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February 1, 2021

VIA ETARIFF

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: *PacifiCorp*, Docket No. ER21-_____-000
Revisions to OATT Schedules 2, 3, 3A, 5 and 6 and Attachment U

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA"),[1] Part 35 of the Federal Energy Regulatory Commission's ("FERC" or the "Commission") regulations,[2] and Order No. 714,[3] PacifiCorp hereby submits revisions to its Open Access Transmission Tariff ("OATT") to update rates for the following ancillary services: Schedule 2, Reactive Supply and Voltage Control from Generation or Other Sources Service; Schedule 3, Regulation and Frequency Response Service; Schedule 3A, Generator Regulation and Frequency Response Service; Schedule 5, Operating Reserve – Spinning Reserve Service; and Schedule 6, Operating Reserve – Supplemental Reserve Service. In addition, the revisions include changes to non-rate terms and conditions of the ancillary services, including self-supply provisions, and various conforming revisions to the OATT contained in Attachment U.

This filing implements a pre-filing settlement agreement on the just and reasonable rates, terms, and conditions for Schedules 2, 3, 3A, 5 and 6 ("2020 Settlement Agreement") between PacifiCorp and transmission customers, which is included as Attachment A to the filing.[4] The 2020 Settlement Agreement is the product of a year of discussions and negotiations between PacifiCorp and its customers, and was reached through stakeholder proceedings conducted by PacifiCorp consistent with the terms of a previous settlement in Docket No. ER17-219-000 (the "ER17-219 Settlement").[5] The 2020 Settlement Agreement is not submitted for acceptance for

[1] 16 U.S.C. § 824d (2006).

[2] 18 C.F.R. Part 35 (2020).

[3] *Electronic Tariff Filings*, Order No. 714, FERC Stats. & Regs. ¶ 31,276 (2008), *order on reh'g*, Order No. 714-A, 147 FERC ¶ 61,115 (2014).

[4] This filing proposes no changes to rates, terms or conditions beyond the changes contemplated by the 2020 Settlement Agreement.

[5] *PacifiCorp*, 163 FERC ¶ 61,035 (2018).

filing under Rule 602 of the Commission's Regulations; however, the rates and non-rate terms and conditions (including moratoria on rate changes) of the 2020 Settlement Agreement are an integrated component of this Section 205 rate filing and the settlement's substantive terms applicable to the provision of the enumerated ancillary services under the PacifiCorp OATT are captured through the attached revisions to the PacifiCorp OATT, thus ensuring that all provisions of the 2020 Settlement Agreement related to transmission service and ancillary services are "on file" with the Commission.

PacifiCorp requests that the Commission accept the enclosed revisions to Schedules 2, 3, 3A, 5 and 6 for filing to be effective January 1, 2021, and accept the enclosed revisions to Attachment U for filing to be effective July 1, 2021, as contemplated by the 2020 Settlement Agreement, without condition or further procedures, and without modification to any of that negotiated settlement's terms.

I. INTRODUCTION

For the past year, PacifiCorp and its customers have been negotiating revised ancillary service rates, terms, and conditions under the PacifiCorp OATT, as required by the ER17-219 Settlement. Among other things, the ER17-219 Settlement directed that, during the moratorium period established by the ER17-219 Settlement, which ended on June 1, 2020,[6] PacifiCorp "shall work with stakeholders in good faith" regarding the methodology and data to calculate reserve requirements for Schedules 3 and 3A,[7] and to work with stakeholders to address issues concerning self-supply for Schedules 3, 3A, 5 and 6.[8]

To facilitate the stakeholder process required by the ER17-219 Settlement, PacifiCorp began conducting stakeholder meetings in December 2019 regarding the rates for Schedules 3, 3A, 5, and 6, and self-supply of those services. During the course of the process, PacifiCorp also made proposals to incorporate a rate update to its Schedule 2 rates, which have not been updated since 2011. It became apparent during the stakeholder process that the best way to implement the ER17-219 Settlement and changes to Schedule 2 would be to reach a pre-filing settlement. This was ultimately successful as in December 2020, PacifiCorp and its customers were able to reach agreement on an integrated package of tariff rate and non-rate modifications and other non-tariff provisions, all as reflected in the 2020 Settlement Agreement.

The ER17-219 Settlement contemplated that PacifiCorp would make a filing under Section 205 of the FPA to update its ancillary service rates for Schedules 3, 3A, 5 and 6, and furthermore instructed that, at the conclusion of the stakeholder process, PacifiCorp "shall conform" its Section 205 filing to reflect "the consensus" reached during the stakeholder process.[9] Accordingly, PacifiCorp hereby files revised tariff records to its OATT to reflect those portions of the 2020 Settlement Agreement that entail rate or other tariff provisions. The non-rate, non-tariff provisions

[6] The ER17-219 Settlement is discussed in section II.B, infra.

[7] ER17-219 Settlement, § 6.2.

[8] *Id*., § 3.7.

[9] *Id*., § 6.4.

set forth in the 2020 Settlement Agreement do not require additional filings by PacifiCorp but are integral components of the settlement package set forth in the 2020 Settlement Agreement.

The rates, terms and conditions of the 2020 Settlement Agreement are negotiated, "black box" provisions. The overall rate impact of the 2020 Settlement Agreement is an increase of $1,244,306.[10] As the increase is greater than $1 million, PacifiCorp also includes cost support with this filing to meet part 35.13 of the Commission's rules and regulations.[11]

The cost support included with this filing consists of the testimony and workpapers of PacifiCorp experts, which are described more fully in section III.A of this transmittal letter. The cost support is PacifiCorp's "base case," which PacifiCorp used as a starting point for its negotiations with customers during the stakeholder process, and which reflects higher rates that PacifiCorp would have proposed in this filing if settlement had not been achieved. PacifiCorp is not proposing to implement the base case rates in this filing and is not seeking Commission approval of the base case rates. Additionally, PacifiCorp acknowledges that the customers executing the 2020 Settlement Agreement do not agree that the "base case" results in just and reasonable rates under Section 205 of the FPA.[12] The rates under the 2020 Settlement Agreement are uniformly lower than those presented in PacifiCorp's base case. Due to the black box nature of the 2020 Settlement Agreement, PacifiCorp also requests waiver of the Commission's rules and regulations to the extent they would require support beyond what is included with this filing. PacifiCorp is authorized to state that the customers executing the 2020 Settlement Agreement support PacifiCorp's waiver requests.

PacifiCorp urges the Commission to accept the revised tariff records included with this filing that implement the 2020 Settlement Agreement, effective January 1, 2021, as contemplated by the 2020 Settlement Agreement. Acceptance of the tariff records without further settlement or hearing procedures or suspension is consistent with the Commission's policy of favoring settlements (in this case a pre-filing settlement predicated on an extensive stakeholder process) that provide "parties with certainty, reduce litigation costs, and permit parties to reach reasonable compromise in resolving difficult issue."[13] Further, the Commission has accepted similar filings

[10] Further information regarding the effect of the rate change from the 2020 Settlement Agreement is provided in Appendix 1 to this letter. Separately, as Exhibit No. PAC-0013, PacifiCorp is providing statements BG/BH, which provide information comparing the base case rates to the existing rates.

[11] 18 C.F.R. § 35.13(a)(1) (2020).

[12] The Settling Parties (as defined in Section III.B.1 below) have agreed that the customers will not protest the instant filing of the settled rates and terms. PacifiCorp understands that the customers would protest, and have reserved their rights to protest, the base case rates in the event that PacifiCorp were to propose them. As more fully explained *infra* at § II.B.3.e of this transmittal letter, in the event that the Commission does not approve the proposals in this filing, PacifiCorp will withdraw this filing without prejudice to it making a new filing of non-settled rates and conditions, and that the customers will be free to protest any such subsequent filing.

[13] *PJM Interconnection, L.L.C.*, 157 FERC ¶ 61,181 at P 6 (Letter Order issued Dec. 5, 2016) (citing *State of Maine*, 91 FERC ¶ 61,213, at 61,772 (2000) ("our strong support of settlements militates in favor of giving these parties certainty, and letting them receive the full benefits of their bargain"); *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs.*, 122 FERC ¶ 61,009, at P 13 (2008) ("the Commission strongly favors settlements, particularly in cases that are highly contested and complex."); *Montana Power Co.*, 77 FERC ¶ 61,110, at 61,434 (1996) ("the Commission strongly favors settlements, which provide the opportunity to eliminate the need for more lengthy proceedings if the parties reach an agreement on the issues that is compatible with the public interest").

under Section 205 to implement the terms of pre-filing settlements with customers.[14] Should the Commission determine not to accept the enclosed tariff records without condition or further procedure, PacifiCorp is obligated by the 2020 Settlement Agreement to seek to withdraw this filing, and the customers have reserved their rights to protest and contest any subsequent filing.[15] Such an outcome would invariably lead to complex and contested litigation between PacifiCorp and its customers over the appropriate rates, terms and conditions of service and self-supply under Schedules 2, 3, 3A, 5 and 6, and perhaps other matters as well. Moreover, such an outcome would effectively nullify the nearly 14 months of good faith work and negotiations undertaken by PacifiCorp and its customers.

II. BACKGROUND

A. PacifiCorp

PacifiCorp is an indirect, wholly owned subsidiary of Berkshire Hathaway Energy Company. PacifiCorp provides delivery of electric power and energy to approximately 1.9 million retail electric customers in six western states: California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp provides transmission services, transmission planning, and system operations for all six states through its PacifiCorp Transmission operating unit. PacifiCorp delivers electricity to its retail electric customers through its Pacific Power and Rocky Mountain Power operating units. PacifiCorp's energy dispatch and supply management operations are conducted by the PacifiCorp Energy Supply Management group.

PacifiCorp operates an integrated transmission system spanning two BAAs – PacifiCorp East ("PACE"), which covers Utah, Wyoming and Southeast Idaho, and PacifiCorp West ("PACW"), which covers Oregon, Washington and California. Together, these BAAs comprise the largest privately owned and operated grid in the Western United States.

PacifiCorp provides wholesale transmission service under its OATT approved by the Commission. PacifiCorp's transmission network is highly integrated with other transmission providers in the western United States. PacifiCorp owns and operates approximately 16,500 miles of transmission lines in 10 states. Under its OATT, PacifiCorp provides Long-Term Firm Point-

[14] *See, e.g., Florida Power Corp*., letter order, Docket No. ER08-105-000 (Dec. 17, 2007) (accepting tariff changes to implement a cost-of-service formula rate for Florida Power Corporation that was negotiated and agreed to with certain transmission customers on a pre-filing basis); *Duke Energy Carolinas, LLC*, 137 FERC ¶ 61,058 (2011) (accepting revised power sale tariff rates reflecting a pre-filing settlement agreement with customers); *Mississippi Power Co*., letter order, Docket No. ER14-1624-000 (May 20, 2014) (accepting revised rates for wholesale requirements service tariff customers negotiated on a pre-filing basis); *Mississippi Power Co*., letter order, Docket No. ER20-1660-00 (Jun. 25, 2020) (accepting revised rates for cost-based rate tariff negotiated on a pre-filing basis with customers); *Duke Energy Florida, LLC*, letter order, Docket No. ER20-919-000 (Mar. 13, 2020) (accepting revised ancillary service rates negotiated on a pre-filing basis with customers).

[15] Pursuant to Sections 8.4 and 8.5 of the 2020 Settlement Agreement, if the Commission accepts this filing subject to any condition or modification, and a Settling Party files notice of an objection to such condition or modification, then the rates, terms, and conditions of the 2020 Settlement Agreement are null and void, and PacifiCorp shall file within ten business days to withdraw the filing from further consideration before the Commission, without prejudice to refiling.

to-Point ("PTP") Transmission Service to 19 transmission customers, Short-Term Firm and Non-Firm PTP Transmission Service to 66 transmission customers under umbrella service agreements, and Network Integration Transmission ("NT") Service to 14 transmission customers, including PacifiCorp Energy Supply Management ("ESM"). PacifiCorp also provides transmission service to certain "legacy" transmission customers under transmission service agreements pre-dating the OATT and has three customers with "Direct Access" NT Service Agreements.[16]

B. The Proceedings in Docket No. ER17-219-000

PacifiCorp's currently effective rates for Schedules 3, 3A, 5 and 6 were established in PacifiCorp's last ancillary service rate case filing, in Docket No. ER17-219-000 (the "2017 Rate Case"). In that proceeding, PacifiCorp proposed to update its stated rates for ancillary service Schedules 3, 3A, 5, and 6. The Commission accepted and suspended the revisions to Schedules 3, 3A, 5 and 6, subject to refund and the outcome of hearing and settlement procedures.[17]

After months of settlement negotiations before a settlement judge, PacifiCorp filed the ER17-219 Settlement on January 31, 2018, that resolved all issues in Docket Nos. ER17-219-000 and EL17-27-000. PacifiCorp also filed an Unopposed Motion to Implement Settlement Rates on an Interim Basis and Request for Shortened Comment Period and Expedited Action on January 31, 2018. The Chief Judge granted this motion, placing the agreed upon settlement ancillary services rates in Schedules 3, 3A, 5, and 6 into effect on February 1, 2018.[18] The Commission approved the ER17-219 Settlement by letter order issued on April 19, 2018.[19]

Article 4 of the ER17-219 Settlement established black box rates for Schedules 3, 3A, 5 and 6 for two periods: July 13, 2017 through December 31, 2018, and then prospectively from January 1, 2018 onward. The rates that became effective on January 1, 2018 are the currently effective rates. Rates for Schedule 2 were not a part of the ER17-219 Settlement.

The ER17-219 Settlement also established a moratorium period that ended on June 30, 2020. During the moratorium period, PacifiCorp could charge only the black box rates and could not propose any new or separate ancillary service schedule charge or other rate, term, or condition of service for Schedules 3, 3A, 5, or 6. The ER17-219 Settlement acknowledged that, following the moratorium period, PacifiCorp could make a filing under Section 205 of the FPA that updates PacifiCorp's regulation reserve study and ancillary services rates for Schedules 3, 3A, 5, and 6 with an effective date no earlier than July 1, 2020.

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[16] The "legacy" transmission customers ("Legacy Customers") are Utah Associated Municipal Power Systems ("UAMPS"), Utah Municipal Power Agency ("UMPA"), and Deseret Generation and Transmission Co-operative, Inc. ("Deseret"). The Legacy Customers' respective agreements are addressed in greater detail in Section III.B.3 of this transmittal letter.

[17] *PacifiCorp*, 158 FERC ¶ 61,121 (2017).

[18] *PacifiCorp*, Order of Chief Judge Granting Motion for Interim Implementation of Settlement Rates, Docket No. ER17-219-003 (Feb. 8, 2018).

[19] *See* fn. 5, *supra*.

The ER17-219 Settlement required the settling parties to collaborate on revisions to the Schedule 3 and 3A rates that could be proposed after the moratorium period. In particular, during the moratorium period, PacifiCorp was required by the ER17-219 Settlement to work with stakeholders in good faith to try to develop consensus regarding the methodology and associated data used to calculate the applicable regulation and operating reserves to be used in the future update of the Schedules 3 and 3A ancillary service rates. Section 6.3 of the ER17-219 Settlement listed ten topics for Schedules 3 and 3A that PacifiCorp and its stakeholders were to consider during the collaborative process. The ten topics are as follows:

1. Development of the ancillary services rates based on cost-causation principles and optimization of resources utilizing a least cost methodology (Section 6.3.1 of the ER17-219 Settlement);

2. Calculation of the fixed charge rate using the Production Fixed Charge Rate Formula of the instant docket (Section 6.3.2);

3. Use of coincidental one-minute data that includes Energy Imbalance Market ("EIM") benefits for, at a minimum, the most recent 24-month period for which data is available (Section 6.3.3);

4. Allocation of System-Wide Portfolio Diversity Benefits among classes (Load, Non-[Variable Energy Resources or "VERs"], and VERs) according to the contribution of the deviation signals of each class to the combined deviation signal for regulation deployment during the test period (Section 6.3.4);

5. Use of data that reflect all events that are reasonably known and measurable at the time of filing, including unit retirements, contract terminations/renewals, resource additions, changes in operational characteristics of the resources providing ancillary services, changes in load growth, etc. (Section 6.3.5);

6. Accounting for contingencies and Disturbance Control Standard events using actual contingency data, including deployment of contingency reserves as well as other Qualifying Events under the Northwest Power Pool Agreement (Section 6.3.6);

7. Treatment of PacifiCorp's Interruptible Contracts as providing self-supply of ancillary services to PacifiCorp's Energy Supply Management, and excluding them from the derivation of the ancillary service rates (Section 6.3.7);

8. Use of a 1-day-in-10-years resource adequacy standard (equivalent to a 2.4 loss of load hours per year) (Section 6.3.8);

9. Inclusion of an intra-hour scheduling discount reflecting the use of wind power production forecasts as of the later of the T-40 base schedule update

or any later deadline that is established for EIM Entity updates to base schedules (Section 6.3.9); and

10. In the calculation of the production plant revenue requirement, provision of revenue offsets (credits) of all revenues generated by PacifiCorp's EIM sales out of the Balancing Authority Area (whether short-term or long-term opportunity sales) for the purpose of serving loads other than firm native load (Section 6.3.10).

The ER17-219 Settlement also addressed certain self-supply issues. The ER17-219 Settlement provided that during the moratorium period, customers would not self-supply ancillary services for Schedules 3 and 3A. In addition, Attachment 1 to the ER17-219 Settlement contained revised terms for self-supply of Schedules 5 and 6, providing the criteria for self-supply or third party-supply of contingency reserves under Schedules 5 and 6 on PacifiCorp's system.

Similar to the approach for Schedules 3 and 3A rate issues, the ER17-219 Settlement required the settling parties to work together on self-supply issues during the moratorium period. For example, section 3.7 of the ER17-219 Settlement required PacifiCorp and its customers to work together during the moratorium period to create a framework for the self-supply of Schedules 3 and 3A, and to update the self-supply provisions for Schedules 5 and 6, including discussion of PacifiCorp's ability to automate e-Tag adjustments. Section 3.7 of the ER17-219 Settlement clarified the settling parties' "intent that they will come to agreement during the Moratorium Period regarding a self-supply framework for all of Schedules 3, 3A, 5, and 6, and that PacifiCorp will file to update Schedules 3, 3A, 5 and 6 after the Moratorium Period to incorporate such self-supply framework." Section 3.7 also provided that, "if the settling parties agree to a final self-supply framework during the moratorium period for Schedules 3, 3A, 5, and 6, PacifiCorp shall make a Section 205 filing at the end of the Moratorium Period or thereafter to implement that self-supply framework."

