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 2020/Q4

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from https://www.ferc.gov/media/form-1 and https://www.ferc.gov/media/form1-3q.

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent Puget Sound Energy, Inc.	02 Year/Period of Report End of 2020/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	04/15/2021

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		
02 Title Controller and PAO	Stephen J King	04/15/2021

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	04/15/2021	End of 2020/Q4

LIST OF SCHEDULES (Electric Utility)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	N/A
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	

Stockholders' Reports Check appropriate box:

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

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 nad 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.

N/A

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 Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/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.

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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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	04/15/2021	End of 2020/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	President & Chief Executive Officer	Mary E. Kipp	891,667
2	Sr. V.P. & Chief Financial Officer	Daniel A. Doyle	544,041
3	Former Chief Executive Officer	Kimberly Harris (Retired	50,725
4	Sr. V.P. General Council & Chief Ethics Compliance Offir	Steven R. Secrist	479,287
5	Sr. V.P. Operations	Booga K. Gilbertson	420,406
6	Sr. V.P. & Chief Information Officer	Margaret F. Hopkins	345,328
7	Former Senior Vice President Policy and Energy Supply	David Mills (Resigned 11/30/2020)	361,900
8	V.P. Customer Operations and Communications	Andrew W. Wappler	332,240
9	V.P. Energy Supply	Ronald J. Roberts	240,418
10	V.P. Regulatory & Government Affairs	Kenneth S. Johnson	269,927
11	V.P. Human Resources	Kimberly Collier	220,728
12	Former Senior Vice President and Chief Administrative Or	Marla D. Mellies (Retired 02/28/202)	83,385
13	Controller & Principal Accounting Officer	Stephen J. King	202,224
14	Corporate Treasurer	Andrea Peterman	191,999
15	Corporate Treasurer	Matt McArthur (Resigned	137,490
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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	04/15/2021	End of 2020/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Scott Armstrong	Seattle, WA
2	Kenton Bradbury	Toronto, Ontario
3	Richard Dinneny	British Columbia
4	Barbara J. Gordon	Bellevue, WA
5	Christopher Hind	Toronto, Ontario
6	Grant Hodgkins	Victoria, B.C.
7	Steven W. Hooper	Bellevue, WA
8	Thomas King	Houston, Texas
9	Mary E. Kipp (President & CEO)	Bellevue, WA
10	Paul McMillian	Calgary, Alberta
11	Mary O. McWilliams	Seattle, WA
12	Christopher Trumpy	British Columbia
13	Martijn Verwoest	Netherlands
14	Steven Zucchet	Toronto, Ontario
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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	04/15/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 105   Line No.: 6   Column: a

Effective December 31, 2020, Mr. Grant Hodgkins was elected to serve on the Board of Directors of both Puget Energy and Puget Sound Energy.

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

Effective December 31, 2020, Mr. Christopher Trumpy was no longer serving on the Board of Directors of Puget Sound Energy.

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	PSE OATT	FERC Docket No. ER12-778
2		Establishment of formula rate.
3	PSE OATT	FERC Docket No. ER18-1249-000
4		Amendment to OATT Schedules
5		7, 8, and 10 to revise depreciation rates.
6	PSE OATT	FERC Docket No. ER20-1489-000
7		Amendment to eliminate recovery of PBOPs.
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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	04/15/2021	End of 2020/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
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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	04/15/2021	End of 2020/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.

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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
Auburn	King	Electric	New	15 years	$ -
Arlington	Snohomish	Natural Gas	New	20 years	$ -
Yelm	Thurston	Electric & Natural Gas	New	20 years	$ -

2. None.

3. None.

4. None.

5. None.

6.

Credit Facilities

As of December 31, 2020, no amounts were drawn and outstanding under PSE's credit facility. No letters of credit were outstanding and $373.8 million was outstanding under the commercial paper program. Outside of the credit agreement, PSE had a $2.7 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

The Company had no new long-term debt activities in the twelve months ended December 31, 2020. For further information, see Note 6, "Long-Term Debt" and Note 7, "Liquidity Facilities and Other Financing Arrangements" in the Company's most recent Annual Report on FERC Form 1 for the year ended December 31, 2020.

7. None.

8. Non-represented employees received on average a 3.46% increase effective on March 1, 2020. Employees of the IBEW received a 3.5% salary increase effective on April 1, 2020. Employees of the UA received a 2.75% salary increase that went into effect October 1, 2020. The estimated annual effect of these changes is $10.2 million. The current contracts with the IBEW and UA will expire March 31, 2026 and September 30, 2021, respectively.

9. Legal Proceedings:

Regulation and Rates

Power Cost Only Rate Case

On December 9, 2020, PSE filed its 2020 power cost only rate case (PCORC). The filing proposed an increase of $78.5 million (or an average of approximately 3.7%) in the Company's overall power supply costs with an anticipated effective date in June 2021. On February 2, 2021, PSE supplemented the PCORC to update its power costs, leading to a requested increase from $78.5 million to $88.0 million (or an average of approximately 4.1%).

On March 2, 2021, the parties to the PCORC reached a multiparty settlement in principle, with Public Counsel not joining the settlement, but also not opposing. The settlement resulted in an estimated revenue increase of $65.3 million or 3.1% and, pending approval by the Washington Commission, is expected to be effective June 2021.

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.

On July 8, 2020, the Washington Commission issued its order on PSE's GRC. The ruling provided for a weighted cost of capital of 7.39% or 6.8% after-tax, and a capital structure of 48.5% in common equity with a return on equity of 9.4%. The order also resulted in a combined net increase to electric of $29.5 million, or 1.6%, and to natural gas of $36.5 million, or 4.0%. However, the Washington Commission extended the amortization of certain regulatory assets, PSE's electric decoupling deferral, and PSE's PGA deferral to mitigate the impact of the rate increase in response to the economic instability created by the COVID-19 pandemic, which reduced the electric revenue increase to approximately $0.9 million, or 0.05% and the natural gas increase to $1.3 million, or 0.15%. The Washington Commission also determined that the Company's proposed attrition adjustment of $23.9 million for electric and $16.2 million for natural gas was not in the public interest at this time. The order also effectively ends the deferral of depreciation expense associated with PSE's advanced metering infrastructure (AMI) investment while allowing the deferral on the return on AMI investments through December 31, 2019. Additional AMI investments will be evaluated in future proceedings for deferrals of return until the AMI project is complete. On July 17, 2020, PSE filed a motion for clarification with the Washington Commission seeking clarification on several items. On July 31, 2020, the Washington Commission issued an order granting PSE's motion for clarification. The ruling adjusted certain items from the final order issued on July 8, 2020, which led to a combined net increase to electric of $59.6 million, or 2.9%, an increase of $30.1 million above the $29.5 million granted in the final order. The order also led to a combined net increase to natural gas of $42.9 million, or 5.6%, an increase of $6.4 million above the $36.5 million granted in the final order. The Washington Commission maintained adjustments which mitigated the impacts of the rate increases in response to the economic instability created by the COVID-19 pandemic, which reduced the electric revenue increase to approximately $27.7 million, or 1.3% and the natural gas increase to $0.2 million, or 0.02%.

On August 6, 2020, PSE filed a petition for judicial review with the Superior Court of the State of Washington for King County (Superior Court) challenging the portion of the final order that requires PSE to pass back to customers the reversal of plant-related excess deferred income taxes in a manner that may deviate from the Internal Revenue Service (IRS) normalization and consistency rules. On August 7, 2020, PSE filed a motion to stay with the Superior Court related to the portions of the final order under judicial review. On September 14, 2020, the Superior Court denied PSE's motion to stay. PSE reviewed the original Washington Commission order including the ramifications of certain tax issues and requested a Private Letter Ruling (PLR) with the IRS regarding this matter. PSE will continue to utilize the average rate assumption method (ARAM) in the turnaround of certain accelerated tax depreciation benefits on PSE assets. On September 23, 2020, PSE filed a compliance filing with the Washington Commission. The natural gas tariffs became effective October 1, 2020 and the electric tariffs on October 15, 2020. On October 7, 2020, PSE, the Washington Commission and interveners agreed to dismiss the petition for judicial review. The agreement is based on a commitment from the Washington Commission that if the IRS ruling finds that the Washington Commission's methodology for reversing plant-related excess deferred income taxes is impermissible, the Washington Commission will open a proceeding to review and enact the changes required by the IRS ruling. There is approximately $25.6 million in annual revenue requirement related to the 2019 GRC which PSE has requested it be allowed to track in order to allow the Washington Commission to decide if it is appropriate for PSE to recover, pending the outcome of the IRS ruling.

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.

While the settlement agreement in the ERF 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 through the PSE Schedule 141X tariff, the ongoing treatment of 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 was left to be 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. Per PSE's Schedule 141Y tariff, following the May 2019 through April 2020 refund period, if the residual balance of credit owed to customers will be greater than $0.1 million, PSE would submit a filing no later than July 31, 2020 with a proposal of passing back the residual balance effective September 1, 2020 through August 31, 2021. As this balance was greater than $0.1 million, PSE filed tariff revisions on July 20, 2020 and the Washington Commission approved the filing on August 27, 2020. Finally, the GRC final order determined that PSE is required to pass back 2019 and 2020 protected excess deferred tax reversals totaling $70.8 million over the 12 months following the rate effective period through PSE's Schedule 141X tariff. The GRC final order also determined that PSE is required to pass back unprotected excess deferred tax balances totaling $38.9 million over 36 months following the rate effective period through PSE's Schedule 141Z tariff. Further details of the outcome associated with PSE's tax deferral filing are discussed in the ERF and GRC disclosures.

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 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 only be changed in a GRC or a power cost only rate case. 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 July 8, 2020, the Washington Commission issued the final order in Dockets UE-190529 and UG-190530, which instructed PSE to extend the collection of amortization balances for electric decoupling delivery and fixed power cost sections originally filed through the annual May 2020 decoupling filing. The extension requires PSE to move amortization balances for electric decoupling as of August 31, 2020 to be collected from customers for a two-year period, instead of the originally approved one-year period. Additionally, through approving the electric cost of service, the final order approved the re-allocation of decoupling balances from Schedule 40 to the remaining electric decoupling groups.

On December 1, 2020, PSE made a tariff correction filing for Schedule 142 amortization rates, with a proposed effective date of January 1, 2021, where it proposed to zero out rates still effective past October 15, 2020 on tariff sheet Schedule 142-H, which was replaced by rates on tariff sheet Schedule 142-I effective October 15, 2020. This resulted in an over-collection from electric decoupled customers of approximately $4.3 million at year-end. As part of this filing, PSE has proposed to true up the over-collection amounts for the period of October 15, 2020 through December 31, 2020 in PSE’s annual May 2021 decoupling filing.

On December 31, 2020, 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 $8.0 million of electric deferred revenue will not be collected within 24 months of the annual period; therefore a reserve adjustment was booked to 2020 electric decoupling revenue. Natural gas deferred revenue will be collected within 24 months of the annual period; therefore, no reserve adjustment was booked to 2020 natural gas decoupling revenue. The previously unrecognized decoupling deferrals of $0.8 million at December 31, 2018, were recognized as decoupling revenue in the year ended December 31, 2019.

Power Cost Adjustment Clause Filing

On July 1, 2019, PSE updated its Schedule 95 rates in the Power Cost Adjustment Clause tariff to reflect the transition fee as required by Section 12 of the Microsoft Special Contract. Additionally, Schedule 95 rates also include portions of fixed power cost adjustments per the allowed decoupling rate re-allocation effective April 1, 2019, resulting from Microsoft becoming a transportation customer as well as small variable power cost adjustments.

On July 8, 2020, the Washington Commission issued the final order in Dockets UE-190529 and UG-190530, which instructed PSE to remove Schedule 95 collection on decoupling allowed rates for Microsoft Special Contracts, which will be included in allowed rates under the Decoupling Schedule 142 effective October 15, 2020.

PSE exceeded the $20.0 million cumulative deferral balance in its PCA mechanism in 2019. The surcharging of deferrals can be triggered by the Company when the balance in the deferral account is a credit of $20.0 million or more. Due to concerns about the economic impact of the COVID-19 pandemic on customers, PSE voluntarily, with Washington Commission Staff support, delayed filing an increase to its Schedule 95 rates in its annual PCA report filing in Docket UE-200398, which was approved on July 30, 2020. Subsequently, PSE filed to recover the deferred balance in Docket UE-200893, effective December 1, 2020, and the Washington Commission approved PSE's request on November 24, 2020. During 2019, actual power costs were higher than baseline power costs, thereby creating an under-recovery of $67.2 million. Under the terms of the PCA's sharing mechanism for under-recovered power costs, PSE absorbed $31.2 million of the under-recovered amount, and customers were responsible for the remaining $36.0 million, or $37.0 million including interest. As PSE had an approved balance owing from customers including interest at the start of 2019 totaling $4.7 million, the approved cumulative deferral balance for the PCA as of December 2019 is $41.7 million. As previously stated, this filing is set to collect the customer's share of the cumulative 2019 imbalance in PSE's PCA mechanism.

Purchased Gas Adjustment Mechanism

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 out-of-cycle PGA rates were effective from May 1, 2019 through April 30, 2020 and on May 1, 2020 the rates were set to zero. At the end of the recovery period, an unamortized balance of $4.9 million remained which PSE requested to be amortized in its annual PGA filing for rates effective November 1, 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. On July 8, 2020, the Washington Commission issued the final order in Dockets UE-190529 and UG-190530, which instructed PSE to extend the collection of amortization balances for the portion of PGA amortization balances originally filed through the annual November 1, 2019 PGA filing under the Supplemental Schedule 106B. The extension requires PSE to move amortization balances for PGA Schedule 106B as of August 31, 2020 to be collected from customers for a three-year period, instead of the originally approved two-year period.

On October 29, 2020, the Washington Commission approved PSE's request for November 2020 PGA rates in Docket UG-200832, effective November 1, 2020. As part of that filing, PSE requested PGA rates increase annual revenue by $32.6 million, while the new tracker rates increased annual revenue by $37.4 million; this was in addition to continuing the collection on the remaining balance of $69.4 million under Supplemental Schedule 106B.

The following table presents the PGA mechanism balances and activity at December 31, 2020 and December 31, 2019:

Puget Sound Energy

(Dollars in Thousands) PGA receivable balance and activity	At December 31, 2020	At December 31, 2019
PGA receivable beginning balance	$ 132,766	$ 9,921
Actual natural gas costs	314,792	406,162
Allowed PGA recovery	(363,886)	(289,876)
Interest	3,983	6,559
PGA receivable ending balance	$ 87,655	$ 132,766

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, 2020 and December 31, 2019, PSE deferred $2.8 million and $21.7 million of depreciation expense for GTZ, respectively. 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. The GTZ accounting petition was consolidated with PSE's 2019 GRC and on July 8, 2020, the Washington Commission issued its order in PSE's 2019 GRC. The ruling authorized PSE to amortize deferred GTZ expenses as proposed in the original GRC filing. The ruling also allows continued deferral of the depreciation expense associated with GTZ investments not already approved for recovery with a book life of 10 years or less, through PSE's next GRC. Finally, the final order set the rate at which PSE could defer and recover carrying charges from PSE's authorized rate of return to the quarterly interest rate established by the FERC.

Crisis Affected Customer Assistance Program

On April 6, 2020, PSE filed with the Washington Commission revisions to its currently effective Tariff WN U-60. The purpose of this filing is to incorporate into PSE's low-income tariff a new temporary bill assistance program, Crisis Affected Customer Assistance Program (CACAP), to mitigate the economic impact of the COVID-19 pandemic on PSE's customers. CACAP would allow PSE customers facing financial hardship due to COVID-19 to receive up to $1,000 in bill assistance. The program puts to immediate use $11.0 million in unspent low income funds from prior years, and supplements other forms of financial assistance. The program does not require an increase to rates and is fully compatible with other low income programs. Based on the COVID-19 pandemic and resulting state of emergency, the Washington Commission allowed the tariff revisions to become effective on April 13, 2020. PSE made an additional filing on July 21, 2020 to increase the amount of electric funds available for distribution by $4.5 million under the CACAP program. The program ended on September 30, 2020.

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 2019 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 have retained its obligation to fund 25% of the environmental remediation and decommissioning costs associated with Unit 4 during PSE's operation. The proposed agreement was subject to approval by the Washington Commission and the Montana Public Service Commission. Additionally, PSE had 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.

On August 14, 2020, an amendment to the agreement was executed selling a portion of PSE's interest in Colstrip Unit 4 to Talen, in addition to NorthWestern Energy. However, after evaluating the likelihood of the regulatory approval process in both Washington and Montana, on October 29, 2020, PSE, NorthWestern Energy, and Talen mutually agreed to terminate the proposed sales agreement and the proposed power purchase agreement and relieve all claims against one another arising out of or relating to the sale agreement. The termination of the proposed sale and proposed PPA resulted in the withdrawal of PSE's filing with the Washington Commission. Colstrip Unit 4 is classified as Electric Utility Plant on the balance sheet, see Note 6, "Utility Plant," to the consolidated financial statements 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, as a replacement to the CPP rule. The ACE rule, along with the repeal of the CPP rule, were finalized in June 2019, and establish emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired plants. On January 19, 2021 the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated the ACE rule and remanded the record back to the Agency for further consideration consistent with its opinion, finding that misinterpreted the Clean Air Act. PSE is evaluating this vacatur to determine impact on operations.

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 Washington State 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. The Department of Ecology and the four parties asked Thurston County to stay this case until the 2020 Washington State legislative session concluded and now the Department of Ecology plans to ask the court to extend the stay until the COVID-19 pandemic is over. Meanwhile, the four companies moved to voluntarily dismiss the federal court litigation without prejudice in March 2020.

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. Following a mediation process and the filing of a settlement stipulation by PSE and all parties, the Washington Commission issued an order on October 31, 2016, that allowed PSE’s parent company, Puget Energy, to create a wholly-owned subsidiary, named Puget LNG, which was formed on November 29, 2016, for the sole purpose of owning, developing and financing the non-regulated activity of the Tacoma LNG facility. Puget LNG has entered into one fuel supply agreement with a maritime customer and is marketing the facility’s expected output to other potential customers.

The Tacoma LNG facility is currently under construction. Pursuant to the Washington Commission’s order, PSE will be allocated 43.0% of the capital and operating costs of the Tacoma LNG facility. PSE and Puget LNG are considered related parties with similar ownership by Puget Energy. Therefore, capital and operating costs that occur under PSE and are allocated to Puget LNG are related party transactions by nature. Per this allocation of costs, $207.7 million of construction work in progress 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, 2020, as PSE is a regulated entity. The portion of the Tacoma LNG facility allocated to PSE will be subject to regulation by the Washington Commission.

11. Reserved.

12. None.

13.

<u>Changes of Ownership</u>:

None

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

a)

Effective January 2, 2020, Ms. Kimberly Harris retired as the Chief Executive Officer and director of the Companies.

b)

On January 3, 2020, Ms. Mary Kipp, the current President of the Companies, assumed the additional role of Chief Executive Officer of the Companies and became a director of the Companies.

Ms. Kipp has served as President of the Companies since August 30, 2019. Prior to her service at the Companies, 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.

Ms. Kipp will not receive any additional compensation for her service as Chief Executive Officer of the Companies.

c)

Effective March 2, 2020, Ms. Marla Mellies retired from her position as the Senior Vice President and Chief Administrative Officer of Puget Sound Energy, Inc. and Puget Sound Energy, Inc.

d)

Effective November 9, 2020, David Mills departed from PSE as Senior Vice President and Chief Strategy Officer.

e)

Effective November 9, 2020, Ron Roberts has been promoted from Director – Generation and Natural Gas Storage, to Vice President, Energy Supply.

f)

Effective December 31, 2020, Christopher Trumpy, a member of the Boards, who served as a representative of British Columbia Investment Management Corporation's ("BCIMC") on the Boards, resigned from the Boards..

g)

Effective December 31, 2020, the sole shareholders of Puget Energy, Inc. and Puget Sound Energy, Inc. (together, the "Companies") appointed Grant Hodgkins 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. Hodgkins will serve.

Mr. Hodgkins currently serves as a Portfolio Manager of BCIMC's Infrastructure and Renewable Resources group, a position he has held since 2017. Prior to joining BCIMC, Mr. Hodgkins was an Advisor at KPMG from 2015 to 2017, serving institutional investors with a focus on power and utility investments, and was a Director of Corporate Development & Planning for Interfor Corporation from 2013 to 2015. Mr. Hodgkins also serves as a director on the Board of Directors of Corix Infrastructure Inc., a water and wastewater utility and contract energy company.

Mr. Hodgkins was selected by BCIMC pursuant to the Amended and Restated Bylaws of each of the Companies, will serve as an Owner Director on their respective Boards. Mr. Hodgkins 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. Hodgkins for his services on the Companies' Boards is a function of his employment arrangement with BCIMC.

14. None.

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	16,412,250,350	15,854,140,158
3	Construction Work in Progress (107)	200-201	712,204,459	591,198,562
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		17,124,454,809	16,445,338,720
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	6,638,902,173	6,192,635,006
6	Net Utility Plant (Enter Total of line 4 less 5)		10,485,552,636	10,252,703,714
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)		10,485,552,636	10,252,703,714
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		8,654,564	8,654,564
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		3,643,360	2,983,185
19	(Less) Accum. Prov. for Depr. and Amort. (122)		24,653	20,713
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	28,773,057	26,955,155
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)		52,700,062	51,453,007
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		20,189,459	20,188,091
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		8,805,120	7,681,161
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		114,086,405	109,239,886
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		49,865,155	43,543,104
36	Special Deposits (132-134)		24,586,299	17,175,665
37	Working Fund (135)		4,959,057	3,712,154
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		91,410	91,410
40	Customer Accounts Receivable (142)		259,100,175	220,795,792
41	Other Accounts Receivable (143)		100,084,411	90,809,156
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		20,080,875	8,293,320
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		4,275,036	3,805,084
45	Fuel Stock (151)	227	16,627,794	15,762,779
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	117,915,543	115,555,118
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	133,577	32,795
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	406,891	335,928

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	11,207	-208,479
55	Gas Stored Underground - Current (164.1)		30,695,202	34,945,592
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		74,680	76,243
57	Prepayments (165)		47,901,985	40,207,822
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)		221,870,303	224,656,494
62	Miscellaneous Current and Accrued Assets (174)		727,282	1,306,156
63	Derivative Instrument Assets (175)		41,819,946	31,307,186
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		8,805,120	7,681,161
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)		892,259,958	827,935,518
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		24,537,297	26,542,709
70	Extraordinary Property Losses (182.1)	230a	108,491,125	121,893,612
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	44,325,180
72	Other Regulatory Assets (182.3)	232	576,279,745	412,199,577
73	Prelim. Survey and Investigation Charges (Electric) (183)		91,392	52,940
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)		38,944	70,201
78	Miscellaneous Deferred Debits (186)	233	187,333,825	205,430,089
79	Def. Losses from Disposition of Utility Plt. (187)		7,006,450	86,136
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		37,990,993	40,177,287
82	Accumulated Deferred Income Taxes (190)	234	365,436,877	1,196,021,909
83	Unrecovered Purchased Gas Costs (191)		87,655,393	132,766,288
84	Total Deferred Debits (lines 69 through 83)		1,394,862,041	2,179,565,928
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		12,895,415,604	13,378,099,610

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	3,014,096,691
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	897,157,882	771,480,383
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-20,759,387	-20,292,289
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)	-180,955,138	-188,476,903
16	Total Proprietary Capital (lines 2 through 15)		4,181,410,457	4,048,678,291
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	4,373,860,000	4,373,860,000
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)		12,896,587	13,364,139
24	Total Long-Term Debt (lines 18 through 23)		4,360,963,413	4,360,495,861
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		161,299,842	175,138,666
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		720,000	1,561,500
29	Accumulated Provision for Pensions and Benefits (228.3)		71,690,906	93,392,467
30	Accumulated Miscellaneous Operating Provisions (228.4)		137,032,633	116,685,343
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		29,833,714	12,692,651
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		208,744,170	177,019,252
35	Total Other Noncurrent Liabilities (lines 26 through 34)		609,321,265	576,489,879
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		373,800,000	176,000,000
38	Accounts Payable (232)		372,349,109	361,508,286
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		455,636	422,022
41	Customer Deposits (235)		26,488,608	32,362,304
42	Taxes Accrued (236)	262-263	105,528,433	99,611,547
43	Interest Accrued (237)		48,189,289	48,918,273
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)		1,527,251	2,389,097
48	Miscellaneous Current and Accrued Liabilities (242)		23,576,198	41,570,159
49	Obligations Under Capital Leases-Current (243)		19,678,860	16,531,463
50	Derivative Instrument Liabilities (244)		61,274,042	26,121,263
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		29,833,714	12,692,651
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)		1,003,033,712	792,741,763
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		96,883,286	95,530,623
57	Accumulated Deferred Investment Tax Credits (255)	266-267	0	0
58	Deferred Gains from Disposition of Utility Plant (256)		12,882,187	1,412,065
59	Other Deferred Credits (253)	269	244,788,439	255,311,849
60	Other Regulatory Liabilities (254)	278	1,030,887,274	1,071,933,845
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)		1,162,110,263	1,943,729,915
64	Accum. Deferred Income Taxes-Other (283)		193,135,308	231,775,519
65	Total Deferred Credits (lines 56 through 64)		2,740,686,757	3,599,693,816
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		12,895,415,604	13,378,099,610

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	3,340,134,916	3,391,632,576		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,680,093,974	1,751,167,612		
5	Maintenance Expenses (402)	320-323	164,912,813	168,501,630		
6	Depreciation Expense (403)	336-337	488,787,631	470,613,251		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	8,336,963	7,703,704		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	129,445,210	121,035,219		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	11,969,181	11,737,268		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		30,979,763	31,893,438		
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		15,210,019	17,366,545		
13	(Less) Regulatory Credits (407.4)		79,561,623	75,940,513		
14	Taxes Other Than Income Taxes (408.1)	262-263	327,965,036	331,568,910		
15	Income Taxes - Federal (409.1)	262-263	70,452,097	64,226,432		
16	- Other (409.1)	262-263	383,340	570,874		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	322,567,097	262,037,296		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	246,538,446	239,898,093		
19	Investment Tax Credit Adj. - Net (411.4)	266				
20	(Less) Gains from Disp. of Utility Plant (411.6)		1,949,557	729,404		
21	Losses from Disp. of Utility Plant (411.7)		67,714	81,967		
22	(Less) Gains from Disposition of Allowances (411.8)		228	981		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		3,892,728	3,837,179		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		2,927,013,712	2,925,772,334		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		413,121,204	465,860,242		

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
2,359,221,575	2,516,261,884	980,913,341	875,370,692			2
						3
1,166,721,795	1,313,659,877	513,372,179	437,507,735			4
138,373,309	141,849,803	26,539,504	26,651,827			5
355,593,325	345,727,153	133,194,306	124,886,098			6
8,184,802	7,533,981	152,161	169,723			7
87,050,694	83,314,999	42,394,516	37,720,220			8
11,969,181	11,737,268					9
30,979,763	31,893,438					10
						11
6,507,593	8,763,271	8,702,426	8,603,274			12
67,036,136	64,670,416	12,525,487	11,270,097			13
225,851,703	232,335,156	102,113,333	99,233,754			14
46,567,661	30,838,206	23,884,436	33,388,226			15
383,340	570,874					16
243,099,351	219,283,109	79,467,746	42,754,187			17
179,278,139	190,762,694	67,260,307	49,135,399			18
						19
1,972,399	755,389	-22,842	-25,985			20
-2,761	-8,354	70,475	90,321			21
228	981					22
						23
3,651,802	3,611,963	240,926	225,216			24
2,076,644,656	2,174,921,264	850,369,056	750,851,070			25
282,576,919	341,340,620	130,544,285	124,519,622			26

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	04/15/2021	End of 2020/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)		413,121,204	465,860,242		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		437,609	1,149,128		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		181,067	379,840		
33	Revenues From Nonutility Operations (417)		25,683,599	27,564,187		
34	(Less) Expenses of Nonutility Operations (417.1)		31,465,041	40,474,706		
35	Nonoperating Rental Income (418)		2,195	47,472		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-467,098	-535,421		
37	Interest and Dividend Income (419)		9,165,837	11,431,257		
38	Allowance for Other Funds Used During Construction (419.1)		23,222,519	15,801,744		
39	Miscellaneous Nonoperating Income (421)		2,788,514	-668,191		
40	Gain on Disposition of Property (421.1)		34,367	63,751		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		29,221,434	13,999,381		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		60,477	60,141		
46	Life Insurance (426.2)		-1,729,724	-1,698,847		
47	Penalties (426.3)		-1,312,816	907,062		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		7,094,727	5,829,260		
49	Other Deductions (426.5)		51,748,872	-374,787		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		55,861,536	4,722,829		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	345,765	641,738		
53	Income Taxes-Federal (409.2)	262-263	-59,845,199	-46,133,494		
54	Income Taxes-Other (409.2)	262-263				
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-58,849,935	-1,512,293		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,801,623			
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)		-120,150,992	-47,004,049		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		93,510,890	56,280,601		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		227,184,834	217,516,084		
63	Amort. of Debt Disc. and Expense (428)		2,481,659	2,314,664		
64	Amortization of Loss on Reaquired Debt (428.1)		2,186,294	2,200,434		
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)		15,326,329	21,746,828		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		14,827,317	14,558,843		
70	Net Interest Charges (Total of lines 62 thru 69)		232,351,799	229,219,167		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		274,280,295	292,921,676		
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)		274,280,295	292,921,676		

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		741,261,386	613,815,928
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	License Hydro Project Excess Earnings		-1,913,051	(1,436,618)
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-1,913,051	(1,436,618)
16	Balance Transferred from Income (Account 433 less Account 418.1)		274,747,393	293,457,097
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Dividends Declared		-149,069,894	(164,575,021)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-149,069,894	(164,575,021)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		865,025,834	741,261,386
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		32,132,048	30,218,997
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		32,132,048	30,218,997
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		897,157,882	771,480,383
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-20,292,289	(19,756,868)
50	Equity in Earnings for Year (Credit) (Account 418.1)		-467,098	(535,421)
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		-20,759,387	(20,292,289)

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)	274,280,295	292,921,676
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	564,835,934	545,619,345
5	Amortization of		
6	Utility Plant Adjustments	11,969,181	11,737,268
7	Property Losses	30,979,763	31,893,438
8	Deferred Income Taxes (Net)	15,377,094	20,607,295
9	Investment Tax Credit Adjustment (Net)		
10	Net (Increase) Decrease in Receivables	-32,865,713	794,067
11	Net (Increase) Decrease in Inventory	635,082	-4,805,124
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	8,438,515	-130,816,693
14	Net (Increase) Decrease in Other Regulatory Assets	-197,582,684	-227,270,664
15	Net Increase (Decrease) in Other Regulatory Liabilities	26,913,294	27,958,487
16	(Less) Allowance for Other Funds Used During Construction	23,222,519	15,801,744
17	(Less) Undistributed Earnings from Subsidiary Companies	-467,098	-535,421
18	Other (provide details in footnote):	141,810,483	71,157,764
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	822,035,823	624,530,536
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-899,660,030	-935,070,312
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	-23,222,519	-15,801,744
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-876,437,511	-919,268,568
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	6,975,024	13,301,696
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)		

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):	-797,082	-4,000,050
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-870,259,569	-912,716,922
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		443,151,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	197,800,000	
67	Other (provide details in footnote):	14,473,228	14,561,350
68	Investment from Parent company		210,000,000
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	212,273,228	667,712,350
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)		
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	-149,069,894	-164,575,021
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	63,203,334	299,840,329
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	14,979,588	11,653,943
87			
88	Cash and Cash Equivalents at Beginning of Period	64,430,923	52,776,980
89			
90	Cash and Cash Equivalents at End of period	79,410,511	64,430,923

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	04/15/2021	2020/Q4

FOOTNOTE DATA

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

Other components of operating cash flows	**Q4 2020**	**Q4 2019**
Other Long-Term Assets	$ (10,143,137)	$(14,678,515)
Other Long-Term Liabilities	$ 46,489,640	$ 22,019,783
Conservation Amortization	$ 99,585,357	$ 96,570,844
Pension Funding	$ (18,000,000)	$(18,000,000)
Net Unrealized (Gain) Loss on Derivative Transactions	$ 26,807,229	$ 3,574,274
Amortization of TCJA Over Collection	$ (13,689,283)	$(19,697,351)
Smart Burn GRC Disallowance	$ 6,332,725	$ -
Other	$ 4,427,952	$ 1,368,729
Total	$141,810,483	$ 71,157,764

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

Other components of investing cash flows	**Q4 2020**	**Q4 2019**
Renewable energy credits	(797,082)	-
Future BPA transmission rights	-	(4,000,050)
Total	(797,082)	(4,000,050)

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

Other components of financing cash flows	**Q4 2020**	**Q4 2019**
Debt issue (redemption costs) costs	$ (8,695)	$ (1,187,773)
Refundable cash received for customer construction projects	14,481,923	16,311,015
Lease Financing Activity	0	(561,893)
Total	$ 14,473,228	$ 14,561,349

NOTES TO FINANCIAL STATEMENTS

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

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

(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 3.5% and 3.4% in 2020 and 2019, respectively; depreciable natural gas utility plant was 2.9% and 2.8% in 2020 and 2019, respectively; and depreciable common utility plant was 7.3% in 2020 and 2019. 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 $207.7 million and $162.8 million 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, 2020, and December 31, 2019, 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 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 AFUDC rate authorized by the Washington Commission for natural gas and electric utility plant additions effective December 19, 2017, was 7.60%. Effective October 1, 2020 for natural gas and October 15, 2020 for electric the authorized AFUDC rate is 7.39%.

