1	5	15
25	1		Static Capacitor	2	26	16
25	1		Static Capacitor	1	2	17
10103	397	24		255	1,463	18
						19
8548	34	1		23	658	20
10068	395	25		255	1,465	21
18616	429	26		278	2,123	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 November 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.: 18 Column: a

Waste Water Treatment Division - Brightwater leases PSE owned transformer at Brightwater Substation. Expiration 5/21/2020.

Schedule Page: 426.1 Line No.: 26 Column: a

State of Washington Admin leases PSE owned transformer at Capitol Substation. Service started November 1972.

Schedule Page: 426.1 Line No.: 39 Column: a

Navy Ault leases PSE owned transformer at Clover Valley Substation. Service started November 1972.

Schedule Page: 426.2 Line No.: 14 Column: a

Center Drive Owners Association leases transformer at Dupont Substation. Service began 12/1/2018.

Schedule Page: 426.2 Line No.: 34 Column: a

Benaroya leases PSE owned transformer at Fairchild Substation. Service started December 2005.

Schedule Page: 426.4 Line No.: 28 Column: a

Air Liquide Industrial US LP leases PSE owned transformer at Liquid Air Substation.

Schedule Page: 426.5 Line No.: 12 Column: a

BioEnergy leases PSE owned transformer at Mirrormont Substation.

Schedule Page: 426.5 Line No.: 28 Column: a

AT&T leases PSE owned transformer at North Bothell Substation.

Schedule Page: 426.5 Line No.: 37 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.: 38 Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Avon Substation. Service started April 2004.

Schedule Page: 426.5 Line No.: 39 Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Mobil Substation. Service started April 2004.

Schedule Page: 426.5 Line No.: 40 Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Renton Substation. Service started April 2004.

Schedule Page: 426.6 Line No.: 2 Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Vail Substation. Service started April 2004.

Schedule Page: 426.6 Line No.: 3 Column: a

Olympic Pipeline leases PSE owned transformer at Olympic Bayview Substation.

Schedule Page: 426.6 Line No.: 9 Column: a

PACCAR Inc. leases PSE owned transformer at PACCAR Substation. Service started December 1992.

Schedule Page: 426.6 Line No.: 10 Column: a

Olympic Pipeline leases PSE owned transformer at Padilla Bay Substation.

Schedule Page: 426.7 Line No.: 1 Column: a

Bellingham Cold Storage leases PSE owned transformer at Roeder Substation. Service started May 1967.

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

AT&T leases PSE owned transformer at Sammamish Substation. Service started 2010.

Schedule Page: 426.8 Line No.: 9 Column: a

Microsoft leases PSE owned transformer at Sterling Substation. Service started 2010.

Schedule Page: 426.8 Line No.: 18 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.: 19 Column: a

Shell leases PSE owned transformer at Texaco East Substation under Schedule 449.

Schedule Page: 426.8 Line No.: 20 Column: a

Shell leases PSE owned transformer at Texaco West Substation under Schedule 449.

Schedule Page: 426.8 Line No.: 32 Column: a

Western Washington University leases PSE owned transformer at Viking Substation.

Schedule Page: 426.8 Line No.: 34 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: 426.9 Line No.: 2 Column: a

Federal Way Campus leases PSE owned transformer at Weyerhaeuser Substation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/17/2020	End of 2019/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	General and Adminstrative Expenses	Puget Energy, Inc.	146	1,455,541
22	General and Adminstrative Expenses	Puget Western, Inc.	146	212,220
23	General and Adminstrative Expenses	Puget Holdings, LLC	146	2,133,912
24	General and Adminstrative Expenses	Puget Intermediate Holdings, Inc.	146	148,860
25	General and Adminstrative Expenses	Puget LNG, LLC	146	869,999
26	General and Adminstrative Expenses	Puget Equico, LLC	146	47,249
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
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