C. The Stakeholder Process

In accordance with the ER17-219 Settlement, PacifiCorp conducted a series of workshops from December 2019 through May 2020. Prior to each workshop, PacifiCorp circulated power point presentations to the stakeholders. During each of the customer workshops, PacifiCorp requested feedback and comments from its customers and stakeholders on its proposals and wrote down questions asked. To the extent answers could not be provided during the workshops, PacifiCorp provided written responses following the workshops.[20] Following each workshop,

[20] PacifiCorp, Comments on PAC Transmission Schedules 3 and 3A Following Customer Workshop February 18, 2020, *available at* https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PacifiCorp_Response_to_Legacy_Customers'_Comments_on_Customer_Workshop_February_18_2020.pdf; PacifiCorp Responses to the Legacy Customers' (LCs') Questions on Rates and Cost Support from March 24, 2020, Customer Meeting (Apr. 15, 2020), *available at* https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PAC_Response_to_Legacy_Customer's_Information_Request_-_04202020_.pdf; Renewable Northwest comments on PacifiCorp Ancillary Services Workshop held March 24, 2020, *available at* https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PAC_Response_to_Renewable_Northwest_Comments.pdf (providing responses to Renewable Northwest's comments); Bonneville Power Administration's Questions and Comments Regarding PacifiCorp's Ancillary Service Rates, *available at*

PacifiCorp requested comments from stakeholders and responded to any comments received in writing. In addition, PacifiCorp developed a questionnaire that provided a status update and summary of certain rate topics. The topics addressed during each workshop and the focus of each workshop are further discussed in Ms. Wiencke's testimony, described in Section III. below.

Following the last workshop in May 2020, PacifiCorp and stakeholders engaged in further negotiations and conferences to reach agreement on the rates, terms, and conditions for Schedules 2, 3, 3A, 5 and 6. PacifiCorp and stakeholders thereafter entered into a Settlement Discussion, Confidentiality and Non-Disclosure Agreement, whereby the parties could engage in confidential negotiations pursuant to Rule 602 of the Commission's Rules of Practice and Procedure and Rule 408 of the Federal Rules of Evidence. Those confidential settlement discussions extended until December 2020, when the 2020 Settlement Agreement was reached.

III. DESCRIPTION OF FILING

Section III.A of this transmittal letter addresses the development of PacifiCorp's base case, which is included solely as cost support to demonstrate the justness and reasonableness of the lower 2020 Settlement Agreement rates. The "base case" rates were developed by PacifiCorp based upon cost and billing determinant data from the 2019 calendar year and reserve requirements based upon a study of 2018 and 2019 (the "Study Period"). The base case materials include the following testimony:

- The testimony of Mary M. Wiencke (Exhibit No. PAC-0001), who explains the background of the ER17-219 Settlement, provides an overview of the 2020 Settlement Agreement and its rates, and a general overview of the stakeholder discussions that were conducted by PacifiCorp in accordance with the ER17-219 Settlement and the confidential settlement discussions pursuant to the Settlement Discussion, Confidentiality and Non-Disclosure Agreement described in Section II.C., supra. Ms. Wiencke's testimony is in Attachment B to this filing.

- The testimony of Kelcey A. Brown (Exhibit No. PAC-0002), who provides background information on aspects of PacifiCorp's operations and the EIM of the California Independent System Operator Corporation ("CAISO") that are relevant to the development of the base case rates. Ms. Brown's testimony is in Attachment C to this filing.

- The testimony and exhibits of Daniel J. MacNeil (Exhibit Nos. PAC-0003 to PAC-0009), who details the calculation of the base case reserve requirements for Regulation and Frequency Response Service and for Operating Reserves-Spinning and Operating Reserves-Supplemental. Mr. MacNeil also discusses the identification of the PacifiCorp generation resources that provide these

https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/PAC_Response_to_BPA_Ancillary_Questions_and_Comments_7April20.pdf (providing responses to Bonneville Power Administration's questions and comments).

services. Mr. MacNeil's testimony and exhibits are in Attachment D to this filing.

- The testimony and exhibits of Dr. Paul A. Dumais (Exhibit Nos. PAC-0010 to PAC-0016), who explains the development of the base case Schedule 2, 3, 3A, 5 and 6 rates. Dr. Dumais's testimony and exhibits are in Attachment E to this filing.

Section III.B of this transmittal letter describes the 2020 Settlement Agreement – Attachment A to this filing – which contains the agreed-upon rates, terms, and conditions reflected in the revised tariff records proposed in this filing, in addition to other terms and provisions that are integral components of the overall settlement package. In all instances involving rates, the 2020 Settlement Agreement reflects "black box" settlement rates that are lower than PacifiCorp's base case rates.

A. The Base Case

1. Schedule 2, Reactive Supply and Voltage Control from Generation Sources Service

PacifiCorp's Schedule 2 rates were last set through a settlement agreement approved by the Commission in Docket No. ER11-3643-000.[21] Since the rate filing in Docket No. ER11-3643-000, PacifiCorp's generating fleet has changed due to the addition of several generating facilities, including a combined cycle unit and wind facilities, as well as the retirement of two thermal generating facilities.[22] In addition, PacifiCorp's Schedule 2 rate filed in that proceeding did not include costs associated with relevant power purchase agreements or wind facilities in existence at the time.[23]

Dr. Dumais explains the development of the reactive power revenue requirement in the base case using data from the Study Period. Dr. Dumais' testimony supports Exhibit No. PAC-0015, which details the derivation of the revenue requirement. Dr. Dumais also supports confidential Exhibit No. PAC-0018, which contains generator technical information, including test reports, D-curves and Vee-curves, and nameplate pictures.

Dr. Dumais applied Commission precedent in identifying PacifiCorp's reactive power revenue requirement for base case rates.[24] For each reactive resource used by PacifiCorp to provide Schedule 2 service during the Study Period, Dr. Dumais referenced the resource's reactive capability to identify the appropriate allocation factors to separate the plant components for real and reactive power. Once the investment in reactive power was determined through the allocation

[21] *PacifiCorp*, 143 FERC ¶ 61,162 (2013).

[22] Dumais Testimony at 38.

[23] *Id*.

[24] *Id.* at 39 (discussing *American Electric Power Service Corp.,* 88 FERC ¶ 61,141 (1999) (Opinion No. 440), *order on reh'g*, 92 FERC ¶ 61,001 (2000), and *Dynegy Generation, Inc*., 121 FERC ¶ 61,025 (2007) (Opinion No. 498), *order on reh'g,* 125 FERC ¶ 61,280 (2009); *Wabash Valley Power Ass'n*, 154 FERC ¶ 61,246 (2016)).

factors, Dr. Dumais used a fixed charge factor to determine the annual revenue requirement. Dr. Dumais identified a total annual reactive power revenue requirement of $22,522,974. This amount is divided by PacifiCorp's 2019 12-month average coincident system peak load of 13,450,317 kWs to derive an annual rate of $1.677 per kW-year.[25]

2. Schedule 3, Regulation and Frequency Response Service; Schedule 3A, Generator Regulation and Frequency Response Service

Schedule 3 reflects the cost of providing Regulation and Frequency Response reserve sufficient to maintain compliance with reliability standard BAL-001-2 and BAL-003-1.1 to customers serving load internal to the PacifiCorp BAAs (PACE and PACW).[26] Schedule 3A reflects the cost of providing Regulation and Frequency Response reserve sufficient to maintain compliance with reliability standard BAL-001-2 and BAL-003-1.1 to customers exporting generation from the PacifiCorp BAAs.[27] PacifiCorp's current rates for Schedules 3 and 3A were established through the ER17-219 Settlement.

With three exceptions, PacifiCorp's methodology to identify the base case reserve requirements for Schedules 3 and 3A is generally the same methodology that was used in its filing in Docket No. ER17-219-000. First, in light of the growth of utility-scale solar resources from a *de minimis* quantity to more than 1,000 MW since the last case, PacifiCorp has split the VERs class into two sub-classes, with separate rates, to account for the distinct characteristics of wind and solar resources.[28] Within the VER class, wind and solar resources on PacifiCorp's system had distinct impacts on Regulation and Frequency Response needs during the Study Period.[29] During the Study Period, utility-scale wind and solar resources operating in PacifiCorp's BAAs totaled 2,745 MW and 1,080 MW, respectively.[30] In comparison, the filing in Docket No. ER17-219-000 was based on a 2015 test year and had a total VERs of 2,588 MW, representing only wind resources as the solar resources in PacifiCorp's BAAs were too small to be tracked.[31] Mr. MacNeil's study verifies the different reserve obligations from the BA's perspective created by wind and solar resources, justifying the separation of these two types of VERs into distinct customer classes for the base case Schedules 3 and 3A charges.[32] With the addition of the VER-Solar class to the existing Schedule 3 classes, the customer classes for Schedule 3 charges are load, VERs-Wind, VERs-Solar, and Non-Dispatchable Non-VERs.

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[25] Dumais Testimony at 75.

[26] Testimony of D. MacNeil at 6.

[27] *Id*.

[28] *Id*. at 3-4.

[29] *Id*. at 9.

[30] *Id*. at 11.

[31] *See* PacifiCorp, Revisions to Open Access Transmission Tariff, Docket No. ER17-219-000, Exhibit No. PAC-13 at 20 (Oct. 28, 2016).

[32] *Id*. at 40. In particular, Mr. MacNeil explains that, prior to any portfolio diversity adjustments, the stand-alone regulation and frequency response requirement for wind is 457 MW during the Study Period, whereas the stand-alone regulation requirement for solar resources is 160 MW for the Study Period.

A second change is that PacifiCorp's study for the base case rates now incorporates the hour-ahead forecast of load produced by the CAISO, replacing the proxy forecast based on conditions in the prior week used in Docket No. ER17-219-000.[33] As Mr. MacNeil explains, the improved load forecasting contributes to a significant reduction in the regulation reserve requirement for load.[34]

The third change is that PacifiCorp's base case regulation requirement forecast is based on a quantile regression methodology that expresses the regulation requirement as a polynomial function based on the relationship between hour ahead forecasts and hour ahead forecast errors at a certain quantile.[35] The forecast and deviations specific to each class were used to calculate a reserve requirement for each hour. The targeted percentile in the quantile regression for each class was calculated such that the hourly reserve requirement achieves the annual reliability target of 0.5 hours per year. The class-level reserve requirements represent the stand-alone requirements for each class, in the absence of any diversity benefits from using a shared regulation reserve supply to meet system requirements.

As the Commission has recognized, diversity benefits result from aggregating the variations of all resources so that one resource's negative deviation can offset some or all of another resource's positive deviation.[36] Mr. MacNeil applied a portfolio diversity analysis to the stand-alone requirements for each class, resulting in a lower overall reserve requirement. Mr. MacNeil explains that, while the sum of the stand-alone reserve requirements for each class yields a total reserve requirement of 1057 MW, the total portfolio requirement when the deviations of all classes are combined is only 680 MW.[37]

Mr. MacNeil also incorporated an adjustment to the reserve requirement to reflect benefits from the diversity offered by PacifiCorp's participation in the EIM. EIM imports from other participating BAAs can help balance PacifiCorp's loads and resources within an hour, reducing the size of reserve shortfalls and the likelihood of a Balancing Authority Area Control Error Limit violation.[38] Using historical EIM diversity benefits, a matrix of average EIM diversity benefits was calculated by hour and season, and applied as a credit to the final BAA regulation reserve requirement in each hour of the study.[39] The effect of the "EIM diversity benefit" is to reduce the

[33] *Id*. at 4.

[34] *Id*.

[35] *Id*. Mr. MacNeil explains that a regression analysis attempts to predict the value of one variable (the response variable) on the basis of one or more variables (predictor variable). A typical regression results in estimates of the conditional mean (i.e., the 50th percentile) of the response variable given certain values of the predictor variables. A quantile regression estimates other specified percentiles (e.g., 25th percentile, 95th percentile, etc.) of the response variable. *Id*. at 35.

[36] Order No. 764 at P 319. *See also* D. MacNeil Testimony at 41 ("the largest deviations in each class tend not to occur simultaneously, and in some cases deviations by one class will offset deviations by another class.").

[37] D. MacNeil Testimony at 42.

[38] *Id*. at 43.

[39] *Id*.

Regulation and Frequency Response reserve requirement from 680 MW to 540 MW,[40] which is the final amount used in the calculation of the base case rates for Schedules 3 and 3A.

Mr. MacNeil conducted a "units most likely" analysis to identify the PacifiCorp generation capacity that is used to provide Schedule 3, 3A, 5 and 6 services. The units most likely analysis has been accepted by the Commission in other cases to identify generation capacity used in ancillary services.[41] Mr. MacNeil took into account each unit's operating characteristics and Study Period evidence of the unit's capacity factor and availability.[42] After identifying these units, Mr. MacNeil then performed an analysis to determine the contribution of each of these PacifiCorp's resources to the supply of operating reserve for Schedules 3, 3A, 5 and 6, ensuring that the same capacity is not double-counted.[43]

With the reserve requirement and units most likely test results, the testimony of Dr. Dumais describes the calculation of the revenue requirement for Schedules 3 and 3A. Using the same fixed charge analysis of PacifiCorp's filing in ER17-219-000,[44] Dr. Dumais calculated base case rates of $1.5790/kw-year for the load class, $8.1060/kw-year for VERs-Wind, $6.6220/kw-year for VERs-Solar, and $3.9630/kw-year for the Non-VERs Non-Dispatchable Class.

3. Schedules 5 and 6

Schedule 5 of the PacifiCorp OATT sets forth rates, terms, and conditions applicable to the provision of Operating Reserve – Spinning Reserve Service, which is needed to serve load in the BAA and to support other transmission usage sourced from generation in the BAA including exports and sales.[45] Schedule 6 of the PacifiCorp OATT sets forth rates, terms, and conditions applicable to PacifiCorp's provision of Operating Reserve - Supplemental Reserve Service, which is needed to serve load in the BAA and to support other transmission usage sourced from generation in the BAA including exports and sales; however, it is not available immediately to serve load but rather within a short period of time.[46] The current rates for Schedules 5 and 6 are both $0.151/MWh, as approved through the ER17-219 Settlement.

The testimony of Mr. MacNeil discusses the base case calculation of the reserve requirements for Schedules 5 and 6 services during the Study Period. The reserve requirements for Operating Reserves under Schedules 5 and 6 are based on the requirements for contingency

[40] *Id*. at 44.

[41] *Consumers Energy Co*., 86 FERC ¶ 63,004 at 65,055 (1999), *aff'd*, 98 FERC ¶ 61,333 (2002).

[42] D. MacNeil Testimony at 51.

[43] *Id*.

[44] As noted in section II.B, *supra*, the ER17-219 Settlement required PacifiCorp to consider using the same the Production Fixed Charge Rate Formula of the ER17-219-000 filing to calculate its updated rates, which is what Dr. Dumais did.

[45] PacifiCorp OATT, Schedule 5. The testimony of Kelcey A. Brown provides an overview of Schedules 5 and 6 and, among other things, explains that PacifiCorp is able to reduce its contingency reserve obligations by participating in the Northwest Power Pool Reserve Sharing Group.

[46] PacifiCorp OATT, Schedule 6.

reserves under regional Reliability Standard BAL-002-WECC-2a during the Study Period. Pursuant to that standard, contingency reserves must be available within ten minutes and, pursuant to Requirement 2 of the standard, at least half must be from "spinning" resources that are online and immediately responsive to system fluctuations. Schedule 5 reflects the cost of spinning reserve necessary for compliance with reliability standard BAL-002-WECC-2a.[47] Schedule 6 reflects the cost of supplemental (*i.e.*, non-spinning) reserve necessary for compliance with reliability standard BAL-002-WECC-2a.[48]

The reserve requirements for spinning reserves and supplemental reserves are based on actual operational data recorded in PacifiCorp's Energy Management System ("EMS") in connection with compliance with the BAL-002-WECC-2a standard.[49] The required annual hourly average amount of spinning reserves for the Study Period was 237.2 average MW, representing half the recorded contingency reserve obligation.[50] The required annual hourly average amount of supplemental reserves under BAL-002-WECC-2a was also 237.2 average MW.[51]

After the reserve requirements were identified, Dr. Dumais calculated the revenue requirements for Schedule 5 and Schedule 6 by applying the weighted cost per kW by the spinning reserves held or the supplemental reserves held.[52] The resulting base case rates for Schedules 5 and 6 are $0.182/MWh and $0.172/MWh, respectively.[53]

B. The 2020 Settlement Agreement

1. Overview

The 2020 Settlement Agreement (Attachment A to this filing) was executed by the "Settling Parties", which are PacifiCorp; Deseret, UAMPS, UMPA, Bonneville Power Administration ("Bonneville"), Avangrid Renewables, LLC, EDP Renewables North America LLC, and NextEra Energy Resources, LLC. In light of the 2020 Settlement Agreement, PacifiCorp is <u>not</u> proposing or requesting approval of the base rates discussed in section III.A, above or Exhibit Nos. PAC-0001 through PAC-0016 to this filing.

The 2020 Settlement Agreement contains revised rate and non-rate terms and conditions. Pursuant to Section 9.3, the 2020 Settlement Agreement is intended to be a "black box" settlement, and, pursuant to Section 9.1, to comprise an "integrated package." In addition, Section 9.1 states

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[47] *Id*. at 8.

[48] *Id*.

[49] As Mr. MacNeil explains, PacifiCorp records data in its EMS showing the amount of total ten-minute reserve credited to individual generation resources and contracts by hour. This data identifies the generation resources that provided spinning reserve capability in each hour of the Study Period. *Id*. at 52.

[50] *Id*. at 49.

[51] *Id*.

[52] Dumas Testimony at 15-17.

[53] *Id*. at 16.

that none of the terms of the 2020 Settlement Agreement are agreed to without each of the others, and that the various provisions of the 2020 Settlement Agreement are not severable.

2. 2020 Settlement Agreement Rates

Section 2.1 of the 2020 Settlement Agreement sets forth revised rates for Schedules 2, 3, 3A, 5, and 6, to be effective January 1, 2021. The rates shown in Table 1 below are reflected in the enclosed tariff records for Schedules 2, 3, 3A, 5 and 6:

Table 1 – Settlement Rates

Schedule	Settlement Rates
Schedule 2 (kW-year)	
Reactive	$1.603
Schedule 3 (per kW-year)	
Load	$1.3859
Schedule 3/3A (per kW-year)	
VERS Wind	$6.6922
VERS Wind – Committed Scheduling Discount	$6.2171
VERS Solar	$5.5836
VERS Solar - Committed Scheduling Discount	$5.1872
Non-VERS Non-Dispatchable	$3.1483
Schedule 5 (per MWh)	
Spinning Reserves	$0.1677
Schedule 6 (per MWh)	
Supplemental Reserves	$0.1677

In addition, as reflected in the revised terms and conditions for Schedules 3 and 3A, Section 2.2 of the 2020 Settlement Agreement requires PacifiCorp to retain a committed scheduling rate for VERs. The committed scheduling discounts shown in Table 1 will be available to VER-Wind and VER-Solar resources. The committed scheduling discounts reflect a 7.1% reduction from the otherwise applicable rate.[54]

The 2020 Settlement Agreement rates are uniformly lower than the base case rates that otherwise would be supported by PacifiCorp. A comparison of the existing rates, base case rates, and settlement rates are provided in Table 2.