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 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 $240.8 million and $236.5 million for 2020 and 2019, 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 Credit Losses

On January 1, 2020, the Company adopted Accounting Standards Update (ASU) 2016-13 Financial Instruments – Credit Losses (ASC 326) which replaces the incurred loss methodology with an expected loss methodology that is referred to as the current expected credit loss (CECL) methodology. The measurement of expected credit losses under the CECL methodology is applicable to financial assets measured at amortized cost, including trade receivables, loan receivables, and held-to-maturity debt securities. It also applies to off-balance sheet credit exposures not accounted for as insurance (loan commitments, standby letters of credit, financial guarantees, and other similar instruments) and net investments in leases recognized by a lessor in accordance with Topic 842 on leases. The only financial assets within the scope of ASU 2016-13 for the Company are trade receivables.

The Company adopted ASU 2016-13 using the modified retrospective method. Results for reporting periods beginning after January 1, 2020 are presented under ASC 326 while prior period amounts continue to be reported in accordance with previously applicable GAAP. The Company did not record an adjustment to retained earnings as of January 1, 2020, for the cumulative effect of adopting ASU 2016-13, as the impact was immaterial.

Management measures expected credit losses on trade receivables on a collective basis by receivable type, which include electric retail receivables, gas retail receivables, and electric wholesale receivables. The estimate of expected credit losses considers historical credit loss information that is adjusted for current conditions and reasonable and supportable forecasts.

The following table presents the activity in the allowance for credit losses for accounts receivable for the year ended December 31, 2020:

Puget Sound Energy

(Dollars in Thousands)	December 31, 2020
Allowance for credit losses:	
Beginning balance	$ 8,294
Provision for credit loss expense	23,292
Receivables charged-off	(11,506)
Total ending allowance balance	$ 20,080

The allowance increased during the period due to both an increase in the provision combined with a reduction in receivables charged-off during the period. During 2020, the Ratepayer Assistance and Preservation of Essential Services proclamation issued by the governor in April 2020 included a moratorium on disconnecting customers, which resulted in a cessation of account receivable write-offs for non-payment. Additionally, the provision increased based on collection experience during the period.

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 and qualifying costs exceed $0.5 million per qualified storm.

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

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.

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.

Variable Interest Entities

On April 12, 2017, PSE entered into a PPA with Skookumchuck Wind Energy Project, LLC (Skookumchuck) in which Skookumchuck would develop a wind generation facility and, once completed, sell bundled energy and associated attributes, namely RECs to PSE over a term of 20 years. Skookumchuck commenced commercial operation in November 2020. PSE has no equity investment in Skookumchuck but is Skookumchuck's only customer. Based on the terms of the contract, PSE will receive all of the output of the facility, subject to curtailment rights. PSE has concluded that it is not the primary beneficiary of this VIE since it does not control the commercial and operating activities of the facility. Additionally, PSE does not have the obligation to absorb losses or receive benefits. Therefore, PSE will not consolidate the VIE. Purchased energy of $4.2 million was recognized in purchased electricity on the Company's consolidated statements of income and included in accounts payable on the Company's consolidated balance sheet for the year ended December 31, 2020.

Subsequent Events

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 April 15, 2021, the date the financial statements were filed with the FERC, and no additional disclosures are required.

(2) New Accounting Pronouncements

Recently Adopted Accounting Guidance

Credit Losses

In 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 measurement of expected credit losses under the CECL methodology is applicable to financial assets measured at amortized cost, including trade receivables. It also applies to off-balance sheet credit exposures not accounted for as insurance and net investments in leases recognized by a lessor in accordance with Topic 842.

The Company adopted ASC 326 using the modified retrospective method for all financial assets measured at amortized cost. Results for reporting periods beginning after January 1, 2020, are presented under ASC 326 while prior period amounts continue to be reported in accordance with previously applicable GAAP. Upon implementation as of January 1, 2020, the impact was immaterial and the Company did not record a transition adjustment to retained earnings.

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 amendments in this update modify the disclosure requirements on fair value measurements in Topic 820, Fair Value Measurement, based on the concepts in the Concepts Statement, including the consideration of costs and benefits. The amendments are effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. The Company adopted this update as of January 1, 2020, and it impacted Note 11, "Fair Value Measurements". As the amendment contemplates changes in disclosures only, it has no material impact on the Company's results of operations, cash flows, or consolidated balance sheets.

Reference Rate Reform

In March 2020, the FASB issued ASU 2020-04, *"Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting*" (Issued March 2020): ASU 2020-04 provides temporary optional expedients and exceptions to the current guidance on contract modifications to ease the financial reporting burdens related to the expected market transition from London Interbank Offered Rate (LIBOR) and other interbank offered rates to alternative reference rates. The Company has term loans, credit agreements, and promissory notes that reference LIBOR. As of December 31, 2020, the Company has not utilized any of the expedients discussed within this ASU, however, it continues to assess other agreements to determine if LIBOR is included and if the expedients would be utilized through the allowed period of December 2022.

(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, 2020, and 2019, included the following:

Puget Sound Energy	Remaining Amortization Period	December 31,	
(Dollars in Thousands)		2020	2019
Storm damage costs electric	5 years	$ 108,491	$ 121,894
Environmental remediation	(a)	102,647	68,486
Decoupling deferrals and interest (b)	Less than 2 years	88,504	43,509
PGA receivable	2 years	87,655	132,766
PCA mechanism	N/A	82,801	41,745
Chelan PUD contract initiation	10.8 years	76,787	83,875
Deferred Washington Commission AFUDC	30 years	59,763	57,553
Lower Snake River	16.4 years	58,442	62,899
Baker Dam licensing operating and maintenance costs	(c)	54,354	56,427

Get to zero depreciation expense deferral	N/A	53,236	22,148
Unamortized loss on reacquired debt	1 to 47 years	37,991	40,177
Property tax tracker	Less than 2 years	24,860	22,442
Advanced metering infrastructure	(a)	22,652	14,845
Generation plant major maintenance, excluding Colstrip	3 to 10 years	10,494	12,744
Mint Farm ownership and operating costs	4.3 years	8,318	10,318
Energy conservation costs	(a)	8,009	25,272
Snoqualmie licensing operating and maintenance costs	(c)	7,435	7,442
Water heater rental property loss	N/A	6,973	—
Colstrip major maintenance	(d)	4,335	2,929
Washington Commission electric vehicle	N/A	3,641	1,430
Colstrip common property	3.4 years	2,472	3,188
White River relicensing and other costs	0.0 years	—	6,399
Various other regulatory assets	(a)	8,247	9,044
Total PSE regulatory assets		$ 918,107	$ 847,532
Deferred income taxes (f)	N/A	(953,987)	(946,936)
Cost of removal	(e)	(508,707)	(469,922)
Repurposed production tax credits	N/A	(79,581)	(24,823)
Production tax credits	(f)	(47,094)	(85,323)
Treasury grants	3 years	(43,164)	(101,981)
Decoupling liability	Less than 2 years	(16,448)	(8,500)
Green direct	N/A	(14,313)	(2,421)
Gain on Sale Shuffleton	N/A	(11,131)	(12,483)
Microsoft special contract regulatory liability	N/A	—	(12,661)
Various other regulatory liabilities	(a)	(10,796)	(11,500)
Total PSE regulatory liabilities		(1,685,221)	(1,676,550)
PSE net regulatory assets (liabilities)		$ (767,114)	$ (829,018)

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

(b) Decoupling deferrals and interest includes a 24 month GAAP reserve of $(8.0) million.

(c) The FERC license requires PSE to incur various O&M expenses over the life of the 40 year and 50 year license for Snoqualmie and Baker, respectively. The regulatory asset represents the net present value of future expenditures and will be offset by actual costs incurred.

(d) Amortization to be determined in a future rate filing.

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

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

(g) For additional information, see Note 13,"Income Taxes" to the consolidated financial statements included in Item 8 of this report.

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 $508.7 million and $469.9 million in 2020 and 2019, respectively, for the cost of removal of utility plant. These amounts are collected from PSE’s customers through depreciation rates.

Power Cost Only Rate Case

On December 9, 2020, PSE filed its 2020 power cost only rate case (PCORC). The filing proposed an increase of $78.5 million (or an average of approximately 3.7%) in the Company's overall power supply costs with an anticipated effective date in June 2021. On February 2, 2021, PSE supplemented the PCORC to update its power costs, leading to a requested increase from $78.5 million to $88.0 million (or an average of approximately 4.1%).

On March 2, 2021, the parties to the PCORC reached a multiparty settlement in principle, with Public Counsel not joining the settlement, but also not opposing. The settlement agreement and supporting testimony was filed with the Washington Commission on April 2, 2021, who held hearings on the matter on April 22, 2021. The settlement resulted in an estimated revenue increase of $65.3 million or 3.07% and, pending approval by the Washington Commission, is expected to be effective June 2021.

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.

On July 8, 2020, the Washington Commission issued its order on PSE's GRC. The ruling provided for a weighted cost of capital of 7.39% or 6.8% after-tax, and a capital structure of 48.5% in common equity with a return on equity of 9.4%. The order also resulted in a combined net increase to electric of $29.5 million, or 1.6%, and to natural gas of $36.5 million, or 4.0%. However, the Washington Commission extended the amortization of certain regulatory assets, PSE's electric decoupling deferral, and PSE's PGA deferral to mitigate the impact of the rate increase in response to the economic instability created by the COVID-19 pandemic, which reduced the electric revenue increase to approximately $0.9 million, or 0.05% and the natural gas increase to $1.3 million, or 0.15%. The Washington Commission also determined that the Company's proposed attrition adjustment of $23.9 million for electric and $16.2 million for natural gas was not in the public interest at this time. The order also effectively ends the deferral of depreciation expense associated with PSE's advanced metering infrastructure (AMI) investment while allowing the deferral on the return on AMI investments through December 31, 2019. Additional AMI investments will be evaluated in future proceedings for deferrals of return until the AMI project is complete. On July 17, 2020, PSE filed a motion for clarification with the Washington Commission seeking clarification on several items. On July 31, 2020, the Washington Commission issued an order granting PSE's motion for clarification. The ruling adjusted certain items from the final order issued on July 8, 2020, which led to a combined net increase to electric of $59.6 million, or 2.9%, an increase of $30.1 million above the $29.5 million granted in the final order. The order also led to a combined net increase to natural gas of $42.9 million, or 5.6%, an increase of $6.4 million above the $36.5 million granted in the final order. The Washington Commission maintained adjustments which mitigated the impacts of the rate increases in response to the economic instability created by the COVID-19 pandemic, which reduced the electric revenue increase to approximately $27.7 million, or 1.3% and the natural gas increase to $0.2 million, or 0.02%.

On August 6, 2020, PSE filed a petition for judicial review with the Superior Court of the State of Washington for King County (Superior Court) challenging the portion of the final order that requires PSE to pass back to customers the reversal of plant-related excess deferred income taxes in a manner that may deviate from the Internal Revenue Service (IRS) normalization and consistency rules. On August 7, 2020, PSE filed a motion to stay with the Superior Court related to the portions of the final order under judicial review. On September 14, 2020, the Superior Court denied PSE's motion to stay. PSE reviewed the original Washington Commission order including the ramifications of certain tax issues and requested a Private Letter Ruling (PLR) with the IRS regarding this matter. PSE will continue to utilize the average rate assumption method (ARAM) in the turnaround of certain accelerated tax depreciation benefits on PSE assets. On September 23, 2020, PSE filed a compliance filing with the Washington Commission. The natural gas tariffs became effective October 1, 2020 and the electric tariffs on October 15, 2020. On October 7, 2020, PSE, the Washington Commission and interveners agreed to dismiss the petition for judicial review. The agreement is based on a commitment from the Washington Commission that if the IRS ruling finds that the Washington Commission's methodology for reversing plant-related excess deferred income taxes is impermissible, the Washington Commission will open a proceeding to review and enact the changes required by the IRS ruling. There is approximately $25.6 million in annual revenue requirement related to the 2019 GRC which PSE has requested it be allowed to track in order to allow the Washington Commission to decide if it is appropriate for PSE to recover, pending the outcome of the IRS ruling.

Expedited Rate Filing Rate Adjustment

On November 7, 2018, PSE filed an 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 rate increase 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 settlement agreement provides that PSE may defer the depreciation expense associated with PSE's ongoing investment in its AMI investment and may defer the return on the AMI investment that was included in the test year of the filing. As noted above, the 2019 GRC effectively ends all deferrals of AMI depreciation expense and deferrals of return on additional AMI investments will be evaluated in future proceedings. 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 passed 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 ended May 1, 2020.

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.

While the settlement agreement in the ERF 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 through the PSE Schedule 141X tariff, the ongoing treatment of 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 was left to be 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. Per PSE's Schedule 141Y tariff, following the May 2019 through April 2020 refund period, if the residual balance of credit owed to customers will be greater than $0.1 million, PSE would submit a filing no later than July 31, 2020 with a proposal of passing back the residual balance effective September 1, 2020 through August 31, 2021. As this balance was greater than $0.1 million, PSE filed tariff revisions on July 20, 2020 and the Washington Commission approved the filing on August 27, 2020. Finally, the GRC final order determined that PSE is required to pass back 2019 and 2020 protected excess deferred tax reversals totaling $70.8 million over the 12 months following the rate effective period through PSE's Schedule 141X tariff. The GRC final order also determined that PSE is required to pass back unprotected excess deferred tax balances totaling $38.9 million over 36 months following the rate effective period through PSE's Schedule 141Z tariff. Further details of the outcome associated with PSE's tax deferral filing are discussed in the ERF and GRC disclosures.

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 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 only be changed in a GRC or a power cost only rate case. 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 July 8, 2020, the Washington Commission issued the final order in Dockets UE-190529 and UG-190530, which instructed

PSE to extend the collection of amortization balances for electric decoupling delivery and fixed power cost sections originally filed through the annual May 2020 decoupling filing. The extension requires PSE to move amortization balances for electric decoupling as of August 31, 2020 to be collected from customers for a two-year period, instead of the originally approved one-year period. Additionally, through approving the electric cost of service, the final order approved the re-allocation of decoupling balances from Schedule 40 to the remaining electric decoupling groups.

On December 1, 2020, PSE made a tariff correction filing for Schedule 142 amortization rates, with a proposed effective date of January 1, 2021, where it proposed to zero out rates still effective past October 15, 2020 on tariff sheet Schedule 142-H, which was replaced by rates on tariff sheet Schedule 142-I effective October 15, 2020. This resulted in an over-collection from electric decoupled customers of approximately $4.3 million at year-end. As part of this filing, PSE has proposed to true up the over-collection amounts for the period of October 15, 2020 through December 31, 2020 in PSE's annual May 2021 decoupling filing.

On December 31, 2020, 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 $8.0 million of electric deferred revenue will not be collected within 24 months of the annual period; therefore a reserve adjustment was booked to 2020 electric decoupling revenue. Natural gas deferred revenue will be collected within 24 months of the annual period; therefore, no reserve adjustment was booked to 2020 natural gas decoupling revenue. The previously unrecognized decoupling deferrals of $0.8 million at December 31, 2018, were 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

For the year ended December 31, 2020, in its PCA mechanism, PSE under recovered its allowable costs by $75.4 million of which $43.3 million was apportioned to customers and $2.0 million of interest was accrued on the deferred customer balance. This compares to an under recovery of allowable costs of $67.2 million for the year ended December 31, 2019, of which $36.0 million amounts were apportioned to customers and accrued $1.0 million of interest on the total deferred customer balance.

Power Cost Adjustment Clause Filing

On July 1, 2019, PSE updated its Schedule 95 rates in the Power Cost Adjustment Clause tariff to reflect the transition fee as required by Section 12 of the Microsoft Special Contract. Additionally, Schedule 95 rates also include portions of fixed power cost adjustments per the allowed decoupling rate re-allocation effective April 1, 2019, resulting from Microsoft becoming a transportation customer as well as small variable power cost adjustments.

On July 8, 2020, the Washington Commission issued the final order in Dockets UE-190529 and UG-190530, which instructed PSE to remove Schedule 95 collection on decoupling allowed rates for Microsoft Special Contracts, which will be included in allowed rates under the Decoupling Schedule 142 effective October 15, 2020.

PSE exceeded the $20.0 million cumulative deferral balance in its PCA mechanism in 2019. The surcharging of deferrals can be triggered by the Company when the balance in the deferral account is a credit of $20.0 million or more. Due to concerns about the economic impact of the COVID-19 pandemic on customers, PSE voluntarily, with Washington Commission Staff support, delayed filing an increase to its Schedule 95 rates in its annual PCA report filing in Docket UE-200398, which was approved on July 30, 2020. Subsequently, PSE filed to recover the deferred balance in Docket UE-200893, effective December 1, 2020, and the Washington Commission approved PSE’s request on November 24, 2020. During 2019, actual power costs were higher than baseline power costs, thereby creating an under-recovery of $67.2 million. Under the terms of the PCA’s sharing mechanism for under-recovered power costs, PSE absorbed $31.2 million of the under-recovered amount, and customers were responsible for the remaining $36.0 million, or $37.0 million including interest. As PSE had an approved balance owing from customers including interest at the start of 2019 totaling $4.7 million, the approved cumulative deferral balance for the PCA as of December 2019 is $41.7 million. As previously stated, this filing is set to collect the customer’s share of the cumulative 2019 imbalance in PSE’s PCA mechanism.

Purchased Gas Adjustment Mechanism

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 out-of-cycle PGA rates were effective from May 1, 2019 through April 30, 2020 and on May 1, 2020 the rates were set to zero. At the end of the recovery period, an unamortized balance of $4.9 million remained which PSE requested to be amortized in its annual PGA filing for rates effective November 1, 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. On July 8, 2020, the Washington Commission issued the final order in Dockets UE-190529 and UG-190530, which instructed PSE to extend the collection of amortization balances for the portion of PGA amortization balances originally filed through the annual November 1, 2019 PGA filing under the Supplemental Schedule 106B. The extension requires PSE to move amortization balances for PGA Schedule 106B as of August 31, 2020 to be collected from customers for a three-year period, instead of the originally approved two-year period.

On October 29, 2020, the Washington Commission approved PSE's request for November 2020 PGA rates in Docket UG-200832, effective November 1, 2020. As part of that filing, PSE requested PGA rates increase annual revenue by $32.6 million, while the new tracker rates increased annual revenue by $37.4 million; this was in addition to continuing the collection on the remaining balance of $69.4 million under Supplemental Schedule 106B.

The following table presents the PGA mechanism balances and activity at December 31, 2020 and December 31, 2019:

Puget Sound Energy

(Dollars in Thousands) PGA receivable balance and activity	At December 31, 2020	At December 31, 2019
PGA receivable beginning balance	$ 132,766	$ 9,921
Actual natural gas costs	314,792	406,162
Allowed PGA recovery	(363,886)	(289,876)
Interest	3,983	6,559
PGA receivable ending balance	$ 87,655	$ 132,766

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, 2020 and December 31, 2019, PSE deferred $2.8 million and $21.7 million of depreciation expense for GTZ, respectively. 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. The GTZ accounting petition was consolidated with PSE's 2019 GRC and on July 8, 2020, the Washington Commission issued its order in PSE's 2019 GRC. The ruling authorized PSE to amortize deferred GTZ expenses as proposed in the original GRC filing. The ruling also allows continued deferral of the depreciation expense associated with GTZ investments not already approved for recovery with a book life of 10 years or less, through PSE's next GRC. Finally, the final order set the rate at which PSE could defer and recover carrying charges from PSE's authorized rate of return to the quarterly interest rate established by the FERC.

Crisis Affected Customer Assistance Program

On April 6, 2020, PSE filed with the Washington Commission revisions to its currently effective Tariff WN U-60. The purpose of this filing is to incorporate into PSE's low-income tariff a new temporary bill assistance program, Crisis Affected Customer Assistance Program (CACAP), to mitigate the economic impact of the COVID-19 pandemic on PSE's customers. CACAP would allow PSE customers facing financial hardship due to COVID-19 to receive up to $1,000 in bill assistance. The program puts to immediate use $11.0 million in unspent low income funds from prior years, and supplements other forms of financial assistance. The program does not require an increase to rates and is fully compatible with other low income programs. Based on the COVID-19 pandemic and resulting state of emergency, the Washington Commission allowed the tariff revisions to become effective on April 13, 2020. PSE made an additional filing on July 21, 2020 to increase the amount of electric funds available for distribution by $4.5 million under the CACAP program. The program ended on September 30, 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 and qualifying costs exceed $0.5 million per qualified storm. For the year ended December 31, 2020, PSE incurred $21.8 million in storm-related electric transmission and distribution system restoration costs, of which the Company deferred $11.2 million as regulatory assets related to storms that occurred in 2020. This compares to $39.3 million incurred in storm-related electric transmission and distribution system restoration costs for the year ended December 31, 2019, 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. 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 former 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 $43.7 million for natural gas and $48.0 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, Tacoma, Everett, and Bellingham, Washington. The Company has taken the lead for the projects, and as of December 31, 2020, the Company's share of future remediation costs is estimated to be approximately $35.7 million. The Company's deferred electric environmental costs are $51.8 million and $13.7 million at December 31, 2020 and 2019, respectively, net of insurance proceeds. The Company's deferred natural gas environmental costs are $50.9 million and $54.8 million at December 31, 2020 and 2019, respectively, net of insurance proceeds.

(4) Dividend Payment Restrictions

The payment of dividends by PSE to Puget Energy is restricted by provisions of certain covenants applicable to long-term debt contained in PSE's electric and natural gas mortgage indentures. At December 31, 2020, approximately $1.1 billion 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 48.1% at December 31, 2020, and the EBITDA to interest expense was 5.2 to 1.0 for the twelve months ended December 31, 2020.

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, 2020, 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 (Dollars in Thousands)	Estimated Useful Life (Years)	Puget Sound Energy December 31, 2020	Puget Sound Energy December 31, 2019
Distribution plant	20-65	$ 8,592,720	$ 8,185,700
Production plant	12-90	3,767,014	3,743,493
Transmission plant	43-75	1,601,731	1,571,186
General plant	5-75	726,327	731,279
Intangible plant (including capitalized software)[1]	3-50	770,317	726,383

Plant acquisition adjustment	N/A	282,792	282,792
Underground storage	25-60	52,927	50,963
Liquefied natural gas storage	25-60	14,498	14,498
Plant held for future use	N/A	46,081	46,385
Recoverable Cushion Gas	N/A	8,655	8,655
Plant not classified	N/A	384,794	316,923
Finance leases, net of accumulated amortization[2]	N/A	881	1,488
Less: accumulated provision for depreciation		(6,087,748)	(5,682,606)
Subtotal		$ 10,160,989	$ 9,997,139
Construction work in progress		712,204	591,199
Net utility plant		$ 10,873,193	$ 10,588,338

1. *Intangible assets include capitalized software and franchise agreements with useful lives ranging between 3-10 years and 10-50 years, respectively.*
2. *At December 31, 2020, and 2019, accumulated amortization of capital leases at PSE was $1.6 million and $1.0 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, 2020. 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 %	$ 587,424	$ —	$ (377,003)
Frederickson 1	Natural Gas	49.85	68,586	—	(20,601)
Jackson Prairie	Natural Gas	33.34	52,927	1,725	(23,705)
Tacoma LNG	Natural Gas	various	—	207,700	—

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, offset by depreciation as included in base rates until the 2019 GRC became effective in October 2020. 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, 2020, and 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, liquefied natural gas storage sites, and leased facilities where disposal is governed by ASC 410-20 “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 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 made changes to the Company’s Colstrip operations, which 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, 2020, the Company reviewed the estimated remediation costs at Colstrip and increased the Colstrip ARO liability by $29.7 million for Colstrip Units 1 and 2 and $2.0 million for Colstrip Units 3 and 4. The environmental remediation liability for Colstrip Units 1 and 2 increased $39.0 million during the same period. The 2020 increase to these Colstrip related liabilities is primarily due to remediation plans approved by the Montana Department of Environmental Quality under a 2012 settlement between the plant operator and the state for the remaining sites at Colstrip. The plant operator is currently contesting the approved plan for Colstrip 1 & 2 under the defined process in the settlement with the state. The Company has recorded the incremental costs for this change under ASC 410-20 “Asset Retirement and Environmental Obligations" and ASC 410-30 “Environmental Remediation". For the twelve months ended December 31, 2019, the company increased the Colstrip ARO liability by $4.2 million for Colstrip Units 1 and 2, and increased $0.5 million for Colstrip Units 3 and 4. The 2019 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, 2020 and 2019, the Company also recorded the Colstrip relief of liability of $9.6 million and $12.4 million, respectively. In addition, the Company recorded Tacoma LNG facility ARO liability of $3.3 million and $3.0 million as of December 31, 2020 and December 31, 2019, respectively. The 2020 and 2019 increases to the Tacoma LNG facility ARO liabilities are primarily due to continued construction of the plant.

Puget Sound Energy	December 31,	
(Dollars in Thousands)	2020	2019

Asset retirement obligation at beginning of the period	$	177,019	$	180,489
Relief of liability		(9,647)		(12,449)
Revisions in estimated cash flows		35,802		3,405
Accretion expense		5,571		5,574
Asset retirement obligation at end of period	$	208,745	$	177,019

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, 2020:

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 the FERC orders the project to be decommissioned, although PSE contends that the 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 2020 and 2019:

(Dollars in Thousands)			December 31,	
Series	Type	Due	2019	2018
Puget Sound Energy:				

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	450,000
4.700%	Senior Secured Note	2051	45,000	45,000
*	Debt discount, issuance cost and other	*	(35,816)	(37,718)
Total PSE long-term debt			$ 4,338,044	$ 4,336,142

1 *Not Applicable.*

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, 2020, 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, 2020, 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 3.25%. 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)	2021	2022	2023	2024	2025	Thereafter	Total
Maturities of:							
PSE	$ 2,412	$ —	$ —	$ —	$ 17,000	$ 4,356,860	$ 4,376,272
Total long-term debt	$ 2,412	$ —	$ —	$ —	$ 17,000	$ 4,356,860	$ 4,376,272

(7) Liquidity Facilities and Other Financing Arrangements

As of December 31, 2020, and 2019, PSE had $373.8 million and $176.0 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 2020 and 2019 was 2.0% and 3.4%, respectively. As of December 31, 2020, 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, 2020, 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, 2020, no amounts were drawn and outstanding under PSE's credit facility. No letters of credit were outstanding and $373.8 million was outstanding under the commercial paper program. Outside of the credit agreement, PSE had a $2.7 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 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, 2020, 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 49 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.

During the first quarter of 2021, mechanical completion was achieved for the Puget LNG facility which triggered an increase in the lease payments for the Port of Tacoma lease. This remeasurement resulted in an increase of the Operating lease ROU asset and Operating lease liabilities of $26.3 million.

The components of lease cost were as follows:

Puget Sound Energy (Dollars in Thousands)	Year Ended December 31, 2020	Year Ended December 31, 2019
Finance lease cost:		

Amortization of right-of-use asset	$	607	$	562
Interest on lease liabilities		34		40
Total Finance lease cost	$	641	$	602
Operating lease cost	$	20,984	$	19,369

Supplemental cash flow information related to leases was as follows:

Puget Sound Energy (Dollars in Thousands)		Year Ended December 31, 2020		Year Ended December 31, 2019
Cash paid for amounts included in the measurement of lease liabilities:				
Operating cash flow for operating leases	$	15,305	$	14,104
Investing cash flow for operating leases		5,679		5,535
Operating cash flow for finance leases		34		40
Financing cash flow for finance leases		607		562
Non-cash disclosure upon commencement of new lease				
Right-of-use assets obtained in exchange for new operating lease liabilities	$	6,302	$	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) **Operating Leases**		At December 31, 2020		At December 31, 2019
Operating lease right-of-use asset	$	172,167	$	183,048
Operating leases liabilities current		19,204		15,862
Operating lease liabilities long-term		160,980		174,327

Total Operating lease liabilities:	$ 180,184	$ 190,189
Finance Leases		
Common Plant	$ 881	$ 1,488
Other current liabilities	475	669
Other deferred credits	320	811
Total finance lease liabilities	$ 795	$ 1,480
Weighted Average Remaining Lease Term		
Operating leases	18.97 Years	19.24 Years
Finance leases	2.00 Years	2.76 Years
Weighted Average Discount Rate		
Operating leases	3.59 %	3.59 %
Finance leases	2.98 %	2.98 %

The following tables summarize the Company's estimated future minimum lease payments as of December 31, 2020, and December 31, 2019, respectively:

Maturities of lease liabilities	Future Minimum Lease Payments	
(Dollars in Thousands)		
At December 31,	Operating Leases	Finance Leases
2021	$ 23,170	$ 508
2022	22,785	279
2023	22,345	98
2024	21,613	—
2025	18,249	—
Thereafter	144,912	—
Total lease payments	$ 253,074	$ 885

Less imputed interest	(72,890)	(90)
Total net present value	$ 180,184	$ 795

Maturities of lease liabilities

(Dollars in Thousands)

At December 31,	Future Minimum Lease Payments 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

Leases Not Yet Commenced

During 2020, PSE entered into two leases for two service centers located in Kent and Puyallup, Washington. The Kent service center lease is expected to commence in 2021 and the Puyallup service center lease is expected to commence in 2022. These leases are expected to result in material rights and obligations upon commencement and will be classified as finance leases.

(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]	
	2020	2019	2020	2019	2020	2019
Electric portfolio derivatives	*	*	$ 22,544	$ 19,933	$ 46,922	$ 17,504
Natural gas derivatives (MMBtus)[3]	320	316	19,276	11,375	14,352	8,617
Total derivative contracts			$ 41,820	$ 31,308	$ 61,274	$ 26,121
Current			33,015	23,626	31,441	13,428
Long-term			8,805	7,682	29,833	12,693
Total derivative contracts			$ 41,820	$ 31,308	$ 61,274	$ 26,121

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1. *Balance sheet classification: Current and Long-term Unrealized gain on derivative instruments.*
2. *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 212.2 million One Million British Thermal Units (MMBtus) and purchased electricity of 6.6 million megawatt hours (MWhs) at December 31, 2020, and 229.3 million MMBtus and 10.4 million MWhs at December 31, 2019.*

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, 2020

(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	$ 41,820	$ —	$ 41,820	$ (21,696)	$ —	$ 20,124
Liabilities:						
Energy derivative contracts	61,274	—	61,274	(21,696)	(9,343)	$ 30,235

Puget Sound Energy

December 31, 2019

(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	$ 31,308	$ —	$ 31,308	$ (14,922)	$ —	$ 16,386
Liabilities:						
Energy						

derivative contracts	26,121	—	26,121	(14,922)	2,000	$ 13,199

1. *All Derivative Contract deals are executed under ISDA, NAESB and WSPP Master Netting Agreements with Right of set-off.*
2. *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	2020	2019
Gas for Power Derivatives:			
Unrealized	Unrealized gain (loss) on derivative instruments, net	5,534	16,970
Realized	Electric generation fuel	5,246	10,828
Power Derivatives:			
Unrealized	Unrealized gain (loss) on derivative instruments, net	(32,341)	(20,544)
Realized	Purchased electricity	(14,958)	48,686
Total gain (loss) recognized in income on derivatives		$ (36,519)	$ 55,940

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, 2020, approximately 98.6% of the Company's energy portfolio exposure, excluding NPNS transactions, is with counterparties that are rated investment grade by rating agencies and 1.4% 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, 2020, 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, 2020, PSE had cash posted as collateral of $17.9 million related to contracts executed on the ICE platform. Also, as of December 31, 2020, PSE had $3.0 million in cash posted as collateral and a $1.0 million letter of credit posted 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, 2020, 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)	2020			2019		
Contingent Feature	Fair Value[1] Liability	Posted Collateral	Contingent Collateral	Fair Value[1] Liability	Posted Collateral	Contingent Collateral
Credit rating[2]	$ 26,966	$ —	$ 26,966	$ 6,110	$ —	$ 6,110
Requested credit for adequate assurance	6,576	—	—	5,253	—	—
Forward value of contract[3]	9,343	20,903	N/A	—	14,827	N/A
Total	$ 42,885	$ 20,903	$ 26,966	$ 11,363	$ 14,827	$ 6,110

1. *Represents the derivative fair value of contracts with contingent features for counterparties in net derivative liability positions. Excludes NPNS, accounts payable and accounts receivable.*
2. *Failure by PSE to maintain an investment grade credit rating from each of the major credit rating agencies provides counterparties a contractual right to demand collateral.*

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 or that are transacted at illiquid delivery locations 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 $52.7 million and $51.5 million at December 31, 2020, and 2019, 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, 2020		December 31, 2019	
(Dollars in Thousands)	Level	Carrying Value	Fair Value	Carrying Value	Fair Value
Financial liabilities:					
Long-term debt (fixed-rate), net of discount[1]	2	$ 4,338,044	$ 6,086,358	$ 4,336,142	$ 5,571,818
Total		$ 4,338,044	$ 6,086,358	$ 4,336,142	$ 5,571,818

1. *The carrying value includes debt issuances costs of $22.9 million and $24.4 million for December 31, 2020, and 2019, 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, 2020			Fair Value December 31, 2019	
(Dollars in Thousands)	Level 2	Level 3	Total	Level 2	Level 3	Total
Assets:						
Electric Derivative Instruments	$ 21,947	$ 597	$ 22,544	$ 19,282	$ 651	$ 19,933
Gas Derivative Instruments	19,139	137	$ 19,276	9,852	1,523	$ 11,375

Total derivative assets	$ 41,086	$ 734	$ 41,820	$ 29,134	$ 2,174	$ 31,308
Liabilities:						
Electric Derivative Instruments	$ 22,607	$ 24,315	$ 46,922	$ 13,474	$ 4,030	$ 17,504
Gas Derivative Instruments	13,080	1,272	$ 14,352	8,376	241	$ 8,617
Total derivative liabilities	$ 35,687	$ 25,587	$ 61,274	$ 21,850	$ 4,271	$ 26,121

Puget Sound Energy Level 3 Roll-Forward Net Asset(Liability) (Dollars in Thousands)	Year Ended December 31,					
	2020			2019		
	Electric	Natural Gas	Total	Electric	Natural Gas	Total
Balance at beginning of period	$ (3,379)	$ 1,282	$ (2,097)	$ 1,362	$ 1,673	$ 3,035
Changes during period						
Realized and unrealized energy derivatives:						
Included in earnings[1]	(23,559)	—	(23,559)	3,558	—	3,558
Included in regulatory assets / liabilities	—	(1,049)	(1,049)	—	3,151	3,151
Settlements[2]	3,220	(1,368)	1,852	(11,265)	(4,708)	(15,973)
Transferred into Level 3	—	—	—	4,390	(398)	3,992
Transferred out Level 3	—	—	—	(1,424)	1,564	140
Balance at end of period	$ (23,718)	$ (1,135)	$ (24,853)	$ (3,379)	$ 1,282	$ (2,097)

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 $(21.3) million and $(3.2) million for the years ended December 31, 2020 and 2019, 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, 2020 and 2019. The Company does 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 adjusts the price for transportation costs to 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, 2020:

Puget Sound Energy (Dollars in Thousands)	Fair Value				Range		
	Assets[1]	Liabilities[1]	Valuation Technique	Unobservable Input	Low	High	Weighted
Electricity	$ 597	$ 24,315	Discounted cash flow	Power Prices (per MWh)	$ 22.82	$ 41.66	$ 31.54
Natural Gas	$ 137	$ 1,272	Discounted cash flow	Natural Gas Prices (per MMBtu)	$ 1.89	$ 3.42	$ 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, 2020, 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 $5.5 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 $22.1 million and $21.7 million for the years 2020 and 2019, 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 this benefit 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 are 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, 2020, and 2019:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2020	2019	2020	2019	2020	2019
Change in benefit obligation:						
Benefit obligation at beginning of period	$ 774,305	$ 677,643	$ 63,000	$ 55,708	$ 11,627	$ 10,636
Amendments	—	—	—	—	44	9,049
Service cost	24,337	22,656	756	1,023	190	61
Interest cost	25,180	28,913	1,464	2,314	368	410
Curtailment Loss / (Gain)	—	—	—	—	—	(7,486)
Actuarial loss (gain)	69,413	84,272	3,663	6,756	604	(287)
Benefits paid	(42,775)	(36,740)	(22,141)	(2,801)	(906)	(982)
Medicare part D subsidy received	—	—	—	—	187	226
Administrative expense	(1,077)	(2,439)	—	—	—	—
Benefit obligation at end of period	$ 849,383	$ 774,305	$ 46,742	$ 63,000	$ 12,114	$ 11,627

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2020	2019	2020	2019	2020	2019
Change in plan assets:						
Fair value of plan assets at beginning of period	$ 753,042	$ 640,242	$ —	$ —	$ 6,289	$ 5,960

Actual return on plan assets	107,409	133,939	—	—	278	1,006
Employer contribution	18,000	18,000	22,141	2,801	257	305
Benefits paid	(42,775)	(36,740)	(22,141)	(2,801)	(906)	(982)
Administrative expense	(1,021)	(2,399)	—	—	—	—
Fair value of plan assets at end of period	$ 834,655	$ 753,042	$ —	$ —	$ 5,918	$ 6,289
Funded status at end of period	$ (14,728)	$ (21,263)	$ (46,742)	$ (63,000)	$ (6,196)	$ (5,338)

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2020	2019	2020	2019	2020	2019
Amounts recognized in Consolidated Balance Sheet consist of:						
Noncurrent assets	$ —	$ —	$ —	$ —	$ —	$ —
Current liabilities	—	—	(6,763)	(22,604)	(293)	(308)
Noncurrent liabilities	(14,728)	(21,263)	(39,979)	(40,396)	(5,903)	(5,030)
Net assets (liabilities)	$ (14,728)	$ (21,263)	$ (46,742)	$ (63,000)	$ (6,196)	$ (5,338)

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2020	2019	2020	2019	2020	2019
Pension Plans with an Accumulated Benefit Obligation in excess of Plan Assets:						
Projected benefit obligation	$ 849,383	$ 774,305	$ 46,742	$ 63,000	$ 12,114	$ 11,627
Accumulated benefit obligation	837,455	762,838	44,033	59,988	12,070	11,604
Fair value of plan assets	834,655	753,042	—	—	5,918	6,289

The following tables summarize PSE's pension benefit amounts recognized in accumulated other comprehensive income (AOCI) for the years ended December 31, 2020, and 2019:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2020	2019	2020	2019	2020	2019
Amounts recognized in Accumulated Other Comprehensive Income consist of:						
Net loss (gain)	$ 210,317	$ 217,502	$ 12,504	$ 16,473	$ 489	$ (364)
Prior service cost (credit)	(1,513)	(3,086)	927	1,276	44	—
Total	$ 208,804	$ 214,416	$ 13,431	$ 17,749	$ 533	$ (364)

The following table summarizes PSE's net periodic benefit cost for the years ended December 31, 2020 and 2019:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2020	2019	2020	2019	2020	2019
Components of net periodic benefit cost:						
Service cost	$ 24,337	$ 22,656	$ 756	$ 1,023	$ 190	$ 61
Interest cost	25,180	28,913	1,464	2,314	368	410
Expected return on plan assets	(49,910)	(50,267)	—	—	(389)	(393)
Amortization of prior service cost (credit)	(1,573)	(1,573)	349	333	—	—
Amortization of net loss (gain)	19,043	12,877	2,385	1,733	(137)	(562)
Net periodic benefit cost	$ 17,077	$ 12,606	$ 4,954	$ 5,403	$ 32	$ (484)

The following table summarizes PSE's benefit obligations recognized in other comprehensive income (OCI) for the years ended December 31, 2020 and 2019:

Puget Sound Energy	Qualified Pension Benefits		SERP Pension Benefits		Other Benefits	
(Dollars in Thousands)	2020	2019	2020	2019	2020	2019
Other changes (pre-tax) in plan assets and benefit obligations recognized in other comprehensive income:						
Net loss (gain)	$ 11,858	$ 559	$ 3,663	$ 6,756	$ 715	$ (900)
Amortization of net (loss) gain	(19,043)	(12,877)	(2,385)	(1,733)	137	562

Settlements, mergers, sales, and closures	—	—	(5,248)	—	—	3,832
Prior service cost (credit)	—	—	—	—	44	—
Amortization of prior service (cost) credit	1,573	1,573	(349)	(333)	—	—
Total change in other comprehensive income for year	$ (5,612)	$ (10,745)	$ (4,319)	$ 4,690	$ 896	$ 3,494

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, 2021, are expected to be at least $18.0 million, $6.8 million and $0.3 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	2020	2019	2020	2019	2020	2019
Discount rate	2.70%	3.35%	2.70%	3.35%	2.70%	3.35%
Rate of compensation increase	4.50	4.50	4.50	4.50	4.50	4.50
Interest crediting rate	4.00	4.00	N/A	N/A	N/A	N/A
Medical trend rate[1]	—	—	—	—	N/A	N/A
Benefit Cost Assumptions						
Discount rate	3.35	4.40	3.35	4.40	3.35	4.40
Return on plan assets	7.15	7.50	—	—	7.00	7.00
Rate of compensation increase	4.50	4.50	4.50	4.50	4.50	4.50
Interest crediting rate	4.00	4.00	N/A	N/A	N/A	N/A
Medical trend rate[1]	—	—	—	—	N/A	N/A

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. The Company's projected benefit obligation for pension plans experienced an actuarial loss of $69.4 million in 2020. This is primarily due to the decrease in the discount rate used in measuring the benefit obligation.

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)	2021	2022	2023	2024	2025	2025-2029
Qualified Pension total benefits	$ 46,500	$ 47,300	$ 48,900	$ 49,900	$ 51,200	$ 261,000
SERP Pension total benefits	6,763	1,901	3,773	6,552	8,041	16,217
Other Benefits total with Medicare Part D subsidy	816	968	936	904	876	3,931
Other Benefits total without Medicare Part D subsidy	997	968	936	904	876	3,931

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:

Asset Class	Allocation 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, 2020, and 2019:

	Recurring Fair Value Measures				Recurring Fair Value Measures			
	December 31, 2020				December 31, 2019			
(Dollars in Thousands)	Level 1	Level 2	Other	Total	Level 1	Level 2	Other	Total
Assets:								
Mutual Funds	$—	$—	$—	$—	$91,658	$—	$—	$91,658
Common Stock								
1 Domestic	228,247	53	—	228,300	204,682	—	—	204,682
1 Foreign	19,216	—	—	19,216	19,464	—	—	19,464
Government Securities	73,006	9,148	—	82,154	34,916	—	—	34,916

Corporate Securities								
1 Domestic	—	6,082	—	6,082	—	—	—	—
1 Foreign	—	3,699	—	3,699	—	—	—	—
Cash and cash equivalents	4,612	3,223	—	7,835	—	150	—	150
Investments measured at NAV								
- Collective Investment Funds	—	—	342,014	342,014	—	—	278,379	278,379
- Partnership	—	—	107,137	107,137	—	—	69,505	69,505
- Mutual Funds	—	—	82,103	82,103	—	—	53,784	53,784
- Other	—	—	1,096	1,096	—	—	—	—
Net (payable) receivable	—	—	(44,981)	(44,981)	—	—	505	505
Total assets	$325,081	$22,205	$487,369	$834,655	$350,720	$150	$402,173	$753,043

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				Recurring Fair Value Measures			
	December 31, 2020				December 31, 2019			
(Dollars in Thousands)	Level 1	Level 2	Other	Total	Level 1	Level 2	Other	Total
Assets:								
Mutual Fund[1]	$ 5,916	$ —	$ —	$ 5,916	$ 6,201	$ —	$ —	$ 6,201
Investments measured at NAV[2]	—	—	—	—	—	—	88	88
Net (payable) receivable	—	—	2	2	—	—	—	—
Total assets	$ 5,916	$ —	$ 2	$ 5,918	$ 6,201	$ —	$ 88	$ 6,289

The following discussion provides information regarding the methods used in valuation of the various asset class investments held for the pension and other postretirement benefit plans.

1 Mutual funds classified as Level 1 securities have pricing inputs that are based on unadjusted prices in an active market. Principal markets for equity prices include published exchanges such as NASDAQ and New York Stock Exchange (NYSE). Mutual fund assets not included in the fair value hierarchy are privately held funds. These funds are not actively traded and utilize net asset value (NAV) as a practical expedient to measure fair value.

1 Common stock investments are traded in active markets on national and international securities exchanges and are valued at closing prices on the last business day of each period presented. They are classified as Level 1 securities.

1 Corporate and some government debt securities are valued using pricing models maximizing the use of observable inputs for similar securities. This includes basing value on yields currently available on comparable securities of issuers with similar credit ratings. Some government debt securities have quoted prices such as certain treasury securities and are classified as Level 1 securities.

1 Cash and cash equivalents comprise mostly of money market funds and foreign currency held. Money market funds are classified as Level 1 instruments as pricing inputs are based on unadjusted prices in an active market while foreign currency held is classified as a Level 2 investment based on inputs that are indirectly observable.

1 Investments in collective trust funds and partnerships are stated at the NAV as determined by the issuer of fund and are based on the fair value of the underlying investments held by the fund less its liabilities. The NAV is used as a practical expedient to estimate fair value. These funds are primarily invested in a blend of corporate and government debt securities as well as international equities.

(13) Income Taxes

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

Puget Sound Energy	Year Ended December 31,	
(Dollars in Thousands)	2020	2019
Charged to operating expenses:		
Current:		
Federal	$ 10,607	$ 18,093
State	383	570
Deferred:		
Federal	15,377	20,628
State	—	—
Total income tax expense	$ 26,367	$ 39,291

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

Puget Sound Energy	Year Ended December 31,	
(Dollars in Thousands)	2020	2019
Income taxes at the statutory rate	$ 63,110	$ 69,735
Increase (decrease):		
Utility plant differences[1]	$ (22,991)	$ (23,025)
AFUDC, net	(6,095)	(4,462)
Executive Compensation	2,440	2,596
Treasury grant amortization	(8,935)	(7,870)
Tax reform	(3,038)	—
Other–net	1,876	2,317
Total income tax expense	$ 26,367	$ 39,291
Effective tax rate	8.8 %	11.8 %

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 $27.6 million in 2020, and 2019, respectively.*

The Company's net deferred tax liability at December 31, 2020, and 2019, is composed of amounts related to the following types of temporary differences:

Puget Sound Energy	Year Ended December 31,	
(Dollars in Thousands)	2020	2019
Utility plant and equipment	$ 1,923,933	$ 1,943,730
Other, net deferred tax liabilities	55,856	50,095
Subtotal deferred tax liabilities	1,979,789	1,993,825
Net regulatory liability for income taxes	(953,987)	(946,936)
Production tax credit carryforward	(35,995)	(67,405)
Subtotal deferred tax assets	(989,982)	(1,014,341)

Total net deferred tax liabilities	$ 989,807	$ 979,484

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.

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.

As of December 31, 2020, and 2019, 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 evaluated the treatment of protected excess deferred income taxes (EDIT) required under Washington Commission Order 08 for compliance with the IRS normalization rules. The Order requires ratemaking and accounting treatment for the EDIT that is different than the treatment afforded prior income tax rate changes. The Company has requested a private letter ruling from the IRS in which it asks the IRS to confirm that the treatment required in the Order complies with the normalization rules. The Company anticipates that the ruling will have no impact on its current or deferred income taxes. If the Company, receives an adverse ruling, it could result in an increase to the revenue requirement of $25.6 million. The Company expects a ruling during 2021.

The Company has open tax years from 2017 through 2020. 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 2019 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 have retained its obligation to fund 25% of the environmental remediation and decommissioning costs associated with Unit 4 during PSE's operation. The proposed agreement was subject to approval by the Washington Commission and the Montana Public Service Commission. Additionally, PSE had 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.

On August 14, 2020, an amendment to the agreement was executed selling a portion of PSE’s interest in Colstrip Unit 4 to Talen, in addition to NorthWestern Energy. However, after evaluating the likelihood of the regulatory approval process in both Washington and Montana, on October 29, 2020, PSE, NorthWestern Energy, and Talen mutually agreed to terminate the proposed sales agreement and the proposed power purchase agreement and relieve all claims against one another arising out of or relating to the sale agreement. The termination of the proposed sale and proposed PPA resulted in the withdrawal of PSE's filing with the Washington Commission. Colstrip 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, as a replacement to the CPP rule. The ACE rule, along with the repeal of the CPP rule, were finalized in June 2019, and establish emission guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired plants. On January 19, 2021 the U.S. Court of Appeals for the District of Columbia Circuit (D.C. Circuit) vacated the ACE rule and remanded the record back to the Agency for further consideration consistent with its opinion, finding that misinterpreted the Clean Air Act. PSE is evaluating this vacatur to determine impact on operations.

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 Washington State 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. The Department of Ecology and the four parties asked Thurston County to stay this case until the 2020 Washington State legislative session concluded and now the Department of Ecology plans to ask the court to extend the stay until the COVID-19 pandemic is over. Meanwhile, the four companies moved to voluntarily dismiss the federal court litigation without prejudice in March 2020.

(15) Commitments and Contingencies

For the year ended December 31, 2020, approximately 15.3% of the Company’s energy output was obtained at an average cost of approximately $0.031 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)	2020	2019
PUD contract costs	$ 116,874	$ 87,135

As of December 31, 2020, 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 2021 Costs	2021 Debt Service Costs	Interest included in 2021 Debt Service Costs	Debt Outstanding
Chelan County PUD:							
Rock Island Project	2031	25.0 %	156	$ 34,895	$ 11,314	$ 5,365	$ 91,674
Rocky Reach Project	2031	25.0	325	30,400	4,518	1,960	30,476
Douglas County PUD:							
Wells Project[1]	2028	24.2	203	37,584	—	—	—
Grant County PUD:							
Priest Rapids Development	2052	0.6	6	1,440	773	389	9,761
Wanapum Development	2052	0.6	7	1,440	773	389	9,761
Total			697	$ 105,759	$ 17,378	$ 8,103	$ 141,672

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)	2021	2022	2023	2024	2025	Thereafter	Total
Columbia River projects	$ 117,664	$ 101,421	$ 100,222	$ 99,473	$ 99,393	$ 499,808	$ 1,017,981

Electric portfolio contracts	299,705	332,444	349,119	356,976	277,250	1,343,699	2,959,193
Electric wholesale market transactions	117,444	21,660	11,540	11,692	11,616	11,616	185,568
Total	$ 534,813	$ 455,525	$ 460,881	$ 468,141	$ 388,259	$ 1,855,123	$ 4,162,742

Total purchased power contracts provided the Company with approximately 13.2 million and 12.5 million MWhs of firm energy at a cost of approximately $491.7 million and $550.6 million for the years 2020 and 2019, respectively.

Clearwater PPA

In February 2021, PSE entered into a PPA with Clearwater Energy Resources LLC to purchase up to 350 MW of wind energy and renewable attributes over a 20 year term beginning in November 2022. The expected payment obligations for power purchases from this contract are summarized in the following table:

(Dollars in Thousands)	2022	2023	2024	2025	2026	Thereafter	Total
Expected payment obligation	$2,430	$34,541	$34,541	$34,541	$34,541	$550,228	$690,822

Natural Gas Supply Obligations

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 to 24 years, provide that the Company must pay a fixed demand charge each month, regardless of actual usage. The Company incurred demand charges for 2020 for firm transportation, storage and peaking services for its natural gas customers of $135.8 million. The Company incurred demand charges in 2020 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)	2021	2022	2023	2024	2025	Thereafter	Total
Natural gas wholesale market transactions	$ 327,775	$ 210,736	$ 155,778	$ 116,016	$ 59,483	$ —	$ 869,788
Firm transportation service	174,912	172,431	163,662	129,503	113,051	804,103	1,557,662

Firm storage service	8,899	8,899	2,270	67	67	56	20,258
Total	$ 511,586	$ 392,066	$ 321,710	$ 245,586	$ 172,601	$ 804,159	$2,447,708

Service Contracts

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

Service Contract Obligations (Dollars in Thousands)	2021	2022	2023	2024	2025	Thereafter	Total
Energy production service contracts	$29,710	$30,423	$31,155	$31,921	$32,177	$105,579	$260,965
Automated meter reading system	45,489	46,436	47,498	47,505	48,229	49,077	284,234
Total	$75,199	$76,859	$78,653	$79,426	$80,406	$154,656	$545,199

Other Commitments and Contingencies

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

(16) 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. Following a mediation process and the filing of a settlement stipulation by PSE and all parties, the Washington Commission issued an order on October 31, 2016, that allowed PSE's parent company, Puget Energy, to create a wholly-owned subsidiary, named Puget LNG, which was formed on November 29, 2016, for the sole purpose of owning, developing and financing the non-regulated activity of the Tacoma LNG facility. Puget LNG has entered into one fuel supply agreement with a maritime customer and is marketing the facility's expected output to other potential customers.

The Tacoma LNG facility is currently under construction. Pursuant to the Washington Commission's order, PSE will be allocated 43.0% of the capital and operating costs of the Tacoma LNG facility. PSE and Puget LNG are considered related parties with similar ownership by Puget Energy. Therefore, capital and operating costs that occur under PSE and are allocated to Puget LNG are related party transactions by nature. Per this allocation of costs, $207.7 million of construction work in progress 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, 2020, as PSE is a regulated entity. The portion of the Tacoma LNG facility allocated to PSE will be subject to regulation by the Washington Commission.

(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, 2020 and 2019, respectively:

Puget Sound Energy	Net unrealized gain (loss) and prior service cost on pension plans	Net unrealized gain (loss) on treasury interest rate swaps	Total
Changes in AOCI, net of tax			
(Dollars in Thousands)			
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)
Other comprehensive income (loss) before reclassifications	(8,717)	—	(8,717)

Amounts reclassified from accumulated other comprehensive income (loss), net of tax	15,853	385	16,238
Net current-period other comprehensive income (loss)	7,136	385	7,521
Balance at December 31, 2020	$ (175,972)	$ (4,984)	$ (180,956)

Details about the reclassifications out of AOCI (loss) for the years ended December 31, 2020 and 2019, 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) 2020	2019
Net unrealized gain (loss) and prior service cost on pension plans:			
Amortization of prior service cost	(a)	$ 1,224	$ 1,240
Amortization of net gain (loss)	(a)	(21,291)	(14,048)
	Total before tax	$ (20,067)	$ (12,808)
	Tax (expense) or benefit	4,214	2,690
	Net of tax	$ (15,853)	$ (10,118)
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	$ (16,238)	$ (10,503)

(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	04/15/2021	End of 2020/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		(185,146,150)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income		10,118,075		
3	Preceding Quarter/Year to Date Changes in Fair Value		(8,095,354)		
4	Total (lines 2 and 3)		2,022,721		
5	Balance of Account 219 at End of Preceding Quarter/Year		(183,123,429)		
6	Balance of Account 219 at Beginning of Current Year		(183,123,429)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income		15,852,757		
8	Current Quarter/Year to Date Changes in Fair Value		(8,716,230)		
9	Total (lines 7 and 8)		7,136,527		
10	Balance of Account 219 at End of Current Quarter/Year		(175,986,902)		

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	04/15/2021	End of 2020/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	(5,738,713)		(190,884,863)		
2	385,239		10,503,314		
3			(8,095,354)		
4	385,239		2,407,960	292,921,676	295,329,636
5	(5,353,474)		(188,476,903)		
6	(5,353,474)		(188,476,903)		
7	385,238		16,237,995		
8			(8,716,230)		
9	385,238		7,521,765	274,280,295	281,802,060
10	(4,968,236)		(180,955,138)		

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	04/16/2021	End of 2020/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)	15,525,534,920	10,098,262,140
4	Property Under Capital Leases	173,048,588	
5	Plant Purchased or Sold		
6	Completed Construction not Classified	384,793,885	234,046,693
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	16,083,377,393	10,332,308,833
9	Leased to Others		
10	Held for Future Use	46,081,282	38,707,048
11	Construction Work in Progress	712,204,459	381,595,894
12	Acquisition Adjustments	282,791,675	282,791,675
13	Total Utility Plant (8 thru 12)	17,124,454,809	11,035,403,450
14	Accum Prov for Depr, Amort, & Depl	6,638,902,173	4,457,465,879
15	Net Utility Plant (13 less 14)	10,485,552,636	6,577,937,571
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	6,068,762,320	4,232,191,897
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	415,067,740	70,201,869
22	Total In Service (18 thru 21)	6,483,830,060	4,302,393,766
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	154,909,688	154,909,688
33	Total Accum Prov (equals 14) (22,26,30,31,32)	6,638,902,173	4,457,465,879

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
4,380,638,189				1,046,634,591	3
				173,048,588	4
					5
127,004,027				23,743,165	6
					7
4,507,642,216				1,243,426,344	8
					9
7,374,234					10
262,747,644				67,860,921	11
					12
4,777,764,094				1,311,287,265	13
1,711,590,160				469,846,134	14
3,066,173,934				841,441,131	15
					16
					17
1,690,779,506				145,790,917	18
					19
					20
20,810,654				324,055,217	21
1,711,590,160				469,846,134	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
1,711,590,160				469,846,134	33

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	04/15/2021	2020/Q4

FOOTNOTE DATA

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, 2020, 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	04/15/2021	End of 2020/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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	58,463,284	81,654
4	(303) Miscellaneous Intangible Plant	72,040,213	3,418,582
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	130,617,699	3,500,236
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	2,788,745	
9	(311) Structures and Improvements	136,290,598	1,662,672
10	(312) Boiler Plant Equipment	526,749,791	7,152,266
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	280,729,774	3,559,223
13	(315) Accessory Electric Equipment	36,594,679	1,587,080
14	(316) Misc. Power Plant Equipment	7,590,052	2
15	(317) Asset Retirement Costs for Steam Production	44,880,991	31,665,367
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,035,624,630	45,626,610
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	10,889,375	
28	(331) Structures and Improvements	166,442,336	200,170
29	(332) Reservoirs, Dams, and Waterways	359,893,018	1,646,304
30	(333) Water Wheels, Turbines, and Generators	129,118,704	763,764
31	(334) Accessory Electric Equipment	45,890,982	
32	(335) Misc. Power PLant Equipment	16,380,475	83,333
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)	733,659,952	2,693,571
36	D. Other Production Plant		
37	(340) Land and Land Rights	16,016,762	
38	(341) Structures and Improvements	131,668,918	448,118
39	(342) Fuel Holders, Products, and Accessories	26,142,874	120,083
40	(343) Prime Movers		
41	(344) Generators	1,572,082,649	46,783,427
42	(345) Accessory Electric Equipment	153,561,011	1,853,077
43	(346) Misc. Power Plant Equipment	20,787,618	242,506
44	(347) Asset Retirement Costs for Other Production	53,575,909	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	1,973,835,741	49,447,211
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	3,743,120,323	97,767,392

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	59,900,709	3,953,436
49	(352) Structures and Improvements	12,203,052	
50	(353) Station Equipment	704,880,585	4,720,056
51	(354) Towers and Fixtures	92,111,430	
52	(355) Poles and Fixtures	405,243,960	4,951,901
53	(356) Overhead Conductors and Devices	320,430,706	9,747,053
54	(357) Underground Conduit	1,210,859	
55	(358) Underground Conductors and Devices	36,956,731	
56	(359) Roads and Trails	2,306,140	
57	(359.1) Asset Retirement Costs for Transmission Plant	2,391,382	-790,744
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	1,637,635,554	22,581,702
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	40,733,248	2,142,823
61	(361) Structures and Improvements	8,102,681	38,744
62	(362) Station Equipment	481,258,749	20,007,384
63	(363) Storage Battery Equipment	1,209,753	362
64	(364) Poles, Towers, and Fixtures	413,597,608	37,264,259
65	(365) Overhead Conductors and Devices	515,575,430	41,810,417
66	(366) Underground Conduit	780,282,029	25,331,666
67	(367) Underground Conductors and Devices	1,055,579,092	49,631,069
68	(368) Line Transformers	518,717,150	25,637,351
69	(369) Services	192,426,095	3,549,005
70	(370) Meters	231,458,479	45,749,206
71	(371) Installations on Customer Premises	228,919	593,340
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	60,115,592	1,682,767
74	(374) Asset Retirement Costs for Distribution Plant	3,234,995	3,128,637
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	4,302,519,820	256,567,030
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	5,095,530	
87	(390) Structures and Improvements	67,906,657	-553,439
88	(391) Office Furniture and Equipment	24,513,319	3,944,802
89	(392) Transportation Equipment	11,143,678	345,634
90	(393) Stores Equipment	170,597	
91	(394) Tools, Shop and Garage Equipment	15,701,877	3,740,291
92	(395) Laboratory Equipment	8,234,370	71,173
93	(396) Power Operated Equipment	4,744,125	233,282
94	(397) Communication Equipment	97,181,307	5,112,506
95	(398) Miscellaneous Equipment	314,613	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	235,006,073	12,894,249
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)	235,006,073	12,894,249
100	TOTAL (Accounts 101 and 106)	10,048,899,469	393,310,609
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)	10,048,899,469	393,310,609

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Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			114,202		2
66,058			58,478,880		3
1,305,920		340,638	74,493,513		4
1,371,978		340,638	133,086,595		5
					6
					7
-1,006,168		-1,006,168	2,788,745		8
573,014			137,380,256		9
813,552		-7,248,346	525,840,159		10
					11
22,482			284,266,515		12
11,037			38,170,722		13
			7,590,054		14
29,663,425			46,882,933		15
30,077,342		-8,254,514	1,042,919,384		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
		-402	10,888,973		27
			166,642,506		28
			361,539,322		29
36,654			129,845,814		30
			45,890,982		31
			16,463,808		32
			5,045,062		33
					34
36,654		-402	736,316,467		35
					36
			16,016,762		37
24,324			132,092,712		38
			26,262,957		39
					40
15,085,568			1,603,780,508		41
819,965			154,594,123		42
			21,030,124		43
			53,575,909		44
15,929,857			2,007,353,095		45
46,043,853		-8,254,916	3,786,588,946		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
		-5,552	63,848,593		48
324,878			11,878,174		49
9,415,799			700,184,842		50
			92,111,430		51
108,853			410,087,008		52
			330,177,759		53
			1,210,859		54
			36,956,731		55
			2,306,140		56
			1,600,638		57
9,849,530		-5,552	1,650,362,174		58
					59
		-1,707	42,874,364		60
			8,141,425		61
3,622,450			497,643,683		62
			1,210,115		63
2,708,493			448,153,374		64
5,263,774			552,122,073		65
1,578,525			804,035,170		66
4,573,361			1,100,636,800		67
3,946,867			540,407,634		68
208,538			195,766,562		69
15,668,977			261,538,708		70
			822,259		71
					72
12,329			61,786,030		73
			6,363,632		74
37,583,314		-1,707	4,521,501,829		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		4,991	5,100,521		86
			67,353,218		87
1,480,933			26,977,188		88
1,949,839			9,539,473		89
			170,597		90
			19,442,168		91
263,054			8,042,489		92
			4,977,407		93
3,408,925			98,884,888		94
33,273			281,340		95
7,136,024		4,991	240,769,289		96
					97
					98
7,136,024		4,991	240,769,289		99
101,984,699		-7,916,546	10,332,308,833		100
					101
					102
					103
101,984,699		-7,916,546	10,332,308,833		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					
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44					
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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	04/15/2021	End of 2020/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	751,377
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	12/31/2021	2,233,975
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	1/1/2030	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				
21	Other Property:			
22	OTHER PROPERTY (less than $250,000)			516,707
23				
24	Land and Rights: (continued)			
25	INTANGIBLE E303 - LOWER SNAKE RIVER WIND	3/31/2014	12/31/2024	22,243,546
26				
27				
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42				
43				
44				
45				
46				
47	Total			38,707,048

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	04/15/2021	End of 2020/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	ADMS-Distribution Management System	20,244,936
2	AMI Project	
3	Bainbridge Project	6,734,525
4	Baker Project	44,759,575
5	Berrydale-Krain Transmission Line Project	1,368,731
6	Bremerton-Bangor Project	1,455,918
7	Eastside Transmission Project	88,876,253
8	Fredonia Project	3,777,562
9	Greenwater Tap Project	1,533,924
10	Lakeside-Ardmore Project	
11	Other Misc. Work Orders	
12	Phantom Lake - Lake Hills Project	2,058,635
13	Residential Electric Vehicle Project	
14	Sammamish-Moorlands Project	10,091,586
15	Sedro-Bellingham Project	3,835,119
16	Skookumchuck Wind Farm Project	
17	Woodland - St Clair Project	3,092,616
18		
19	CWIP less than $1,000,000 each - Electric Distribution	111,472,068
20	CWIP less than $1,000,000 each - Electric Transmission	43,542,809
21	CWIP less than $1,000,000 each - Electric General Plant & Intangibles	24,995,486
22	CWIP less than $1,000,000 each - Electric Generation	11,934,493
23	WSDOT	1,821,658
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	381,595,894

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	3,994,578,142	3,994,415,717	162,425	
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	322,189,363	322,189,363		
4	(403.1) Depreciation Expense for Asset Retirement Costs	-33,150,634	-33,150,634		
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)	289,038,729	289,038,729		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	102,239,471	102,239,471		
13	Cost of Removal	29,220,591	29,220,591		
14	Salvage (Credit)	-333,170	-333,170		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	131,793,232	131,793,232		
16	Other Debit or Cr. Items (Describe, details in footnote):	80,530,683	80,530,683		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	4,232,354,322	4,232,191,897	162,425	
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	755,849,822	755,849,822		
21	Nuclear Production				
22	Hydraulic Production-Conventional	219,100,903	219,100,903		
23	Hydraulic Production-Pumped Storage				
24	Other Production	912,501,675	912,501,675		
25	Transmission	569,727,297	569,727,297		
26	Distribution	1,676,691,397	1,676,691,397		
27	Regional Transmission and Market Operation				
28	General	98,483,228	98,483,228		
29	TOTAL (Enter Total of lines 20 thru 28)	4,232,354,322	4,232,354,322		

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	04/15/2021	2020/Q4

FOOTNOTE DATA

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

The 2017 General Rate Case on Dockets UE-170033 and UG-170034, approved by the WUTC, instructed the company to repurpose Federal hydro grants and production tax credits ("PTCs") to offset certain Colstrip costs (unrecovered plant, decommissioning and remediation cost and Colstrip transition fund) and to move the balances to 108 FERC accounts. This balance represents the use of the repurposed PTCs and hydro grants to offset incurred costs related to Colstrip. In addition, Other debit and credit items includes manual adjustments to comply with the referenced docket.