Table 2 – Comparison of 2020 Settlement Agreement Rates to Currently Effective Rates and Base Case Rates

[54] The 7.1% committed scheduling discount is adopted from the base case materials, and is explained in the testimony of Mr. MacNeil, Exhibit No. PAC-0003, p. 47.

Schedule	Existing Rate	Base Case Rates	Settlement Rates
Schedule 2 (kW-year)			
Reactive	$0.5500	$1.677	$1.603
Schedule 3/3A (kW-year)			
Load	$2.1240	$1.5790	$1.3859
Schedule 3/3A			
VERS Wind	$6.5930	$8.1060	$6.6922
VERS Wind – Discount	$5.6310	$7.5300	$6.2171
VERS Solar	n/a	$6.6220	$5.5836
VERS Solar – Discount	n/a	$6.1520	$5.1872
Non-VERS Non-Dispatchable	$1.7940	$3.9630	$3.1483
Schedule 5 (MWh)			
Spinning Reserves	$0.1510	$0.1820	$0.1677
Schedule 6 (MWh)			
Supplemental Reserves	$0.1510	$0.1720	$0.1677

As shown on Appendix 1 to this transmittal letter, the Settlement Rates result in a revenue increase to wholesale customers paying the Schedule 2, 3/3A, 5 and 6 rates of $1,244,306. The Attachment determines the revenue change by comparing the Settlement Rates to Current Rates and multiplying the result by 2019 billing units for wholesale customers. Appendix 1 shows the revenue change by schedule.[55]

3. 2020 Settlement Agreement Non-Rate Terms and Conditions

In addition to settling the rates for Schedules 2, 3, 3A, 5 and 6, the 2020 Settlement Agreement addresses a number of important non-rate terms and conditions, including two different moratorium periods, and self-supply issues for certain ancillary services, as discussed below. All of the non-rate terms and conditions of the 2020 Settlement Agreement will be implemented either through: (1) the revised OATT eTariff records included with this filing, or (2) updated business practices posted to PacifiCorp's OASIS when the 2020 Settlement Agreement becomes effective.

a. Billing for Ancillary Services under the Legacy Transmission Service and Operating Agreements

Article III of the 2020 Settlement Agreement provides that all billing for ancillary services under three separate amended and restated transmission service and operating agreements ("ARTSOAs") that provide the rates, terms and conditions for service by PacifiCorp to the Legacy Customers will continue pursuant to current practices. Section 3.1 addresses billing and the reservation of rights under the ARTSOA between PacifiCorp and UMPA. Section 3.2 addresses

[55] PacifiCorp is separately including, as Exhibit No. PAC-0013, a statement BG/BH showing what the impacts of the base rates would be.

billing and the reservation of rights under the ARTSOA between PacifiCorp and Deseret. Section 3.3 addresses billing and the reservation of rights under the ARTSOA between PacifiCorp and UAMPS. The provisions of Article III are reflected in the attached revisions to Schedules 3 and 3A.

b. Moratorium

Article IV of the 2020 Settlement Agreement establishes two separate moratoria. First, the settlement establishes a moratorium period on changes to the settlement rates, terms, and conditions. Section 4.1 states that "Except as specifically provided in Sections 4.5, 4.6, and 4.7 below, no Settling Party shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedules 2, 3, 3A, 5 and/or 6 or Attachment U, or seek any change to PacifiCorp's business practices under or applicable to the same, including but not limited to PacifiCorp business practices 39 and 63, that differ from those provided in this Settlement Agreement and propose an effective date prior to January 1, 2023 (the "Rate Schedule Moratorium Period")."

The first exception to the Rate Schedule Moratorium Period is in Section 4.5, which states: "The Rate Schedule Moratorium Period shall not preclude PacifiCorp from proposing tariff or business practice changes that PacifiCorp believes are needed to accommodate and implement the Extended Day-Ahead Market ("EDAM") currently being developed by the CAISO. Each Joint Customer reserves its rights to protest or otherwise challenge any such filing."

The second exception to the Rate Schedule Moratorium Period is in Section 4.6, which states: "The Rate Schedule Moratorium does not preclude PacifiCorp from proposing a reduction in the rate set forth in the Schedule 2 attached to this Settlement Agreement. PacifiCorp shall provide notice to each Joint Customer of any proposal to modify the Schedule 2 rate schedule at least thirty (30) days in advance of any Section 205 filing. Each Joint Customer reserves its rights under the FPA to protest or otherwise challenge any such filing."

The third exception to the Rate Schedule Moratorium Period is in Section 4.7, which states: "The parties will negotiate in good faith to attempt to reach agreement on self-supply arrangements relating to jointly owned units. PacifiCorp agrees to continue to allow UAMPS, UMPA, and Deseret to self-supply from jointly owned units without performance evaluations through October 1, 2021 to allow the parties to work toward mutual agreement on self-supply arrangements specific to jointly owned units. If the parties succeed in agreeing on an approach, the parties will agree to an implementation date that provides a reasonable amount of time to ready their systems for compliance with any agreed-upon approach. If mutual agreement is not reached by September 1, 2021, PacifiCorp and each Legacy Customer may thereafter make a unilateral filing with FERC pursuant to Sections 205 and 206 of the FPA, respectively."

As discussed earlier, a separate moratorium period for changes to the ARTSOA billing provisions is established by Section 4.4 of the 2020 Settlement Agreement, which states that the ARTSOA billing provisions in Article III, described above, shall not be changed with an effective date prior to December 1, 2025 (the "ARTSOA Moratorium Period").

In addition, Section 4.3 of the 2020 Settlement Agreement acknowledges the proceeding in Docket No. ER20-2528-000, which concerns an application by Airport Solar, LLC ("Airport Solar") for rates to be paid by PacifiCorp for Reactive Supply and Voltage Control from Generation Sources Services by Airport Solar. Section 4.3 states that during the Rate Schedule Moratorium Period, PacifiCorp will not seek to recover or pass-through costs it may incur as a result of Airport Solar's application or revenue requirement.[56] Additionally, during the Rate Schedule Moratorium Period, Section 4.3 provides that PacifiCorp will not propose to recover or pass through any costs it may incur as a result of any other generator that receives a FERC approved Schedule 2 rate, including any resulting revenue requirement. Furthermore, Section 4.3 provides that none of the Joint Customers shall make a filing with FERC seeking compensation from PacifiCorp pursuant to a Schedule 2 rate for reactive power during the Rate Schedule Moratorium Period. Section 4.3 also states that PacifiCorp is not prohibited by the 2020 Settlement Agreement from making a filing with the Commission, after the expiration of the Rate Schedule Moratorium Period, seeking to prospectively recover or pass-through costs that PacifiCorp incurs after the Rate Schedule Moratorium Period as a result of Airport Solar's Schedule 2 charges or any other resource that has a Schedule 2 rate on file with the Commission. Transmission customers would reserve all rights to challenge any such recovery or pass-through.

To ensure that the moratorium periods are "on file" with the Commission under Section 205, the moratorium provisions of the 2020 Settlement Agreement discussed above are reflected in the enclosed revisions to Schedules 2, 3, 3A, 5, and 6 of the PacifiCorp OATT. The provisions of Section 4.7 of the 2020 Settlement Agreement are reflected in section 4.2(H) of the revised Attachment U of the PacifiCorp OATT.

c. Non-VER Participating Resources

Article V of the 2020 Settlement Agreement sets forth certain understandings of the Settling Parties regarding the treatment of Non-VER resources under Schedules 3 and 3A of the OATT. The provisions of Article V are in the nature of clarifications and a commitment to further cooperate regarding certain issues:

- A Non-VER Participating Resource in the EIM administered by CAISO qualifies as a dispatchable Non-VER resource.[57]

- Non-VER resources dispatchable by PacifiCorp qualify as dispatchable Non-VERS.[58]

- PacifiCorp will not charge Non-VER Participating Resources or Non-VER resources dispatchable by PacifiCorp for Schedules 3 and 3A services. PacifiCorp shall consider, on a good faith basis, requests by customers to identify a resource that should qualify as a

[56] Nothing contained in this rate filing should be construed as an admission by PacifiCorp or any signatory party to the 2020 Settlement Agreement of the just and reasonableness of any revenue requirement (or portion thereof) proposed in Docket No. ER20-2528-000.

[57] 2020 Settlement Agreement at § 5.1.

[58] *Id*.

dispatchable Non-VER in this context due to its ability to follow PacifiCorp instructions, notwithstanding the fact that the resource is not directly dispatchable by PacifiCorp.[59]

Each of these provisions are reflected in the revisions to Schedules 3 and 3A.

d. Self-Supply

Article VI of the 2020 Settlement Agreement discusses self-supply of certain ancillary services. It provides that PacifiCorp shall reasonably and in good faith consider customer requests for self-supply, third party supply and pooling agreements among customers under Schedules 3, 3A, 5 and 6 of the OATT on a case-by-case and non-discriminatory basis. Article VI primarily leaves issues of self-supply of Schedule 3 and 3A to be addressed on a case-by-case basis, subject to the requirement that PacifiCorp must consider requests for self-supply, pooling arrangements, and third-party supply on a non-discriminatory basis.

Under the 2020 Settlement Agreement, the Settling Parties have developed revisions to existing Attachment U of the PacifiCorp OATT, which contains certain requirements for self-supply of Operating Reserves under Schedules 5 and 6, as well as revisions to PacifiCorp's existing Business Practice Nos. 39 (Electronic Tagging of Reserves ("e-Tags")).

As part of the revisions of Attachment U, the Settling Parties incorporated PacifiCorp's existing Business Practice No. 34 ("Self-Supply or Third-Party Supply of Ancillary Services-Certification Process and Requirements") into Attachment U. This was done for purposes of clarity and to avoid potential conflicts between Attachment U and Business Practice No. 34. As a result, Business Practice No. 34 is to be retired as a separate document on the effective date of the revised Attachment U (July 1, 2021).

The revisions to Attachment U provide clarification and streamline the requirements for self-supply and third-party supply of ancillary services. Attachment U now addresses self-supply and third-party supply of Schedules 3, 3A, 4, 5, 6 and 9. In addition, Attachment U, among other things, removes duplicative material, clarifies the eligibility requirements for self-supply or third-party resources (including requirements for EIM non-participating resources and for jointly owned units), and identifies additional information requirements for self-suppliers. As provided in section 4.1 of the revised Attachment U, a self-supply or third-party supply arrangement for ancillary services will be set forth in a service agreement between PacifiCorp and the customer.

In addition, as discussed above, Section 4.7 of the 2020 Settlement Agreement, which concerns self-supply by UAMPS, UMPA and Deseret from jointly owned units, is included as section 4.2(H) of Attachment U.

Revisions to Business Practice No. 39 (Electronic Tagging of Reserves) clarify the use of dynamic e-Tags. Business Practice 63 (Transmission Customer Provision of Reactive Supply and Voltage Control from Generation or Other Sources Service) is revised to explicitly extend to customers using VERs the same right to receive credits against their Schedule 2 charges for self-provision of reactive power that non-VER customers have today.

[59] *Id*.

The revised Business Practice Nos. 39 and 63 are included as Exhibits G and H to the 2020 Settlement Agreement and will be implemented through updated OASIS postings of the business practices consistent with the effective date of the 2020 Settlement Agreement.

e. Withdrawal of Section 205 Filing

Article VIII of the 2020 Settlement Agreement sets out a process to implement the agreed upon terms as between the Settling Parties, including the integrated package of rates, terms and conditions that are embodied within this Section 205 filing with a requested January 1, 2021 effective date for the revisions to Schedules 2, 3, 3A, 5 and 6, and a requested July 1, 2021 effective date for the revisions to Attachment U. Pursuant to Sections 8.4 and 8.5 of the 2020 Settlement Agreement, if the Commission accepts this filing subject to any condition or modification, and a Settling Party files notice of an objection to such condition or modification, then the rates, terms, and conditions of the 2020 Settlement Agreement are null and void, and PacifiCorp shall file within ten business days to withdraw the filing from further consideration before the Commission, without prejudice to refiling. In that event, each Settling Party specifically reserves its right(s) under the FPA to protest and otherwise contest the methodologies, approaches, or results of PacifiCorp's "base case" filing or related cost support or materials if such materials are presented in a subsequent filing with the Commission.

C. The Enclosed Revisions Implementing the 2020 Settlement Agreement are Just and Reasonable

PacifiCorp requests that the Commission accept the enclosed revisions implementing the 2020 Settlement Agreement, without condition or further proceedings. PacifiCorp was obligated by the ER17-219 Settlement to (1) to work with parties in good faith in an effort that ultimately produced the current settlement and (2) file under Section 205 to implement the matters upon which consensus was reached. Pursuant to that Commission-approved process, the 2020 Settlement Agreement represents the result of more than a year of time and dedicated resources by the Settling Parties to resolve the issues, on a pre-filing basis, regarding PacifiCorp's rates, terms and conditions for Schedules 2, 3, 3A, 5 and 6.

The rates that will be implemented through the 2020 Settlement Agreement are uniformly lower than the rates developed in the base case materials as shown in Table 2, *supra*. Furthermore, the 2020 Settlement Agreement provides both PacifiCorp and its customers with important assurances of stability in the rates through the moratoria periods.

The enclosed revisions contained in Attachment A are just and reasonable and consistent with the Commission's policy of favoring settlements that provide "parties with certainty, reduce litigation costs, and permit parties to reach reasonable compromise in resolving difficult issue."[60]

[60] *PJM Interconnection, L.L.C.*, 157 FERC ⁋ 61,181 at P 6 (Letter Order issued Dec. 5, 2016) (citing *State of Maine*, 91 FERC ¶ 61,213, at 61,772 (2000) ("our strong support of settlements militates in favor of giving these parties certainty, and letting them receive the full benefits of their bargain"); *San Diego Gas & Elec. Co. v. Sellers of Energy & Ancillary Servs*., 122 FERC ¶ 61,009, at P 13 (2008) ("the Commission strongly favors settlements, particularly in cases that are highly contested and complex."); *Montana Power Co*., 77 FERC ¶ 61,110, at 61,434

In two of PacifiCorp's prior rate cases involving ancillary services, the total time to resolve the proceeding, from the date of the initial filing to the filing of a settlement agreement, lasted 27 months[61] and 15 months.[62] Acceptance of the tariff records implementing the 2020 Settlement Agreement thus can be said to avoid considerable litigation costs and time by the parties, as well as preserve the Commission's resources.

Finally, PacifiCorp's filing is consistent with other similar filings under section 205 to implement the terms of pre-filing settlements with customers,[63] including pre-filing settlements concerning ancillary service rates.[64]

IV. CONTENTS OF THE FILING

This filing consists of the following documents:

- This transmittal letter;
- Appendix 1 (Comparison of Existing Rates to Settlement Rates)
- Revised tariff sheets in e-Tariff format;
- Attachment A: The 2020 Settlement Agreement, including:
    - Clean and Marked Versions of Schedules 2, 3, 3A, 5 and 6;
    - Clean and Marked Versions of Attachment U;
    - Clean and Marked Versions of Business Practice 39;
    - Clean and Marked Versions of Business Practice 63;
- Attachment B: Direct Testimony of Mary M. Wiencke, Vice President of Transmission Regulation and Market Policy for PacifiCorp (Exhibit No. PAC-0001);
- Attachment C: Direct Testimony of Kelcey A. Brown, former Vice President of Energy Supply Management (Exhibit No. PAC-0002);

(1996) ("the Commission strongly favors settlements, which provide the opportunity to eliminate the need for more lengthy proceedings if the parties reach an agreement on the issues that is compatible with the public interest").

[61] *See* Docket No. ER11-3643-000.

[62] *See* Docket No. ER17-219-000.

[63] *See, e.g., Florida Power Corp*., letter order, Docket No. ER08-105-000 (Dec. 17, 2007) (accepting tariff changes to implement a cost-of-service formula rate for Florida Power Corporation that was negotiated and agreed to with certain transmission customers on a pre-filing basis); *Duke Energy Carolinas, LLC*, 137 FERC ¶ 61,058 (2011) (accepting revised power sale tariff rates reflecting a pre-filing settlement agreement with customers); *Mississippi Power Co*., letter order, Docket No. ER14-1624-000 (May 20, 2014) (accepting revised rates for wholesale requirements service tariff customers negotiated on a pre-filing basis); *Mississippi Power Co*., letter order, Docket No. ER20-1660-00 (Jun. 25, 2020) (accepting revised rates for cost-based rate tariff negotiated on a pre-filing basis with customers); *Duke Energy Florida, LLC*, letter order, Docket No. ER20-919-000 (Mar. 13, 2020) (accepting revised ancillary service rates negotiated on a pre-filing basis with customers).

[64] *Duke Energy Florida, LLC*, letter order, Docket No. ER20-919-000 (Mar. 13, 2020) (accepting revised ancillary service rates negotiated on a pre-filing basis with customers).

- Attachment D: Direct Testimony of Daniel J. MacNeil, Resource and Commercial Strategy Adviser (Exhibit No. PAC-0003), and the following exhibits:
    - Exhibit No. PAC-0004 (Table A Study Results: Schedule 5, Spinning Reserve);
    - Exhibit No. PAC-0005 (Table B Study Results: Schedule 6, Supplemental Reserve);
    - Exhibit No. PAC-0006 (Table C Study Results: Schedules 3/3A, Regulation & Frequency Response);
    - Exhibit No. PAC-0007 (Table D Adjusted Study Results: Schedule 5, Spinning Reserve);
    - Exhibit No. PAC-0008 (Table E Adjusted Study Results: Schedule 6, Supplemental Reserve);
    - Exhibit No. PAC-0009 (Table F Adjusted Study Results: Schedules 3/3A, Regulation & Frequency Response);
    - Exhibit No. PAC-0010 (Workpapers)
- Attachment E: Direct Testimony of Dr. Paul A. Dumais, Vice President of Dumais Consulting LLC (Exhibit No. PAC-0011)
    - Exhibit No. PAC-0012 – Resume of Dr. Paul A. Dumais
    - Exhibit No. PAC-0013 – Statements BG and BH (base case)
    - Exhibit No. PAC-0014 – Waiver Request of Filing Requirements Under Code of Federal Regulations 35.13
    - Exhibit No. PAC-0015 – Ancillary Services 3/3A, 5 and 6 - Weighted Cost Per kW and Rate Design
    - Exhibit No. PAC-0016 – Ancillary Services 3/3A, 5 and 6 - Production Fixed Charge Rate
    - Exhibit No. PAC–0017 – Reactive Power Revenue Requirement and Rates
    - Exhibit No. PAC-0018 – Generator Information (contains privileged and confidential information)
- Attachment F: Model Protective Agreement in accordance with 18 C.F.R. § 388.112.