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.	5/31/1960		
2	Common			10,200
3	Retained Earnings			-20,292,289
4	Additional Paid in Capital			47,237,244
5	Subtotal			26,955,155
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
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41				
42	Total Cost of Account 123.1 $ 1,817,902		TOTAL	26,955,155

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
-467,098		-20,759,387		3
2,285,000		49,522,244		4
1,817,902		28,773,057		5
				6
				7
				8
				9
				10
				11
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				41
1,817,902		28,773,057		42

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	04/15/2021	End of 2020/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)	15,762,779	16,627,794	
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)	99,932,988	100,276,846	
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	3,821,990	4,168,351	Electric & Gas
8	Transmission Plant (Estimated)	571,263	661,860	Electric & Gas
9	Distribution Plant (Estimated)	9,104,743	10,345,436	Electric & Gas
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	2,124,134	2,463,050	Electric & Gas
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	115,555,118	117,915,543	Electric & Gas
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	32,795	133,577	Electric & Gas
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	-208,479	11,207	Electric & Gas
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	131,142,213	134,688,121	

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	04/15/2021	2020/Q4

FOOTNOTE DATA

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.

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)	2021 No. (d)	2021 Amt. (e)
1	Balance-Beginning of Year	77,704.00	335,928	9,034.00	
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	144,500		
10					
11	Transfer: Talen MT	-3,292.00			
12	Initial Allocation to PSE				
13					
14					
15	Total	6,708.00	144,500		
16					
17	Relinquished During Year:				
18	Charges to Account 509	27.00			
19	Other:				
20	California Carbon Allowas	4,263.00	73,537		
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	80,122.00	406,891	9,034.00	
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	4,722.00			
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA	354.00			
39	Cost of Sales				
40	Balance-End of Year	4,368.00			
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)		4		
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2022		2023		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
9,029.00		9,034.00		234,981.00		339,782.00	335,928	1
								2
								3
								4
								5
								6
								7
								8
						10,000.00	144,500	9
								10
				5,324.00		2,032.00		11
				3,686.00		3,686.00		12
								13
								14
				9,010.00		15,718.00	144,500	15
								16
								17
						27.00		18
								19
						4,263.00	73,537	20
								21
								22
								23
								24
								25
								26
								27
								28
9,029.00		9,034.00		243,991.00		351,210.00	406,891	29
								30
								31
								32
								33
								34
								35
						4,722.00		36
								37
						354.00		38
								39
						4,368.00		40
								41
								42
							4	43
								44
								45
								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	04/15/2021	2020/Q4

FOOTNOTE DATA

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

Plant	12/31/19 Estimated Balance of Withheld Allowances Yrs 2009-2025	Estimated EPA Withheld Allowances Sold During 2020	12/31/20 Estimated Balance of Withheld Allowances Yrs 2009-2025
Colstrip Unit 1	1106	145	961
Colstrip Unit 2	1081	144	937
Colstrip Unit 3	694	36	658
Colstrip Unit 4	1841	29	1812
	4722	354	4368

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

2020 proceeds from sales of allowances withheld by the Environmental Protection Agency were as follows:

Plant	2020 Proceeds
Colstrip Unit 1	1.45
Colstrip Unit 2	1.44
Colstrip Unit 3	0.36
Colstrip Unit 4	0.29
Total Proceeds	3.54

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)	2021 No. (d)	2021 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	04/15/2021	End of 2020/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.

2022		2023		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
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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	04/15/2021	End of 2020/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	36,469,729		407	11,776,485	24,693,244
2	2015 Storm	9,302,743		407	9,302,743	
3	2016 Storm	10,437,020		407	3,505,402	6,931,618
4	2017 Storm Excess Costs	12,707,858				12,707,858
5	2017 Storm Recovery	12,215,519				12,215,519
6	2018 Storm Excess Costs	12,247,269				12,247,269
7	2019 Storm Excess Costs	28,513,473				28,513,473
8	2020 Storm Excess Costs		11,182,144			11,182,144
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20	TOTAL	121,893,611	11,182,144		24,584,630	108,491,125

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	04/15/2021	End of 2020/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		403, 187	-15,577,404	110,972,219
22	Contra PTCs Monetized for Unrec P	-82,224,443		108	-28,747,776	-110,972,219
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49	TOTAL	44,325,180			-44,325,180	

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	04/15/2021	2020/Q4

FOOTNOTE DATA

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 occurring 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. Per the 2019 GRC order, PSE’s rates no longer include depreciation expense for Colstrip Units 1&2, therefore all depreciation related to Colstrip Units 1&2 should cease being recorded effective on the eventual rate effective date for electric (pro-rated for October).

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). Per the 2019 GRC order, PSE’s rates no longer include depreciation expense for Colstrip Units 1&2, therefore all depreciation related to Colstrip Units 1&2 should cease being recorded effective on the eventual rate effective date for electric (pro-rated for October).

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	04/15/2021	End of 2020/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	n/a				
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21	**Generation Studies**				
22	Grays Harbor Feasibility Study	8,389	186051048		
23	Maria Energy Storage Phase 1	250	186052891		
24	Wenatchee Solar Facilities Study	575	186053554		
25	Fresh Aire Facilities Study	1,021	186054033		
26	Grays Harbor Facilities Study	1,011	186056890		
27	Stony Lake 200MW Bttry Strg FacSty	33,526	186056891		
28	Energy Strg Resrc Feasibility Sty	1,062	186057224		
29	Energy Strg Resrc Sys Impct Sty	85	186057790		
30	Leprechaun Solr 250MW SysImpct Sty	7,994	186057981		
31	South Hill Enrgy StrgSys Impct Sty	4,100	186057982		
32	Logjam 100MW Bttry Strg Feas Sty	10,449	186058369		
33	Spire 100MW Bttry Strg Feas Sty	13,328	186058370		
34	Energy Strg Rescr Facilities Sty	8,880	186058571		
35	Steelhead Feasibility Study	6,177	186058590		
36					
37					
38					
39	Generation Studies Total	97,147			
40	Grand Total	97,147			

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	04/15/2021	End of 2020/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Unamortized Energy Conservation Costs	25,272,250	241,359,031	182.3, 908	258,621,828	8,009,453
2	WUTC Deferred AFUDC	57,553,295	5,049,363	406	2,839,505	59,763,153
3	Colstrip 1&2 Western Energy Coal Reserve - 10 years	2,565,332	52,533,703	501, 406	576,479	54,522,556
4	Colstrip Deferred Depreciation - 17.5 years	622,429		406	138,804	483,625
5	Environmental Remediation Costs	30,516,287	15,387,073	Multiple	19,680,524	26,222,836
6	Property Tax Tracker	22,442,303	39,873,518	408	37,455,656	24,860,165
7	Decoupling Mechanism	43,509,129	177,674,777	Multiple	124,677,130	96,506,776
8	Low Income Home Energy Assistance Program	1	27,330,384	108, 253	27,330,384	1
9	Power Cost Adjustment Mechanism	41,744,976	87,170,453	557, 419	46,114,601	82,800,828
10	White River Regulatory Assets - 3 years	6,398,912		182.3, 407	6,395,132	3,780
11	Chelan PUD - 20 years	83,875,443		555	7,088,066	76,787,377
12	Mint Farm Deferral - 15 years	14,980,283		407.3	2,885,052	12,095,231
13	Lower Snake River Deferral - 25 years	67,694,566		253, 407.3	4,733,855	62,960,711
14	Credit Card Fee Deferral - 3 years	861,608	326,762	182.3, 407	1,188,370	
15	WUTC AMI and Electric Vehicle Deferral	14,162,763	65,784,468	Multiple	8,683,978	71,263,253
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44	TOTAL	412,199,577	712,489,532		548,409,364	576,279,745

Name of Respondent Puget Sound Energy, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

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-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.: 15 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	04/15/2021	End of 2020/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	2,048,905	26,902	186,253	1,024,850	1,050,957
2	Carbon Offset Program		13,174,119	253	52,533,703	-39,359,584
3	Damage Claims	4,517,228	13,068,674	186	13,627,454	3,958,448
4	Clearing Account Charges	5,181,408	687,262	184,186	5,483,755	384,915
5	FAS133 Net Unrealized		43,167,303	244	43,167,303	
6	Chelan Prepayments - 20 Yrs	5,877,077	271,676	555	643,972	5,504,781
7	Ferndale Maintenance - 12 Yrs	1,803,708		553	240,494	1,563,214
8	Encogen Maintenance - 10 Yrs	7,525,876		553	1,172,145	6,353,731
9	Environmental Remediation Exp	37,969,867	49,788,224	186,228	11,333,914	76,424,177
10	Real Estate Operating Leases -	7,549,261	772,252	Various	16,135	8,305,378
11	FSAS 71 - Snoqualmie License	7,442,314		253	7,562	7,434,752
12	Baker Article	4,759,765	4,362	242	457,521	4,306,606
13	SFAS 71 - Baker License	56,426,750	718,239	253	2,791,351	54,353,638
14	Colstrip Maintenance - 3 Yrs	2,936,909	3,819,766	Various	2,413,925	4,342,750
15	AMI	3,295,137	13,199,657	Various	7,756,602	8,738,192
16	Fredonia Maintenance - 9 Yrs	7,200,776	9,261	553	1,042,482	6,167,555
17	Fredrickson Maintenance - 7 Yrs	3,549,360		513,553	862,291	2,687,069
18	Goldendale Maintenance 4-8 Yrs	1,698,301		514,553	694,251	1,004,050
19	Whitehorn Maintenance - 6 Yrs	1,796,180		186,553	483,577	1,312,603
20	Mint Farm Maintenance - 3-7 Yrs	1,052,168	269,143	513,553	353,038	968,273
21	Sumas Maintenance - 11 Yrs	2,856,306		553	322,721	2,533,585
22	Non-Temp Facility	7,785,798	16,464,910	186	12,360,364	11,890,344
23	Residential Exchange	6,397,663	56,287,964	253	55,545,802	7,139,825
24	GTZ Depreciation	22,148,375	44,031,941	186	63,392,272	2,788,044
25	Minor Items	3,610,957	17,657,971	186,456	13,788,406	7,480,522
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47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	205,430,089				187,333,825

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	04/15/2021	End of 2020/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	611,977,826	121,616,293
3	Production Tax Credit	67,404,994	35,994,092
4	Pension and Other Compensation	69,624,102	61,553,262
5	Regulatory Assets	58,549,953	56,562,069
6	Derivative Instruments	10,487,446	13,487,589
7	Other	31,932,404	31,829,254
8	TOTAL Electric (Enter Total of lines 2 thru 7)	849,976,725	321,042,559
9	Gas		
10	SFAS 109	334,958,136	34,745,948
11	Derivative Instruments	2,388,606	4,048,074
12	Pension and Other Compensation	3,905,229	3,480,808
13	Regulatory Assets	1,477,679	132,755
14			
15	Other	3,315,534	1,986,733
16	TOTAL Gas (Enter Total of lines 10 thru 15	346,045,184	44,394,318
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	1,196,021,909	365,436,877

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	04/15/2021	End of 2020/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	
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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
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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

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	04/15/2021	End of 2020/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Account 214 - Common Stock Expense	7,133,879
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20		
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)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
12/22/97	12/01/27	12/22/97	12/01/27	300,000,000	21,060,000	3
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	14,625,000	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	225,480,690	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	226,697,190	33

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	04/15/2021	2020/Q4

FOOTNOTE DATA

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 (Total line 33, column 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)	274,280,295
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	26,367,331
11	Others	101,406,328
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	-201,969,193
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	200,084,761
28	Show Computation of Tax:	
29		
30	Taxable Income	200,084,761
31	Tax @21%	42,017,800
32	PTC	-31,410,902
33	Current Federal Tax	10,606,898
34	Current State Tax	383,340
35	Deferred Tax	15,377,093
36	Total Tax	26,367,331
37		
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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	04/15/2021	2020/Q4

FOOTNOTE DATA

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

Capitalized Interest	11,236,537
Conservation Activity	17,262,798
Derivative Instruments	26,807,229
Environmental Costs	6,712,565
Non-Deductible Items	3,986,712
Property Tax Rate Tracker	728,243
Other Adjustment	21,269,757
Storm Related Activity	13,402,487
Subtotal	101,406,328

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

Allowance for Funds Used During Construction	(40,259,694)
Decoupling Revenue	(21,554,591)
Electric and Gas Purchase Contracts	(17,773,637)
Plant Related	(5,564,119)
Pensions and Other Compensation	(9,139,369)
Regulatory Assets	(65,131,206)
Treasury Grant Amortization	(42,546,578)
Subtotal	(201,969,194)
Total Adjustments to Tax Expense	(100,562,866)

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)	BALANCE AT BEGINNING OF YEAR: Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1						
2	Income	-712,472		10,990,238	-11,561,702	-314,477
3	Employment	418,347		26,429,449	-26,846,284	
4	Other					
5						
6						
7	Property	63,183,481		75,115,012	-70,426,758	-162,559
8	Excise	16,978,697		120,224,242	-117,117,812	-140,691
9	Municipal	18,779,311		122,265,500	-122,751,814	
10	Other	964,183		9,684,644	-9,784,579	314,477
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41	TOTAL	99,611,547		364,709,085	-358,488,949	-303,250

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-1,598,413		46,951,001			-35,960,763	2
1,512		8,498,657			17,930,792	3
						4
						5
						6
67,709,176		54,316,257			20,798,756	7
19,944,436		81,665,533			38,558,709	8
18,292,997		79,625,628			42,639,871	9
1,178,725		1,745,628			7,939,016	10
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105,528,433		272,802,704			91,906,381	41

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)						
10							
11							
12							
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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	04/15/2021	End of 2020/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
			3
			4
			5
			6
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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	04/15/2021	End of 2020/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Deferred Comp - Salary	8,478,766	Various	3,027,743	3,553,515	9,004,538
2	SFAS 106 Unfunded Liability	34,446,862	417	27,604,289	7,581,327	14,423,900
3	Low Income Program	27,278,861	Various	42,211,682	43,910,444	28,977,623
4	Sch 85 Line Extension Cost	13,134,990	456	476,573	1,075,722	13,734,139
5	Green Power Tariff	7,660,757	456	3,431,218	2,462,291	6,691,830
6	Landlord Incentives - 5-11 Yrs	9,039,832	931	2,561,897	1,930,448	8,408,383
7	PTC Deferred Post June '10	-2	407		2	
8	Workers Comp - IBNR	2,348,577	186	983,227		1,365,350
9	Residential Exchange		555	189,977,697	189,977,697	
10	Operating Leases Obligation		186			
11	Decoupling	-1	456	19,542,488	27,545,181	8,002,692
12	LSR License O&M - 25 Yrs	9,036,284	Various	9,260,737	8,807,105	8,582,652
13	Snoqualmie License O&M	7,442,314	186	7,562		7,434,752
14	Ferndale License Misc Def - 6 Yrs		186			
15	Baker License Misc Def	56,426,750	186	2,791,351	718,239	54,353,638
16	Unearned Revenue - 11-20 Yrs	3,572,338	454	6,638,167	4,760,516	1,694,687
17	Deferred Pole Contact			8,871,281	8,871,281	
18	PGA Unrealized Gain	2,757,356	175, 244	192,554,556	194,721,765	4,924,565
19	Equity Reserve AMI	1,180,824	419, 186	40,516	2,101,190	3,241,498
20	Montana PTC	67,495,756	Various	124,245,292	95,577,499	38,827,963
21	Unclaimed Property	97,976	131	839,635	849,806	108,147
22	Colstrip 3&4 Final	40,970	131	1,097,360	1,097,591	41,201
23	Mint Farm Misc Def Credit - 15 Yrs	4,661,989	419	884,724		3,777,265
24	Deferred Interchange		555	2,772,928	2,772,928	
25	Tacoma LNG		Various		12,818,652	12,818,652
26	Green Direct Liquidated Damages		143			
27	Microsoft Special Contract Regula					
28	Minor Items	210,650	Various	105,000	565,986	671,636
29	Covid-19 Help		182, 131	26,544,016	42,483,451	15,939,435
30	Microsoft EA		232		928,775	928,775
31	Service Now		232		835,118	835,118
32						
33						
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46						
47	TOTAL	255,311,849		666,469,939	655,946,529	244,788,439

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	04/15/2021	End of 2020/Q4

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

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

Line No.	Account	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(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

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	04/15/2021	End of 2020/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	1,344,468,676	17,681,047	37,698,459
3	Gas	599,261,239	13,670,151	12,798,767
4	Non-Operating		-16,980	633,715
5	TOTAL (Enter Total of lines 2 thru 4)	1,943,729,915	31,334,218	51,130,941
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,943,729,915	31,334,218	51,130,941
10	Classification of TOTAL			
11	Federal Income Tax	1,943,729,915		
12	State Income Tax			
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	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
		various	545,711,896	various	13,063,341	791,802,709	2
		various	232,737,353	various	3,562,979	370,958,249	3
						-650,695	4
			778,449,249		16,626,320	1,162,110,263	5
							6
							7
							8
			778,449,249		16,626,320	1,162,110,263	9
							10
						1,943,729,915	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	04/15/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 274 Line No.: 2 Column: g
Related to Electric FAS 109.

Schedule Page: 274 Line No.: 2 Column: h
Related to Electric FAS 109.

Schedule Page: 274 Line No.: 2 Column: i
Related to Electric FAS 109.

Schedule Page: 274 Line No.: 2 Column: j
Related to Electric FAS 109.

Schedule Page: 274 Line No.: 3 Column: g
Related to Gas FAS 109.

Schedule Page: 274 Line No.: 3 Column: h
Related to Gas FAS 109.

Schedule Page: 274 Line No.: 3 Column: i
Related to Gas FAS 109.

Schedule Page: 274 Line No.: 3 Column: j
Related to Gas FAS 109.

Schedule Page: 274 Line No.: 11 Column: b
Federal Income tax beginning balance changed by -1 for rounding to balance.

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	44,644,169	2,373,191	1,483,223
4	Storm Damage	43,588,848	2,584,606	23,390,318
5	Derivative Instruments	8,489,113	16,099,655	17,392,123
6	Regulatory Assets	88,406,962	38,128,930	44,374,920
7	Other	17,858,960	-3,212,848	5,634,990
8				
9	TOTAL Electric (Total of lines 3 thru 8)	202,988,052	55,973,534	92,275,574
10	Gas			
11	Pension related	5,043,563	1,203,585	752,230
12	Derivative Instruments	2,388,606	20,737,854	19,078,386
13	Regulatory Assets	19,011,952	10,643,118	15,985,840
14	Other	2,343,346	1,187,617	305,667
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	28,787,467	33,772,174	36,122,123
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	231,775,519	89,745,708	128,397,697
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	04/15/2021	End of 2020/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
						45,534,137	3
		various	161,309	various	161,309	22,783,136	4
		various	149,244			7,047,401	5
		various	3,901,222	various	4,007,898	82,267,648	6
						9,011,122	7
							8
			4,211,775		4,169,207	166,643,444	9
							10
						5,494,918	11
						4,048,074	12
		various	1,989,512	various	2,043,858	13,723,576	13
						3,225,296	14
							15
							16
			1,989,512		2,043,858	26,491,864	17
							18
			6,201,287		6,213,065	193,135,308	19
							20
							21
							22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Unamort. Gain from Disposition of Allowance	225	411.8	241	16	
2	Summit Purchase Buyout	1,312,500	456, 495	1,312,500		
3	Renewable Energy Credits	1,417,447	Multiple	6,879,979	5,897,889	435,357
4	Treasury Grants - Wind Project Expansion	879,877	407.4	9,172,184	8,463,347	171,040
5	PTC Cost Deferral	85,322,773	407.3	51,252,319	11,491,685	45,562,139
6	Decoupling Mechanisms	8,500,273	Multiple	48,932,984	56,880,263	16,447,552
7	Regulatory Liability Tax Reform	946,935,959	409	1,012,063,574	9,462,930	-55,664,685
8	Microsoft Special Contract Reg Liability	12,661,278	253, 254	22,759,303	10,098,025	
9	Green Direct Liquidated Damages	2,420,712	143, 254	2,686,721	14,579,288	14,313,279
10	Gain on Sale Shuffleton - Electric	12,482,801	187, 254	12,572,250	60,016	-29,433
11	FAS 109 EDIT Unprotected Gas & Electric		254	3,820,869	49,140,076	45,319,207
12	FAS 109 EDIT Protected Gas & Electric		254	13,098,586	977,431,404	964,332,818
13						
14						
15						
16						
17						
18						
19						
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37						
38						
39						
40						
41	TOTAL	1,071,933,845		1,184,551,510	1,143,504,939	1,030,887,274

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	04/15/2021	2020/Q4

FOOTNOTE DATA

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 expired 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).

Schedule Page: 278 Line No.: 11 Column: a

In the 2019 GRC, paragraph 325 in Order No. 10, the Commission has ordered PSE to defer grossed-up Unprotected EDIT in the amount of $47.9 million for electric and $3.8 million for gas to separate FERC 254 - Other Regulatory Liabilities Accounts. The Commission has also ordered PSE to begin amortizing the balance from these accounts over a period of 3 years, amounting to approximately $16 million for electric and $1.3 million for natural gas per year.

Schedule Page: 278 Line No.: 12 Column: a

For purposes of tracking the Schedule 141X activity, the Tax Department shall create two new FAS 109 (electric and gas) 254 Commission regulatory liability accounts which will represent grossed-up protected EDIT amounts of $1,032,172,942 to be passed back to customers. The total of the two new Commission 254 regulatory liability grossed up PP EDIT balances of $1,032,172,942 will be passed back to customers over several years through Schedule 141X.

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	04/15/2021	End of 2020/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	1,186,013,491	1,139,356,243
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	800,606,511	861,688,507
5	Large (or Ind.) (See Instr. 4)	103,961,314	107,951,534
6	(444) Public Street and Highway Lighting	17,831,939	18,056,669
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	2,108,413,255	2,127,052,953
11	(447) Sales for Resale	148,083,640	197,298,066
12	TOTAL Sales of Electricity	2,256,496,895	2,324,351,019
13	(Less) (449.1) Provision for Rate Refunds	-8,462,662	-14,827,619
14	TOTAL Revenues Net of Prov. for Refunds	2,264,959,557	2,339,178,638
15	Other Operating Revenues		
16	(450) Forfeited Discounts	415,406	2,128,526
17	(451) Miscellaneous Service Revenues	11,508,786	11,894,207
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	15,832,125	17,462,763
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	39,536,390	117,042,184
22	(456.1) Revenues from Transmission of Electricity of Others	26,969,311	28,555,566
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	94,262,018	177,083,246
27	TOTAL Electric Operating Revenues	2,359,221,575	2,516,261,884

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
10,976,067	10,756,628	1,039,596	1,025,024	2
				3
7,942,292	8,837,457	131,009	130,009	4
1,095,916	1,161,149	3,304	3,343	5
73,947	77,996	7,660	7,315	6
				7
				8
				9
20,088,222	20,833,230	1,181,569	1,165,691	10
6,875,538	6,653,074	8	8	11
26,963,760	27,486,304	1,181,577	1,165,699	12
				13
26,963,760	27,486,304	1,181,577	1,165,699	14

Line 12, column (b) includes $ -7,892,330 of unbilled revenues.
Line 12, column (d) includes -239,911 MWH relating to unbilled revenues

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

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

This includes $8,708,550 of transportation revenue

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

This includes $6,778,860 of transportation revenue

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

This includes $2,394,653 of transportation revenue

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

This includes $2,931,137 of transportation revenue

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

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

Schedule 87 Tax Surcharge	5,309,208
Temporary Service Charge	1,105,707
Line Extension Revenue	994,167
Disconnection/Reconnection Charges	1,331,555
Non-Consumption & Consumption Misc. Service Charges	1,828,514
Schedule 73 Conversion	423,292

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

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
Disconnection/Reconnection Charge	1,187,554
Non-Consumption & Consumption Misc. Service Charges	2,155,028

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

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

Decoupling Revenues	22,609,626
Gain/(Loss) on sales or assignment of Non-core Gas	8,661,803
Misc. Other Utility Revenue	7,282,266
Summit Buyout	855,144

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

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

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	04/15/2021	End of 2020/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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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	04/15/2021	End of 2020/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	Residential Sales:					
2	SCH_7AE	2,549	217,780	2	1,274,500	0.0854
3	SCH_7E	11,033,510	1,186,234,828	1,039,594	10,613	0.1075
4	Non-consumption		-274,943			
5	Unbilled	-59,992	-164,174			0.0027
6	Total	10,976,067	1,186,013,491	1,039,596	10,558	0.1081
7						
8	Commercial Sales:					
9	SCH_8E	252,343	27,947,495	30,485	8,278	0.1108
10	SCH_10E	25,575	2,098,515	13	1,967,308	0.0821
11	SCH_11E	133,017	11,663,790	311	427,707	0.0877
12	SCH_12E	16,317	1,409,523	13	1,255,154	0.0864
13	SCH_24EC	2,227,679	245,113,533	89,119	24,997	0.1100
14	SCH_25EC	2,505,567	249,496,326	7,114	352,202	0.0996
15	SCH_26EC	1,526,455	141,828,134	721	2,117,136	0.0929
16	SCH_29E	13,107	1,040,014	606	21,629	0.0793
17	SCH_31EC	754,599	69,132,781	350	2,155,997	0.0916
18	SCH_35E	4,782	261,057	2	2,391,000	0.0546
19	SCH_40EC	88,652	6,924,516	26	3,409,692	0.0781
20	SCH_43E	109,839	10,462,858	147	747,204	0.0953
21	SCH_46EC	20,694	1,436,260	2	10,347,000	0.0694
22	SCH_49EC	418,617	30,088,958	14	29,901,214	0.0719
23	SCH_55E	2,063	599,602	824	2,504	0.2906
24	SCH_56E	1,747	589,888	842	2,075	0.3377
25	SCH_58E	2,130	439,964	305	6,984	0.2066
26	SCH_59E	79	19,226	31	2,548	0.2434
27	Non-consumption		-552,093			
28	Unbilled	-160,970	-8,102,386			0.0503
29	Total	7,942,292	791,897,961	130,925	60,663	0.0997
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	20,312,203	2,116,306,795	0	0	0.1042
42	Total Unbilled Rev.(See Instr. 6)	-223,981	-7,893,540	0	0	0.0352
43	TOTAL	20,088,222	2,108,413,255	0	0	0.1050

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	04/15/2021	End of 2020/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 Sales:					
2	SCH_24EI	80,241	9,004,797	2,643	30,360	0.1122
3	SCH_25EI	156,401	16,429,082	432	362,039	0.1050
4	SCH_26EI	199,960	19,456,903	87	2,298,391	0.0973
5	SCH_31EI	441,247	40,363,897	118	3,739,381	0.0915
6	SCH_40EI	36,106	2,780,861	2	18,053,000	0.0770
7	SCH_46EI	68,770	4,780,880	4	17,192,500	0.0695
8	SCH_49EI	116,456	8,471,511	5	23,291,200	0.0727
9	Non-consumption		-3,061			
10	Unbilled	-3,265	281,792			-0.0863
11	Total	1,095,916	101,566,662	3,291	333,004	0.0927
12						
13	Lighting Sales:					
14	SCH_03E	7	527	1	7,000	0.0753
15	SCH_24EL	10,637	1,240,965	1,117	9,523	0.1167
16	SCH_25EL	1,019	124,423	8	127,375	0.1221
17	SCH_50E	54	5,797	10	5,400	0.1074
18	SCH_51E	2,509	626,604	1,010	2,484	0.2497
19	SCH_52E	12,739	2,473,774	2,331	5,465	0.1942
20	SCH_53E	36,583	12,048,732	3,031	12,070	0.3294
21	SCH_54E	6,643	605,324	48	138,396	0.0911
22	SCH_57E	3,510	499,069	105	33,429	0.1422
23	Non-consumption		-7,449			
24	Unbilled	246	214,173			0.8706
25	Total	73,947	17,831,939	7,661	9,652	0.2411
26						
27	Transportation Sales:					
28	SCH_449EC		5,142	1		
29	SCH_449EI		2,087,260	12		
30	SCH_459EI		434,892	3		
31	SCH_MSOFT		8,698,853	84		
32	Unbilled		-122,945			
33	Total		11,103,202	100		
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	20,312,203	2,116,306,795	0	0	0.1042
42	Total Unbilled Rev.(See Instr. 6)	-223,981	-7,893,540	0	0	0.0352
43	TOTAL	20,088,222	2,108,413,255	0	0	0.1050

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	04/15/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 304 Line No.: 27 Column: a

Excludes $8,579,231 for electric transportation revenues classified on page 300 as (456.1), Revenues from Transmission of Electricity of Others.