V. REQUEST FOR WAIVERS

The information contained in this filing provides a sufficient basis upon which to accept the proposed changes to its OATT Schedules 2, 3, 3A, 5, and 6 as well as Attachment U, each as set out in Attachment A, without condition, modification, or trial-type proceedings. To the extent this filing may require waivers of Section 35.13 of the regulations,[65] PacifiCorp respectfully requests such waivers, including waiver of the full Period I-Period II data requirements of Section

[65] 18 C.F.R. § 35.13.

35.13(d) and waiver of the requirement for sworn testimony in light of the National Emergency concerning the Novel Coronavirus Disease.[66]

In support, PacifiCorp notes that the 2020 Settlement Agreement was negotiated on a black box basis, rather than calculated based on specific cost-of-service data. However, PacifiCorp is including its base case cost support to demonstrate the justness and reasonableness of the 2020 Settlement Agreement rates.

In prior cases involving ancillary service rates, the Commission has accepted ancillary service rate increases for filing without requiring the full cost-of-service statements of Section 35.13.[67] The base case cost support and supporting worksheets included with testimony accompanying this filing, together with PacifiCorp's publicly available FERC Form No. 1, provide ample support for the reasonableness of the 2020 Settlement Agreement rates. Exhibit No. PAC-0014 provides information on the sources of the data used in the rate calculation, including the specific FERC Form 1 references for each type of cost data information. As shown on that exhibit, all of the cost data comes from the FERC Form 1, calculated within the attached workpapers, or is inapplicable to the rate design. Further, PacifiCorp notes that it was obligated by the ER17-219 Settlement approved by the Commission to consider using the same fixed charge rate as the basis for developing the rates that PacifiCorp proposes in this filing. Specifically, Section 6.3.2 of the ER17-219 Settlement required that, during the stakeholder process, PacifiCorp and stakeholders consider "[c]alculation of the fixed charge rate using the Production Fixed Charge Rate Formula of the instant docket." The "Production Fixed Charge Rate Formula" uses Form 1 cost data as inputs rather than the inputs provided by cost-of-service statements. The rates submitted in the instant filing incorporate this aspect of the ER17-219 Settlement, as the rates are calculated using the same fixed charge rate as was proposed in Docket No. ER17-219-000. This is further discussed in the testimony of Dr. Dumais.

VI. REQUEST FOR CONFIDENTIAL TREATMENT

Exhibit No. PAC-0018 contains the privileged information for PacifiCorp's generators used in the development of the proposed rates. Among other things, Exhibit No. PAC-0018 includes test reports showing the leading and lagging MVAr of PacifiCorp units under test conditions, D-curves (reactive capability curves) and Vee-curves (stator current versus field current). If released, this proprietary information would cause PacifiCorp competitive harm. Accordingly, PacifiCorp respectfully requests confidential treatment for Exhibit No. PAC-0018 pursuant to 18 C.F.R. § 388.112. Consistent with the Commission's requirements, PacifiCorp is filing a confidential version of this filing and a public redacted version of this filing that excludes

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[66] *Temporary Action to Facilitate Social Distancing*, 174 FERC ¶ 61,047 (2021) (extending the blanket waiver of requirements to hold meetings in-person and provide or obtain notarized documents in open access transmission tariffs through and including July 30, 2021).

[67] *See e.g., ALLETE, Inc*., 165 FERC ¶ 61,278 (2018); *Southern Indiana Gas & Electric Co., Inc.,* 167 FERC ¶ 61,190 (2019); *Alliant Energy Corporate Services, Inc*., 166 FERC ¶ 61,106 (2019); *Duke Energy Carolinas, LLC*, 165 FERC ¶ 61,277 (2018); *FirstEnergy Solutions Corp*., 152 FERC ¶ 61,164 (2015); *Wisconsin Public Service Corp*., letter order, Docket No. ER18-2115-000 (Oct. 2, 2018). *See also Tuscola Wind II, LLC*, 168 FERC ¶ 61,214 (2019); *Minonk Wind, LLC,* 167 FERC ¶ 61,188 (2019); *Crystal Lake Wind Energy I, LLC*, 171 FERC ¶ 61,252 (2020).

Exhibit No. PAC-0018. A proposed protective agreement, based upon the Commission's Model Protective Order, is provided as Attachment F to this filing.

VII. EFFECTIVE DATE AND APPROVAL

PacifiCorp respectfully requests that the Commission accept these revisions to Schedules 2, 3, 3A, 5 and 6 of the PacifiCorp OATT for filing to become effective, without any suspension or hearing, on January 1, 2021, as contemplated by the 2020 Settlement Agreement. In addition, PacifiCorp respectfully requests that the Commission accept the tariff to Attachment U of the PacifiCorp OATT to become effective, without any suspension or hearing, on July 1, 2021, as contemplated by the 2020 Settlement Agreement. The Commission should accept PacifiCorp's proposed revisions to Attachment U and Schedules 2, 3, 3A, 5 and 6. The proposed revisions are just and reasonable, cost-justified, modeled after methodologies accepted by the Commission for other public utilities, and consistent with relevant reliability standards and Commission orders, including Order Nos. 764 and 764-A.[68]

The Commission should also be aware that the 2020 Settlement Agreement is contingent on Commission approval without change or condition. Should the Commission order any change that any Settling Party finds unacceptable, PacifiCorp is obligated by section 8.5 of the 2020 Settlement Agreement to withdraw the instant filing, without prejudice to submitting a new, unilateral filing which each customer has preserved the right to protest.

PacifiCorp respectfully requests waiver of any requirements of the Commission's rules and regulations, as well as any authorizations as may be necessary or required to permit the proposed revisions to be accepted by FERC and made effective in the manner proposed herein.

VIII. COMMUNICATIONS

All communications and correspondence regarding this filing should be provided to the following persons:

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[68] *Integration of Variable Energy Resources*, Order No. 764, FERC Stats. & Regs. ¶ 31,331 (2012) ("Order No. 764"), *order on reh'g*, Order No. 764-A, FERC Stats. & Regs. ¶ 61,232 (2012) ("Order No. 764-A"), *order on reh'g and clarification*, Order No. 764-B, 144 FERC ¶ 61,222 (2013) ("Order No. 764-B").

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IX. SERVICE

PacifiCorp has e-mailed a copy of this filing to all OATT transmission customers that have provided PacifiCorp an e-mail contact address and representatives of all the signatories to the 2020 Settlement Agreement. To the extent that customers have not provided PacifiCorp a contact email, PacifiCorp has served such customers with a hard copy of this filing.

PacifiCorp has also served a copy of this filing on each of the following state public utility commissions regulating PacifiCorp's retail service operations: California Public Utilities Commission; Idaho Public Utilities Commission; Oregon Public Utility Commission; Public Service Commission of Utah; Washington Utilities and Transportation Commission; and Wyoming Public Service Commission.

X. CONCLUSION

PacifiCorp respectfully requests that the Commission: (1) accept the enclosed tariff sheet revisions for filing; (2) allow the revisions to Schedules 2, 3, 3A, 5 and 6 of the PacifiCorp OATT to become effective January 1, 2021, without suspension, condition, or modification; (3) allow the revisions to Attachment U of the PacifiCorp OATT to become effective July 1, 2021, without suspension, condition, or modification; and (4) grant any other waivers or authorizations necessary to make the revised tariff sheets effective upon the date requested.

Respectfully submitted,

/s/ Matthew Loftus

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Attorneys for PacifiCorp

Comparison of Existing Rates to Settlement Rates **Appendix 1**

			Current	Settlement	
		Billing Units	Revenues	Revenues	Settlement Less Current
1	Schedule 2		$ 959,887	$ 2,797,647	$ 1,837,760
2	Schedule 3 - Load	13,821 (MW)	2,446,363	1,596,245	(850,118)
3	Schedule 3/3A				
4	VERS -Wind	469	3,091,460	3,137,971	46,511
5	VERS-Solar	123	808,962	685,108	(123,854)
6	Non-VERS - Nondispatchable	248	428,228	751,498	323,270
7	Non-VERS - Dispatchable	200	358,800	-	(358,800)
8	Subtotal - NonVERS	448	787,028	751,498	(35,530)
9	Subtotal	(MW)	4,687,449	4,525,939	(161,510)
10	Total Schedule 3/3A		7,133,812	6,122,184	(1,011,628)
11	Schedule 5	12,276,069 (MWh)	1,853,686	2,058,697	205,010
12	Schedule 6	12,764,293 (MWh)	1,927,408	2,140,572	213,164
13	Total		$ 11,874,794	$ 13,119,099	$ 1,292,944

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator subject to any credits provided pursuant to applicable PacifiCorp business practices. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

Transmission Customers Obligated to acquire Reactive Supply and Voltage Control from Generation Sources Service: All Transmission Customers purchasing Long-Term Firm Point-to-Point Transmission Service, Short-Term Firm Point-to-Point Transmission Service, Non-Firm Point-to-Point Transmission Service, or Network Integration Transmission Service from the Transmission Provider shall be required to acquire Reactive Supply and Voltage Control from Generation Sources Service from the Transmission Provider.

Charge for Reactive Supply and Voltage Control from Generation Sources Service: For Point-To-Point Transmission Service, the rate shall be applied to the Transmission Customer's Reserved Capacity. For purposes of charging the rates set forth in this Schedule 2 to Transmission Customers purchasing Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff. For Network Integration Transmission Service, the rate shall be applied to the Transmission Customer's Monthly Network Load.

1.	Yearly Rate	$1.603/kW/Year
2.	Monthly Rate	$0.134/kW/Month
3.	Weekly Rate	$0.031/kW/Week
4.	Daily Rate	$0.004/kW/Day
5.	Hourly Rate	$0.183/MWh

The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 2 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 2 times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Rate Schedule Moratorium Period:

The rates and charges under this Schedule 2 cannot be changed with any effective date prior to January 1, 2023 unless the Transmission Provider proposes a reduction in the rates or charges under this Schedule 2. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 2 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

In addition, during this rate schedule moratorium period, the Transmission Provider will not propose to recover or pass-through any costs, including those in Docket No. ER20-2528, it

may incur as a result of any generator that receives a FERC approved Schedule 2 rate, including any resulting revenue requirement. Following this rate schedule moratorium period, the Transmission Provider shall not propose to recover or pass-through any such reactive power costs it incurs during the rate schedule moratorium period. None of the parties to the settlement agreement included with the filing in Docket No. [*TBD*] shall make a filing with FERC seeking compensation from the Transmission Provider pursuant to a Schedule 2 rate for reactive power during this rate schedule moratorium period. After the expiration of this rate schedule moratorium period, the Transmission Provider is not prohibited from seeking authorization to recover or pass-through future costs that the Transmission Provider incurs after this rate schedule moratorium period as a result of a Schedule 2 rate filed by a third party with the Commission.

Reactive Supply and Voltage Control from Generation Sources Service to be Provided: The Transmission Provider shall ensure that generation interconnected with its Transmission System meets the voltage support and reactive control requirements of the Western Electricity Coordinating Council.

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the BA that performs this function for the Transmission Provider).

The Transmission Provider must offer this service when the Transmission Service is used to serve load within its BAA. The Transmission Customer must purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation as further described in applicable PacifiCorp business practices. The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements.

For purposes of serving load under this schedule, the amount of and charges for Regulation and Frequency Response Service are differentiated by load, Variable Energy Resources (VERs), and resources that are not VERs (Non-VERs). The Transmission Customer shall pay a total Regulation and Frequency Response Service charge under this tariff equal to the sum of the charges applicable to the customer's load, VERs, and Non-VERs, as set forth below. To the extent the BA performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA.

Charge for Regulation and Frequency Response Service:

The load charges below apply to all load served by Network Integration Transmission Service or by Point-To-Point Transmission Service. Firm imports do not reduce the load obligation.

The rates below are applied to the Transmission Customer's Monthly Network Load for Network Integration Transmission Service or to the load served by Point-To-Point Transmission Service.

Load

1. Yearly Rate		$1.3859 per kW-Year
2. Monthly Rate		$0.1155 per kW-Month

The charges below apply to all generators serving Network Load and are differentiated by the type of resources (VERs or Non-VERs) serving that load. The Transmission Provider shall charge the Transmission Customer the monthly rate times the lesser of the nameplate capacity of the generator, the capacity in a MOD-25 report, or the interconnection capacity of the resource set forth in an Interconnection Agreement.

Each year by December 1, the Transmission Customer shall provide to the Transmission Provider an attestation of the nameplate capacity, the interconnection capacity set forth in an Interconnection Agreement, or the capacity shown in a MOD-25 report for each VER and Non-VER resource owned or controlled by the Transmission Customer and located within the BAA.

VERs (Solar)- Uncommitted Scheduling

1. Yearly Rate		$5.5836 per kW-Year
2. Monthly Rate		$0.4653 per kW-Month

VERs (Wind)- Uncommitted Scheduling

1. Yearly Rate		$6.6922 per kW-Year
2. Monthly Rate		$0.5577 per kW-Month

VERs - Committed Scheduling

To qualify for this committed scheduling rate for a month, the VER customer must: (i) provide notification to PacifiCorp in advance of the month that it intends to engage in Committed Scheduling; and (ii) during every hour of that month (except as specified below), a VER customer must utilize and submit into BSAP by 57 minutes prior to the operating hour (T-57), consistent with PacifiCorp's EIM Business Practice, hour-ahead base schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of no more than 72 minutes prior to the operating hour (T-72) without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule. In any calendar month for up to two operating hour intervals, a VER customer may utilize and submit into BSAP by T-57, hour-ahead schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of up to 90 minutes prior to the operating hour (T-90), without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule, and still be eligible for this rate. Use and submission into BSAP of hour-ahead schedules older than PacifiCorp's VER forecast vendor's forecast at T-90 in any hour during a calendar month will make a VER customer ineligible for this rate in that month. Upon notification by the PacifiCorp EIM Entity, the VER customer is required to submit a manual override or modification to the PacifiCorp VER forecast vendor's forecast to reflect a known or expected system constraint and ensure the submission of a balanced Base Schedule consistent with the requirements set forth in Attachment T.

VERs (Solar) - Committed Scheduling

1. Yearly Rate		$5.1872 per kW-Year
2. Monthly Rate		$0.4323 per kW-Month

VERs (Wind) - Committed Scheduling

1. Yearly Rate		$6.2171 per kW-Year
2. Monthly Rate		$0.5181 per kW-Month

Non-VERs

1. Yearly Rate		$3.1483 per kW-Year
2. Monthly Rate		$0.2624 per kW-Month

Rate Schedule Moratorium Period:

The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 3 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California Independent System Operator.[1] Each party to the Docket No. [TBD] Settlement Agreement reserves its rights to protest or otherwise challenge any such filing.

ARTSOA Moratorium Period:

The Amended and Restated Transmission Service and Operating Agreement ("ARTSOA") billing provisions referenced below shall not be changed with an effective date prior to December 1, 2025 (the "ARTSOA Moratorium Period"):

1. In accordance with the Sixth Amended and Restated Transmission Service and Operating Agreement between Utah Municipal Power Agency ("UMPA") and PacifiCorp (the "UMPA

[1] Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedules 3, 3A, 5 and 6. The parties to the Docket No. [TBD] Settlement Agreement agree to engage with PacifiCorp in good faith discussions regarding potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (4) take no action to prevent, inhibit or limit such direct access.

ARTSOA"), the Transmission Provider shall bill UMPA under Schedule 3/3A based only on its Aggregate Peak Demand ("APD"), as such term is defined in the UMPA ARTSOA, and shall not charge or seek to charge UMPA for generation at all under Schedule 3/3A or otherwise during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UMPA for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UMPA each reserve their respective rights and positions regarding whether the UMPA ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UMPA's generation.

2. In accordance with the Seventh Amended and Restated Transmission Service and Operating Agreement between Deseret Generation & Transmission Co-Operative, Inc. ("Deseret") and PacifiCorp (the "Deseret ARTSOA"), the Transmission Provider shall bill Deseret under Schedule 3/3A based only on its Aggregate Peak Demand plus the Deseret Area Load for which Deseret has the obligation to supply Regulation Reserve Service, and shall only charge or seek to charge Deseret under Schedule 3/3A for off-system sales associated with Deseret Resources, as all such terms are defined in the Deseret ARTSOA, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge Deseret for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and Deseret each reserve their respective rights and positions regarding whether the Deseret ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to Deseret's generation.

3. In accordance with the Fifth Amended and Restated Transmission Service and Operating Agreement between Utah Associated Municipal Power Systems ("UAMPS") and PacifiCorp (the "UAMPS ARTSOA"), the Transmission Provider shall bill UAMPS under Schedule 3/3A based only on its Monthly Coincident Peak Demand as such term is defined in the UAMPS ARTSOA, and shall not charge or seek to charge UAMPS for generation under Schedule 3/3A or otherwise, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UAMPS for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UAMPS each reserve their respective rights and positions regarding whether the UAMPS ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UAMPS' generation.

Self-Supply, Third-Party Supply and Pooling:

A Transmission Customer may choose to supply all or a portion of its Regulation and Frequency Response Service obligation through self-supply or third-party supply consistent with the requirements herein, Attachment U, and PacifiCorp's business practices. A Transmission Customer may request to supply all or a portion of its Regulation and Frequency Response Service through pooling agreement, which the Transmission Provider shall consider on a case-by-case and non-discriminatory basis.

For a Transmission Customer that chooses to supply its Regulation and Frequency Response Obligation through self-supply, third-party supply, or pooling agreements, the total charge for failure to supply its Regulation and Frequency Response Service obligation shall not exceed the Monthly Rate pursuant to this Schedule 3 times the highest amount in megawatts not covered under self-supply, third-party supply or pooling agreements.

Clarifications regarding Non-VER Participating Resources:

A Non-VER Participating Resource in the Energy Imbalance Market ("EIM") qualifies as a dispatchable Non-VER resource. Additionally, Non-VER resources dispatchable by the Transmission Provider qualify as dispatchable Non-VERS. The Transmission Provider will not charge Non-VER Participating Resources or Non-VER resources dispatchable by the Transmission Provider for Schedules 3 and 3A services. PacifiCorp shall consider, on a good faith basis, requests by customers to identify a resource that should qualify as a dispatchable Non-VER in this context due to its ability to follow PacifiCorp instructions, notwithstanding the fact that the resource is not directly dispatchable by PacifiCorp.

SCHEDULE 3A

Generator Regulation and Frequency Response Service

Generator Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Generator Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes for a generator located within the BAA. The obligation to maintain this balance between resources and the generator's schedule lies with the Transmission Provider (or the BAA that performs this function for the Transmission Provider).

The Transmission Provider must offer this service when transmission service is provided for a generator physically or electrically located in the Transmission Provider's BAA. Generator Regulation and Frequency Response Service applies to the extent that a Transmission Customer is not already subject to Regulation and Frequency Response Service provided under Schedule 3. When applicable, the Transmission Customer must purchase Generator Regulation and Frequency Response Service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements, as further described in applicable PacifiCorp business practices which may include self-supplying regulation reserve capacity from generation or non-generation resources or through dynamically scheduling its generation to another BAA. The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Generator Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements.

For purposes of exports or Third-Party Sales, the amount of and charges for Generator Regulation and Frequency Response Service are differentiated by the type of exporting resource (Variable Energy Resources (VERs) or resources that are not VERs (Non-VERs)) and are set forth below. To the extent a BA performs this service for the Transmission Provider, charges to

the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA. The Transmission Provider may not charge a Transmission Customer for regulation reserves under both Schedule 3 and Schedule 3A for the same transaction.

Charge for Generator Regulation and Frequency Response Service:

The charges below apply to generation that originates in the PacifiCorp BAA and terminates in another BAA or for any resource not designated as a Network Resource. The Transmission Provider shall charge the Transmission Customer the monthly rate times the lesser of the nameplate capacity of the generator, the capacity in a MOD-25 report, or the interconnection capacity of the resource set forth in an Interconnection Agreement

Each year by December 1, the Transmission Customer shall provide to the Transmission Provider attestation of the nameplate capacity, the interconnection capacity set forth in an Interconnection Agreement, or the capacity shown in a MOD-25 report for each VER and Non-VER resource owned or controlled by the Transmission Customer and located within the BAA.

VERs (Solar) - Uncommitted Scheduling

1. Yearly Rate		$5.5836 per kW-Year
2. Monthly Rate		$0.4653 per kW-Month

VERs (Wind) - Uncommitted Scheduling

1. Yearly Rate		$6.6922 per kW-Year
2. Monthly Rate		$0.5577 per kW-Month

VERs - Committed Scheduling

To qualify for this committed scheduling rate for a month, the VER customer must: (i) provide notification to PacifiCorp in advance of the month that it intends to engage in Committed Scheduling; and (ii) during every hour of that month (except as specified below), a VER customer must utilize and submit into BSAP by 57 minutes prior to the operating hour (T-57), consistent with PacifiCorp's EIM Business Practice, hour-ahead base schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of no more than 72 minutes prior to the

operating hour (T-72) without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule. In any calendar month for up to two operating hour intervals, a VER customer may utilize and submit into BSAP by T-57, hour-ahead schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of up to 90 minutes prior to the operating hour (T-90), without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule, and still be eligible for this rate. Use and submission into BSAP of hour-ahead schedules older than PacifiCorp's VER forecast vendor's forecast at T-90 in any hour during a calendar month will make a VER customer ineligible for this rate in that month. Upon notification by the PacifiCorp EIM Entity, the VER customer is required to submit a manual override or modification to the PacifiCorp VER forecast vendor's forecast to reflect a known or expected system constraint and ensure the submission of a balanced Base Schedule consistent with the requirements set forth in Attachment T.

VERs (Solar) – Committed Scheduling

1. Yearly Rate		$5.1872 per kW-Year
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VERs (Wind) – Committed Scheduling

1. Yearly Rate		$6.2171 per kW-Year
2. Monthly Rate		$0.5181 per kW-Month

Non-VERs - Committed Scheduling

1. Yearly Rate		$3.1483 per kW-Year
2. Monthly Rate		$0.2624 per kW-Month

Rate Schedule Moratorium Period:

The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 3A as provided in the Docket No. [TBD] Settlement

Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California Independent System Operator.[1] Each party to the Docket No. [TBD] Settlement Agreement reserves its rights to protest or otherwise challenge any such filing.

ARTSOA Moratorium Period:

The Amended and Restated Transmission Service and Operating Agreement ("ARTSOA") billing provisions referenced below shall not be changed with an effective date prior to December 1, 2025 (the "ARTSOA Moratorium Period"):

1. In accordance with the Sixth Amended and Restated Transmission Service and Operating Agreement between Utah Municipal Power Agency ("UMPA") and PacifiCorp (the "UMPA ARTSOA"), the Transmission Provider shall bill UMPA under Schedule 3/3A based only on its Aggregate Peak Demand ("APD"), as such term is defined in the UMPA ARTSOA, and shall not charge or seek to charge UMPA for generation at all under Schedule 3/3A or otherwise during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UMPA for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UMPA each reserve their respective rights and positions regarding whether the UMPA ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UMPA's generation.

2. In accordance with the Seventh Amended and Restated

[1] Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedules 3, 3A, 5 and 6. The parties to the Docket No. [TBD] Settlement Agreement agree to engage with PacifiCorp in good faith on potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (3) take no action to prevent, inhibit or limit such direct access.

Transmission Service and Operating Agreement between Deseret Generation & Transmission Co-Operative, Inc. ("Deseret") and PacifiCorp (the "Deseret ARTSOA"), the Transmission Provider shall bill Deseret under Schedule 3/3A based only on its Aggregate Peak Demand plus the Deseret Area Load for which Deseret has the obligation to supply Regulation Reserve Service, and shall only charge or seek to charge Deseret under Schedule 3/3A for off-system sales associated with Deseret Resources, as all such terms are defined in the Deseret ARTSOA, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge Deseret for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and Deseret each reserve their respective rights and positions regarding whether the Deseret ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to Deseret's generation.

3. In accordance with the Fifth Amended and Restated Transmission Service and Operating Agreement between Utah Associated Municipal Power Systems ("UAMPS") and PacifiCorp (the "UAMPS ARTSOA"), the Transmission Provider shall bill UAMPS under Schedules 3 and 3A based only on its Monthly Coincident Peak Demand as such term is defined in the UAMPS ARTSOA, and shall not charge or seek to charge UAMPS for generation under Schedule 3/3A or otherwise, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UAMPS for generation under Schedules 3 and 3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UAMPS each reserve their respective rights and positions regarding whether the UAMPS ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UAMPS' generation.

Self-Supply, Third-Party Supply and Pooling:

A Transmission Customer may choose to supply all or a portion of its Generator Regulation and Frequency Response Service obligation through self-supply or third-party supply consistent with the requirements herein, Attachment U, and PacifiCorp's business practices. A Transmission Customer may request to supply all or a portion of its Generator Regulation and Frequency Response Service obligation through pooling agreements, which the Transmission Provider shall consider on a case-by-case and non-discriminatory basis.

For a Transmission Customer that chooses to supply its Generator Regulation and Frequency Response Service obligation

through self-supply, third-party supply, or pooling agreements, the total charge for failure to supply its Generator Regulation and Frequency Response Service obligation shall not exceed the Monthly Rate pursuant to this Schedule 3A times the highest amount in megawatts not covered under self-supply, third-party supply or pooling agreements.

Clarifications regarding Non-VER Participating Resources:

A Non-VER Participating Resource in the Energy Imbalance Market ("EIM") qualifies as a dispatchable Non-VER resource. Additionally, Non-VER resources dispatchable by the Transmission Provider qualify as dispatchable Non-VERS. The Transmission Provider will not charge Non-VER Participating Resources or Non-VER resources dispatchable by PacifiCorp for Schedules 3 and 3A services. PacifiCorp shall consider, on a good faith basis, requests by customers to identify a resource that should qualify as a dispatchable Non-VER in this context due to its ability to follow PacifiCorp instructions, notwithstanding the fact that the resource is not directly dispatchable by PacifiCorp.

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load in the BAA and to support other transmission usage sourced from generation in the BAA including exports and sales. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its BAA and to support other transmission usage sourced from generation in the BAA including exports and sales. The Transmission Customer must purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the BA performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA.

Charges for Spinning Reserve Service:

Under the current NERC Regional Reliability Standard BAL-002-WECC, the Transmission Provider is required to maintain a minimum amount of contingency reserve equal to the sum of three percent of hourly integrated load plus three percent of hourly integrated generation with at least half as spinning. Consistent with the Transmission Provider operating in accordance with this reliability standard, the charges for Schedule 5 below apply one and one-half percent to load and one and one-half percent to generation.

For load, the rates below are charged to a Network Customer's hourly integrated load (including losses).

For generation, the rates below are applied to customers by charging actual hourly generation delivered to the Transmission Provider at the Point of Receipt.

The rate shall be an Hourly Rate of:

Schedule 5 (Spinning Reserves)		$0.1677 per MWh

Rate Schedule Moratorium Period:

The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 5 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California Independent System Operator.[1]

Self-Supply, Third-Party Supply and Pooling:

A Transmission Customer may choose to supply all or a portion of its reserve obligation through self-supply or third-party supply consistent with the procedures set forth in Attachment U to the Tariff. A Transmission Customer may request to supply all or a portion of its reserve obligation through pooling agreements, which the Transmission Provider shall consider on a case-by-case and non-discriminatory basis.

For a Transmission Customer choosing to supply a portion of its reserve obligation through self-supply, third-party supply or pooling agreements, detailed hourly calculation procedures are set forth in Attachment V to the Tariff.

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[1] Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedule 5. The parties to the Docket No. [TBD] Settlement Agreement agree to engage with PacifiCorp in good faith on potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (4) take no action to prevent, inhibit or limit such direct access.

Spinning Reserve Service to be Provided:

The Transmission Provider, using its generators controlled by automatic generation control, will provide the capacity required to provide Spinning Reserve Service for a Transmission Customer. Upon an outage of a generation resource for which Spinning Reserve Service has been purchased from the Transmission Provider, the Transmission Provider will provide replacement capacity commencing immediately upon such outage until the earlier of (1) the restoration of such resource to service by the Transmission Customer or (2) the end of ten (10) full minutes after the occurrence of such outage.

To the extent that the Transmission Provider determines that a Transmission Customer's specific Spinning Reserve Requirements are not being fully met through the purchase of Spinning Reserve Service as provided above, the Transmission Provider reserves the right (upon filing with the Commission) to require such Transmission Customer to purchase a greater amount of Spinning Reserve Service.

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the BAA and to support other transmission usage sourced from generation in the BAA including exports and sales; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its BAA and to support other transmission usage sourced from generation in the BAA including exports and sales. The Transmission Customer must purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the BA performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA.

Charges for Supplemental Reserve Service:

Under the current NERC Regional Reliability Standard BAL-002-WECC, the Transmission Provider is required to maintain a minimum amount of contingency reserve equal to the sum of three percent of hourly integrated load plus three percent of hourly integrated generation with at least half as spinning. Consistent with the Transmission Provider operating in accordance with this reliability standard, the charges for Schedule 6 below apply one and one-half percent to load and one and one-half percent to generation.

For load, the rates below are charged to a Network Customer’s hourly integrated load (including losses).

For generation, the rates below are applied to customers by charging actual hourly generation delivered to the Transmission Provider at the Point of Receipt.

The rate shall be an Hourly Rate of:

Schedule 6 (Supplemental)		$0.1677 per MWh

Rate Schedule Moratorium Period:

The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 6 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California Independent System Operator.[1] Each party to the Docket No. [TBD] Settlement Agreement reserves its rights to protest or otherwise challenge any such filing.

Self-Supply:

A Transmission Customer may choose to supply all or a portion of its reserve obligation through self-supply or third-party supply consistent with the procedures set forth in Attachment U to the Tariff. A Transmission Customer may request to supply all or a portion of its reserve obligation through pooling agreements, which the Transmission Provider shall consider on a case-by-case and non-discriminatory basis.

[1] Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedule 6. The parties to the Docket No. [TBD] Settlement Agreement settlement agreement included with the filing in Docket No. [TBD] agree to engage with PacifiCorp in good faith on potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (4) take no action to prevent, inhibit, or limit such direct access.

For a Transmission Customer choosing to supply a portion of its reserve obligation through self-supply, third-party supply or pooling agreements, detailed hourly calculation procedures are set forth in Attachment V to the Tariff.

Supplemental Reserve Service to be Provided:

The Transmission Provider, using its generators controlled by automatic generation control, will provide the capacity required to provide Supplemental Reserve Service for a Transmission Customer. Upon an outage of a generation resource for which Supplemental Reserve Service has been purchased from the Transmission Provider, the Transmission Provider will provide replacement capacity commencing at the end of ten (10) full minutes after such outage until the earlier of (1) the restoration of such resource to service by the Transmission Customer or (2) the end of the first full hour immediately following such outage.

To the extent that the Transmission Provider determines that a Transmission Customer's specific Supplemental Reserve Requirements are not being fully met through the purchase of Supplemental Reserve Service as provided above, the Transmission Provider reserves the right (upon filing with the Commission) to require such Transmission Customer to purchase a greater amount of Supplemental Reserve Service.

ATTACHMENT U

Requirements for Self-Supply Ancillary Services

1. Purpose
2. Practice
3. Generally Applicable Provisions
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   - 3.2 Operating Tests
   - 3.3 SCADA (metering) requirements for reserves
   - 3.4 Failure to Meet Requirements or Failure to Perform
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1. Purpose

The purpose of this Attachment U is to clarify certain practices pertaining to self-supply or third-party supply of Schedule 3 – Regulation and Frequency Response Service, Schedule 3A – Generator Regulation and Frequency Response Service, Schedule 4 – Energy Imbalance Service, Schedule 5 – Operating Reserve – Spinning Reserve Service, Schedule 6 – Operating Reserve – Supplemental Reserve Service, and Schedule 9 – Generator Imbalance Service under the OATT. Self-supply and third-party supply may include pooling agreements, which PacifiCorp shall consider for approval in good faith and on a reasonable, non-discriminatory, case-by-case basis.

2. Practice

The following are the requirements of PacifiCorp, which is the Balancing Authority and Transmission Operator, for Transmission Customers who wish to self-supply or to arrange for third-party purchase of OATT Schedule 3 – Regulation and Frequency Response Service, Schedule 3A – Generator Regulation and Frequency Response Service, Schedule 4 – Energy Imbalance Service, Schedule 5 – Operating Reserve – Spinning Reserve Service, Schedule 6 – Operating Reserve – Supplemental Reserve Service, and Schedule 9 – Generator Imbalance Service. PacifiCorp requires that self-supplied or third-party supplied Ancillary Services satisfy the requirements for the above-referenced schedules under the currently effective PacifiCorp OATT and satisfy the relevant reliability standards of NERC or any successor organization.

3. Generally Applicable Provisions

3.1 Service Agreement

A Transmission Customer requesting to self-supply or to arrange for third-party supply of Schedules 3/3A, 4, 5, 6, or 9 shall execute a revision to its existing transmission service agreement or a separate service agreement with PacifiCorp specifying, as applicable: (1) the detailed arrangements made to supply the services including, but not limited to, specification of the amount of service required to meet the party's Ancillary Services obligation, identification of the resource(s) supplying the service and the Balancing Authority Area where the resource(s) are located; (2) metering and communications equipment; (3) procedures for data exchange or automation; (4) the calculation of the Transmission Customer's obligation; and (5) processes for

forecasting, deploying, and verifying performance of self-supply or third-party supply.

3.2 Operating Tests

PacifiCorp may, after providing notice fifteen (15) business days in advance, require operational testing of the resources identified as providing self-supply or third-party supply of Schedules 3/3A, 4, 5, 6, or 9, in addition to testing performed by the Generation Owner to meet NERC reliability standards or Western Electricity Coordinating Council ("WECC") regional criterion. PacifiCorp will monitor resources designated and accepted for self-supply to ensure compliance with NERC reliability standards, WECC regional criterion, and PacifiCorp requirements for time, output and power quality.

Resources that do not fully comply with NERC reliability standards, WECC regional criterion, and PacifiCorp requirements will be disqualified as self-supply or third-party supply resources until such a time as an operating test establishes that the resource(s) can respond in accordance with NERC reliability standards, WECC regional criterion, and PacifiCorp requirements.

3.3 SCADA (metering) requirements for reserves

For resources to qualify for self-supply or third-party supply of Schedules 3/3A, 4, 5, 6, or 9, the following data must be supplied by the designated self-supply or third-party supply resource. Real time data must be supplied through telemetry acceptable to PacifiCorp.

- Net Generation MW
- Net Generator MVAr
- Real power flow through each of the low side feeder breakers
- Reactive power flow through each of the low side feeder breakers
- Reactive power flow from each of the shunt capacitor banks
- A phase high side transmission voltage
- B phase high side transmission voltage
- C phase high side transmission voltage
- Accumulator pulses for interchange metering kWh
- Status of all low and high side breakers

- 10-minute ramp rate, limited by capacity
- Pmax and Pmin
- Ramp Rate MW/min
- Status – Active/Inactive
- Deploy and Deploy Acknowledge Signals

3.4 Failure to Meet Requirements or Failure to Perform

In the event that any of the requirements set forth in this Attachment U fail to be met, PacifiCorp will resume billing the Transmission Customer for the specific Ancillary Service(s) for which the Transmission Customer has failed to meet the requirements. Beginning on the date of the failure, PacifiCorp will bill the Transmission Customer until such failure is cured. This may include any penalties, charges or other consequences to which PacifiCorp is subject related to the failure. Further detail regarding the process and protocol for addressing failure to meet eligibility requirements or failure to self-supply is set forth below or in the relevant transmission service agreement.

3.5 Requests for Additional Information

PacifiCorp may, consistent with Good Utility Practice, request such additional information, beyond what is specifically required by this Attachment U, from the Transmission Customer regarding the self-supply or third-party supply of an Ancillary Service as is reasonably necessary to ensure that the Ancillary Service is supplied in a reliable manner. All such requests shall be limited to reliability specific data.

PacifiCorp shall treat any information designated as confidential by the Transmission Customer as confidential except to the extent that disclosure of this information is required by another provision of the PacifiCorp OATT, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice. Further, PacifiCorp shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

3.6 Rejection of Requests or Termination of Existing Self-Supply or Third-Party Supply Arrangements

PacifiCorp may, consistent with Good Utility Practice, reject a request for self-supply or third-party supply of Ancillary Service(s) or suspend operation of an existing arrangement for self-supply or third-party supply in the event that such self-

supply or third-party supply will impair reliability of the relevant PacifiCorp Balancing Authority Area or the interconnected electric system. Prior to rejecting a request for self- or third-party supply or suspending an existing arrangement for self- or third-party supply, PacifiCorp shall provide reasonable advance notice to the Transmission Customer and shall discuss the rejection or termination, as applicable, with the Transmission Customer.

3.7 Responsibility for Necessary Equipment Installation

The Transmission Customer is responsible for the installation of all equipment (including but not limited to metering and telecommunications equipment) necessary to meet the requirements to self-supply or purchase third-party supply as specified in this Attachment U. The Transmission Customer will reimburse PacifiCorp or its affiliates for any expenses prudently incurred to accommodate the request for self-supply or third-party supply. The equipment to be installed for self-supply or third-party supply shall be specified in the agreement required by section 3.1.

4. SPECIFIC ANCILLARY SERVICE ALTERNATIVE SUPPLY REQUIREMENTS

4.1 SCHEDULE 3/3A – REGULATION AND FREQUENCY RESPONSE SERVICE

This section sets forth the resource eligibility requirements for self-supply or third-party supply of Schedules 3/3A – Regulation and Frequency Response Service. Additional detail regarding the self-supply or third-party supply of this service will be set forth in the transmission service agreement between the Transmission Customer and PacifiCorp. The agreement may cover, among other things, the Transmission Customer's reserve obligation, elections to self-supply or third-party supply, pooling arrangements, and processes for forecasting, deployment, and performance verification of self-supply or third-party supply of Schedules 3/3A.