Schedule Page: 304.1 Line No.: 27 Column: a

Excludes $8,579,231 for electric transportation revenues classified on page 300 as (456.1), Revenues from Transmission of Electricity of Others.

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	04/15/2021	End of 2020/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	Port of Bremerton	RQ	Sch005	0.132	0.132	0.132
2	Port of Brownsville	RQ	Sch005	0.139	0.139	0.139
3	City of Des Moines	RQ	Sch005	0.195	0.195	0.195
4	Kingston Port District	RQ	Sch005	0.114	0.114	0.114
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	0.097	0.097	0.097
8	Port of Skagit - LaConner Marina	RQ	Sch005	0.079	0.079	0.079
9	Port of Skagit - North Basin	RQ	Sch005	0.132	0.132	0.132
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	OS	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) 04/15/2021	Year/Period of Report End of 2020/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 #9			
2	BC Hydro	OS	FERC #9			
3	Black Hills Power, Inc.	OS	FERC #8			
4	Bonneville Power Administration	AD	FERC #8			
5	Bonneville Power Administration	AD	FERC #9			
6	Bonneville Power Administration	OS	FERC #8			
7	Bonneville Power Administration	OS	FERC #9			
8	BP Energy Company	AD	FERC #8			
9	BP Energy Company	OS	FERC #8			
10	Brookfield Renewable Trading and Marke	OS	FERC #8			
11	California ISO	OS	FERC #8			
12	Chelan County PUD	OS	FERC #8			
13	Chelan County PUD	OS	FERC #9			
14	Citigroup Energy Inc.	OS	FERC #8			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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	City of Roseville	OS	FERC #8			
2	Clatskanie Peoples Utility District	OS	FERC #8			
3	ConocoPhillips Company	OS	FERC #8			
4	DTE Energy Trading	OS	FERC #8			
5	EDF Trading N.A., LLC.	OS	FERC #8			
6	Energy Keepers, Inc.	AD	FERC #8			
7	Energy Keepers, Inc.	OS	FERC #8			
8	Eugene Water & Electric Board	OS	FERC #8			
9	Exelon Generation Company LLC	OS	FERC #8			
10	Grant County PUD No.2	OS	FERC #9			
11	Gridforce Energy Management, LLC.	AD	FERC #8			
12	Gridforce Energy Management, LLC.	OS	FERC #9			
13	Idaho Power Company	OS	FERC #8			
14	Idaho Power Company	OS	FERC #9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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.
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LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Morgan Stanley Capital Group Inc.	AD	FERC #8			
2	Morgan Stanley Capital Group Inc.	OS	FERC #8			
3	NaturEner Power Watch, LLC	AD	FERC #8			
4	NaturEner Power Watch, LLC	OS	FERC #9			
5	NextEra Energy Marketing, LLC	OS	FERC #8			
6	NorthWestern Energy	OS	FERC #8			
7	NorthWestern Energy	OS	FERC #9			
8	P.U.D. No. 1 of Douglas County	AD	FERC #8			
9	P.U.D. No. 1 of Douglas County	OS	FERC #8			
10	P.U.D. No. 1 of Douglas County	OS	FERC #9			
11	P.U.D. No. 1 of Okanogan County	OS	FERC #8			
12	PacifiCorp	AD	FERC #8			
13	PacifiCorp	OS	FERC #8			
14	PacifiCorp	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	04/15/2021	End of 2020/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	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	Portland General Electric Company	AD	FERC #8			
2	Portland General Electric Company	OS	FERC #8			
3	Portland General Electric Company	OS	FERC #9			
4	Powerex Corp.	OS	FERC #8			
5	Public Service Company of Colorado	OS	FERC #8			
6	Rainbow Energy Marketing	OS	FERC #8			
7	Sacramento Municipal Utility District	OS	FERC #8			
8	Sacramento Municipal Utility District	OS	FERC #9			
9	Seattle City Light Marketing	OS	FERC #8			
10	Seattle City Light Marketing	OS	FERC #9			
11	Shell Energy North America (US)	AD	FERC #8			
12	Shell Energy North America (US)	OS	FERC #8			
13	Snohomish County PUD	OS	FERC #8			
14	Tacoma Power	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) 04/15/2021	Year/Period of Report End of 2020/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.
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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	Tacoma Power	OS	FERC #8			
2	Tacoma Power	OS	FERC #9			
3	The Energy Authority	OS	FERC #8			
4	TransAlta Energy Marketing U.S.	AD	FERC #8			
5	TransAlta Energy Marketing U.S.	OS	FERC #8			
6	TransCanada Energy Sales Ltd.	OS	FERC #8			
7	TransCanada Energy Sales Ltd.	OS	FERC #8			
8	Vitol Inc.	OS	FERC #8			
9	Western Area Power Admin (SN)	OS	FERC #8			
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
839	8,335	29,465	2,865	40,665	1
1,546	15,309	54,333	2,934	72,576	2
1,393	12,269	48,947	2,565	63,781	3
673	7,155	23,657	1,253	32,065	4
179	2,782	6,275		9,057	5
711	8,278	24,989	2,771	36,038	6
605	6,090	21,248	1,644	28,982	7
489	4,964	17,173	900	23,037	8
850	8,300	29,866	4,119	42,285	9
29	151	1,059		1,210	10
			541	541	11
481,603		10,031,886		10,031,886	12
83		1,043		1,043	13
76,800		1,637,168		1,637,168	14
7,314	73,633	257,012	19,051	349,696	
6,868,224	0	147,729,867	4,077	147,733,944	
6,875,538	**73,633**	**147,986,879**	**23,128**	**148,083,640**	

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.
56		1,414		1,414	1
38		909		909	2
955		60,245		60,245	3
5			181	181	4
			-1	-1	5
1,173,956		27,634,770		27,634,770	6
113		1,749		1,749	7
			8	8	8
96,926		2,174,755		2,174,755	9
17,489		415,598		415,598	10
928,140		20,138,290		20,138,290	11
5,420		109,509		109,509	12
8		65		65	13
99,137		2,244,160		2,244,160	14
7,314	73,633	257,012	19,051	349,696	
6,868,224	0	147,729,867	4,077	147,733,944	
6,875,538	**73,633**	**147,986,879**	**23,128**	**148,083,640**	

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.
9,734		67,206		67,206	1
9,173		206,356		206,356	2
304,460		6,544,119		6,544,119	3
177,000		3,711,372		3,711,372	4
55,381		960,609		960,609	5
			7	7	6
37,895		955,051		955,051	7
43,840		1,116,980		1,116,980	8
164,671		3,681,488		3,681,488	9
9		36		36	10
			298	298	11
263		6,165		6,165	12
71,906		1,779,763		1,779,763	13
9		242		242	14
7,314	73,633	257,012	19,051	349,696	
6,868,224	0	147,729,867	4,077	147,733,944	
6,875,538	**73,633**	**147,986,879**	**23,128**	**148,083,640**	

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.
35			3,426	3,426	1
475,128		10,991,244		10,991,244	2
			478	478	3
141		2,533		2,533	4
969		14,453		14,453	5
56,721		1,563,232		1,563,232	6
86		2,565		2,565	7
			10	10	8
14,010		327,744		327,744	9
3		10		10	10
380		21,825		21,825	11
			-1,600	-1,600	12
142,765		3,760,097		3,760,097	13
149		3,083		3,083	14
7,314	73,633	257,012	19,051	349,696	
6,868,224	0	147,729,867	4,077	147,733,944	
6,875,538	**73,633**	**147,986,879**	**23,128**	**148,083,640**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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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.
			999	999	1
307,080		6,275,348		6,275,348	2
36		1,209		1,209	3
259,293		4,339,330		4,339,330	4
316		1,106		1,106	5
12,066		323,965		323,965	6
4,808		49,427		49,427	7
19		499		499	8
86,994		2,163,661		2,163,661	9
110		3,371		3,371	10
			-160	-160	11
531,032		12,865,236		12,865,236	12
34,780		841,014		841,014	13
			-20	-20	14
7,314	73,633	257,012	19,051	349,696	
6,868,224	0	147,729,867	4,077	147,733,944	
6,875,538	**73,633**	**147,986,879**	**23,128**	**148,083,640**	

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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.
28,615		615,415		615,415	1
2		38		38	2
74,849		1,554,510		1,554,510	3
			-90	-90	4
1,047,137		17,975,434		17,975,434	5
15,540		318,942		318,942	6
5,596		71,868		71,868	7
6,414		83,820		83,820	8
8,080		77,940		77,940	9
					10
					11
					12
					13
					14
7,314	73,633	257,012	19,051	349,696	
6,868,224	0	147,729,867	4,077	147,733,944	
6,875,538	**73,633**	**147,986,879**	**23,128**	**148,083,640**	

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	04/15/2021	2020/Q4

FOOTNOTE DATA

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 (2019) Adjs	Post Period (2021) Adjs	EQR Corrections	Total
MWH	0	0	0	0
Amount	837	0	-296	541

*Accounting adjustments not in EQR refiling. Deemed immaterial.

Schedule Page: 310.1 Line No.: 4 Column: j

	Prior Period (2019) Adjs	Post Period (2021) Adjs	EQR Corrections	Total
MWH	0	5	0	5
Amount	80	100	1	181

*Accounting adjustments not in EQR refiling. Deemed immaterial.

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

	Prior Period (2019) Adjs	Post Period (2021) Adjs	EQR Corrections	Total
MWH	0	0	0	0
Amount	0	0	-1	-1

*Accounting adjustments not in EQR refiling. Deemed immaterial.

Schedule Page: 310.1 Line No.: 8 Column: j

	Prior Period (2019) Adjs	Post Period (2021) Adjs	EQR Corrections	Total
MWH	0	0	0	0
Amount	0	0	8	8

Accounting adjustments not in EQR refiling. Deemed immaterial.

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

	Prior Period (2019) Adjs	Post Period (2021) Adjs	EQR Corrections	Total
MWH	0	0	0	0
Amount	0	0	7	7

*Accounting adjustments not in EQR refiling. Deemed immaterial.

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

	Prior Period (2019) Adjs	Post Period (2021) Adjs	EQR Corrections	Total
MWH	0	0	0	0
Amount	298	0	0	298

Schedule Page: 310.3 Line No.: 1 Column: j

	Prior Period (2019) Adjs	Post Period (2021) Adjs	EQR Corrections	Total
MWH	35	0	0	35
Amount	2125	0	1301	3426

*Correction of August 2020 transaction made after EQR refiling. Deemed immaterial, so no second refiling was made.

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

	Prior Period (2019) Adjs	Post Period (2021) Adjs	EQR Corrections	Total
MWH	0	0	0	0
Amount	478	0	0	478

Schedule Page: 310.3 Line No.: 8 Column: j

	Prior Period (2019) Adjs	Post Period (2021) Adjs	EQR Corrections	Total
MWH	0	0	0	0
Amount	0	0	10	10

*Correction of May 2020 transaction made after EQR refiling. Deemed immaterial, so no second refiling was made.

Schedule Page: 310.3 Line No.: 12 Column: j

	Prior Period (2019) Adjusts	Post Period (2021) Adjs	EQR Corrections	Total
MWH	0	0	0	0
Amount	0	-1600	0	-1600

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

	Prior Period (2019) Adjs	Post Period (2021) Adjs	EQR Corrections	Total
MWH	0	0	0	0
Amount	999	0	0	999

Schedule Page: 310.4 Line No.: 11 Column: j

	Prior Period (2019) Adjs	Post Period (2021) Adjs	EQR Corrections	Total
MWH	0	0	0	0
Amount	-160	0	0	-160

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

	Prior Period (2019) Adjs	Post Period (2021) Adjs	EQR Corrections	Total
MWH	0	0	0	0
Amount	-20	0	0	-20

Schedule Page: 310.5 Line No.: 4 Column: j

	Prior Period (2019) Adjs	Post Period (2021) Adjs	EQR Corrections	Total
MWH	0	0	0	0
Amount	0	0	-90	-90

*Correction of September 2020 transaction made after EQR refiling. Deemed immaterial, so no second refiling was made.

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	1,418,219	1,345,911
5	(501) Fuel	40,960,557	94,983,743
6	(502) Steam Expenses	7,208,774	10,513,412
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,718,348	1,806,882
10	(506) Miscellaneous Steam Power Expenses	12,144,628	10,493,096
11	(507) Rents	67	24,198
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	63,450,593	119,167,242
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,452,883	1,868,541
16	(511) Maintenance of Structures	1,446,086	1,957,038
17	(512) Maintenance of Boiler Plant	10,215,749	14,045,708
18	(513) Maintenance of Electric Plant	4,853,143	7,058,869
19	(514) Maintenance of Miscellaneous Steam Plant	2,194,510	3,353,819
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	20,162,371	28,283,975
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	83,612,964	147,451,217
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	1,905,737	2,032,967
45	(536) Water for Power		
46	(537) Hydraulic Expenses	3,155,093	3,392,829
47	(538) Electric Expenses	327,662	250,971
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,454,258	1,823,961
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	7,842,750	7,500,728
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	174,111	190,186
54	(542) Maintenance of Structures	369,632	351,293
55	(543) Maintenance of Reservoirs, Dams, and Waterways	531,968	419,922
56	(544) Maintenance of Electric Plant	1,070,248	1,107,383
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,751,412	3,485,637
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,897,371	5,554,421
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	12,740,121	13,055,149

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	3,689,391	4,270,611
63	(547) Fuel	158,146,138	187,880,093
64	(548) Generation Expenses	12,224,365	12,036,694
65	(549) Miscellaneous Other Power Generation Expenses	3,590,712	4,023,936
66	(550) Rents	8,736,539	6,167,238
67	TOTAL Operation (Enter Total of lines 62 thru 66)	186,387,145	214,378,572
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	417,748	516,853
70	(552) Maintenance of Structures	969,873	978,519
71	(553) Maintenance of Generating and Electric Plant	27,640,573	30,074,646
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	971,550	670,988
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	29,999,744	32,241,006
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	216,386,889	246,619,578
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	490,923,638	559,286,807
77	(556) System Control and Load Dispatching	28,600	123,404
78	(557) Other Expenses	-23,424,499	-21,388,429
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	467,527,739	538,021,782
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	780,267,713	945,147,726
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,158,889	2,701,249
84			
85	(561.1) Load Dispatch-Reliability	39,019	85,035
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,854,883	1,625,328
87	(561.3) Load Dispatch-Transmission Service and Scheduling	717,666	670,141
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	1,495,172	2,914,429
90	(561.6) Transmission Service Studies	-3,266	
91	(561.7) Generation Interconnection Studies	1,851,359	1,572,656
92	(561.8) Reliability, Planning and Standards Development Services	85,418	87,714
93	(562) Station Expenses	1,174,568	1,235,002
94	(563) Overhead Lines Expenses	395,317	291,575
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	123,613,131	121,674,523
97	(566) Miscellaneous Transmission Expenses	2,575,598	2,952,511
98	(567) Rents	402,913	462,594
99	TOTAL Operation (Enter Total of lines 83 thru 98)	136,360,667	136,272,757
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	26,245	53,697
102	(569) Maintenance of Structures	1,042	5,291
103	(569.1) Maintenance of Computer Hardware	39,549	35
104	(569.2) Maintenance of Computer Software	101,366	178,304
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,869,970	1,884,698
108	(571) Maintenance of Overhead Lines	7,996,676	7,321,785
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	62,831	78,942
111	TOTAL Maintenance (Total of lines 101 thru 110)	11,097,679	9,522,752
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	147,458,346	145,795,509

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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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	1,353,996	2,828,108
135	(581) Load Dispatching	1,575,173	1,603,559
136	(582) Station Expenses	1,703,678	2,240,360
137	(583) Overhead Line Expenses	2,620,130	2,577,803
138	(584) Underground Line Expenses	4,572,644	4,481,910
139	(585) Street Lighting and Signal System Expenses		4,408
140	(586) Meter Expenses	1,427,029	2,529,507
141	(587) Customer Installations Expenses	4,067,571	3,574,238
142	(588) Miscellaneous Expenses	11,861,691	10,194,399
143	(589) Rents	1,488,072	1,501,277
144	TOTAL Operation (Enter Total of lines 134 thru 143)	30,669,984	31,535,569
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	562,112	567,073
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	2,399,917	1,367,269
149	(593) Maintenance of Overhead Lines	39,110,880	34,816,830
150	(594) Maintenance of Underground Lines	10,877,780	9,900,645
151	(595) Maintenance of Line Transformers	105,740	107,940
152	(596) Maintenance of Street Lighting and Signal Systems	2,233,280	2,003,455
153	(597) Maintenance of Meters	637,708	580,259
154	(598) Maintenance of Miscellaneous Distribution Plant		
155	TOTAL Maintenance (Total of lines 146 thru 154)	55,927,417	49,343,471
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	86,597,401	80,879,040
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	139,672	129,197
160	(902) Meter Reading Expenses	13,019,003	12,300,425
161	(903) Customer Records and Collection Expenses	21,576,494	23,579,145
162	(904) Uncollectible Accounts	17,587,947	14,594,914
163	(905) Miscellaneous Customer Accounts Expenses		
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	52,323,116	50,603,681

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	103,871,753	99,686,489
169	(909) Informational and Instructional Expenses	2,425,446	2,523,745
170	(910) Miscellaneous Customer Service and Informational Expenses	74	201
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	106,297,273	102,210,435
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	703,409	649,824
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	703,409	649,824
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	58,642,337	51,395,112
182	(921) Office Supplies and Expenses	6,377,768	9,505,816
183	(Less) (922) Administrative Expenses Transferred-Credit	24,400,564	23,278,644
184	(923) Outside Services Employed	12,433,837	10,889,883
185	(924) Property Insurance	5,097,991	4,830,519
186	(925) Injuries and Damages	3,187,136	6,404,903
187	(926) Employee Pensions and Benefits	31,318,359	29,646,355
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	8,586,645	8,596,791
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	38,795	76,114
192	(930.2) Miscellaneous General Expenses	7,507,939	8,237,224
193	(931) Rents	6,397,476	7,138,619
194	TOTAL Operation (Enter Total of lines 181 thru 193)	115,187,719	113,442,692
195	Maintenance		
196	(935) Maintenance of General Plant	16,260,127	16,780,773
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	131,447,846	130,223,465
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	1,305,095,104	1,455,509,680

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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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 Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	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	Brookfield Energy Marketing LP	OS				
14	California ISO - EIM Purchases	OS				
	Total					

PURCHASED POWER (Account 555)
(Including power 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	AD				
2	California ISO	OS				
3	Cascade Community Solar	LU				
4	Chelan County PUD #1	OS				
5	Chelan PUD - Rock Island and Rocky Rea	LF				
6	Citigroup Energy (Financial)	OS				
7	Citigroup Energy Inc	OS				
8	City of Roseville	OS				
9	Clatskanie PUD	OS				
10	Conoco, Inc.	OS				
11	CP Energy Marketing (Epcor)	OS				
12	System Deviation	EX				
13	Douglas County PUD #1	OS				
14	Douglas PUD - Wells Project	LF				
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	DTE Energy Trading	OS				
2	Edaleen Dairy, LLC	LU				
3	EDF Trading NA LLC	OS				
4	Electron Hydro, LLC	LU				
5	Emerald City Renewables, LLC	LU				
6	Energy Keepers Inc.	OS				
7	Eugene Water & Electric	OS				
8	Exelon Generation Co LLC	OS				
9	Farm Power Lynden LLC	LU				
10	Farm Power Rexville LLC	IU				
11	Grant County PUD #2	OS				
12	Grant PUD - Priest Rapids Project	AD				
13	Grant PUD - Priest Rapids Project	LF				
14	Gridforce Energy Management, LLC.	OS				
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Iberdrola Renewables (PPM Energy)	OS				
2	Idaho Power Company	OS				
3	Ikea U.S. West, Inc.	LU				
4	Island Community Solar	LU				
5	Kerr Dam-Energy Keeper	LU				
6	Iberdrola Renewables (Klondike Wind P)	AD				
7	Iberdrola Renewables (Klondike Wind P)	LU				
8	Knudsen Wind Turbine#1	LU				
9	Koma Kulshan Associates	LU				
10	Lake Washington School District #414	LU				
11	Morgan Stanley CG	AD				
12	Morgan Stanley CG	OS				
13	Morgan Stanley CG (Financial)	OS				
14	NextEra Energy Power Marketing	OS				
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Puget Sound Hydro (Nooksack)	LU				
2	Northwestern Energy	OS				
3	Okanogan PUD	OS				
4	Pacific Gas & Elec - Exchange	EX				
5	Pacificorp	OS				
6	Port of Coupeville	LU				
7	Portland General Electric	OS				
8	Powerex Corp.	OS				
9	Rainbow Energy Marketing	OS				
10	Rainer BioGas	LU				
11	Residential Exchange	AD				
12	Seattle City Light Marketing	OS				
13	Shell Energy (Coral Pwr)	AD				
14	Shell Energy (Coral Pwr)	OS				
	Total					

PURCHASED POWER (Account 555)
(Including power 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)	Average Monthly CP Demand (f)
1	Skookumchuck Hydro	LU				
2	Skookumchuck Wind PPA	LU				
3	Smith Creek Hydro	LU				
4	Snohomish County PUD #1	OS				
5	Swauk Wind LLC	LU				
6	Tacoma Power	OS				
7	Tenaska Power Services Co.	OS				
8	The Energy Authority	OS				
9	Transalta Centralia Generation LLC	LF				
10	TransAlta Energy Marketing	OS				
11	TransCanada Energy Sales Ltd	OS				
12	Turlock Irrigation District	OS				
13	Twin Falls Hydro	LU				
14	Van Dyk S Holsteins	LU				
	Total					

PURCHASED POWER (Account 555)
(Including power 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	VanderHaak Dairy Digester	IU				
2	Vitol Inc.	OS				
3	South Fork II Associates(Weeks Falls)	LU				
4	Wells Fargo (Financial)	OS				
5	Western Area Power Association	OS				
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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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.
					-3,959	-3,959	1
91				2,007		2,007	2
64,801				1,576,169		1,576,169	3
	18,587			389,504		389,504	4
18,325				978,563		978,563	5
1				127		127	6
12,986				1,233,017		1,233,017	7
1,400				57,775		57,775	8
151				10,166		10,166	9
1,094,016				21,244,989		21,244,989	10
					312	312	11
406,149				9,116,770		9,116,770	12
6,096				176,213		176,213	13
681,371				9,290,750		9,290,750	14
16,957,849	431,587	515,467		537,714,150	-46,790,507	490,923,643	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		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)	
					-54,175	-54,175	1
5,263				481,653		481,653	2
25				1,966		1,966	3
102,702				1,729,252		1,729,252	4
1,994,734				28,335,219	33,469,068	61,804,287	5
				502,865		502,865	6
677,469				19,410,870		19,410,870	7
231				1,386		1,386	8
2,609				35,332		35,332	9
549,609				13,872,820		13,872,820	10
750				33,250		33,250	11
		102,467					12
4,395				1,431,264		1,431,264	13
1,348,999				41,980,536		41,980,536	14
16,957,849	431,587	515,467		537,714,150	-46,790,507	490,923,643	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		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)	
37,550				847,729		847,729	1
495				46,971		46,971	2
1,967				54,880		54,880	3
95,825				6,479,668		6,479,668	4
31,179				2,960,401		2,960,401	5
896				16,237		16,237	6
19,290				524,765		524,765	7
296,861				6,808,516		6,808,516	8
4							9
3,770				131,247		131,247	10
18,407				650,193		650,193	11
					-217,705	-217,705	12
453,108				13,306,397		13,306,397	13
6				195		195	14
16,957,849	431,587	515,467		537,714,150	-46,790,507	490,923,643	

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	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received	MegaWatt Hours Delivered	Demand Charges ($)	Energy Charges ($)	Other Charges ($)	Total (j+k+l) of Settlement ($)	
(g)	(h)	(i)	(j)	(k)	(l)	(m)	
1,255,240				30,782,371		30,782,371	1
12,637				209,639		209,639	2
212				14,319		14,319	3
-31,528				2,935		2,935	4
293,721				13,951,748		13,951,748	5
					41,995	41,995	6
136,728				9,376,202		9,376,202	7
135				3,723		3,723	8
40,696				3,379,177		3,379,177	9
373				31,273		31,273	10
4					267,644	267,644	11
586,468				19,194,282		19,194,282	12
				1,746,376		1,746,376	13
11,108				196,814		196,814	14
16,957,849	431,587	515,467		537,714,150	-46,790,507	490,923,643	

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

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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)	
24,137				2,291,767		2,291,767	1
9,545				171,036		171,036	2
3,023				52,418		52,418	3
	413,000	413,000					4
20,584				485,047		485,047	5
31,593				2,730		2,730	6
167,857				5,033,265		5,033,265	7
143,856				4,064,400		4,064,400	8
2,976				134,541		134,541	9
1,591				172,410		172,410	10
					-80,293,647	-80,293,647	11
142,166				4,018,755		4,018,755	12
					-40	-40	13
645,807				14,733,933		14,733,933	14
16,957,849	431,587	515,467		537,714,150	-46,790,507	490,923,643	

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

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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)	
4,476				485,137		485,137	1
150,505				4,230,089		4,230,089	2
66				7,117		7,117	3
37,625				352,957		352,957	4
13,427				1,274,865		1,274,865	5
157,041				4,300,373		4,300,373	6
604				-4,467		-4,467	7
38,078				703,934		703,934	8
3,337,348				175,051,726		175,051,726	9
1,668,494				40,734,132		40,734,132	10
100				4,300		4,300	11
891				11,670		11,670	12
88,706				6,652,952		6,652,952	13
111				12,031		12,031	14
16,957,849	431,587	515,467		537,714,150	-46,790,507	490,923,643	

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

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,615				91,024		91,024	1
11,200				193,720		193,720	2
15,902				1,192,619		1,192,619	3
				8,649,948		8,649,948	4
200				1,200		1,200	5
							6
							7
							8
							9
							10
							11
							12
							13
							14
16,957,849	431,587	515,467		537,714,150	-46,790,507	490,923,643	

Name of Respondent Puget Sound Energy, Inc.	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: a

Prior Period Adjustment, 3 Bar G Wind

Schedule Page: 326 Line No.: 2 Column: a

Contract Expires Dec. 2029, 3 Bar G Wind

Schedule Page: 326 Line No.: 5 Column: a

Contract Expires Sep, 2022, Powerex (Point Roberts)

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

Contract Expires Dec, 2021, Bio Energy

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

Contract Expires Dec, 2032, Black Creek Hydro

Schedule Page: 326 Line No.: 9 Column: a

Contract Expires Dec, 2031, Bloks Evergreen Dairy

Schedule Page: 326 Line No.: 11 Column: a

Prior Period Adjustment, BPA

Schedule Page: 326.1 Line No.: 1 Column: a

Prior Period Adjustment, CAISO

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

Contract Expires Jan, 2022, CC Solar

Schedule Page: 326.1 Line No.: 5 Column: a

Contract Expires Oct, 2031, Chelan RR & RI

Amortization	$7,596,199.32
Debt Service	$16,438,201.24
Administrative	$9,434,667.85
Grand Total	$33,469,068.41

Schedule Page: 326.1 Line No.: 6 Column: a

Power Financial Hedging Transactions, Citigroup Energy

Schedule Page: 326.1 Line No.: 14 Column: a

Contract Expires Sep, 2028, Douglas Wells Project

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

Contract Expires Dec, 2021, Edaleen Dairy

Schedule Page: 326.2 Line No.: 4 Column: a

Contract Terminated Nov, 2020, Electron Hydro

Schedule Page: 326.2 Line No.: 5 Column: a

Contract Expires Dec, 2029, Emerald City

Schedule Page: 326.2 Line No.: 9 Column: a

Contract Expires Dec, 2019, Farm Power Lynden

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

Contract Expires Dec, 2021, Farm Power Rexville

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

Prior Period Adjustment, Grant Priest Rapids Project

Schedule Page: 326.2 Line No.: 13 Column: a

Contract Expires Apr, 2052, Grant Priest Rapids Project

Schedule Page: 326.3 Line No.: 3 Column: a

Contract Expires Dec, 2031, Ikea

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

Contract Expires May, 2021, Island Solar

Schedule Page: 326.3 Line No.: 5 Column: a

Contract Expires Jul, 2035, Kerr Dam

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

Prior Period Adjustment, Klondike III

Name of Respondent Puget Sound Energy, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

Schedule Page: 326.3 Line No.: 7 Column: a
Contract Expires Nov, 2027, Klondike III
Schedule Page: 326.3 Line No.: 8 Column: a
Contract Expires Dec, 2029, Knudsen
Schedule Page: 326.3 Line No.: 9 Column: a
Contract Expires Mar, 2037, Koma Kulshan
Schedule Page: 326.3 Line No.: 10 Column: a
Contract Expires Dec, 2021, Lake Washington
Schedule Page: 326.3 Line No.: 12 Column: a
Prior Period Adjustment, Morgan Stanley
Schedule Page: 326.3 Line No.: 13 Column: a
Power Financial Hedging Transactions, Morgan Stanley
Schedule Page: 326.4 Line No.: 1 Column: a
Contract Expires Dec, 2021, Nooksack
Schedule Page: 326.4 Line No.: 6 Column: a
Contract Expires May, 2021, Port of Coupeville
Schedule Page: 326.4 Line No.: 10 Column: a
Contract Expires Jan, 2022, Rainier Biogas
Schedule Page: 326.4 Line No.: 11 Column: a
Residential Exchange
Schedule Page: 326.4 Line No.: 13 Column: a
Prior Period Adjustment, Shell
Schedule Page: 326.5 Line No.: 1 Column: a
Contract Expires Dec, 2025, Skookumchuck Hydro
Schedule Page: 326.5 Line No.: 2 Column: a
Contract Expires Nov, 2045, Skookumchuck Wind
Schedule Page: 326.5 Line No.: 3 Column: a
Contract Expires Jan, 2026, Smith Creek
Schedule Page: 326.5 Line No.: 5 Column: a
Contract Expires Dec, 2021, Swauk Wind
Schedule Page: 326.5 Line No.: 9 Column: a
Contract Expires Dec, 2025, TransAlta Centralia
Schedule Page: 326.5 Line No.: 13 Column: a
Contract Expires Mar, 2025, Twin Falls
Schedule Page: 326.5 Line No.: 14 Column: a
Contract Expires Dec, 2020, Van Dyk-S
Schedule Page: 326.6 Line No.: 1 Column: a
Contract Expires Dec, 2021, Vanderhaak
Schedule Page: 326.6 Line No.: 3 Column: a
Contract Expires Nov, 2022, Weeks Falls
Schedule Page: 326.6 Line No.: 4 Column: a
Power Financial Hedging Transactions,Wells Fargo