A. Generating Resource Eligibility Requirements

The following resource eligibility requirements apply for the self-supply or third-party supply of Schedules 3/3A (Regulation and Frequency Response Service) where the resource supplying the service and the Network Load or resource requiring this service are in the same PacifiCorp Balancing Authority Areas.

1. The Network Load or resource receiving Schedule 3/3A service through self-supply or third-party supply must have real time metering observable by the Balancing Authority.

2. The resource providing self-supply or third-party supply must be deliverable on transmission within the applicable PacifiCorp BAA.

3. The Transmission Customer must have dedicated capacity for the provision of this service which may not be used to satisfy any other capacity obligations.

4. The resource providing self-supply or third-party supply must have a point of contact that is available any time the resource is designated for Schedule 3/3A.

5. An Energy Imbalance Market ("EIM") non-participating resource must be placed under automatic generation control ("AGC"), which is required to satisfy all Schedule 3/3A requirements in real time and to compensate for instantaneous load swings or resource losses within the PacifiCorp BAA. PacifiCorp reserves the right to determine the quantity and resource priority on AGC within the PacifiCorp BAA to meet the requirements under this section or those set forth in the transmission service agreement.

6. An EIM participating resources providing self-supply or third-party supply must follow the California Independent System Operator ("CAISO") Dispatch Operating Point or grid operator instruction to satisfy all reserve requirements in real time.

In addition to requirements 1 and 3-6 above, the following resource eligibility requirements apply where the resource providing self-supply or third-party supply is located in a non-PacifiCorp Balancing Authority Area (i.e., external resource) and the load or resource requiring this service is in a PacifiCorp BAA.

1. The BAA where the external resource is located ("External Balancing Authority") must be a certified BAA by NERC or its successor organization.

2. The resource providing self-supply or third-party supply must be deliverable on transmission to the applicable PacifiCorp BAA.

3. The external resource must be pseudo-tied to the PacifiCorp BAA. The pseudo-tie must meet the requirements in PacifiCorp Business Practice #25. In addition, the external resource must have observable real-time metering. The customer must provide: (i) documentation of a firm transmission path from the external resource to a PacifiCorp BAA; and a letter from the External Balancing Authority which certifies that Regulation and Frequency Response Service is supplied in accordance with all current policies and guidelines of the NERC Operating Manual, NERC Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Schedule 3/3A to loads that are located physically in another BAA.

4. The External Balancing Authority must make arrangements to appropriately account for the resource in its own reserve obligations.

5. If the pseudo-tie equipment providing the external resource's data to PacifiCorp is not used or not useable, PacifiCorp will bill the Transmission Customer for this service for the duration of the period in which the signal was unavailable, including any and all costs or penalties incurred by PacifiCorp associated with its provision of the service. Inability of the External Balancing Authority to receive the signal by means of the pseudo-tie equipment shall not give rise to charges for this service, unless PacifiCorp also is not able to receive the resource signal and is therefore unable to include the resource in the PacifiCorp BAA Schedule 3/3A obligation. The External Balancing Authority must correct the failure to receive the signal as soon as practicable. If the signal to the External Balancing Authority is not restored expeditiously within the operating day, the self-supply or third-party supply may be terminated and the Transmission Customer will be billed for Schedule 3/3A service for the impacted operating day(s).

4.2 SCHEDULE 5 & 6 – OPERATING RESERVES – SPINNING RESERVE SERVICE & SUPPLEMENTAL RESERVE SERVICE

A. Resource Eligibility Requirements

The following resource eligibility requirements apply for the self-supply or third-party supply of Schedules 5 & 6 (Operating Reserves – Spinning Reserve Service & Supplemental Reserve Service) where the resource and the Network Load or resource requiring this service are in the same PacifiCorp Balancing Authority Areas.

1. The Network Load or resource receiving Schedules 5 & 6 service through self-supply or third-party supply must have real time metering observable by the Balancing Authority.

2. The resource providing self-supply or third-party supply must be deliverable on transmission within the applicable PacifiCorp BAA.

3. The Transmission Customer must have dedicated capacity for the provision of this service which may not be used to satisfy any other capacity obligations.

4. The resource providing self-supply or third-party supply must have a point of contact that is available any time the resource is designated for operating reserve service.

5. For Schedule 5 – Operating Reserves – Spinning Reserve Service, the resource must have uncommitted available capacity which is on-line and loaded at less than maximum output and which may be used to satisfy the Transmission Customer's Schedule 5 obligation.

6. For Schedule 6 – Operating Reserves – Supplemental Reserve Service, the service may be self-supplied or purchased from any resource or interruptible load to meet the Transmission Customer's Schedule 6 obligation. The resource must be capable of serving demand in 10 minutes, or consist of uncommitted available capacity that is on-line and loaded at less than maximum output which can be fully applied in 10 minutes. To provide self-supply, the interruptible load must be located within a PacifiCorp BAA and must be capable of being interrupted and fully deployed within 10 minutes. If the Transmission Customer

seeks to use interruptible load for self-supply or third-party supply, the Transmission Customer must provide a detailed description of the load curtailment method, measurement of the deployment, and process utilized to trigger the curtailment.

7. Transmission Customer must provide, upon request, access to logs, dispatch records or SCADA data to verify that a resource providing self-supply is not fully loaded and has reserves that are actually spinning, and that the reserves are capable of being applied as reported.

8. Each resource must be capable of being evaluated consistent with the performance test described in Section D below. This requirement applies to the self-supplying Transmission Customer's ownership share or resource capacity rights for a jointly owned resource.

9. The resource must be capable of responding to automated deployment signals.

Requirements 1, 3-8 above also apply for the self-supply or third-party supply of Schedules 5 and 6 where the resource is located in an External Balancing Authority and the Network Load or resource receiving this service are in a PacifiCorp BAA. Requirements 2 and 9 do not apply to a generating resource located in an External Balancing Authority.

B. Scheduling Self-Supply or Third-Party Supply of Schedule 5 and 6

The following scheduling requirements apply for the self-supply or third-party supply of Schedules 5 & 6 where the resource and the load or resource receiving this service are in the same PacifiCorp BAA.

1. The resource providing self-supply or third-party supply must be deliverable on transmission to the applicable PacifiCorp BAA.

2. Transmission Customers must submit day-ahead information that identifies the specific resources and capacity levels designated for Schedule 5 and 6 through the Base Schedule Aggregation Portal ("BSAP"), or other means mutually acceptable to both parties.

3. Schedule 5 and 6 requirements must be scheduled using the CAISO BSAP scheduling portal through Day Ahead rolling seven-day submissions, or other means mutually acceptable to both parties. These submissions can be updated up to 57 minutes before the operating hour.

4. Forecast submissions for resources providing self-supply or third-party supply should be at the unit level if PacifiCorp's network model includes the resource by unit, or at the resource level if PacifiCorp's network model includes the resource at the resource level.

5. BSAP submissions should be entered as "AS-SP" for spin (Schedule 5) or "AS-NS" for non-spin (Schedule 6) values, as appropriate.

External Resources

The following scheduling requirements apply for the self-supply or third-party supply of Schedules 5 & 6 (Operating Reserves – Spinning Reserve Service and Operating Reserves – Supplemental Reserve Service) where the resource providing self-supply or third-party supply and the load or resource receiving this service are in different Balancing Authority Areas.

6. For a resource in an External Balancing Authority, Schedule 5 and 6 requirements must be scheduled using a Capacity e-Tag consistent with PacifiCorp Business Practice #39, E-tagging Reserves or a Dynamic e-Tag consistent with PacifiCorp Business Practice #25.

7. When e-Tagging Schedule 5 and 6 requirements, the Transmission Customer will include one of the following in the comment field to identify the specific type of reserve being e-Tagged:

- RES-SPIN-PUR = Purchased Spinning Reserves
- RES-SPIN-SP = Self-Provided Spinning Reserves
- RES-NS-PUR = Purchased Non-Spinning Reserves
- RES-NS-SP = Self-Provided Non-Spinning Reserves

8. Every day at midnight (PPT), PacifiCorp will capture and record e-Tagged forecast values.

C. Deployment of Self-Supply or Third-Party Supply of Schedule 5 and 6

The following deployment requirements apply for the self-supply or third-party supply of Schedules 5 & 6 where the resource providing self-supply or third-party supply and the load or resource receiving this service are in the same PacifiCorp Balancing Authority Area.

1. Schedule 5 and 6 deployment will occur through an automated process enabled by an interface between PacifiCorp and the Transmission Customer. The interface will be facilitated by a third-party vendor selected by the Transmission Customer. The Transmission Customer is responsible for engaging with a vendor to create an appropriate interface.

2. Deployment signals will be sent automatically through an electronic interface between PacifiCorp, Transmission Customer, and the vendor providing the electronic interface. The signal will identify the amount of Schedule 5 and 6 reserves to deploy. The Transmission Customer must have a point of contact available, all hours and every day, to be used to communicate the deployment of the reserves, when necessary.

3. During a contingency event, the amount of Schedule 5 and 6 reserves called upon for each self-supplying Transmission Customer will be calculated as follows:

   (Customer scheduled self-supply / Total PacifiCorp BAA (PACE or PACW) Contingency Reserve Obligation) * Generation Loss

4. For each self-supplying Transmission Customer, the deployment obligation is for 60 minutes.

External Resources

In addition to items 3 and 4 above, the following deployment requirements apply for the self-supply or third-party supply of Schedules 5 & 6 where the resource providing self-supply or third-party supply and the load or resource receiving this service are in different Balancing Authority Areas.

5. Consistent with Business Practice #39, when the service is needed, the Schedule 5 and 6 reserves must be deployed by the Transmission Customer. PacifiCorp will confirm that the Transmission Customer’s Schedule 5 and 6

reserves are being held via e-Tag. Once confirmation is validated, PacifiCorp will provide an automatic signal to communicate a loss of resource in the appropriate BAA and request deployment of Schedule 5 and 6 reserves. The Transmission Customer will make arrangements for the External Balancing Authority to communicate its Automatic Control Error ("ACE") and an acknowledgement signal to inform PacifiCorp that Schedule 5 and 6 reserves are being deployed.

6. During periods within the hour when Schedule 5 and 6 reserves are required, when using a Capacity e-Tag the Transmission Customer must submit an adjustment of the energy profile on the e-Tag within 7 minutes reflecting the amount of energy flow anticipated for the balance of the hour and subsequent hours. If the Transmission Customer is using a Dynamic e-Tag, then the Transmission Customer must submit updates to the Dynamic e-Tag energy profile with the integrated value (MWh) within 30 minutes after the completion of the operating hour, the e-Tag shall use the value obtained from a common agreed on source, and the e-Tag data must be submitted into the CAISO EIM as part of the base schedules for interchange.

D. Performance Verification & Failure Events

The following performance requirements apply for the self-supply or third-party supply of Schedules 5 & 6 – Operating Reserves – Spinning Reserve Service and Operating Reserves – Supplemental Reserve Service – where the resource and the Network Load or resource requiring this service are in the same PacifiCorp Balancing Authority Area. Failure of a self-supply resource to physically respond to a call to deploy Schedule 5 or 6 reserves may result in Failure Event and/or an assessment of a strike.

PacifiCorp will count as a single failure event (each a "Failure Event"), any hour or consecutive group of hours that a resource does not successfully respond when deployed to provide reserves and that occurs before PacifiCorp provides written notice of the Failure Event to the resource owner and all Transmission Customers relying on the resource for reserves.

To determine whether a Failure Event has occurred, a performance test will be conducted associated with each call for deployment of Schedule 5 or 6 reserves. The test will be

performed for each resource or group of resources in the following manner:

1. The resource's starting generation (average generation at the time the signal for deployment is sent) will be compared to the average generation 10 minutes following the deployment signal and during minutes 11-60 following the deployment signal.

2. Failure of the 10-minute test results if the average generation value is not greater than or equal to starting generation plus the identified Schedule 5 or 6 reserve obligation.

3. Failure of the 60-minute test results if the average generation value at during minutes 11-60 minutes is not greater than or equal to starting generation plus the identified Schedule 5 or 6 reserve obligation.

4. Failure of either the 10-minute or 60-minute test results in a Failure Event.

5. If the Transmission Customer has indicated that self-supply is available on more than a single resource or a group of resources, the performance test described above will be applied to the total available resources as compared to the average generation of the resource or group of resources.

External Resources

The following performance requirements apply for the self-supply or third-party supply of Schedules 5 & 6 – Operating Reserves – Spinning Reserve Service and Operating Reserves – Supplemental Reserve Service – where the resource and the Network Load or resource requiring this service are in different Balancing Authority Areas.

6. Failure of a self-supply resource to physically respond to a call to deploy Schedule 5 or 6 reserves may result in Failure Event. To determine whether a Failure Event has occurred, a performance test will be conducted associated with each call for deployment of Schedule 5 or 6 reserves. For Transmission Customers using an external resource to self-supply, the test will be performed for each resource or group of resources in the following manner:

7. PacifiCorp will review whether the e-Tag was implemented within the specified time listed in section C.6 per the e-Tag type, and verify an associated change to the net-scheduled-interchange (NSI) with the External Balancing Authority. If the e-Tag was not implemented and there was not change to NSI, a strike will be issued.

E. Assessment of Strikes

Upon written notice, a Failure Event may be assessed a "strike." The written notice will inform the Transmission Customer of the underlying Failure Event and the strike. "Written notice" for purposes of this Attachment U includes notice given electronically.

Upon each written assessment of a strike as provided above, and before another strike may be assessed to the same resource, PacifiCorp will allow the affected Transmission Customer(s) up to three business days in which to provide written notice to PacifiCorp of the specific remedy to the resource failure that has been implemented, of alternative self-supply arrangements that have been made, or of the intent to take the applicable reserve service(s) from PacifiCorp. Absent any such written notice to PacifiCorp, the affected Customer(s) shall be subject to the applicable reserve service(s) as defined in Schedule 5 and/or Schedule 6 of PacifiCorp's OATT for the duration of the failure.

A resource that accumulates three strikes within a rolling 12-month period will be disqualified for the balance of the month in which the third strike occurs and the entirety of the following month. PacifiCorp will give affected Transmission Customer(s) written notice of the third strike and resource disqualification. PacifiCorp will allow Transmission Customer(s) up to five business days in which to formally notify PacifiCorp of alternative self-supply arrangements or be subject to the applicable reserve service(s) as defined in Schedule 5 and/or Schedule 6 of PacifiCorp's OATT. No Transmission Customer may designate or utilize a disqualified resource to provide self-supply service. Following the disqualification period, strikes for the resource shall be reset to zero and the resource will be again eligible to provide self-supply service subject to the provisions herein.

If a Failure Event is caused by an unplanned outage of a self-supplying resource or transmission line, no strike will be

issued for the operating hour in which the unplanned outage occurs. Unless the Transmission Customer is able to meet its self-supply obligation through a different resource or group of resources, the Transmission Customer will be billed for Schedules 5 & 6 for the duration of the unplanned outage if an unplanned outage prevents the Transmission Customer from fulfilling its self-supply obligation. The Transmission Customer may be required to supply documentation of the unplanned outage and demonstration that the Failure Event was caused by that outage.

PacifiCorp will provide written reports of all performance evaluation results to the resource owner and the Transmission Customer(s) using the resource for self-supply, if different.

F. Settlement of Self-Supply or Third-Party Supply of Schedule 5 and 6

Energy supplied by a Transmission Customer during periods of Schedule 5 or 6 reserve deployment for resources located within a PacifiCorp BAA will be settled financially for the amount of energy deployed by the Transmission Customer's resource in accordance with Schedule 9 of PacifiCorp's OATT.

Energy supplied by a Transmission Customer during periods of Schedule 5 or 6 reserve deployment for resources located outside of a PacifiCorp BAA will be settled financially for the amount of energy deployed by the Transmission Customer's resource in accordance with Attachment T of PacifiCorp's OATT.

G. Monthly Report To Customers Regarding Schedule 5 and 6 Deployment

PacifiCorp will provide a monthly report to all self-supplying Transmission Customers that includes the following information for each deployment of Schedule 5 or 6 reserves:

- Contingency ID number
- North West Power Pool Reserves (committed or requested)
- Date, Event Start Time
- Reason for Deployment that identifies the regional event declared, or other reason why the deployment occurred (transmission or generator)
- Total MW Loss

Customers may request additional information beyond that provided in the monthly report. PacifiCorp shall provide such information or explain why it believes that it may not properly do so.

H. Exclusion of Certain Jointly Owned Units

PacifiCorp agrees to continue to allow Utah Associated Municipal Power Systems ("UAMPS"), the Utah Municipal Power Agency ("UMPA"), and Deseret Generation and Transmission Co-operative, Inc. ("Deseret") to self-supply from jointly owned units without performance evaluations through October 1, 2021 to allow the parties to work toward mutual agreement on self-supply arrangements specific to jointly owned units. If the parties succeed in agreeing on an approach, the parties will agree to an implementation date that provides a reasonable amount of time to ready their systems for compliance with any agreed-upon approach. If mutual agreement is not reached by September 1, 2021, PacifiCorp and each of UAMPS, UMPA, and Deseret may thereafter make a unilateral filing with FERC pursuant to Sections 205 and 206 of the FPA, respectively.

4.3 SCHEDULE 4 – ENERGY IMBALANCE SERVICE

A. Eligibility Requirements

The following eligibility requirements apply for the self-supply or third-party supply of Schedule 4 – Energy Imbalance Service

1. The specific Network Loads for which the service is to be provided must be the total Network Load obligation within the PacifiCorp Balancing Authority Area and have observable real-time metering and telemetry.

2. The resources providing the service must be located in the same PacifiCorp Balancing Authority Area as the Network Load and must have observable real time metering.

3. The resource providing the service must be deliverable resources as defined by a current transmission service agreement or resources that are interconnected to PacifiCorp's system and have an active generation interconnection agreement with PacifiCorp.

4. The capacity used for this service must be dedicated to Network Load service requirements and may not being used to satisfy any other capacity obligations.

5. The resource (or a resource dispatch center) must have a point of contact that is available any time the resource is designated for regulation and frequency response service.

6. The Transmission Customer must designate adequate resources to satisfy the Network Load obligation at all times. The designated resources must be under automatic generation control, satisfying all reserve requirements in real time and as required to compensate for instantaneous load swings or generation losses within the PacifiCorp BAA. The Transmission Provider reserves the right to determine the quantity and location of resources placed under AGC within the PacifiCorp BAA.

B. Resources Moved Electronically to External Balancing Authority

If the metered Network Load requiring imbalance service has been moved electronically into an External Balancing Authority, certified by NERC or its successor organization, by means of a pseudo-tie, this Section B shall apply.