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Seattle City Light	Seattle City Light	Seattle City Light	OLF
2	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	OS
3	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	OLF
4	Snohomish County PUD	Snohomish County PUD	Snohomish County PUD	OLF
5	Tacoma City Light	Tacoma City Light	Tacoma City Light	OS
6				
7	Bonneville Power 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	Bonneville Power Administration	Bonneville Power Admin	Lewis County PUD	FNO
16				
17	Morgan Stanley Capital	Various	Various	LFP
18	Morgan Stanley Capital	Various	Various	LFP
19	Powerex	Various	Various	LFP
20	Powerex	Various	Various	LFP
21	Powerex	Various	Various	LFP
22	Powerex Microsoft	Various	Various	LFP
23	Sierra Pacific Industries	Various	Various	LFP
24	TransAlta Energy	Various	Various	LFP
25	Seattle City Light	Various	Various	LFP
26	Vantage Wind Energy LLC- Invenergy	Various	Various	LFP
27	Whatcom County PUD	Whatcom County PUD	Whatcom County PUD	LFP
28				
29	Brookfield Renewables	Various	Various	SFP
30	Morgan Stanley Capital	Various	Various	SFP
31	Powerex	Various	Various	SFP
32	Powerex	Various	Various	SFP
33	Sierra Pacific Industries	Various	Various	SFP
34	Snohomish County PUD	Various	Various	SFP
	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.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Seattle City Light	Various	Various	SFP
2				
3	Avista	Various	Various	NF
4	Brookfield Renewables	Various	Various	NF
5	Exelon Generation	Various	Various	NF
6	Macquarie Energy, LLC	Various	Various	NF
7	Morgan Stanley Capital	Various	Various	NF
8	Portland General Electric	Various	Various	NF
9	Powerex	Various	Various	NF
10	Powerex	Various	Various	NF
11	Seattle City Light Marketing	Various	Various	NF
12	Shell Energy North America	Various	Various	NF
13	Shell Energy North America	Various	Various	NF
14	Snohomish County PUD	Various	Various	NF
15	Snohomish County PUD	Various	Various	NF
16	Tacoma Power	Various	Various	NF
17	The Energy Authority	Various	Various	NF
18	TransAlta Energy	Various	Various	NF
19	TransAlta Energy	Various	Various	NF
20	Turlock Irrigation District	Various	Various	NF
21				
22	Transportation Customers			
23	Air Liquide	Various	Air Liquide	FNO
24	Air Products	Various	Air Products	FNO
25	AMCOR Rigid Plastics USA	Various	AMCOR Rigid Plastics USA	FNO
26	Bellingham Cold Storage -	Various	Bellingham Cold Storage - Orchar	FNO
27	Bellingham Cold Storage - Roeder	Various	Bellingham Cold Storage - Roeder	FNO
28	Boeing	Various	Boeing	FNO
29	BP Products North America Inc	Various	BP Products North America	FNO
30	Center Drive Owners	Various	Center Drive Owners	FNO
31	Shell Oil Products (Equilon)	Various	Shell (Equilon)	FNO
32	Tesoro	Various	Tesoro	FNO
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	04/15/2021	End of 2020/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	Air Liquide	Various	Air Liquide	AD
2	Air Products	Various	Air Products	AD
3	BP Products North America Inc	Various	BP Products North America	AD
4	Bellingham Cold Storage - Orchard	Various	Bellingham Cold Storage - Orchar	AD
5	Center Drive Owners	Various	Center Drive Owners	AD
6	AMCOR Rigid Plastics USA	Various	AMCOR Rigid Plastics USA	AD
7	Avangrid Renewables, LLC	Various	Various	AD
8	Avista	Various	Various	AD
9	Boeing	Various	Various	AD
10	Bonneville Power Administration	Various	Various	AD
11	Brookfield Energy Marketing, LP	Various	Various	AD
12	Macquarie Energy, LLC	Various	Various	AD
13	Morgan Stanley Capital	Various	Various	AD
14	Portland General Electric	Various	Various	AD
15	Powerex	Various	Various	AD
16	Seattle City Light	Various	Various	AD
17	Shell Energy North America	Various	Various	AD
18	Shell Oil Products (Equilon)	Various	Shell (Equilon)	AD
19	Snohomish County PUD	Various	Various	AD
20	Tesoro	Various	Various	AD
21	The Energy Authority	Various	Various	AD
22	TransAlta Energy	Various	Various	AD
23	Tacoma Power	Various	Various	AD
24	Tacoma Power	Various	Various	AD
25	Whatcom County PUD	Whatcom County PUD	Whatcom County PUD	AD
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FRS #155	Stillwater Substn	Bothell Substation		16,325	16,325	1
FRS #60	Beverly Park Substn	Goldbar Substation				2
FRS #28	Beverly Park Substn	Hilton Lake Substn		77,903	77,903	3
FRS #28	Beverly Park Substn	Olympic Pipe Substn		6,196	6,196	4
FRS #62	Starwood Substation	Baldi Substation				5
						6
PSE OATT	Custer Substation	Blaine&Semiahmo Sub		80,454	80,454	7
PSE OATT	Bellingham Substn	City of Sumas Sub		31,952	31,952	8
PSE OATT	White River Substn	Teanaway Substation		19,619	19,619	9
PSE OATT	Murray Bellingham	Fidalgo Substation		223,916	223,916	10
PSE OATT	Maple Valley Substn	Ames Lake Tap		22,394	22,394	11
PSE OATT	Olympia Substation	Luhr Beach Tap		14,666	14,666	12
PSE OATT	Maple Valley Substn	North Bend Substn				13
PSE OATT	Various	Sea Tac Airport		131,336	131,336	14
PSE OATT	BPAT.PSE	Tono Substation		303	303	15
						16
PSE OATT	John Day, COB	John Day, COB	100	878,400	878,400	17
PSE OATT	Various Washington	Various Washington	90	190,986	190,986	18
PSE OATT	John Day, COB	John Day, COB	225	1,917,048	1,917,048	19
PSE OATT	Various Washington	Various Washington				20
PSE OATT	Various Washington	Various Washington	90	591,750	591,750	21
PSE OATT	Various Washington	Various Washington	88	772,992	772,992	22
PSE OATT	Various Washington	Various Washington	15	131,760	131,760	23
PSE OATT	John Day, COB	John Day, COB	75	658,800	658,800	24
PSE OATT	Various Washington	Various Washington	16	70,672	70,672	25
PSE OATT	Various Washington	Various Washington				26
PSE OATT	Custer Substation	Enterprise Sub	2	17,568	17,568	27
						28
PSE OATT	John Day, COB	John Day, COB	30	1,320	1,320	29
PSE OATT	John Day, COB	John Day, COB	28	1,344	1,344	30
PSE OATT	Various Washington	Various Washington	2,512	89,949	89,949	31
PSE OATT	Various Washington	Various Washington	90	6,480	6,480	32
PSE OATT	Various Washington	Various Washington	33	24,132	24,132	33
PSE OATT	Various Washington	Various Washington	2,140	56,387	56,387	34
			5,550	**8,438,687**	**8,438,687**	

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.
PSE OATT	Various Washington	Various Washington	16	768	768	1
						2
PSE OATT	John Day, COB	John Day, COB		240	240	3
PSE OATT	John Day, COB	John Day, COB		23,247	23,247	4
PSE OATT	John Day, COB	John Day, COB		24,531	24,531	5
PSE OATT	John Day, COB	John Day, COB		808	808	6
PSE OATT	John Day, COB	John Day, COB		12,722	12,722	7
PSE OATT	John Day, COB	John Day, COB		155,169	155,169	8
PSE OATT	John Day, COB	John Day, COB		39,148	39,148	9
PSE OATT	Various Washington	Various Washington		9,115	9,115	10
PSE OATT	John Day, COB	John Day, COB		191	191	11
PSE OATT	John Day, COB	John Day, COB		61,462	61,462	12
PSE OATT	Various Washington	Various Washington		12,649	12,649	13
PSE OATT	John Day, COB	John Day, COB		857	857	14
PSE OATT	Various Washington	Various Washington		3,176	3,176	15
PSE OATT	Various Washington	Various Washington				16
PSE OATT	John Day, COB	John Day, COB		16,931	16,931	17
PSE OATT	Various Washington	Various Washington		29,949	29,949	18
PSE OATT	John Day, COB	John Day, COB		296	296	19
PSE OATT	John Day, COB	John Day, COB		1	1	20
						21
						22
PSE OATT	Rocky Reach 115KV Sw	Air Liquide		73,252	73,252	23
PSE OATT	Rocky Reach 115KV Sw	Air Products		52,110	52,110	24
PSE OATT	Rocky Reach 115KV Sw	AMCOR Rigid Plastics		44,476	44,476	25
PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Orch		18,773	18,773	26
PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Roed		15,320	15,320	27
PSE OATT	Rocky Reach 115KV Sw	Boeing		367,001	367,001	28
PSE OATT	Rocky Reach 115KV Sw	BP Products North Ac		862,375	862,375	29
PSE OATT	Rocky Reach 115KV Sw	Center Drive Owners		4,329	4,329	30
PSE OATT	Rocky Reach 115KV Sw	Equilon Refinery		322,155	322,155	31
PSE OATT	Rocky Reach 115KV Sw	Tesoro		252,984	252,984	32
						33
						34
			5,550	**8,438,687**	**8,438,687**	

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	04/15/2021	End of 2020/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.
PSE OATT	Rocky Reach 115KV Sw	Air Liquide				1
PSE OATT	Rocky Reach 115KV Sw	Air Products				2
PSE OATT	Rocky Reach 115KV Sw	BP Products North Aa				3
PSE OATT	Rocky Reach 115KV Sw	B'ham Cold Stor-Orch				4
PSE OATT	Rocky Reach 115KV Sw	Center Drive Owners				5
PSE OATT	Various Washington	Various Washington				6
PSE OATT	Various Washington	Various Washington				7
PSE OATT	Various Washington	Various Washington				8
PSE OATT	Various Washington	Various Washington				9
PSE OATT	Various Washingto	Various Washingto				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	Various Washington	Various Washington				21
PSE OATT	Various Washington	Various Washington				22
PSE OATT	Various Washington	Various Washington				23
PSE OATT	Various Washington	Various Washington				24
PSE OATT	Custer Substation	Enterprise Sub				25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			5,550	**8,438,687**	**8,438,687**	

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.
166,149			166,149	1
		600	600	2
8,225		600	8,825	3
1,490		600	2,090	4
		4,576	4,576	5
				6
278,832		247,930	526,762	7
103,381		166,067	269,448	8
74,134		61,189	135,323	9
874,717		223,645	1,098,362	10
87,767		42,076	129,843	11
59,224		55,049	114,273	12
215,511		103,135	318,646	13
381,950		313,883	695,833	14
343		3,209	3,552	15
				16
945,770		304,389	1,250,159	17
518,597		635,048	1,153,645	18
2,068,104		790,235	2,858,339	19
		51,002	51,002	20
1,598,696		1,560,650	3,159,346	21
2,091,003		802,275	2,893,278	22
356,421		146,849	503,270	23
709,328		379,089	1,088,417	24
190,819		17,105	207,924	25
-12		-1	-13	26
47,523		18,844	66,367	27
				28
4,202		962	5,164	29
4,278		212	4,490	30
271,023		35,010	306,033	31
17,596		2,447	20,043	32
69,764		37,591	107,355	33
174,790		69,815	244,605	34
16,770,042	**634,651**	**9,564,618**	**26,969,311**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
2,445		220	2,665	1
				2
	485	107	592	3
	29,421	15,000	44,421	4
	28,722	13,658	42,380	5
	1,044	486	1,530	6
	21,976	9,329	31,305	7
	226,154	96,545	322,699	8
	54,151	29,419	83,570	9
	35,311	11,971	47,282	10
	344	125	469	11
	103,979	37,475	141,454	12
	44,935	34,419	79,354	13
	1,211	871	2,082	14
	12,806	5,101	17,907	15
				16
	27,174	13,356	40,530	17
	45,522	26,813	72,335	18
	1,414	129	1,543	19
	2		2	20
				21
				22
187,451		99,109	286,560	23
141,488		74,017	215,505	24
110,252		94,309	204,561	25
56,101		27,029	83,130	26
47,390		26,712	74,102	27
1,118,542		789,642	1,908,184	28
2,193,418		1,129,212	3,322,630	29
13,034		9,100	22,134	30
892,461		607,026	1,499,487	31
687,835		466,991	1,154,826	32
				33
				34
16,770,042	**634,651**	**9,564,618**	**26,969,311**	

Name of Respondent Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		-1,322	-1,322	1
		-667	-667	2
		-14,862	-14,862	3
		-620	-620	4
		-63	-63	5
		-766	-766	6
		-3,418	-3,418	7
		-133	-133	8
		-9,578	-9,578	9
		-15,958	-15,958	10
		-48	-48	11
		-2,940	-2,940	12
		-15,562	-15,562	13
		-5	-5	14
		-36,063	-36,063	15
		-18	-18	16
		-1,952	-1,952	17
		-5,683	-5,683	18
		-236	-236	19
		-5,124	-5,124	20
		-351	-351	21
		-11,802	-11,802	22
		-148	-148	23
		-4	-4	24
		-311	-311	25
				26
				27
				28
				29
				30
				31
				32
				33
				34
16,770,042	**634,651**	**9,564,618**	**26,969,311**	

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	04/15/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 1 Column: d

Contract expired on June 30, 2020.

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.: 1 Column: i

A correction for Q2 reported volume 16MWH for Seattle City Light's (SCL): additional 16,037MWH should be added to Q2 transfer of energy, totaling 16,053MWH for Q2. Therefore the total of 2020 is 16,325 MWH.

Schedule Page: 328 Line No.: 2 Column: e

Grandfathered Exchange and Transfer Agreement for service to Snohomish County PUD's Goldbar substation.

Schedule Page: 328 Line No.: 2 Column: h

Grandfathered Exchange and Transfer Agreement for service to Snohomish County PUD's Goldbar substation.

Schedule Page: 328 Line No.: 2 Column: m

Use of facilities charges.

Schedule Page: 328 Line No.: 3 Column: d

Contract expires with two years written notice.

Schedule Page: 328 Line No.: 3 Column: e

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Hilton Lake substation.

Schedule Page: 328 Line No.: 3 Column: h

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Hilton Lake substation.

Schedule Page: 328 Line No.: 3 Column: m

Use of facilities charges.

Schedule Page: 328 Line No.: 4 Column: d

Contract expires with two years written notice.

Schedule Page: 328 Line No.: 4 Column: e

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Olympic Pipe substation.

Schedule Page: 328 Line No.: 4 Column: h

Grandfathered Exchange and Transfer Agreement where power is delivered over the Beverly Park - Sammamish line to Snohomish County PUD's Olympic Pipe substation.

Schedule Page: 328 Line No.: 4 Column: m

Use of facilities charges.

Schedule Page: 328 Line No.: 5 Column: d

Use of facilities on pre-888 contract with Baldi substation.
Contract expires every 10 years but is automatically renewed unless otherwise requested.

Schedule Page: 328 Line No.: 5 Column: e

Grandfathered Transfer Agreement with the City of Tacoma where Puget Sound Energy transfers transmission and energy to Tacoma's North Fork Well Field Complex.

Schedule Page: 328 Line No.: 5 Column: h

Grandfathered Transfer Agreement with the City of Tacoma where Puget Sound Energy transfers transmission and energy to Tacoma's North Fork Well Field Complex.

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

Use of facilities charges.

Schedule Page: 328 Line No.: 7 Column: e

Full title of the FERC rate is 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

Name of Respondent Puget Sound Energy, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

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.: 15   Column: h

Billing demand is based on monthly peak consistent with Puget Sound Energy's OATT.

Schedule Page: 328   Line No.: 15   Column: m

Includes ancillary services, Washington State tax, facilities fees, and loss return charges.

Schedule Page: 328   Line No.: 17   Column: d

Contract expires August 1, 2025.

Schedule Page: 328   Line No.: 17   Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328   Line No.: 18   Column: d

Contract expires October 1, 2025.

Schedule Page: 328   Line No.: 18   Column: m

Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328   Line No.: 19   Column: d

Powerex LFP 225 MW - Inlcudes three contracts wiht the following end dates:
25 MW - October 1, 2022
100 MW - September 1, 2023
100 MW - September 1, 2024

Schedule Page: 328   Line No.: 19   Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328   Line No.: 20   Column: d

Powerex LFP 225 MW - Charges shown are state taxes and loss return charges on redirected reserve capacity.

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Puget Sound Energy, Inc.	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/15/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 328 Line No.: 20 Column: m
Includes Washington State tax and loss return charges on redirected reserve capacity.
Schedule Page: 328 Line No.: 21 Column: a
Long-Term point-to-point transmission resale.
Schedule Page: 328 Line No.: 21 Column: d
Contract ended on October 1, 2020.
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 April 1, 2024.
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 December 1, 2021.
Schedule Page: 328 Line No.: 23 Column: m
Includes ancillary services, Washington State tax and loss return charges.
Schedule Page: 328 Line No.: 24 Column: d
Contract expires on October 1, 2022 (25MW) and January 1, 2022 (50MW).
Schedule Page: 328 Line No.: 24 Column: m
Includes ancillary services and loss return charges.
Schedule Page: 328 Line No.: 25 Column: d
Contract expires on July 1, 2025.
Schedule Page: 328 Line No.: 25 Column: m
Includes ancillary services, Washington State tax and loss return charges.
Schedule Page: 328 Line No.: 26 Column: d
Contract expires on July 1, 2025.
Schedule Page: 328 Line No.: 26 Column: m
Includes ancillary services, Washington State tax and loss return charges.
Schedule Page: 328 Line No.: 27 Column: d
Contract expires with one year written notice.
Schedule Page: 328 Line No.: 27 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
Includes ancillary services, Washington State tax and loss return charges.
Schedule Page: 328 Line No.: 33 Column: m
Includes ancillary services, Washington State tax and loss return charges.
Schedule Page: 328 Line No.: 34 Column: m
Includes ancillary services, Washington State tax and loss return charges.
Schedule Page: 328.1 Line No.: 1 Column: m
Includes ancillary services, Washington State tax 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

Name of Respondent Puget Sound Energy, Inc.	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

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 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, Washington State tax, and loss return charges.

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

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 12 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 13 Column: m

Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328.1 Line No.: 14 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 15 Column: m

Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328.1 Line No.: 17 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 18 Column: m

Includes ancillary services, Washington State tax and loss return charges.

Schedule Page: 328.1 Line No.: 19 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 20 Column: m

Includes ancillary services and loss return charges.

Schedule Page: 328.1 Line No.: 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: f

Full name of the point of receipt is Rocky Reach 115KV Switchyard.

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 449.

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 449.

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 459.

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

Name of Respondent Puget Sound Energy, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

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.: 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 449.

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.: 32 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.: 32 Column: m
Includes ancillary services, Washington State tax and loss return 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

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	04/15/2021	2020/Q4

FOOTNOTE DATA

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.

Schedule Page: 328.2 Line No.: 22 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 23 Column: m

Distribution of prior year unreserved use penalty charges.

Schedule Page: 328.2 Line No.: 24 Column: m

Prior period transmission losses adjustment.

Schedule Page: 328.2 Line No.: 25 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	04/15/2021	End of 2020/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	04/15/2021	End of 2020/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			37,307,088		7,714,512	45,021,600
2	Bonneville Power Admin	LFP	20,188,829	20,188,829	51,565,253		9,156,970	60,722,223
3	Bonneville Power Admin	SFP			688		142	830
4	Bonneville Power Admin	NF	965	965	268,000	5,191	1,122	274,313
5	Bonneville Power Admin	OS					2,227	2,227
6	Bonneville Power Admin	OS					7,296	7,296
7	Bonneville Power Admin	OS					5,387,601	5,387,601
8	Bonneville Power Admin	OS					25,000	25,000
9	Bonneville Power Admin	OS					6,140,505	6,140,505
10	Bonneville Power Admin	AD					19,227	19,227
11	Brookfiled Energy Mrktg	OS					-342,687	-342,687
12	Chelan County PUD No. 1	OLF	2,114,198	2,114,198			5,402,583	5,402,583
13	EDF Trading NA LLC	OS					-17,204	-17,204
14	Energy Keepers Inc.	OS					-1,600	-1,600
15	Eugene Water & Electric	OS					-1,352	-1,352
16	Grant County PUD No. 2	OS					140,952	140,952
	TOTAL		24,566,432	24,566,432	89,232,668	633,697	33,746,766	123,613,131

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	04/15/2021	End of 2020/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Iberdrola Renewables	OS					-230,363	-230,363
2	Idaho Power Company	OS					-31,954	-31,954
3	Klickitat County PUD	OLF	2,016,713	2,016,713			1,342,287	1,342,287
4	Klondike Wind Power III	OS					382,155	382,155
5	Klondike Wind Power III	AD					-583	-583
6	Morgan Stanley CG	OS					-808,480	-808,480
7	NextEra	OS					-8,958	-8,958
8	NorthWestern Energy	SFP	14,472	14,472	91,639		1,646	93,285
9	NorthWestern Energy	NF	12,305	12,305		73,016	4,910	77,926
10	NorthWestern Energy	OS					10,315	10,315
11	NorthWestern Energy	AD					39,977	39,977
12	NorthWestern Energy	OS					402,925	402,925
13	Pacific Corp	OS					-63,407	-63,407
14	Portland General Elec	NF	600	600		490		490
15	Portland General Elec	AD					170	170
16	Powerex Corp	OS					-648,452	-648,452
	TOTAL		24,566,432	24,566,432	89,232,668	633,697	33,746,766	123,613,131

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	04/15/2021	End of 2020/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	Powerex Corp	AD					-3,000	-3,000
2	Seattle City Light	OS					134,352	134,352
3	Shell Energy	OS					-15,700	-15,700
4	Snohomish County PUD #1	OS					96,772	96,772
5	Snohomish County PUD #1	AD					48,386	48,386
6	Tacoma Power	OS					-14,200	-14,200
7	Talen Energy Marketing	NF	218,350	218,350		555,000		555,000
8	Talen Energy Marketing	OS					727,282	727,282
9	The Energy Authority	OS					-316,886	-316,886
10	TransAlta Energy Mrktng	OS					530,422	530,422
11	TransAlta Energy Mrktng	OS					-1,492,402	-1,492,402
12	TransAlta Energy Mrktng	AD					-1,464	-1,464
13	Whatcom Co PUD #1	OS					11,769	11,769
14	Whatcom Co PUD	AD					7,952	7,952
15	Misc. Adjustment	OS					6,001	6,001
16								
	TOTAL		24,566,432	24,566,432	89,232,668	633,697	33,746,766	123,613,131

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	04/15/2021	2020/Q4

FOOTNOTE DATA

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 20,188,829. 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 20,188,829 is reported with the long-term firm contracts on Line 2.

Schedule Page: 332 Line No.: 1 Column: e

Fixed transmission capacity charges that are related to the contracts for the Mid-Columbia 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 20,188,829. 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 20,188,829 is reported with the long-term firm contracts on Line 2.

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

Fixed transmission capacity charges other than those related to the 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 20,188,829. 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 20,188,829 is reported with the long-term firm contracts 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

Intertie charge and capacity rights charges.

Schedule Page: 332 Line No.: 8 Column: g

Non-refundable TSR fee

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 is BPA - CA Wind Integration from prior periods:

Schedule Page: 332 Line No.: 11 Column: g

Reimbursement from Brookfield Energy Marketing for use of PSE capacity on Bonneville Power Administration lines.

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

Contract end date is October 31, 2031.

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

Use of facilities charges.

Schedule Page: 332 Line No.: 13 Column: g

Reimbursement from EDF Trading NA LLC for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332 Line No.: 14 Column: g

Reimbursement from Energy Keeper Inc. for use of PSE capacity on Bonneville Power Administration lines.

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

Reimbursement from Eugene Water & Electric Trading NA LLC for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332 Line No.: 16 Column: g

Use 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 January 2020.

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

Reimbursement from NextEra for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.1 Line No.: 8 Column: g

Ancillary services.

Schedule Page: 332.1 Line No.: 9 Column: g

Ancillary services.

Schedule Page: 332.1 Line No.: 10 Column: g

Loss return charges.

Schedule Page: 332.1 Line No.: 11 Column: g

Northwestern prior period adjustment of non-firm transmission charges.

Schedule Page: 332.1 Line No.: 12 Column: g

Use of facilities charges.

Schedule Page: 332.1 Line No.: 13 Column: g

Reimbursement from Pacificorp for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.1 Line No.: 15 Column: g

Portland General Electric wheeling secondary adjustment for 2019.

Schedule Page: 332.1 Line No.: 16 Column: g

Reimbursement from Powerex for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.2 Line No.: 1 Column: g

Powerex prior period adjustment for 2019.

Schedule Page: 332.2 Line No.: 2 Column: g

Prepay Amortization charge

Schedule Page: 332.2 Line No.: 3 Column: g

Reimbursement from Shell Energy for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.2 Line No.: 4 Column: g

Actual cost capacity charges

Schedule Page: 332.2 Line No.: 5 Column: g

Prior period actual cost capacity charges for Snohomish County PUD #1 for 2018.

Schedule Page: 332.2 Line No.: 6 Column: g

Reimbursement from Tacoma Power for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.2 Line No.: 8 Column: g

Premium Amortization for 2020.

Schedule Page: 332.2 Line No.: 9 Column: g

Reimbursement from The Energy Authority for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.2 Line No.: 10 Column: g

Ancillary services - reserves.

Schedule Page: 332.2 Line No.: 11 Column: g

Reimbursement from TransAlta Energy Marketing for use of PSE capacity on Bonneville Power Administration lines.

Schedule Page: 332.2 Line No.: 12 Column: g

Prior year adjustment of transmission resale

Schedule Page: 332.2 Line No.: 13 Column: g

Interconnection losses charges.

Schedule Page: 332.2 Line No.: 14 Column: g

Prior period adjustment of inconnection losses charges.

Schedule Page: 332.2 Line No.: 15 Column: g

Includes $1,500 of PSE fee for application to the PSE TPC and $4,500 EIM PR application fee.

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	04/15/2021	End of 2020/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	761,871
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	8,000
7	Board of Director Fees and Expenses	718,056
8	Other Membership Dues	628,590
9	Treasury Fees & Expenses	172,287
10	Misc General Expense - Electric	5,214,865
11	State/Fed Govt Related Industry Expenses	4,270
12		
13		
14		
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46	TOTAL	7,507,939

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	04/15/2021	End of 2020/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			11,487,466		11,487,466
2	Steam Production Plant	43,747,792	4,820,273			48,568,065
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	19,402,829		1,193,954		20,596,783
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	75,368,773	3,218,715			78,587,488
7	Transmission Plant	36,486,655	46,501			36,533,156
8	Distribution Plant	147,604,076	63,909			147,667,985
9	Regional Transmission and Market Operation					
10	General Plant	14,150,474				14,150,474
11	Common Plant-Electric	18,832,726	35,404	74,369,274		93,237,404
12	TOTAL	355,593,325	8,184,802	87,050,694		450,828,821

B. Basis for Amortization Charges

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
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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	4,517,401		4,517,401	
2					
3	Federal fees:				
4	Upper & Lower Baker Project	1,378,485		1,378,485	
5	Snoqualmie 1 & 2 Project	97,910		97,910	
6	FERC Regulatory Comm Trading	1,024,642		1,024,642	
7					
8	Other Charges:				
9	FERC Regulatory Legal Fees		220,033	220,033	
10	State Regulatory Legal Fees		313,559	313,559	
11	Transmission Rate Case		105,098	105,098	
12	General Rate Case Legal Fees		946,321	946,321	
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46	TOTAL	7,018,438	1,585,011	8,603,449	

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	4,517,401					1
							2
							3
Electric	928	1,378,485					4
Electric	928	97,910					5
Electric	928	1,024,642					6
							7
							8
Electric	928	220,033					9
Electric	928	313,559					10
Electric	928	105,098					11
Electric	928	946,321					12
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		8,603,449					46

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 2020	
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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) 04/15/2021	Year/Period of Report End of 2020/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
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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	23,324,921		
4	Transmission	8,039,978		
5	Regional Market			
6	Distribution	18,011,512		
7	Customer Accounts	8,787,592		
8	Customer Service and Informational	2,316,804		
9	Sales	595,405		
10	Administrative and General	34,770,514		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	95,846,726		
12	Maintenance			
13	Production	4,765,022		
14	Transmission	2,467,901		
15	Regional Market			
16	Distribution	10,555,676		
17	Administrative and General	214,076		
18	TOTAL Maintenance (Total of lines 13 thru 17)	18,002,675		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	28,089,943		
21	Transmission (Enter Total of lines 4 and 14)	10,507,879		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	28,567,188		
24	Customer Accounts (Transcribe from line 7)	8,787,592		
25	Customer Service and Informational (Transcribe from line 8)	2,316,804		
26	Sales (Transcribe from line 9)	595,405		
27	Administrative and General (Enter Total of lines 10 and 17)	34,984,590		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	113,849,401	6,176	113,855,577
29	Gas			
30	Operation			
31	Production-Manufactured Gas	79,933		
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	2,180,063		
34	Storage, LNG Terminaling and Processing	955,211		
35	Transmission			
36	Distribution	20,019,408		
37	Customer Accounts	6,211,504		
38	Customer Service and Informational	1,286,390		
39	Sales	-42,328		
40	Administrative and General	15,433,254		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	46,123,435		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing	284,120		
47	Transmission			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	5,984,079		
49	Administrative and General	138,709		
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	6,406,908		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)	79,933		
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	2,180,063		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	1,239,331		
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)	26,003,487		
58	Customer Accounts (Line 37)	6,211,504		
59	Customer Service and Informational (Line 38)	1,286,390		
60	Sales (Line 39)	-42,328		
61	Administrative and General (Lines 40 and 49)	15,571,963		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	52,530,343	2,850	52,533,193
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	166,379,744	9,026	166,388,770
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	63,329,124	3,436	63,332,560
69	Gas Plant	29,580,100	1,605	29,581,705
70	Other (provide details in footnote):	47,406,288	2,572	47,408,860
71	TOTAL Construction (Total of lines 68 thru 70)	140,315,512	7,613	140,323,125
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,698,301	146	2,698,447
74	Gas Plant	1,508,769	82	1,508,851
75	Other (provide details in footnote):	17,333	1	17,334
76	TOTAL Plant Removal (Total of lines 73 thru 75)	4,224,403	229	4,224,632
77	Other Accounts (Specify, provide details in footnote):	28,056,106	1,522	28,057,628
78				
79				
80				
81				
82				
83				
84				
85				
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91				
92				
93				
94				
95	TOTAL Other Accounts	28,056,106	1,522	28,057,628
96	TOTAL SALARIES AND WAGES	338,975,765	18,390	338,994,155

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	04/15/2021	2020/Q4

FOOTNOTE DATA

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	18,389	1	18,390
163 Store Expense	3,908,469	212	3,908,681
182 Regulatory Asset	12,510,299	679	12,510,978
185 Temporary Facilities	17,609	1	17,610
149 Misc. Deferred Debits	1,403,506	76	1,403,582
186 Misc. Deferred Debits	2,396,557	130	2,396,687
Misc. 400 Accounts	4,893,881	265	4,894,146
143 Accts Receivable Misc.			0
Prelim Survey OG 183			0
Allocated OG 184	2,904,940	158	2,905,098
Misc. 200 Accounts	2,456	0	2,456
Jackson Prairie Joint Venture - Capital - PSE Share			0
Jackson Prairie Joint Venture - Expense - PSE Share			0
TOTAL	28,056,106	1,522	28,507,628

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 12/31/2020	ACCUMULATED PROVISION FOR DEPR & AMORT
C302	Franchises	417,355	108,797
C303	Software Development	588,465,706	288,715,115
C389	Land and Land Rights	53,483,328	2,674,812
C390	Structures and Improvements	202,513,583	87,085,298
C391	Office Furniture and Equipment	127,776,645	60,871,429
C392	Transportation Equipment	2,818,351	1,083,426
C393	Stores Equipment	92,576	44,409
C394	Tools/Shop/Garage Equipment	1,511,886	1,201,164
C396	Power Operated Equipment	719,016	752,936
C397	Communication Equipment	91,372,480	27,966,026
C398	Miscellaneous Equipment	681,897	1,322,390
C399	Other Tangible Property	524,934	106,127
Total	Common Plant in Service	1,070,377,757	471,931,929

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	28,383,912	18,832,726	9,551,186	(D)
404 Amortization of LTD Term Plant	112,693,394	74,772,067	37,921,327	(D)
901 Customer Accounts and Collection Supervision	240,735	139,819	100,916	(A)
902 Meter Reading Expense	2,447,118	1,531,896	915,222	(B)
903 Customer Records and Collections	34,621,701	20,108,284	14,513,417	(A)
904 Uncollectible Accounts	-72,861	-48,343	-24,518	(D)
908 Customer Assistance	1,896,787	1,101,654	795,133	(A)
909 Information and Instructional Advertising	2,605,563	1,513,311	1,092,252	(A)
910 Miscellaneous Customer Services and Information	129	75	54	(A)
912 Common Sales	-136,558	-79,313	-57,245	(A)
920 Administrative and General Salaries	83,837,258	55,626,021	28,211,237	(D)
921 Office Supplies & Expense	3,492,806	2,317,477	1,175,329	(D)
922 Administrative Expense Transferred	-36,775,530	-24,400,564	-12,374,966	(D)
923 Outside Services Employed	16,310,898	10,822,281	5,488,617	(D)
924 Property Insurance	-316,913	-190,433	-126,480	(C)
925 Injuries & Damages	5,679,884	3,298,877	2,381,007	(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.