1. The pseudo-tie requires identification and observable real-time metering of the specific Network Loads for which the service is to be provided. PacifiCorp requires a letter in advance from the External Balancing Authority which certifies that this service is supplied in accordance with all current policies and guidelines of the NERC Operating Manual, NERC Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Ancillary Services to loads that are located physically in an External Balancing Authority Area.

2. PacifiCorp will accept, in lieu of the showing required in Section A.1 above, a letter in advance from the External Balancing Authority which certifies that this service is supplied in accordance with all current policies and guides of the NERC Operating Manual, NERC

Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Ancillary Services to loads that are physically located in an External Balancing Authority Area.

3. Whenever the pseudo-tie equipment providing the Network Load's data to PacifiCorp or the External Balancing Authority is not used or not useable, the dispatcher for the entity that is not receiving the load signal shall immediately contact the dispatcher for the other entity to inform it of the loss of the signal. Thereafter, until both entities are again receiving the load signal through the pseudo-tie equipment, the Transmission Customer should provide fixed schedules from the External Balancing Authority each hour to minimize the impact of load imbalance.

4. If the External Balancing Authority or the supplier of imbalance service fails to meet the requirements set forth in Section B.2 (i.e., fails to notify PacifiCorp of the External Balancing Authority's loss of its ability to receive the Network Load's signal or fails to supply fixed schedule adjustments when called upon by PacifiCorp), PacifiCorp reserves the right to bill the Transmission Customer for this service for the duration of the failure, including reimbursement for any penalties according to Schedules 4 or 9 in the PacifiCorp OATT, charges or other consequences which PacifiCorp is subject to, related to the failure.

5. PacifiCorp reserves the right to request more information from the External Balancing Authority or the Network Load's supplier of imbalance service, in addition to the above referenced letter, to ensure that this service is supplied in a reliable manner. Further, PacifiCorp reserves the right to reject the request to self-supply or third-party supply such service, in the event that PacifiCorp, in its reasonable judgment, concludes that such self-supply or third-party purchase would impair reliability in the relevant PacifiCorp BAA or the interconnected system. PacifiCorp also reserves the right to terminate the self-supply or third-party supply if, in its reasonable judgment, PacifiCorp concludes that such self-supply or third- party supply is impairing reliability in the relevant PacifiCorp Balancing Authority Area or the interconnected system.

4.4 SCHEDULE 9 – GENERATOR IMBALANCE SERVICE

A. Self-Supply Under Schedule 3 Entities

For load serving entities who have certified as a self-supply entity for regulation and frequency response service (Schedule 3) under the requirements of this Attachment U and request generator imbalance self-certification, this Section A shall apply. Generator Imbalance Service may be self-supplied from Resources or undesignated Network Resources located within the PacifiCorp BAA under the limited set of conditions defined below. Self-supply of Generator Imbalance service created by fixed point-to-point schedules can only be provided for resources located in the PacifiCorp BAA.

The following information will be required to demonstrate that the self-supply of generator imbalance service created by point-to-point schedules during generator derates or unit tripping:

1. The resources providing the service must have observable real time metering. In addition, PacifiCorp will define specific OASIS scheduling points of receipt which will apply to Customer's requesting self-supply. Customers will be obligated to demonstrate self-supply from these specific OASIS points of receipt within the PacifiCorp BAA for purposes of this section. The current list of OASIS points of receipt for section is ("PACE", "PACEW", and "PACW"). PacifiCorp reserves the right to modify this list without notice as required to maintain transmission system reliability and compliance with the PacifiCorp OATT.

2. Documentation that the resources are deliverable Resources or Network Resources and are defined by a current Network Integration Transmission Service Agreement, interconnection agreement, or legacy load service agreement on file at FERC.

3. Any Network Resources used to supply point-to-point imbalance service must be undesignated according to the PacifiCorp business practice, "Termination of Network Resources", consistent with section 30.3 of the PacifiCorp OATT. The resources utilized must be undesignated from

within specified OASIS points of receipt to self-supply point-to-point transactions originating from that particular point of receipt.

4. Resources or undesignated Network Resources must be on-line, spinning, and responsive to the loss of another undesignated unit.

5. The hourly quantity of resources or undesignated Network Resources with a point of receipt plus the purchases made and delivered on point-to-point service into each PacifiCorp point of receipt must exceed the total quantity of point-to-point transactions exiting the defined point of receipt and PacifiCorp BAA for each hour.

6. Adequate resources must remain 'designated' and available for load service as required to satisfy the Customer's Network Load obligation at all times during any period of point-to-point self-supply.

7. The party claiming generation imbalance self-supply must be previously certified as self-providing, or purchasing from third parties, regulation and frequency response service (Schedule 3) as specified in this Attachment U.

8. A point of contact is always available, all hours, every day to be used to call on resources necessary for load coverage.

B. Resources Moved Electronically to External Balancing Authority

If the Resource requiring imbalance service has been moved electronically into an External Balancing Authority Area, certified by NERC or its successor organization, by means of a pseudo-tie, this Section B shall apply. The point-to-point transmission service for the pseudo-tie resource will be established. Intra-hour transfers and the associated transmission service provided will be defined as the instantaneous output of the resource, therefore imbalance will be deemed to be self-supplied. End of hour true-ups of actual hourly integrated values are required for Balancing Authority Area energy accounting purposes.

1. The pseudo-tie requires identification and observable real-time metering of the specific Resource for which the service is to be provided. PacifiCorp requires a letter in advance from the External Balancing Authority which certifies that this service is supplied in accordance with all current policies and guidelines of the NERC Operating Manual, NERC Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Ancillary Services to loads that are located physically in another Balancing Authority Area.

2. PacifiCorp will accept, in lieu of the showing required in Section A.1 above, a letter in advance from the External Balancing Authority which certifies that this service is supplied in accordance with all current policies and guides of the NERC Operating Manual, NERC Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Ancillary Services to resources that are electronically transferred into another Balancing Authority.

3. Whenever the pseudo-tie equipment providing the Resource's data to PacifiCorp or the External Balancing Authority is not used or not useable, the dispatcher for the entity that is not receiving the load signal shall immediately contact the dispatcher for the other entity to inform it of the loss of the signal. Thereafter, until both entities are again receiving the load signal through the pseudo-tie equipment, the Transmission Customer should provide fixed schedules from the External Balancing Authority each hour to minimize the impact of generator imbalance.

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator subject to any credits provided pursuant to applicable PacifiCorp business practices. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

Transmission Customers Obligated to acquire Reactive Supply and Voltage Control from Generation Sources Service: All Transmission Customers purchasing Long-Term Firm Point-to-Point Transmission Service, Short-Term Firm Point-to-Point Transmission Service, Non-Firm Point-to-Point Transmission Service, or Network Integration Transmission Service from the Transmission Provider shall be required to acquire Reactive Supply and Voltage Control from Generation Sources Service from the Transmission Provider.

Charge for Reactive Supply and Voltage Control from Generation Sources Service: For Point-To-Point Transmission Service, the rate shall be applied to the Transmission Customer's Reserved Capacity. For purposes of charging the rates set forth in this Schedule 2 to Transmission Customers purchasing Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff. For Network Integration Transmission Service, the rate shall be applied to the Transmission Customer's Monthly Network Load.

1.	Yearly Rate	$~~0.55~~1.603/kW/Year
2.	Monthly Rate	$~~0.046~~0.134/kW/Month
3.	Weekly Rate	$~~0.011~~0.031/kW/Week
4.	Daily Rate	$~~0.001~~0.004/kW/Day
5.	Hourly Rate	$~~0.063~~0.183/MWh

The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 2 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 2 times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Rate Schedule Moratorium Period:

The rates and charges under this Schedule 2 cannot be changed with any effective date prior to January 1, 2023 unless the Transmission Provider proposes a reduction in the rates or charges under this Schedule 2. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 2 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

In addition, during this rate schedule moratorium period, the Transmission Provider will not propose to recover or pass-through any costs, including those in Docket No. ER20-2528, it may incur

as a result of any generator that receives a FERC approved Schedule 2 rate, including any resulting revenue requirement. Following this rate schedule moratorium period, the Transmission Provider shall not propose to recover or pass-through any such reactive power costs it incurs during the rate schedule moratorium period. None of the parties to the settlement agreement included with the filing in Docket No. [*TBD*] shall make a filing with FERC seeking compensation from the Transmission Provider pursuant to a Schedule 2 rate for reactive power during this rate schedule moratorium period. After the expiration of this rate schedule moratorium period, the Transmission Provider is not prohibited from seeking authorization to recover or pass-through future costs that the Transmission Provider incurs after this rate schedule moratorium period as a result of a Schedule 2 rate filed by a third party with the Commission.

Reactive Supply and Voltage Control from Generation Sources Service to be Provided: The Transmission Provider shall ensure that generation interconnected with its Transmission System meets the voltage support and reactive control requirements of the Western Electricity Coordinating Council.

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the BA that performs this function for the Transmission Provider).

The Transmission Provider must offer this service when the Transmission Service is used to serve load within its BAA. The Transmission Customer must purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation as further described in applicable PacifiCorp business practices. The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements.

For purposes of serving load under this schedule, the amount of and charges for Regulation and Frequency Response Service are differentiated by load, Variable Energy Resources (VERs), and resources that are not VERs (Non-VERs). The Transmission Customer shall pay a total Regulation and Frequency Response Service charge under this tariff equal to the sum of the charges applicable to the customer’s load, VERs, and Non-VERs, as set forth below. To the extent the BA performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA.

Charge for Regulation and Frequency Response Service:

The load charges below apply to all load served by Network Integration Transmission Service or by Point-To-Point Transmission Service. Firm imports do not reduce the load obligation.

The rates below are applied to the Transmission Customer's Monthly Network Load for Network Integration Transmission Service or to the load served by Point-To-Point Transmission Service.

Load

	~~Effective rates July 13, 2017 through December 31, 2017~~	~~Effective rates beginning January 1, 2018~~
1. Yearly Rate	~~$2.25 per kW-Year~~	$~~2.124~~1.3859 per kW-Year
2. Monthly Rate	~~$0.188 per kW-Month~~	$~~0.177~~0.1155 per kW-Month

The charges below apply to all generators serving Network Load and are differentiated by the type of resources (VERs or Non-VERs) serving that load. The ~~applicable differentiated rate below is applied to customers by charging~~Transmission Provider shall charge the Transmission Customer the monthly rate times the lesser of the nameplate capacity of the generator, the capacity in a MOD-25 report, or the interconnection capacity of the resource set forth in an Interconnection Agreement.

Each year by December 1, the Transmission Customer shall provide to the Transmission Provider~~,~~ an attestation of the nameplate capacity~~ of VERs and Non-VERs~~, the interconnection capacity set forth in an Interconnection Agreement, or the capacity shown in a MOD-25 report for each VER and Non-VER resource owned or controlled by the Transmission Customer and located within the BAA.

VERs (Solar)- Uncommitted Scheduling

1. Yearly Rate		$5.5836 per kW-Year
2. Monthly Rate		$0.4653 per kW-Month

VERs (Wind)- Uncommitted Scheduling

	~~Effective Rates from July 13, 2017 through December 31, 2017~~	~~Effective Rates beginning January 1, 2018~~
1. Yearly Rate	~~$6.984 per kW-Year~~	$~~6.593~~6.6922 per kW-Year
2. Monthly Rate	~~$0.582 per kW-Month~~	$~~0.549~~0.5577 per kW-Month

VERs - Committed Scheduling

To qualify for this committed scheduling rate for a month, the VER customer must: (i) provide notification to PacifiCorp in advance of the month that it intends to engage in Committed Scheduling; and (ii) during every hour of that month (except as specified below), a VER customer must utilize and submit into BSAP by 57 minutes prior to the operating hour (T-57), consistent with PacifiCorp's EIM Business Practice, hour-ahead base schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of no more than 72 minutes prior to the operating hour (T-72) without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule. In any calendar month for up to two operating hour intervals, a VER customer may utilize and submit into BSAP by T-57, hour-ahead schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of up to 90 minutes prior to the operating hour (T-90), without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule, and still be eligible for this rate. Use and submission into BSAP of hour-ahead schedules older than PacifiCorp's VER forecast vendor's forecast at T-90 in any hour during a calendar month will make a VER customer ineligible for this rate in that month. Upon notification by the PacifiCorp EIM Entity, the VER customer is required to submit a manual override or modification to the PacifiCorp VER forecast vendor's forecast to reflect a known or expected system constraint and ensure the submission of a balanced Base Schedule consistent with the requirements set forth in Attachment T.

VERs (Solar) - Committed Scheduling

	~~Effective Rates from July 13, 2017 through December 31, 2017~~	~~Effective Rates beginning January 1, 2018~~

1. Yearly Rate	~~$5.965 per kW-Year~~	$~~5.631~~5.1872 per kW-Year
2. Monthly Rate	~~$0.497 per kW-Month~~	$~~0.469~~0.4323 per kW-Month

VERs (Wind) - Committed Scheduling

1. Yearly Rate		$6.2171 per kW-Year
2. Monthly Rate		$0.5181 per kW-Month

Non-VERs

	~~Effective Rates from July 13, 2017 through December 31, 2017~~	~~Effective Rates beginning January 1, 2018~~
1. Yearly Rate	~~$1.90 per kW-Year~~	$~~1.794~~3.1483 per kW-Year
2. Monthly Rate	~~$0.158 per kW-Month~~	$~~0.150~~0.2624 per kW-Month

Rate Schedule Moratorium Period:

The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 3 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California

Independent System Operator.[1] Each party to the Docket No. [TBD] Settlement Agreement reserves its rights to protest or otherwise challenge any such filing.

ARTSOA Moratorium Period:

The Amended and Restated Transmission Service and Operating Agreement ("ARTSOA") billing provisions referenced below shall not be changed with an effective date prior to December 1, 2025 (the "ARTSOA Moratorium Period"):

1. In accordance with the Sixth Amended and Restated Transmission Service and Operating Agreement between Utah Municipal Power Agency ("UMPA") and PacifiCorp (the "UMPA ARTSOA"), the Transmission Provider shall bill UMPA under Schedule 3/3A based only on its Aggregate Peak Demand ("APD"), as such term is defined in the UMPA ARTSOA, and shall not charge or seek to charge UMPA for generation at all under Schedule 3/3A or otherwise during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UMPA for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UMPA each reserve their respective rights and positions regarding whether the UMPA ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UMPA's generation.

2. In accordance with the Seventh Amended and Restated Transmission Service and Operating Agreement between Deseret Generation & Transmission Co-Operative, Inc. ("Deseret") and PacifiCorp (the "Deseret ARTSOA"), the Transmission Provider shall bill Deseret under Schedule 3/3A based only on its Aggregate Peak Demand plus the Deseret Area Load for which Deseret has the obligation to supply Regulation Reserve Service, and shall only charge or seek to charge Deseret under Schedule 3/3A for off-system sales associated with Deseret Resources, as all such terms are defined in the Deseret ARTSOA, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge Deseret for

[1] Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedules 3, 3A, 5 and 6. The parties to the Docket No. [TBD] Settlement Agreement agree to engage with PacifiCorp in good faith discussions regarding potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (4) take no action to prevent, inhibit or limit such direct access.

generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and Deseret each reserve their respective rights and positions regarding whether the Deseret ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to Deseret's generation.

3. In accordance with the Fifth Amended and Restated Transmission Service and Operating Agreement between Utah Associated Municipal Power Systems ("UAMPS") and PacifiCorp (the "UAMPS ARTSOA"), the Transmission Provider shall bill UAMPS under Schedule 3/3A based only on its Monthly Coincident Peak Demand as such term is defined in the UAMPS ARTSOA, and shall not charge or seek to charge UAMPS for generation under Schedule 3/3A or otherwise, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UAMPS for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UAMPS each reserve their respective rights and positions regarding whether the UAMPS ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UAMPS' generation.

Self-Supply, Third-Party Supply and Pooling:

A ~~Network~~Transmission Customer may choose to ~~self-~~supply all or a portion of its Regulation and Frequency Response Service obligation through self-supply or third-party supply consistent with the requirements herein, Attachment U, and PacifiCorp's business practices ~~and consistent with the settlement in Docket Nos. ER17-219 and EL17-27.~~. A Transmission Customer may request to supply all or a portion of its Regulation and Frequency Response Service through pooling agreement, which the Transmission Provider shall consider on a case-by-case and non-discriminatory basis.

~~The~~For a Transmission Customer that chooses to supply its Regulation and Frequency Response Obligation through self-supply, third-party supply, or pooling agreements, the total charge for failure to ~~self-~~supply its Regulation and Frequency Response Service obligation shall not exceed the Monthly Rate pursuant to this Schedule 3 times the highest amount in megawatts not covered under self-supply, third-party supply or pooling agreements.

Clarifications regarding Non-VER Participating Resources:

A Non-VER Participating Resource in the Energy Imbalance Market ("EIM") qualifies as a dispatchable Non-VER resource. Additionally, Non-VER resources dispatchable by the Transmission

Provider qualify as dispatchable Non-VERS. The Transmission Provider will not charge Non-VER Participating Resources or Non-VER resources dispatchable by the Transmission Provider for Schedules 3 and 3A services. PacifiCorp shall consider, on a good faith basis, requests by customers to identify a resource that should qualify as a dispatchable Non-VER in this context due to its ability to follow PacifiCorp instructions, notwithstanding the fact that the resource is not directly dispatchable by PacifiCorp.

SCHEDULE 3A

Generator Regulation and Frequency Response Service

Generator Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Generator Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes for a generator located within the BAA. The obligation to maintain this balance between resources and the generator's schedule lies with the Transmission Provider (or the BAA that performs this function for the Transmission Provider).

The Transmission Provider must offer this service when transmission service is provided for a generator physically or electrically located in the Transmission Provider's BAA. Generator Regulation and Frequency Response Service applies to the extent that a Transmission Customer is not already subject to Regulation and Frequency Response Service provided under Schedule 3. When applicable, the Transmission Customer must purchase Generator Regulation and Frequency Response Service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements, as further described in applicable PacifiCorp business practices which may include self-supplying regulation reserve capacity from generation or non-generation resources or through dynamically scheduling its generation to another BAA. The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Generator Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements.

For purposes of exports or Third-Party Sales, the amount of and charges for Generator Regulation and Frequency Response Service are differentiated by the type of exporting resource (Variable Energy Resources (VERs) or resources that are not VERs (Non-VERs)) and are set forth below. To the extent a BA performs this service for the Transmission Provider, charges to the

Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA. The Transmission Provider may not charge a Transmission Customer for regulation reserves under both Schedule 3 and Schedule 3A for the same transaction.