928 Regulatory Commission	1,539,680	1,021,578	518,102	(D)
930.1 Common Gen Advertising Exp	0			
930.2 Miscellaneous General Expense	9,781,292	6,489,887	3,291,405	(D)
931 Rents	8,195,342	5,437,609	2,757,733	(D)
935 Maintenance of General Plant	23,575,510	15,642,351	7,933,159	(D)
Total Expense	156,922,841	100,332,465	56,590,376	

(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: 66.35%, and Gas: 33.65%
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	04/15/2021	End of 2020/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)	4,258,300	4,908,361	6,738,858	9,604,093
3	Net Sales (Account 447)	(5,932,972)	(9,229,340)	(13,974,493)	(20,138,290)
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
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43					
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45					
46	TOTAL	(1,674,672)	(4,320,979)	(7,235,635)	(10,534,197)

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Puget Sound Energy, Inc.	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/15/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 397 Line No.: 2 Column: e

	Q1 2020	Q2 2020	Q3 2020	Q4 2020	YTD 2020
EIM Purchases	$ 4,210,160	$ 628,792	$ 1,579,535	$ 2,872,263	$ 9,290,750
Intertie Purchases	48,140	21,269	250,962	(7,028)	$ 313,343
Total by Quarter	**$ 4,258,300**	**$ 650,061**	**$ 1,830,497**	**$ 2,865,235**	**$ 9,604,093**

Schedule Page: 397 Line No.: 3 Column: e

	Q1 2020	Q2 2020	Q3 2020	Q4 2020	YTD 2020
EIM Purchases	$ (5,932,972)	$ (3,290,290)	$ (4,698,470)	$ (6,145,882)	$ (20,067,614)
Intertie Purchases	-	(6,078)	(46,683)	(17,915)	$ (70,676)
Total by Quarter	**$ (5,932,972)**	**$ (3,296,368)**	**$ (4,745,153)**	**$ (6,163,797)**	**$ (20,138,290)**

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch				80,159		6,935,305
2	Reactive Supply and Voltage				23,485		148,207
3	Regulation and Frequency Response	20,871		3,474	6,286		2,286,037
4	Energy Imbalance	-51,090		-4,293,283	-143,677		-6,042,709
5	Operating Reserve - Spinning	1,671,304		576,194	7,175		934,893
6	Operating Reserve - Supplement	1,672,695		501,758	7,175		909,633
7	Other	15,373		5,973,007	-11,485		233,411
8	Total (Lines 1 thru 7)	3,329,153		2,761,150	-30,882		5,404,777

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	04/15/2021	2020/Q4

FOOTNOTE DATA

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

Schedule 1 purchases can be broken down as follows:

Number of Units	Unit of measure	Dollars
126,890	MW	$ 24,334,204
1,121	MWh	1,020
		$ 24,335,224

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
70216	MW	73803
168	MWh	0
		73803

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

Sales can be broken down as follows:

Schedule 3, Units: 4,890 MW, Dollars: $576,019
Schedule 13, Units: 1,397 MW, Dollars: $1,710,018

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

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	04/15/2021	End of 2020/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	5,033	14	1800	4,062	363	575	33	4,013	294
2	February	4,735	4	1800	3,776	351	575	33	656	409
3	March	4,552	9	900	3,625	321	575	31	656	315
4	Total for Quarter 1				11,463	1,035	1,725	97	5,325	1,018
5	April	3,923	2	1000	3,021	298	575	29	631	371
6	May	3,420	4	900	2,528	291	575	26	606	324
7	June	3,892	25	1800	2,694	296	575	327	602	231
8	Total for Quarter 2				8,243	885	1,725	382	1,839	926
9	July	4,471	27	1800	3,269	312	575	315	608	319
10	August	4,438	17	1800	3,232	302	591	313	611	363
11	September	4,204	10	1800	2,997	304	591	312	651	237
12	Total for Quarter 3				9,498	918	1,757	940	1,870	919
13	October	4,207	26	900	3,278	325	591	13	769	530
14	November	4,487	9	900	3,559	322	591	15	824	370
15	December	4,683	23	1800	3,750	324	591	18	615	408
16	Total for Quarter 4				10,587	971	1,773	46	2,208	1,308
17	Total Year to Date/Year				39,791	3,809	6,980	1,465	11,242	4,171

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	04/15/2021	End of 2020/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	700					400	300		
4	Total for Quarter 1						1,200	900		
5	April	700					400	300		
6	May	700					400	300		
7	June	700					400	300		
8	Total for Quarter 2						1,200	900		
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	3,600		

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	04/15/2021	End of 2020/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: 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	363					363		25	
2	February	363					363		25	
3	March	363					363		25	
4	Total for Quarter 1						1,089		75	
5	April	363					363		25	
6	May	363					363		25	
7	June	363					363			
8	Total for Quarter 2						1,089		50	
9	July	363					363		17	
10	August	363					363		17	
11	September	363					363		17	
12	Total for Quarter 3						1,089		51	
13	October	363					363			
14	November	363					363			
15	December	363					363		12	
16	Total for Quarter 4						1,089		12	
17	Total Year to Date/Year						4,356		188	

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	04/15/2021	End of 2020/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	6,096			4,062	363	1,338	333	4,038	294
2	February	5,798			3,776	351	1,338	333	681	409
3	March	5,615			3,625	321	1,338	331	681	315
4	Total for Quarter 1				11,463	1,035	4,014	997	5,400	1,018
5	April	4,986			3,021	298	1,338	329	656	371
6	May	4,483			2,528	291	1,338	326	631	324
7	June	4,955			2,694	296	1,338	627	602	231
8	Total for Quarter 2				8,243	885	4,014	1,282	1,889	926
9	July	5,534			3,269	312	1,338	615	625	319
10	August	5,501			3,232	302	1,354	613	628	363
11	September	5,267			2,997	304	1,354	612	668	237
12	Total for Quarter 3				9,498	918	4,046	1,840	1,921	919
13	October	5,270			3,278	325	1,354	313	769	530
14	November	5,550			3,559	322	1,354	315	824	370
15	December	5,746			3,750	324	1,354	318	627	408
16	Total for Quarter 4				10,587	971	4,062	946	2,220	1,308
17	Total Year to Date/Year				39,791	3,809	16,136	5,065	11,430	4,171

Schedule Page: 400 Line No.: 1 Column: j

Other Service (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

Other Service (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

Other Service (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

Other Service (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

Other Service (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

Other Service (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.: 9 Column: j

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Schedule Page: 400 Line No.: 14 Column: j

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Schedule Page: 400.1 Line No.: 1 Column: c

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Puget Sound Energy, Inc.	(1) X An Original (2) __ A Resubmission	04/15/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 400.1 Line No.: 13 Column: d

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Puget Sound Energy, Inc.	(1) X An Original (2) __ A Resubmission	04/15/2021	2020/Q4

FOOTNOTE DATA

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FOOTNOTE DATA

Long-Term Firm Service and Short-Term Firm Service for the month were the same value for multiple hours on the same day.

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Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

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

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)	20,088,222
3	Steam	4,006,318			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	7,314
5	Hydro-Conventional	980,194			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	6,868,224
7	Other	6,714,406			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	11,700,918	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	22,176
10	Purchases	16,957,849	27	Total Energy Losses	1,588,951
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	28,574,887
12	Received	431,587			
13	Delivered	515,467			
14	Net Exchanges (Line 12 minus line 13)	-83,880			
15	Transmission For Other (Wheeling)				
16	Received	8,438,687			
17	Delivered	8,438,687			
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)	28,574,887			

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	04/15/2021	End of 2020/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM: Puget Sound Energy, Inc.

Line No.	Month	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	2,942,636	742,484	4,245	14	1800
30	February	2,639,852	598,617	3,965	4	1800
31	March	2,928,017	872,064	3,836	9	900
32	April	2,509,983	872,591	3,147	2	1000
33	May	1,958,513	420,376	2,646	4	900
34	June	1,896,179	410,134	2,811	25	800
35	July	2,142,672	517,621	3,418	27	1800
36	August	2,147,438	509,386	3,361	17	1800
37	September	2,006,384	463,291	3,122	10	1800
38	October	2,293,985	573,566	3,464	26	900
39	November	2,297,570	311,753	3,692	9	900
40	December	2,811,653	575,899	3,924	23	1800
41	TOTAL	28,574,882	6,867,782			

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Puget Sound Energy, Inc.	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/15/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 401 Line No.: 29 Column: Sys

NAME OF SYSTEM: Point Roberts Transfer Point

2020

Line No.	Month (a)	Total Monthly Energy (MWH) (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK: Megawatts (see Instr. 4) (d)	MONTHLY PEAK: Day of Month (e)	MONTHLY PEAK: Hour (f)
1	January	2,537		6.2	14	1,900
2	February	2,206		4.3	19	800
3	March	2,025		4.5	15	800
4	**Total**	**6,768**	**0**			
5	April	1,380		3.2	2	800
6	May	1,100		2.2	3	800
7	June	979		1.8	9	1,200
8	**Total**	**3,459**	**0**			
9	July	957		1.7	3	1,800
10	August	933		1.6	16	1,600
11	September	940		1.8	27	900
12	**Total**	**2,831**	**0**			
13	October	1,344		3.5	25	800
14	November	1,819		3.3	11	900
15	December	2,104		4.3	24	900
16	**Total**	**5,266**	**0**			
17	**Yr Total**	**18,324**	**0**			

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FOOTNOTE DATA

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	04/15/2021	End of 2020/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			370.00		
6	Net Peak Demand on Plant - MW (60 minutes)	168			412		
7	Plant Hours Connected to Load	67			8558		
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	8009000			2094329000		
13	Cost of Plant: Land and Land Rights	0			2788745		
14	Structures and Improvements	0			130966084		
15	Equipment Costs	0			405646263		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			539401092		
18	Cost per KW of Installed Capacity (line 17/5) Including	0.0000			1457.8408		
19	Production Expenses: Oper, Supv, & Engr	22753			53329		
20	Fuel	1391080			39569478		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	263282			3788366		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	38127			63104		
26	Misc Steam (or Nuclear) Power Expenses	6165024			5934975		
27	Rents	0			67		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	379309			820868		
30	Maintenance of Structures	159409			1095515		
31	Maintenance of Boiler (or reactor) Plant	256889			7500670		
32	Maintenance of Electric Plant	1782492			1616446		
33	Maintenance of Misc Steam (or Nuclear) Plant	303439			747127		
34	Total Production Expenses	10761804			61189945		
35	Expenses per Net KWh	1.3437			0.0292		
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	3514	0	0	1343215	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	8629	0	0	8562	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	27.729	0.000	0.000
41	Average Cost of Fuel per Unit Burned	26.894	0.000	0.000	29.459	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	1.558	0.000	0.000	1.720	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.012	0.000	0.000	0.019	0.000	0.000
44	Average BTU per KWh Net Generation	7571.196	0.000	0.000	10982.616	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *MINT FARM* (b)			Plant Name: *SUMAS* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Outdoor			Outdoor		
3	Year Originally Constructed	2007			1993		
4	Year Last Unit was Installed	2007			1993		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	320.00			127.00		
6	Net Peak Demand on Plant - MW (60 minutes)	330			133		
7	Plant Hours Connected to Load	6503			4350		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	16			13		
12	Net Generation, Exclusive of Plant Use - KWh	1729277600			477344100		
13	Cost of Plant: Land and Land Rights	1194000			795165		
14	Structures and Improvements	12026050			5697005		
15	Equipment Costs	99888187			80387126		
16	Asset Retirement Costs	0			0		
17	Total Cost	113108237			86879296		
18	Cost per KW of Installed Capacity (line 17/5) Including	353.4632			684.0889		
19	Production Expenses: Oper, Supv, & Engr	319467			214801		
20	Fuel	41484294			11687916		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	259160			360933		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2419865			2263643		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	5309			2987		
30	Maintenance of Structures	138151			70592		
31	Maintenance of Boiler (or reactor) Plant	825894			241822		
32	Maintenance of Electric Plant	1763320			849954		
33	Maintenance of Misc Steam (or Nuclear) Plant	223589			11889		
34	Total Production Expenses	47439049			15704537		
35	Expenses per Net KWh	0.0274			0.0329		
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	11502879	0	0	3634479	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1095334	0	0	1095334	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.606	0.000	0.000	3.216	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.606	0.000	0.000	3.216	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.293	0.000	0.000	2.936	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.024	0.000	0.000	0.024	0.000	0.000
44	Average BTU per KWh Net Generation	7285.990	0.000	0.000	8339.832	0.000	0.000

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	04/15/2021	End of 2020/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)	207.00			107.00		
6	Net Peak Demand on Plant - MW (60 minutes)	215			114		
7	Plant Hours Connected to Load	1666			617		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	4			4		
12	Net Generation, Exclusive of Plant Use - KWh	166220500			28957401		
13	Cost of Plant: Land and Land Rights	1502988			0		
14	Structures and Improvements	4106157			1610745		
15	Equipment Costs	80342555			64873418		
16	Asset Retirement Costs	0			0		
17	Total Cost	85951700			66484163		
18	Cost per KW of Installed Capacity (line 17/5) Including	415.2256			621.3473		
19	Production Expenses: Oper, Supv, & Engr	322680			21066		
20	Fuel	8049601			1306132		
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	1438939			4773		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	7121			2305		
30	Maintenance of Structures	329341			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	2064796			79942		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	12212478			1414218		
35	Expenses per Net KWh	0.0735			0.0488		
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	1937031	2475	0	233130	4314	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1095334	139900	0	1095334	139900	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.004	84.282	0.000	3.402	84.282	0.000
41	Average Cost of Fuel per Unit Burned	4.004	118.908	0.000	3.402	118.908	0.000
42	Average Cost of Fuel Burned per Million BTU	3.655	20.237	0.000	3.106	20.237	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.047	0.217	0.000	0.030	0.202	0.000
44	Average BTU per KWh Net Generation	12869.130	10746.163	0.000	9663.974	10003.033	0.000

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
165.00			136.00			315.00			5
169			135			314			6
2835			3794			7334			7
0			0			0			8
165			136			315			9
0			0			0			10
16			6			18			11
370606000			478493004			2016713000			12
1051000			699814			1288140			13
9540997			6178023			37301570			14
155725696			61264627			282675917			15
0			443797			0			16
166317693			68586261			321265627			17
1007.9860			504.3107			1019.8909			18
214303			1854064			285276			19
10533419			9492274			44182262			20
0			0			0			21
90334			22770			1503789			22
0			0			0			23
0			0			0			24
2625114			818855			2670577			25
0			44630			0			26
0			0			0			27
0			0			0			28
9956			321172			17256			29
19716			65162			57346			30
334706			216895			352528			31
1533274			740493			1487319			32
56256			22470			518410			33
15417078			13598785			51074763			34
0.0416			0.0284			0.0253			35
Gas	Oil		Gas			Gas			36
Mcf	Bbl		Mcf			Mcf			37
3038907	40	0	3073840	0	0	12763222	0	0	38
1095334	131700	0	1095334	0	0	1095334	0	0	39
3.466	0.000	0.000	3.088	0.000	0.000	3.462	0.000	0.000	40
3.466	23.451	0.000	3.088	0.000	0.000	3.462	0.000	0.000	41
3.164	4.240	0.000	2.819	0.000	0.000	3.160	0.000	0.000	42
0.028	0.039	0.000	0.020	0.000	0.000	0.022	0.000	0.000	43
8982.153	9138.324	0.000	7036.431	0.000	0.000	6932.070	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	04/15/2021	End of 2020/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
253.00			169.20			149.00			5
247			144			152			6
0			149			607			7
0			0			0			8
253			149			149			9
0			0			0			10
0			6			6			11
1100429000			4657300			29415310			12
0			364590			785528			13
6594636			1519164			3194161			14
119601339			36751794			37369235			15
1030922			0			0			16
127226897			38635548			41348924			17
502.8731			228.3425			277.5096			18
844534			68627			16994			19
29447198			497465			1363333			20
0			0			0			21
920139			0			0			22
0			0			0			23
0			0			0			24
2510399			470963			545168			25
0			0			0			26
0			0			0			27
0			0			0			28
0			2322			3648			29
19711			144205			65238			30
486345			0			0			31
2223072			745264			626667			32
311330			0			0			33
36762728			1928846			2621048			34
0.0334			0.4142			0.0891			35
Gas	Oil		Gas	Oil		Gas	Oil		36
Mcf	Bbl		Mcf	Bbl		Mcf	Bbl		37
8432082	63	0	76227	652	0	430740	279	0	38
1095334	140000	0	1095334	139000	0	1095334	138900	0	39
3.491	0.000	0.000	5.714	122.452	0.000	3.102	82.563	0.000	40
3.491	120.973	0.000	5.714	94.903	0.000	3.102	97.353	0.000	41
3.187	20.574	0.000	5.216	16.256	0.000	2.832	16.688	0.000	42
0.027	0.174	0.000	0.098	0.290	0.000	0.046	0.356	0.000	43
8393.381	8448.739	0.000	18790.393	17814.359	0.000	16081.084	21353.280	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	04/15/2021	End of 2020/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: *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
256	152	340	6
8779	8751	8502	7
0	0	0	8
0	0	0	9
0	0	0	10
7	6	5	11
764889947	478168716	972680380	12
8131854	0	203682	13
15120072	3413472	31393624	14
407627628	168603717	654262269	15
22037384	12455466	17350201	16
452916938	184472655	703209776	17
1659.0364	1174.9851	2050.1743	18
333083	271618	248885	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
416514	529616	631404	25
0	0	0	26
3283223	1063763	4389552	27
0	0	0	28
182148	139052	89934	29
167342	37811	42646	30
0	0	0	31
4834881	5716185	7378787	32
0	0	0	33
9217191	7758045	12781208	34
0.0121	0.0162	0.0131	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) X An Original (2) __ A Resubmission	04/15/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 402 Line No.: -1 Column: b

Colstrip 1&2 ceased operation on January 3, 2020. All assets were retired in 2019 and thus lines 13 through 17 are zero. Colstrip 1&2 O&M costs for 2020 were primarily related to the plant decommissioning and remediation. Fuel costs shown are primarily trailing costs from 2019.

Schedule Page: 403 Line No.: -1 Column: e

Peak load plant.

Schedule Page: 403 Line No.: -1 Column: f

Peak load plant.

Schedule Page: 402 Line No.: 1 Column: c

This is a cogeneration plant.

Schedule Page: 402 Line No.: 5 Column: b

Jointly owned. Amount represents 50% of rated capacity of 754,000 KW up until January 3, 2020 when the plant ceased operations.

Schedule Page: 402 Line No.: 5 Column: c

Jointly owned. Amount represents 25% of rated capacity of 1,480,000 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: 402 Line No.: 35 Column: b

Colstrip ceased operations on January 3, 2020 so KWH were only for three days of generation in 2020. Total costs were primarily related to the plant decommissioning and remediation. Fuel costs shown are primarily trailing costs from 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.

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	04/15/2021	End of 2020/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)	105.00	91.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	105	109
7	Plant Hours Connect to Load	8,685	8,685
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	20	19
12	Net Generation, Exclusive of Plant Use - Kwh	383,706,200	362,138,355
13	Cost of Plant		
14	Land and Land Rights	8,314,619	554,101
15	Structures and Improvements	35,903,750	114,462,004
16	Reservoirs, Dams, and Waterways	122,777,044	115,733,203
17	Equipment Costs	67,569,228	105,773,492
18	Roads, Railroads, and Bridges	1,588,316	808,565
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	236,152,957	337,331,365
21	Cost per KW of Installed Capacity (line 20 / 5)	2,249.0758	3,706.9381
22	Production Expenses		
23	Operation Supervision and Engineering	754,954	955,343
24	Water for Power	0	0
25	Hydraulic Expenses	1,035,369	1,876,006
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	851,885	685,526
28	Rents	0	0
29	Maintenance Supervision and Engineering	61,256	54,384
30	Maintenance of Structures	83,641	92,756
31	Maintenance of Reservoirs, Dams, and Waterways	65,564	196,264
32	Maintenance of Electric Plant	49,660	194,086
33	Maintenance of Misc Hydraulic Plant	1,713,504	818,181
34	Total Production Expenses (total 23 thru 33)	4,615,833	4,872,546
35	Expenses per net KWh	0.0120	0.0135

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
54.00	0.00	0.00	5
47	0	0	6
8,772	0	0	7
			8
50	0	0	9
50	0	0	10
19	0	0	11
234,349,600	0	0	12
			13
2,001,428	0	0	14
16,276,752	0	0	15
123,029,077	0	0	16
18,857,885	0	0	17
2,648,182	0	0	18
0	0	0	19
162,813,324	0	0	20
3,015.0616	0.0000	0.0000	21
			22
196,452	0	0	23
0	0	0	24
249,905	0	0	25
0	0	0	26
916,998	0	0	27
0	0	0	28
58,471	0	0	29
193,235	0	0	30
270,141	0	0	31
826,502	0	0	32
219,727	0	0	33
2,931,431	0	0	34
0.0125	0.0000	0.0000	35

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	04/15/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 406   Line No.: 11   Column: b

There was a total of 39 fulltime equivalent employees at Baker. They work at both Upper Baker and Lower Baker so split the total number between the two, 20 for Upper Baker, and 19 for Lower Baker.

Schedule Page: 406   Line No.: 11   Column: c

There was a total of 39 fulltime equivalent employees at Baker. They work at both Upper Baker and Lower Baker so split the total number between the two, 20 for Upper Baker, and 19 for Lower Baker.

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)	

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	04/15/2021	End of 2020/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 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
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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	533,930	2,812,124
3						
4						
5						
6						
7						
8						
9						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) [X] An Original (2) [ ] A Resubmission	04/15/2021	End of 2020/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		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
1,022,591	105,222	102,244	26,149	Diesel	1,476	2
						3
						4
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						6
						7
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						46

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Puget Sound Energy, Inc.	(1) X An Original (2) __ A Resubmission	04/15/2021	2020/Q4

FOOTNOTE DATA

Schedule Page: 410 Line No.: 2 Column: e

Generation is in kWh.

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	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	2,612.96		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	04/15/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	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					1,671.39		
9	55 KV Tot					77.47		
10	ARC as per FAS 143							
11								
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31								
32								
33								
34								
35								
36					TOTAL	2,612.96		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	04/15/2021	End of 2020/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								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	115,533,810	117,299,149					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
	48,596,359	822,405,791	871,002,150	12,344,623	11,097,679	402,913	23,845,215	36

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (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
	13,785,559	226,506,351	240,291,910					7
	32,779,038	458,809,991	491,589,029					8
	266,423	19,955,002	20,221,425					9
		1,600,637	1,600,637					10
								11
								12
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								26
								27
								28
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								30
								31
								32
				12,344,623	11,097,679	402,913	23,845,215	33
								34
								35
	48,596,359	822,405,791	871,002,150	12,344,623	11,097,679	402,913	23,845,215	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	04/15/2021	2020/Q4

FOOTNOTE DATA

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	04/15/2021	End of 2020/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Lake Hills	Phantom Lake	2.00	HPD, VDE	16.00	1	1
2							
3							
4							
5							
6							
7							
8							
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40							
41							
42							
43							
44	TOTAL		2.00		16.00	1	1

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	04/15/2021	End of 2020/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1272 ACSR			115	3,592,805	8,474,295	4,563,082		16,630,182	1
									2
									3
									4
									5
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									35
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									37
									38
									39
									40
									41
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									43
				3,592,805	8,474,295	4,563,082		16,630,182	44

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 Puget Sound Energy, Inc.	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report End of 2020/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	BAKER RIVER UPPER SKAGIT	DU	12.50	2.40	
2	BAKERVIEW WHATCOM	DU	115.00	12.50	
3	BARNES LAKE THURSTON	DU	115.00	12.50	
4	BELLIS WHATCOM	DU	115.00	12.50	
5	BELMORE SOUTH WEST KING	DU	115.00	12.50	
6	BERTHUSEN WHATCOM	DU	115.00	12.50	
7	BIG ROCK SKAGIT	DU	115.00	12.50	
8	BIRCH BAY WHATCOM	DU	115.00	12.50	
9	BLACKBURN	DU	115.00	12.50	
10	BLACK DIAMOND SOUTH EAST KING	DU	115.00	12.50	
11	BLAINE WHATCOM	DU	115.00	12.50	
12	BLUMAER THURSTON	DU	115.00	12.50	
13	BONNEY LAKE EAST PIERCE	DU	115.00	12.50	
14	BOW LAKE SOUTH WEST KING	DU	115.00	12.50	
15	BREMERTON SOUTH PENNISULA	DU	115.00	12.50	
16	BRIDLE TRAILS CENTRAL KING	DU	115.00	12.50	
17	BRIGHTWATER IPS NORTH KING	DU	115.00	4.00	
18	BRITTON WHATCOM	DU	115.00	12.50	
19	BROOKS HILL ISLAND	DU	115.00	12.50	
20	BUCKLEY EAST PIERCE	DU	55.00	12.50	
21	BUCKLIN HILL NORTH PENNISULA	DU	115.00	12.50	
22	BURLINGTON SKAGIT	DU	115.00	12.50	
23	BURROWS BAY SKAGIT	DU	115.00	12.50	
24	CAMBRIDGE SOUTH KING	DU	115.00	12.50	
25	CAPITOL THURSTON	DU	115.00	12.50	
26	CAROLINA WHATCOM	DU	115.00	12.50	
27	CEDARHURST EAST PIERCE	DU	115.00	12.50	
28	CENTER CENTRAL KING	DU	115.00	13.09	
29	CENTER CENTRAL KING	DU	115.00	13.09	
30	CENTRAL KITSAP NORTH PENNISULA	DU	115.00	12.50	
31	CHAMBERS THURSTON	DU	115.00	12.50	
32	CHICO SOUTH PENNISULA	DU	115.00	12.50	
33	CHICO SOUTH PENNISULA	DU	34.50	12.50	
34	CHRISTENSENS CORNER NORTH PENNISULA	DU	115.00	12.50	
35	CHRISTOPHER AUBURN	DU	115.00	12.50	
36	CLAY CREEK SOUTH EAST KING	DU	55.00	7.00	
37	CLE ELUM KITTITAS	DU	115.00	34.50	
38	CLOVER VALLEY ISLAND	DU	115.00	12.50	
39	CLYDE HILL CENTRAL KING	DU	115.00	12.50	
40	CLYMER KITTITAS	DU	115.00	12.50	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	COLLEGE CENTRAL KING	DU	115.00	12.50	
2	COTTAGE BROOK NORTH KING	DU	115.00	12.50	
3	COUPEVILLE ISLAND	DU	115.00	12.50	
4	CRESCENT HARBOR ISLAND	DU	115.00	13.00	
5	CRESTWOOD NORTH KING	DU	115.00	12.50	
6	CRYSTAL MOUNTAIN GEN. SE KING	DU	34.50	12.50	
7	CRYSTAL MOUNTAIN GEN. SE KING	DU	12.50	4.16	
8	CUMBERLAND SE KING	DU	115.00	12.50	
9	CUSTER WHATCOM	DU	115.00	12.50	
10	DECATUR THURSTON	DU	115.00	12.50	
11	DES MOINES SOUTH WEST KING	DU	115.00	12.50	
12	DIERINGER EAST PIERCE	DU	115.00	12.50	
13	DUPONT EAST PIERCE	DU	115.00	12.50	
14	DUVALL NORTH KING	DU	115.00	12.50	
15	EARLINGTON SOUTH KING	DU	115.00	12.50	
16	EAST PORT ORCHARD SOUTH PENNISULA	DU	115.00	12.50	
17	EAST VALLEY SOUTH KING	DU	115.00	12.50	
18	EASTGATE CENTRAL KING	DU	115.00	12.50	
19	EASTON KITTITAS	DU	115.00	12.50	
20	EDGEWOOD EAST PIERCE	DU	115.00	12.50	
21	ELD INLET THURSTON	DU	115.00	12.50	
22	ELECTRON GEN. EAST PIERCE	DU	115.00	2.40	
23	ELECTRON HEIGHTS EAST PIERCE	DU	55.00	12.50	
24	ELECTRON HEIGHTS EAST PIERCE	DU	115.00	55.00	
25	ELECTRON HEIGHTS EAST PIERCE	DU	55.00	2.40	
26	ELLINGSON SOUTH EAST KING	DU	115.00	12.50	
27	ENCOGEN GEN. WHATCOM	DU	115.00	13.80	
28	ENCOGEN GEN. WHATCOM	DU	115.00	13.80	
29	ENUMCLAW SOUTH EAST KING	DU	115.00	12.50	
30	EVERGREEN NORTH KING	DU	115.00	12.50	
31	FABER ISLAND	DU	115.00	12.50	
32	FACTORIA CENTER KING	DU	115.00	12.50	
33	FAIRCHILD EAST PIERCE	DU	115.00	12.50	
34	FAIRWOOD CENTRAL KING	DU	115.00	12.50	
35	FALCON SOUTH KING	DU	115.00	12.50	
36	FALL CITY EAST KING	DU	115.00	12.50	
37	FERNWOOD SOUTH PENNISULA	DU	115.00	12.50	
38	FOSS CORNER	DU	115.00		
39	FOUR CORNERS SOUTH EAST KING	DU	115.00	12.50	
40	FRAGARIA SOUTH PENNISULA	DU	115.00	12.50	

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	04/15/2021	End of 2020/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	FREDERICKSON GEN STATION E PIERCE	DU	115.00	13.20	
2	FREDERICKSON GEN STATION E PIERCE	DU	12.50	4.20	
3	FREDERICKSON GEN STATION E PIERCE	DU	12.50		
4	FREDERICKSON GEN STATION E PIERCE	DU	115.00	6.60	
5	FREDONIA SKAGIT	DU	115.00	13.20	
6	FREDONIA SKAGIT	DU	115.00	12.50	13.20
7	FREELAND ISLAND	DU	115.00	12.50	
8	FREEWAY SOUTH WEST KING	DU	115.00	12.50	
9	FRIENDLY GROVE THURSTON	DU	115.00	13.09	
10	FRUITLAND EAST PIERCE	DU	115.00	12.50	
11	GAGES SKAGIT	DU	115.00	12.50	
12	GARDELLA EAST PIERCE	DU	115.00	12.50	
13	GLACIER WHATCOM	DU	55.00	12.50	
14	GLENCARIN SOUTH KING	DU	115.00	12.50	
15	GOODES CORNER EAST KING	DU	115.00	12.50	
16	GRADY SOUTH KING	DU	115.00	12.50	
17	GRAVELLY LAKE EAST PIERCE	DU	115.00	12.50	
18	GREENBANK ISLAND	DU	115.00	12.50	
19	GREENWATER SOUTH EAST KING	DU	55.00	13.90	
20	GREENWATER SOUTH EAST KING	DU	34.50	12.50	
21	GRIFFIN THURSTON	DU	115.00	12.50	
22	HAMILTON SKAGIT	DU	115.00	12.50	
23	HANNEGAN WHATCOM	DU	115.00	12.50	
24	HAPPY VALLEY WHATCOM	DU	115.00	12.50	
25	HARVEST SOUTH KING	DU	115.00	12.50	
26	HAWKS PRAIRIE THURSTON	DU	115.00	13.09	
27	HAZELWOOD CENTRAL KING	DU	115.00	12.50	
28	HEMLOCK EAST PIERCE	DU	115.00	12.50	
29	HICKOX SKAGIT	DU	115.00	12.50	
30	HIGHLANDS CENTRAL KING	DU	115.00	12.50	
31	HILLCREST ISLAND	DU	115.00	12.50	
32	HOBART SOUTH EAST KING	DU	115.00	12.50	
33	HOLDEN EAST PIERCE	DU	115.00	12.50	
34	HOLLYWOOD NORTH KING	DU	115.00	12.50	
35	HOPKINS RIDGE WIND FARM Columbia Cnty	DU	115.00	34.50	
36	HOUGHTON NORTH KING	DU	115.00	12.50	
37	HYAK EAST KING	DU	115.00	12.50	
38	INGLEWOOD NORTH KING	DU	115.00	12.50	
39	JOHNSON HILL THURSTON	DU	115.00	12.50	
40	JUANITA NORTH KING	DU	115.00	12.50	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	KAPOWSIN EAST PIERCE	DU	115.00	12.50	
2	KENDALL WHATCOM	DU	115.00	12.50	55.00
3	KENILWORTH NORTH KING	DU	115.00	12.50	
4	KENMORE NORTH KING	DU	115.00	12.50	
5	KENT SOUTH KING	DU	115.00	12.50	
6	KINGSTON	DU	115.00	12.50	
7	KITTITAS	DU	115.00	12.50	
8	KITTS CORNER SOUTHWEST KING	DU	115.00	12.50	
9	KLAHANIE EAST KING	DU	230.00	12.50	
10	KNOBLE EAST PIERCE	DU	115.00	12.50	
11	KRAIN CORNER SOUTH EAST KING	DU	115.00	55.00	
12	LABOUNTY WHATCOM	DU	115.00	12.50	
13	LACEY THURSTON	DU	115.00	12.50	
14	LAKE HILLS CENTRAL KING	DU	115.00	12.50	
15	LAKE LEOTA NORTH KING	DU	115.00	12.50	
16	LAKE LOUISE WHATCOM	DU	115.00	12.50	
17	LAKE MCDONALD EAST KING	DU	115.00	12.50	
18	LAKE MERIDIAN SOUTH KING	DU	115.00	12.50	
19	LAKE TAPPS EAST PIERCE	DU	55.00	12.50	
20	LAKE WILDERNESS SOUTH KING	DU	115.00	12.50	
21	LAKE YOUNGS SOUTH KING	DU	115.00	12.50	
22	LAKOTA SOUTHWEST KING	DU	115.00	12.50	
23	LANGLEY ISLAND	DU	115.00	12.50	
24	LAUREL WHATCOM	DU	115.00	13.09	
25	LEA HILL SOUTHEAST KING	DU	115.00	12.50	
26	LIQUID AIR SOUTH KING -	DU	115.00	4.20	
27	LOCHLEVEN CENTRAL KING	DU	115.00	13.09	
28	LONG LAKE SOUTH PENNISULA	DU	115.00	12.50	
29	LONGMIRE THURSTON	DU	115.00	12.50	
30	LUHR BEACH THURSTON	DU	115.00	12.50	
31	LYNDEN WHATCOM	DU	115.00	12.50	
32	M STREET SOUTH EAST KING	DU	115.00	12.50	
33	MANCHESTER SOUTH PENNISULA	DU	115.00	12.50	
34	MANHATTAN SOUTHWEST KING	DU	115.00	12.50	
35	MAPLEWOOD CENTRAL KING	DU	115.00	12.50	
36	MARCH POINT COGEN SKAGIT	DU	115.00	13.80	
37	MARINE VIEW SOUTHWEST KING	DU	115.00	12.50	
38	MAXWELTON ISLAND COUNTY	DU	115.00	13.00	
39	MCALLISTER SPRINGS THURSTON	DU	115.00	12.50	
40	MCKENZIE WHATCOM	DU	115.00	12.50	

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1	MCKINLEY THURSTON	DU	115.00	12.50	
2	MCWILLIAMS NORTH PENNISULA	DU	115.00	12.50	
3	MEDINA CENTRAL KING	DU	115.00	12.50	
4	MERCER ISLAND CENTRAL KING	DU	115.00	12.50	
5	MERCERWOOD CENTRAL KING	DU	115.00	12.50	
6	MERIDETH SOUTH EAST KING	DU	115.00	12.50	
7	MIDLAKES CENTRAL KING	DU	115.00	12.50	
8	MIDWAY SOUTH WEST KING	DU	115.00	12.50	
9	MILLER BAY NORTH PENNISULA	DU	115.00	12.50	
10	MIRRORMONT EAST KING	DU	115.00	12.50	
11	MOBILE UNIT #2 SOUTH KING	DU	66.00	12.50	
12	MOBILE UNIT #3 SOUTH KING	DU	115.00	12.50	
13	MOBILE UNIT #4 SOUTH KING	DU	115.00	12.50	
14	MOBILE UNIT #5 SOUTH KING	DU	115.00	12.50	
15	MOBILE UNIT #6 SOUTH KING	DU	115.00	12.50	
16	MOTTMAN THURSTON	DU	115.00	12.50	
17	MOUNT SI NORTH KING	DU	230.00	115.00	
18	MOUNT VERNON SKAGIT	DU	115.00	12.50	
19	MURDEN COVE NORTH PENNISULA	DU	115.00	12.50	
20	NORKIRK NORTH KING	DU	115.00	12.50	
21	NORLUM SKAGIT	DU	115.00	12.50	
22	NORPAC SOUTHKING	DU	115.00	12.50	
23	NORTH BELLEVUE CENTRAL KING	DU	115.00	13.09	
24	NORTH BEND EAST KING	DU	115.00	12.50	
25	NORTH BOTHELL NORTHKING	DU	115.00	12.50	
26	NORTH NORMANDY SOUTHWEST KING	DU	115.00	12.50	
27	NORTHRUP CENTRAL KING	DU	115.00	12.50	
28	NORWAY HILL NORTH KING	DU	115.00	12.50	
29	NUGENTS CORNER WHATCOM	DU	34.50	12.50	
30	NUGENTS CORNER WHATCOM	DU	115.00	34.50	
31	NUGENTS CORNER WHATCOM	DU	12.50	12.50	
32	OLD TOWN WHATCOM	DU	115.00	12.50	
33	OLYMPIA BREWERY THURSTON	DU	115.00	12.50	
34	OLYMPIC ARCO PUMP WHATCOM	DU	115.00	4.20	
35	OLYMPIC AVON SKAGIT	DU	115.00	4.20	
36	OLYMPIC MOBIL WHATCOM	DU	115.00	4.20	
37	OLYMPIC RENTON SOUTH KING	DU	115.00	4.20	
38	OLYMPIA SWITCH	DU	115.00		
39	OLYMPIC VAIL PIPELINE THURSTON	DU	115.00	4.20	
40	OLYMPIC BAYVIEW SKAGIT	DU	115.00	4.36	

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1	ORCHARD SOUTH KING	DU	115.00	12.50	
2	ORILLIA SOUTH KING	DU	115.00	12.50	
3	ORTING EAST PIERCE	DU	115.00	12.50	
4	OSCEOLA SOUTH EAST KING	DU	115.00	12.50	
5	OVERLAKE CENTRAL KING	DU	115.00	12.50	
6	PACCAR CENTRAL KING	DU	115.00	12.50	
7	PADILLA BAY PIPELINE SKAGIT	DU	115.00	12.50	
8	PADILLA BAY PIPELINE SKAGIT	DU	12.50	4.16	
9	PANTHER LAKE SOUTH KING	DU	115.00	12.50	
10	PATTERSON THURSTON	DU	115.00	12.50	
11	PEASLEY CANYON SOUTHWEST KING	DU	115.00	12.50	
12	PETHS CORNER SKAGIT	DU	115.00	12.50	
13	PHANTOM LAKE CENTRAL KING	DU	115.00	12.50	
14	PICKERING CENTRAL KING	DU	115.00	12.50	
15	PINE LAKE EAST KING	DU	115.00	12.50	
16	PIPE LAKE SOUTH EAST KING	DU	115.00	12.50	
17	PLATEAU EAST KING	DU	115.00	12.50	
18	PLEASANT GLADE THURSTON	DU	115.00	12.50	
19	PLUM STREET THURSTON	DU	115.00	13.09	
20	PLYMOUTH WHATCOM	DU	115.00	12.50	
21	POINT ROBERTS WHATCOM	DU	25.00	12.50	
22	PORT GAMBLE NORTH PENNISULA	DU	115.00	12.50	
23	PORT MADISON NORTH PENNISULA	DU	115.00	12.50	
24	POULSBO NORTH PENNISULA	DU	115.00	12.50	
25	PRESIDENT PARK CENTRAL KING	DU	115.00	13.09	
26	PRINE THURSTON	DU	115.00	13.09	
27	PRINE THURSTON	DU	115.00	12.50	
28	QUARRY EAST PIERCE	DU	115.00	12.50	
29	RAINIER VIEW THURSTON	DU	115.00	12.50	
30	REDMOND NORTH KING	DU	115.00	12.50	
31	REDONDO SOUTHWEST KING	DU	115.00	12.50	
32	RENTON JUNCTION SOUTH KING	DU	115.00	12.50	
33	RHODES LAKE EAST PIERCE	DU	115.00	12.50	
34	RITA STREET SKAGIT	DU	115.00	12.50	
35	RIVERBEND SKAGIT	DU	115.00	12.50	
36	ROCHESTER THURSTON	DU	115.00	12.50	
37	ROCKY POINT SOUTH PENNISULA	DU	115.00	12.50	
38	ROEDER WHATCOM	DU	115.00	13.09	
39	ROLLING HILLS SOUTH KING	DU	115.00	12.50	
40	ROSE HILL CENTRAL KING	DU	115.00	12.50	

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1	SAHALEE NORTH KING	DU	115.00	12.50	
2	SAINT CLAIR THURSTON	DU			
3	SAMMAMISH NORTH KING	DU	230.00	115.00	
4	SCENIC NORTH KING	DU	115.00	12.50	
5	SCHUETT WHATCOM	DU	115.00	12.50	
6	SEATAC SOUTH KING	DU	115.00	13.09	
7	SEHOME WHATCOM	DU	115.00	12.50	
8	SEMIAHMOO WHATCOM	DU	115.00	12.50	
9	SEQUOIA SOUTH KING	DU	115.00	12.50	
10	SERWOLD NORTH PENNISULA	DU	115.00	12.50	
11	SHANNON WHATCOM	DU	34.50	12.50	
12	SHANNON WHATCOM	DU	115.00	34.50	
13	SHAW EAST PIERCE	DU	115.00	12.50	
14	SHERIDAN NORTH PENNISULA	DU	115.00	12.50	
15	SHERWOOD SOUTH EAST KING	DU	115.00	12.50	
16	SHUFFLETON YARD SOUTH KING	DU	55.00	12.50	
17	SHUFFLETON YARD SOUTH KING	DU	55.00	7.20	
18	SHUFFLETON YARD SOUTH KING		12.50	12.50	
19	SHUFFLETON YARD SOUTH KING	DU	12.50	4.20	
20	SHUFFLETON YARD SOUTH KING	DU	34.50	12.50	
21	SHUFFLETON YARD SOUTH KING	DU	115.00	34.50	
22	SHUFFLETON YARD SOUTH KING	DU	115.00	12.50	
23	SHUFFLETON YARD SOUTH KING	DU	115.00	12.50	
24	SHUFFLETON YARD SOUTH KING	DU	230.00	115.00	34.50
25	SILVERDALE NORTH PENNISULA	DU	115.00	12.50	
26	SINCLAIR INLET SOUTH PENNISULA	DU	115.00	12.50	
27	SKYKOMISH NORTH KING	DU	115.00	12.50	
28	SLATER WHATCOM	DU	115.00	12.50	
29	SNOQUALMIE EAST KING	DU	115.00	12.50	
30	SNOQUALMIE (BLACK CREEK GEN)	DU	34.50	12.50	
31	SNOQUALMIE GEN. #1	DU	117.90	6.90	2.00
32	SNOQUALMIE GEN. #2	DU	117.90	7.20	
33	SOMERSET CENTRAL KING	DU	115.00	12.50	
34	SOOS CREEK SOUTH KING	DU	115.00	12.50	
35	SOUTH BELLEVUE CENTRAL KING	DU	115.00	12.50	
36	SOUTH KEYPORT NORTH PENNISULA	DU	115.00	12.50	
37	SOUTH KIRKLAND NORTH KING	DU	115.00	12.50	
38	SOUTH MERCER CENTRAL KING	DU	115.00	12.50	
39	SOUTHWICK THURSTON	DU	115.00	12.50	
40	SOUTHCENTER SOUTH KING	DU	115.00	12.50	

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	SOUTH WHIDBEY SWITCH ISLAND	DU	115.00		
2	SPANAWAY EAST PIERCE	DU	115.00	12.50	
3	SPANAWAY EAST PIERCE		115.00	7.20	
4	SPIRITBROOK NORTH KING	DU	115.00	12.50	
5	SPURGEON CREEK	DU	115.00	12.50	
6	STARWOOD SOUTH KING	DU	115.00	12.50	
7	STATE STREET WHATCOM	DU	115.00	13.09	
8	STERLING NORTH KING	DU	115.00	12.50	
9	STEWART EAST PIERCE	DU	115.00	12.50	
10	SUMAS GEN STATION	DU	115.00	13.80	
11	SUMMIT PARK SKAGIT	DU	115.00	12.50	
12	SUMNER EAST PIERCE	DU	115.00	12.50	
13	SUNRISE EAST PIERCE	DU	115.00	12.50	
14	SWANTOWN ISLAND	DU	115.00	12.50	
15	SWEPTWING SOUTHWEST KING	DU	115.00	12.50	
16	TANGLEWILDE THURSTON	DU	115.00	12.50	
17	TEN MILE WHATCOM	DU	115.00	4.20	
18	TEXACO EAST SKAGIT	DU	115.00	13.80	
19	TEXACO WEST SKAGIT	DU	115.00	13.80	
20	THORP KITTITAS	DU	34.50	12.50	
21	THURSTON THURSTON	DU	115.00	12.50	
22	TILLICUM EAST PIERCE	DU	115.00	12.50	
23	TOLT NORTH KNG	DU	115.00	12.50	
24	TOTEM NORTH KING	DU	115.00	12.50	
25	TRACYTON NORTH PENNISULA	DU	115.00	12.50	
26	UNION HILL EAST KING	DU	115.00	13.09	
27	VALLEY JUNCTION	DU	115.00		
28	VAN WYCK WHATCOM	DU	115.00	12.50	
29	VASHON SOUTH PENNISULA	DU	115.00	12.50	
30	VICTORIA PARK SOUTH KING	DU	115.00	12.50	
31	VIKING WHATCOM	DU	115.00	12.50	
32	VISTA WHATCOM	DU	115.00	12.50	
33	VITULLI NORTH KING	DU	115.00	12.50	
34	WABASH SOUTH EAST KING	DU	55.00	12.50	
35	WAYNE NORTH KING	DU	115.00	12.50	
36	WEST AUBURN SOUTHWEST KING	DU	115.00	12.50	
37	WEST CAMPUS SOUTHWEST KING	DU	115.00	12.50	
38	WEST ISSAQUAH EAST KING	DU	115.00	13.09	
39	WEST OLYMPIA THURSTON	DU	115.00	12.50	
40	WHIDBEY ISLAND OAK HARBOR	DU			

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	04/15/2021	End of 2020/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	WEYERHAEUSER SW KING	DU	115.00	12.50	
2	WEYERHAEUSER WHR BRANCH	DU	55.00	4.16	
3	WHITEHORN WHATCOM	DU	115.00	13.20	
4	WHITE RIVER TRANSM. EAST PIERCE	DU	115.00	55.00	
5	WHITE RIVER TRANSM. EAST PIERCE	DU	55.00	7.20	
6	WHITEHORN GEN WHATCOM	DU	12.50		
7	WHITEHORN GEN WHATCOM	DU	12.50	0.50	
8	WHITEHORN GEN WHATCOM	DU	12.50	4.20	
9	WILKESON EAST PIERCE	DU	55.00	12.50	
10	WILSON SKAGIT	DU	115.00	12.50	
11	WINSLOW NORTH PENNISULA	DU	115.00	12.50	
12	WOBURN WHATCOM	DU	115.00	12.50	
13	WOLDALE KITTITAS	DU	115.00	12.50	
14	WOODLAND EAST PIERCE	DU	115.00	12.50	
15	YELM THURSTON	DU	115.00	12.50	
16	ZENITH SOUTHWEST KING	DU	115.00	12.50	
17	TOTAL DISTRIBUTION STATIONS		37714.80	4660.59	104.70
18					
19	SUMMARY - TRANSMISSION CAPACITY		5815.00	2041.00	246.30
20	SUMMARY - DISTRIBUTION CAPACITY		37714.80	4660.59	104.70
21	TOTAL		43529.80	6701.59	351.00
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
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.
325	1		Static Capacitor	2	21	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	42	11
215	1					12
160	1					13
200	1		Reactor	1	10	14
325	1					15
650	2		Static Capacitor	2	84	16
650	2		Static Capacitor	2	42	17
325	1					18
325	1		Static Capacitor	1	42	19
650	2		Static Capacitor	1	42	20
533	3					21
650	2		Static Capacitor	1	45	22
390	3		Static Capacitor	7	106	23
325	1		Reactor	1	45	24
8548	34	1		23	596	25
						26
20	1		Static Capacitor	1	4	27
9	1					28
50	2		Static Capacitor	2	6	29
20	1		Static Capacitor	1	5	30
80	2		Static Capacitor	1	24	31
80	2		Static Capacitor	1	24	32
80	2					33
50	2		Static Capacitor	2	10	34
25	1		Static Capacitor	1	5	35
25	1		Static Capacitor	1	5	36
133	2					37
25	1					38
8	1					39
120	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.
3	3					1
25	1		Static Capacitor	1	5	2
20	1		Static Capacitor	1	5	3
25	1		Static Capacitor	1	5	4
50	2		Static Capacitor	2	9	5
25	1		Static Capacitor	1	5	6
20	1		Static Capacitor	1	5	7
25	1		Static Capacitor	1	2	8
25	1		Static Capacitor	1	5	9
25	1		Static Capacitor	1	2	10
25	1		Static Capacitor	1	5	11
20	1		Static Capacitor	1	2	12
25	1		Static Capacitor	1	5	13
75	3		Static Capacitor	1	5	14
50	2		Static Capacitor	2	10	15
50	2		Static Capacitor	2	11	16
13	1					17
20	1		Static Capacitor	1	5	18
20	1					19
19	2		Static Capacitor	1	2	20
25	1					21
25	1		Static Capacitor	1	5	22
25	1					23
25	1		Static Capacitor	1	5	24
50	2					25
20	1		Static Capacitor	1	5	26
25	1		Static Capacitor	1	5	27
40	1		Static Capacitor	1	6	28
25	1		Static Capacitor	1	6	29
25	1		Static Capacitor	1	2	30
25	1		Static Capacitor	1	10	31
25	1		Static Capacitor	1	5	32
16	2					33
20	1		Static Capacitor	1	5	34
25	1		Static Capacitor	1	5	35
1	1	1				36
50	1					37
20	1		Static Capacitor	1	5	38
25	1		Static Capacitor	1	5	39
12	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
20	1					3
25	1		Static Capacitor	1	5	4
25	1		Static Capacitor	1	5	5
8	1		Static Capacitor			6
4	1					7
25	1		Static Capacitor	1	3	8
20	1		Static Capacitor	1	5	9
20	1		Static Capacitor	1	2	10
25	1		Static Capacitor	1	5	11
25	1					12
20	1		Static Capacitor	1	5	13
25	1					14
25	1		Static Capacitor	2	6	15
25	1		Static Capacitor	1	5	16
25	1		Static Capacitor	1	5	17
50	2		Static Capacitor	1	5	18
20	1					19
25	1		Static Capacitor	1	2	20
20	1		Static Capacitor	1	2	21
25	1					22
2	1					23
40	3					24
3	2					25
25	1		Static Capacitor	1	4	26
150	3					27
68	1					28
25	1		Static Capacitor	1	2	29
50	2		Static Capacitor	2	10	30
25	1		Static Capacitor	1	4	31
50	2		Static Capacitor	2	10	32
50	2		Static Capacitor	1	5	33
25	1		Static Capacitor	1	3	34
25	1		Static Capacitor	1	5	35
25	1					36
25	1		Static Capacitor	1	5	37
			Static Capacitor	1	23	38
25	1		Static Capacitor	1	5	39
25	1		Static Capacitor	1	2	40

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.
170	2					1
2	2					2
3	2					3
			Spare GSU			4
110	2					5
75						6
20	1		Static Capacitor	1	5	7
25	1		Static Capacitor	1	5	8
25	1		Static Capacitor	1	5	9
25	1		Static Capacitor	1	5	10
25	1		Static Capacitor	1	5	11
25	1		Static Capacitor	1	5	12
5	1					13
25	1		Static Capacitor	1	5	14
25	1		Static Capacitor	1	5	15
25	1		Static Capacitor	1	5	16
20	1		Static Capacitor	1	5	17
9	1					18
20	1		Static Capacitor	1	5	19
8	1					20
20	1		Static Capacitor	1	5	21
20	1					22
20	1		Static Capacitor	1	2	23
25	1					24
50	2		Static Capacitor	1	5	25
25	1		Static Capacitor	1	2	26
25	1		Static Capacitor	1	3	27
25	1		Static Capacitor	1	5	28
25	1					29
25	1		Static Capacitor	1	5	30
20	1		Static Capacitor	1	3	31
25	1		Static Capacitor	1	2	32
20	1		Static Capacitor	1	2	33
25	1		Static Capacitor	1	5	34
167	2		Static Capacitor	2	29	35
25	1		Static Capacitor	1	5	36
20	1		Static Capacitor	1	5	37
25	1		Static Capacitor	1	5	38
25	1		Static Capacitor	1	5	39
50	2		Static Capacitor	2	10	40

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)	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)	
20	1		Static Capacitor	1	5	1
30	1	1	Static Capacitor	1	2	2
25	1		Static Capacitor	1	5	3
25	1		Static Capacitor	1	5	4
50	2		Static Capacitor	2	8	5
25	1		Static Capacitor	1	5	6
25	1		Static Capacitor	1	5	7
25	1		Static Capacitor	1	5	8
25	1	1	Static Capacitor	1	5	9
25	1		Static Capacitor	1	5	10
40	1	3				11
20	1		Static Capacitor	1	5	12
25	1		Static Capacitor	1	4	13
25	1		Static Capacitor	1	5	14
25	1		Static Capacitor	1	5	15
20	1		Static Capacitor	1	5	16
25	1		Static Capacitor	1	5	17
25	1					18
18	1		Static Capacitor	1	2	19
25	1		Static Capacitor	1	5	20
25	1		Static Capacitor	1	5	21
25	1		Static Capacitor	1	5	22
20	1					23
25	1		Static Capacitor	1	5	24
25	1		Static Capacitor	1	3	25
20	2					26
50	2		Static Capacitor	2	12	27
25	1		Static Capacitor	2	10	28
25	1		Static Capacitor	1	5	29
25	1		Static Capacitor	1	2	30
40	2		Static Capacitor	2	10	31
25	1		Static Capacitor	1	5	32
25	1		Static Capacitor	1	2	33
25	1		Static Capacitor	1	5	34
25	1		Static Capacitor	1	5	35
140	3					36
25	1		Static Capacitor	1	5	37
25	1		Static Capacitor	1	5	38
25	1					39
20	1		Static Capacitor	1	5	40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1		Static Capacitor	1	5	1
20	1		Static Capacitor	1	2	2
25	1					3
25	1					4
20	1					5
25	1		Static Capacitor	1	5	6
25	1		Static Capacitor	1	5	7
			Static Capacitor	1	42	8
25	1		Static Capacitor	1	5	9
25	1		Static Capacitor	1	5	10
9	1					11
25	1					12
15	1					13
25	1					14
25	1					15
20	1		Static Capacitor	1	5	16
25	1	1	Static Capacitor	1	2	17
25	1		Static Capacitor	1	2	18
25	1		Static Capacitor	1	5	19
25	1		Static Capacitor	1	5	20
20	1					21
25	1		Static Capacitor	1	5	22
50	2		Static Capacitor	2	10	23
25	1		Static Capacitor	1	5	24
25	1		Static Capacitor	1	5	25
25	1		Static Capacitor	1	5	26
25	1		Static Capacitor	1	5	27
25	1		Static Capacitor	1	5	28
8	1					29
25	1					30
5	1					31
20	1		Static Capacitor	1	5	32
20	1		Static Capacitor	1	5	33
6	1					34
19	2					35
9	1					36
9	1					37
			Static Capacitor	1	42	38
6	1					39
6	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	4	1
25	1		Static Capacitor	1	5	2
25	1		Static Capacitor	1	2	3
20	1		Static Capacitor	1	2	4
25	1					5
50	2		Static Capacitor	2	10	6
9	1					7
4	1					8
25	1		Static Capacitor	1	5	9
20	1		Static Capacitor	1	5	10
25	1		Static Capacitor	1	5	11
20	1		Static Capacitor	1	2	12
25	1		Static Capacitor	1	5	13
25	1		Static Capacitor	1	5	14
25	1		Static Capacitor	1	5	15
25	1		Static Capacitor	1	3	16
25	1		Static Capacitor	1	5	17
25	1		Static Capacitor	1	5	18
25	1		Static Capacitor	1	5	19
25	1					20
19	2					21
20	1		Static Capacitor	1	4	22
25	1		Static Capacitor	1	5	23
25	1					24
25	1		Static Capacitor	1	5	25
25	1		Static Capacitor	1	5	26
20	1		Static Capacitor	1	5	27
9	1					28
25	1		Static Capacitor	1	5	29
50	2		Static Capacitor	2	10	30
25	1		Static Capacitor	1	5	31
50	2		Static Capacitor	2	10	32
25	1		Static Capacitor	1	5	33
20	1					34
20	1		Static Capacitor	1	5	35
40	2		Static Capacitor	1	5	36
50	2					37
20	1		Static Capacitor	1	5	38
25	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) 04/15/2021	Year/Period of Report End of 2020/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1		Static Capacitor	1	5	1
			Static Capacitor	1	40	2
25	1	1	Static Capacitor	1	5	3
4	1					4
20	1					5
50	2					6
25	1		Static Capacitor	1	5	7
25	1		Static Capacitor	1	5	8
25	1		Static Capacitor	1	5	9
25	1		Static Capacitor	1	5	10
8	1					11
25	1			1	5	12
25	1		Static Capacitor	1	5	13
40	1		Static Capacitor	1	5	14
25	1		Static Capacitor	1	5	15
9		1				16
3		1				17
10		1				18
8		1				19
10		2				20
25		1				21
25		12				22
13		1				23
50		1				24
25	1		Static Capacitor	1	5	25
20	1		Static Capacitor	1	5	26
9	1					27
20	1		Static Capacitor	1	5	28
25	1					29
5	1					30
20	1					31
53	1					32
25	1		Static Capacitor	1	5	33
25	1		Static Capacitor	1	5	34
25	1		Static Capacitor	1	5	35
20	1		Static Capacitor	1	4	36
25	1		Static Capacitor	1	5	37
20	1					38
25	1		Static Capacitor	1	5	39
25	1		Static Capacitor	1	5	40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
			Static Capacitor	2	42	1
20	1		Static Capacitor	1	5	2
		1				3
25	1		Static Capacitor	1	5	4
25	1		Static Capacitor	1	5	5
50	2		Static Capacitor	2	10	6
25	1		Static Capacitor	1	5	7
50	2		Static Capacitor	2	10	8
25	1		Static Capacitor	1	5	9
240	2					10
20	1		Static Capacitor	1	4	11
20	1		Static Capacitor	1	5	12
25	1		Static Capacitor	1	5	13
20	1					14
25	1		Static Capacitor	1	3	15
25	1		Static Capacitor	1	5	16
9	1					17
50	2					18
80	2					19
9	1					20
50	2		Static Capacitor	1	5	21
25	1		Static Capacitor	1	5	22
25	1					23
25	1		Static Capacitor	1	5	24
20	1		Static Capacitor	1	2	25
25	1		Static Capacitor	1	5	26
			Static Capacitor	1	23	27
9	1					28
50	2		Static Capacitor	2	10	29
25	1		Static Capacitor	1	5	30
20	1		Static Capacitor	1	5	31
20	1		Static Capacitor	1	5	32
50	2		Static Capacitor	2	10	33
9	1					34
25	1					35
25	1		Static Capacitor	1	4	36
25	1		Static Capacitor	1	2	37
25	1		Static Capacitor	1	5	38
25	1		Static Capacitor	1	5	39
			Static Capacitor	1	23	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)	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)	
20	1					1
8	3					2
170	2					3
83	3					4
3	3					5
1	2					6
2	2					7
2	2					8
9	1					9
25	1		Static Capacitor	1	5	10
25	1					11
25	1					12
20	1					13
25	1		Static Capacitor	1	2	14
25	1		Static Capacitor	2	26	15
25	1		Static Capacitor	1	5	16
9760	397	30		258	1,453	17
						18
8548	34	1		23	596	19
9760	397	30		258	1,453	20
18308	431	31		281	2,049	21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Name of Respondent Puget Sound Energy, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

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.: 17   Column: a

Waste Water Treatment Division - Brightwater leases PSE owned transformer at Brightwater Substation. Expiration 5/21/2020.

Schedule Page: 426.1   Line No.: 25   Column: a

State of Washington Admin leases PSE owned transformer at Capitol Substation. Service started November 1972.

Schedule Page: 426.1   Line No.: 38   Column: a

Navy Ault leases PSE owned transformer at Clover Valley Substation. Service started November 1972.

Schedule Page: 426.2   Line No.: 13   Column: a

Center Drive Owners Association leases transformer at Dupont Substation. Service began 12/1/2018.

Schedule Page: 426.2   Line No.: 33   Column: a

Benaroya leases PSE owned transformer at Fairchild Substation. Service started December 2005.

Schedule Page: 426.5   Line No.: 10   Column: a

BioEnergy leases PSE owned transformer at Mirrormont Substation.

Schedule Page: 426.5   Line No.: 25   Column: a

AT&T leases PSE owned transformer at North Bothell Substation.

Schedule Page: 426.5   Line No.: 34   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.: 35   Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Avon Substation. Service started April 2004.

Schedule Page: 426.5   Line No.: 36   Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Mobil Substation. Service started April 2004.

Schedule Page: 426.5   Line No.: 37   Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Renton Substation. Service started April 2004.

Schedule Page: 426.5   Line No.: 39   Column: a

BP Pipelines (North America) leases PSE owned transformer at Olympic Vail Substation. Service started April 2004.

Schedule Page: 426.5   Line No.: 40   Column: a

Olympic Pipeline leases PSE owned transformer at Olympic Bayview Substation.

Schedule Page: 426.6   Line No.: 6   Column: a

PACCAR Inc. leases PSE owned transformer at PACCAR Substation. Service started December 1992.

Schedule Page: 426.6   Line No.: 7   Column: a

Olympic Pipeline leases PSE owned transformer at Padilla Bay Substation.

Schedule Page: 426.6   Line No.: 38   Column: a

Bellingham Cold Storage leases PSE owned transformer at Roeder Substation. Service started May 1967.

Schedule Page: 426.7   Line No.: 3   Column: a

AT&T leases PSE owned transformer at Sammamish Substation. Service started 2010.

Schedule Page: 426.8   Line No.: 8   Column: a

Microsoft leases PSE owned transformer at Sterling Substation. Service started 2010.

Name of Respondent Puget Sound Energy, Inc.	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2021	Year/Period of Report 2020/Q4

FOOTNOTE DATA

Schedule Page: 426.8 Line No.: 17 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.: 18 Column: a

Shell leases PSE owned transformer at Texaco East Substation under Schedule 449.

Schedule Page: 426.8 Line No.: 19 Column: a

Shell leases PSE owned transformer at Texaco West Substation under Schedule 449.

Schedule Page: 426.8 Line No.: 31 Column: a

Western Washington University leases PSE owned transformer at Viking Substation.

Schedule Page: 426.8 Line No.: 33 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.: 1 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	04/15/2021	End of 2020/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	General and Administrative Expenses	Puget Energy, Inc.	146	932,492
22	Operations and Maintenance Expenses	Puget LNG, LLC	146	310,215
23	General and Administrative Expenses	Puget Holdings, LLC	146	919,544
24				
25				
26				
27				
28				
29				
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Schedule	Page No.

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