Charge for Generator Regulation and Frequency Response Service:

The charges below apply to generation that originates in the PacifiCorp BAA and terminates in another BAA or for any resource not designated as a Network Resource. The ~~applicable differentiated rate below is applied to customers by charging~~Transmission Provider shall charge the Transmission Customer the monthly rate times the lesser of the nameplate capacity of the generator~~.~~, the capacity in a MOD-25 report, or the interconnection capacity of the resource set forth in an Interconnection Agreement

Each year by December 1, the Transmission Customer shall provide to the Transmission Provider~~,~~ attestation of the nameplate capacity ~~of VERs and Non-VERs~~, the interconnection capacity set forth in an Interconnection Agreement, or the capacity shown in a MOD-25 report for each VER and Non-VER resource owned or controlled by the Transmission Customer and located within the BAA.

VERs (Solar) - Uncommitted Scheduling

1. Yearly Rate		$5.5836 per kW-Year
2. Monthly Rate		$0.4653 per kW-Month

VERs (Wind) - Uncommitted Scheduling

	~~Effective Rates from July 13, 2017 through December 31, 2017~~	~~Effective Rates beginning January 1, 2018~~
1. Yearly Rate	~~$6.984 per kW-Year~~	$~~6.593~~6.6922 per kW-Year
2. Monthly Rate	~~$0.582 per kW-Month~~	$~~0.549~~0.5577 per kW-Month

VERs - Committed Scheduling

To qualify for this committed scheduling rate for a month, the VER customer must: (i) provide notification to PacifiCorp in advance of the month that it intends to engage in Committed Scheduling; and (ii) during every hour of that month (except as specified below), a VER customer must utilize and submit into BSAP by 57 minutes prior to the operating hour (T-57), consistent with PacifiCorp's EIM Business Practice, hour-ahead base schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of no more than 72 minutes prior to the operating hour (T-72) without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule. In any calendar month for up to two operating hour intervals, a VER customer may utilize and submit into BSAP by T-57, hour-ahead schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of up to 90 minutes prior to the operating hour (T-90), without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule, and still be eligible for this rate. Use and submission into BSAP of hour-ahead schedules older than PacifiCorp's VER forecast vendor's forecast at T-90 in any hour during a calendar month will make a VER customer ineligible for this rate in that month. Upon notification by the PacifiCorp EIM Entity, the VER customer is required to submit a manual override or modification to the PacifiCorp VER forecast vendor's forecast to reflect a known or expected system constraint and ensure the submission of a balanced Base Schedule consistent with the requirements set forth in Attachment T.

VERs (Solar) – Committed Scheduling

	~~Effective Rates from July 13, 2017 through December 31, 2017~~	~~Effective Rates beginning January 1, 2018~~
1. Yearly Rate	~~$5.965 per kW-Year~~	$~~5.631~~5.1872 per kW-Year
2. Monthly Rate	~~$0.497 per kW-Month~~	$~~0.469~~0.4323 per kW-Month

VERs (Wind) – Committed Scheduling

1. Yearly Rate		$6.2171 per kW-Year
2. Monthly Rate		$0.5181 per kW-Month

Non-VERs – Committed Scheduling

	~~Effective Rates from July 13, 2017 through December 31, 2017~~	~~Effective Rates beginning January 1, 2018~~
1. Yearly Rate	~~$1.90 per kW-Year~~	$~~1.794~~3.1483 per kW-Year
2. Monthly Rate	~~$0.158 per kW-Month~~	$~~0.150~~0.2624 per kW-Month

Rate Schedule Moratorium Period:

The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 3A as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California Independent System Operator.[1] Each party to the Docket No. [TBD] Settlement Agreement reserves its rights to protest or otherwise challenge any such filing.

ARTSOA Moratorium Period:

The Amended and Restated Transmission Service and Operating Agreement ("ARTSOA") billing provisions referenced below shall not be changed with an effective date prior to December 1, 2025

[1] Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedules 3, 3A, 5 and 6. The parties to the Docket No. [TBD] Settlement Agreement agree to engage with PacifiCorp in good faith on potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (3) take no action to prevent, inhibit or limit such direct access.

(the "ARTSOA Moratorium Period"):

1. In accordance with the Sixth Amended and Restated Transmission Service and Operating Agreement between Utah Municipal Power Agency ("UMPA") and PacifiCorp (the "UMPA ARTSOA"), the Transmission Provider shall bill UMPA under Schedule 3/3A based only on its Aggregate Peak Demand ("APD"), as such term is defined in the UMPA ARTSOA, and shall not charge or seek to charge UMPA for generation at all under Schedule 3/3A or otherwise during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UMPA for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UMPA each reserve their respective rights and positions regarding whether the UMPA ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UMPA's generation.

2. In accordance with the Seventh Amended and Restated Transmission Service and Operating Agreement between Deseret Generation & Transmission Co-Operative, Inc. ("Deseret") and PacifiCorp (the "Deseret ARTSOA"), the Transmission Provider shall bill Deseret under Schedule 3/3A based only on its Aggregate Peak Demand plus the Deseret Area Load for which Deseret has the obligation to supply Regulation Reserve Service, and shall only charge or seek to charge Deseret under Schedule 3/3A for off-system sales associated with Deseret Resources, as all such terms are defined in the Deseret ARTSOA, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge Deseret for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and Deseret each reserve their respective rights and positions regarding whether the Deseret ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to Deseret's generation.

3. In accordance with the Fifth Amended and Restated Transmission Service and Operating Agreement between Utah Associated Municipal Power Systems ("UAMPS") and PacifiCorp (the "UAMPS ARTSOA"), the Transmission Provider shall bill UAMPS under Schedules 3 and 3A based only on its Monthly Coincident Peak Demand as such term is defined in the UAMPS ARTSOA, and shall not charge or seek to charge UAMPS for generation under Schedule 3/3A or otherwise, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UAMPS for generation under Schedules 3 and 3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UAMPS each reserve their respective rights and positions

regarding whether the UAMPS ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UAMPS' generation.

Self-Supply, Third-Party Supply and Pooling:

A ~~Network~~ Transmission Customer may choose to ~~self-~~supply all or a portion of its Generator Regulation and Frequency Response Service obligation through self-supply or third-party supply consistent with the requirements herein, Attachment U, and PacifiCorp's business practices ~~and consistent with the settlement in Docket Nos. ER17-219 and EL17-27.~~. A Transmission Customer may request to supply all or a portion of its Generator Regulation and Frequency Response Service obligation through pooling agreements, which the Transmission Provider shall consider on a case-by-case and non-discriminatory basis.

~~The~~For a Transmission Customer that chooses to supply its Generator Regulation and Frequency Response Service obligation through self-supply, third-party supply, or pooling agreements, the total charge for failure to ~~self-~~supply its Generator Regulation and Frequency Response Service obligation shall not exceed the Monthly Rate pursuant to this Schedule 3A times the highest amount in megawatts not covered under self-supply, third-party supply or pooling agreements.

Clarifications regarding Non-VER Participating Resources:

A Non-VER Participating Resource in the Energy Imbalance Market ("EIM") qualifies as a dispatchable Non-VER resource. Additionally, Non-VER resources dispatchable by the Transmission Provider qualify as dispatchable Non-VERS. The Transmission Provider will not charge Non-VER Participating Resources or Non-VER resources dispatchable by PacifiCorp for Schedules 3 and 3A services. PacifiCorp shall consider, on a good faith basis, requests by customers to identify a resource that should qualify as a dispatchable Non-VER in this context due to its ability to follow PacifiCorp instructions, notwithstanding the fact that the resource is not directly dispatchable by PacifiCorp.

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load in the BAA and to support other transmission usage sourced from generation in the BAA including exports and sales. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its BAA and to support other transmission usage sourced from generation in the BAA including exports and sales. The Transmission Customer must purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the BA performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA.

Charges for Spinning Reserve Service:

Under the current NERC Regional Reliability Standard BAL-002-WECC, the Transmission Provider is required to maintain a minimum amount of contingency reserve equal to the sum of three percent of hourly integrated load plus three percent of hourly integrated generation with at least half as spinning. Consistent with the Transmission Provider operating in accordance with this reliability standard, the charges for Schedule 5 below apply one and one-half percent to load and one and one-half percent to generation.

For load, the rates below are charged to a Network Customer’s hourly integrated load (including losses).

For generation, the rates below are applied to customers by charging actual hourly generation delivered to the Transmission Provider at the Point of Receipt.

The rate shall be an Hourly Rate of:

	~~Effective Rates from February 13, 2017 through December 31, 2017~~	~~Effective Rates beginning January 1, 2018~~
Schedule 5 (Spinning Reserves)	~~$0.16 per MWh~~	$~~0.151~~0.1677 per MWh

~~Rate Schedule Moratorium Period:~~

~~The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 5 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.~~

~~The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California Independent System Operator.~~[1]

Self-Supply~~, Third-Party Supply and Pooling~~:

A Transmission Customer may choose to ~~self-~~supply all or a portion of its reserve obligation~~ through self-supply or third-party supply consistent with the procedures set forth in Attachment U to the Tariff. A Transmission Customer may request to supply all or a portion of its reserve obligation through~~

[1] ~~Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedule 5. The parties to the Docket No. [TBD] Settlement Agreement agree to engage with PacifiCorp in good faith on potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (4) take no action to prevent, inhibit or limit such direct access.~~

pooling agreements, which the Transmission Provider shall consider on a case-by-case and non-discriminatory basis.

For a Transmission Customer choosing to ~~self-~~supply a portion of its reserve obligation through self-supply, third-party supply or pooling agreements, detailed hourly calculation procedures are set forth in Attachment V to the Tariff.

~~The Transmission Customer shall schedule that portion which it will self-supply and/or supply from third parties pursuant to procedures set forth in Attachment U to the Tariff.~~

Spinning Reserve Service to be Provided:

The Transmission Provider, using its generators controlled by automatic generation control, will provide the capacity required to provide Spinning Reserve Service for a Transmission Customer. Upon an outage of a generation resource for which Spinning Reserve Service has been purchased from the Transmission Provider, the Transmission Provider will provide replacement capacity commencing immediately upon such outage until the earlier of (1) the restoration of such resource to service by the Transmission Customer or (2) the end of ten (10) full minutes after the occurrence of such outage.

To the extent that the Transmission Provider determines that a Transmission Customer's specific Spinning Reserve Requirements are not being fully met through the purchase of Spinning Reserve Service as provided above, the Transmission Provider reserves the right (upon filing with the Commission) to require such Transmission Customer to purchase a greater amount of Spinning Reserve Service.

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the BAA and to support other transmission usage sourced from generation in the BAA including exports and sales; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its BAA and to support other transmission usage sourced from generation in the BAA including exports and sales. The Transmission Customer must purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the BA performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA.

Charges for Supplemental Reserve Service:

Under the current NERC Regional Reliability Standard BAL-002-WECC, the Transmission Provider is required to maintain a minimum amount of contingency reserve equal to the sum of three percent of hourly integrated load plus three percent of hourly integrated generation with at least half as spinning. Consistent with the Transmission Provider operating in accordance with this reliability standard, the charges for Schedule 6 below apply one and one-half percent to load and one and one-half percent to generation.

For load, the rates below are charged to a Network Customer’s hourly integrated load (including losses).

For generation, the rates below are applied to customers by charging actual hourly generation delivered to the Transmission Provider at the Point of Receipt.

The rate shall be an Hourly Rate of:

	~~Effective Rates from February 13, 2017 through December 31, 2017~~	~~Effective Rates beginning January 1, 2018~~
Schedule 6 (Supplemental)	~~$0.16 per MWh~~	$~~0.151~~0.1677 per MWh

Rate Schedule Moratorium Period:

The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 6 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California Independent System Operator.[1] Each party to the Docket No. [TBD] Settlement Agreement reserves its rights to protest or otherwise challenge any such filing.

Self-Supply:

A Transmission Customer may choose to ~~self-~~supply all or a portion of its reserve obligation~~.~~ through self-supply or

[1] Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedule 6. The parties to the Docket No. [TBD] Settlement Agreement settlement agreement included with the filing in Docket No. [TBD] agree to engage with PacifiCorp in good faith on potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (4) take no action to prevent, inhibit, or limit such direct access.

third-party supply consistent with the procedures set forth in Attachment U to the Tariff. A Transmission Customer may request to supply all or a portion of its reserve obligation through pooling agreements, which the Transmission Provider shall consider on a case-by-case and non-discriminatory basis.

For a Transmission Customer choosing to ~~self-~~supply a portion of its reserve obligation through self-supply, third-party supply or pooling agreements, detailed hourly calculation procedures are set forth in Attachment V to the Tariff.

~~The Transmission Customer shall schedule that portion which it will self-supply and/or supply from third parties pursuant to procedures set forth in Attachment U of the Tariff.~~

Supplemental Reserve Service to be Provided:

The Transmission Provider, using its generators controlled by automatic generation control, will provide the capacity required to provide Supplemental Reserve Service for a Transmission Customer. Upon an outage of a generation resource for which Supplemental Reserve Service has been purchased from the Transmission Provider, the Transmission Provider will provide replacement capacity commencing at the end of ten (10) full minutes after such outage until the earlier of (1) the restoration of such resource to service by the Transmission Customer or (2) the end of the first full hour immediately following such outage.

To the extent that the Transmission Provider determines that a Transmission Customer's specific Supplemental Reserve Requirements are not being fully met through the purchase of Supplemental Reserve Service as provided above, the Transmission Provider reserves the right (upon filing with the Commission) to require such Transmission Customer to purchase a greater amount of Supplemental Reserve Service.

ATTACHMENT U

Requirements for Self-Supply ~~of Schedules 5 and 6~~ Ancillary Services

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~~**Definitions**~~

~~No definitions other than the following, those provided hereinafter, and those currently contained in PacifiCorp's Open Access Transmission Tariff ("OATT") or North American Electric~~

~~Reliability Corporation ("NERC") reliability standards are required for this Attachment U.~~

~~***Customer*** – Reference for the purpose of this Attachment U, refers to a customer that has successfully met qualifications to self-supply Ancillary Services.~~

~~***Internal Resource*** – A resource in a PacifiCorp Balancing Authority Area ("BAA") including one that is dynamically scheduled or pseudo-tied into a PacifiCorp BAA. These resources are classified as either Participating or Non-Participating Resources.~~

~~***External Resource*** – A resource that does not meet the definition of an Internal Resource but provides self-supply (or third-party supply) service via a capacity tag.~~

1. Purpose

The purpose of this Attachment U is to clarify ~~the~~certain practices ~~outlined in the OATT~~ pertaining to self-supply or third-party supply of ~~ancillary services certification process and requirements.~~Schedule 3 – Regulation and Frequency Response Service, Schedule 3A – Generator Regulation and Frequency Response Service, Schedule 4 – Energy Imbalance Service, Schedule 5 – Operating Reserve – Spinning Reserve Service, Schedule 6 – Operating Reserve – Supplemental Reserve Service, and Schedule 9 – Generator Imbalance Service under the OATT. Self-supply and third-party supply may include pooling agreements, which PacifiCorp shall consider for approval in good faith and on a reasonable, non-discriminatory, case-by-case basis.

2. Practice

The following are the requirements of PacifiCorp, which is the Balancing Authority and Transmission Operator, for Transmission Customers who wish to self-supply or to arrange for third-party purchase of ~~specific Ancillary Services~~OATT Schedule 3 – Regulation and Frequency Response Service, Schedule 3A – Generator Regulation and Frequency Response Service, Schedule 4 – Energy Imbalance Service, Schedule 5 – Operating Reserve – Spinning Reserve Service, Schedule 6 – Operating Reserve – Supplemental Reserve Service, and Schedule 9 – Generator Imbalance Service. PacifiCorp requires that ~~these~~self-supplied or third-party supplied Ancillary Services satisfy the requirements for ~~Schedules 5 and 6~~the above-referenced schedules under the currently effective PacifiCorp OATT and satisfy the relevant reliability standards of NERC or any successor organization. ~~In addition to these requirements and the requirements listed below, the party~~

3. Generally Applicable Provisions

3.1 Service Agreement

A Transmission Customer requesting to self-supply or to arrange for third-party ~~purchase~~supply of Schedules 3/3A, 4, 5, 6, or 9 shall ~~also~~ execute ~~an Umbrella Service Agreement or~~ a revision to ~~an~~its existing transmission service agreement~~, as applicable,~~ or a separate service agreement with PacifiCorp specifying, as applicable: (1) the detailed arrangements made to supply the services including, but not limited to, specification of the

amount of service required to meet the party's Ancillary Services obligation, identification of the ~~generation~~ resource(s) ~~or system~~ supplying the service and ~~its~~the Balancing Authority Area~~, specification of~~ where the resource(s) are located; (2) metering and communications equipment~~, and~~; (3) procedures for data exchange or automation; (4) the calculation of the Transmission Customer's obligation; and (5) processes for forecasting, deploying, and verifying performance of self-supply or third-party supply. ~~In addition, PacifiCorp reserves the right to require pre-acceptance testing of the units identified and periodic testing, at such times determined by PacifiCorp, thereafter to ensure that the service can be provided~~

3.2 Operating Tests

PacifiCorp may, after providing notice fifteen (15) business days in advance, require operational testing of the resources identified as providing self-supply or third-party supply of Schedules 3/3A, 4, 5, 6, or 9, in addition to testing performed by the Generation Owner to meet NERC reliability standards or Western Electricity Coordinating Council ("WECC") regional criterion. PacifiCorp will monitor resources designated and accepted for self-supply to ensure compliance with NERC reliability standards, WECC regional criterion, and PacifiCorp requirements for time, output and power quality.

Resources that do not fully comply with NERC reliability standards, WECC regional criterion, and PacifiCorp requirements will be disqualified as self-supply or third-party supply resources until such a time as an operating test establishes that the resource(s) can respond in accordance with NERC reliability standards~~ and the contractual agreement.~~**~~Telemetry (metering)~~**, WECC regional criterion, and PacifiCorp requirements.

3.3 SCADA (metering) requirements for reserves

For ~~an Internal Resource~~resources to qualify for self-supply ~~of Operating Reserve-Spinning Reserve Service (Schedule 5) or Operating Reserve - Supplemental Reserve Service (Schedule 6) the following four-second, industry-standard~~or third-party supply of Schedules 3/3A, 4, 5, 6, or 9, the following data must be supplied by the designated self-supply or third-party supply resource. Real time data must be supplied through telemetry acceptable to PacifiCorp. ~~In general, an example of an acceptable~~

~~telemetry method is a Remote Terminal Unit ("RTU") or Inter-Control Center Communication Protocol ("ICCP"). The latter is subject to WECC Operations Network ("WON") guidelines. To the extent any data items are not applicable to a particular resource, they are not required. To the extent applicable data items are already provided through an effective interconnection agreement, they are not separately required.~~

- Net Generation MW
- Net Generator MVAr
- Real power flow through each of the low side feeder breakers
- Reactive power flow through each of the low side feeder breakers
- Reactive power flow from each of the shunt capacitor banks
- A phase high side transmission voltage
- B phase high side transmission voltage
- C phase high side transmission voltage
- Accumulator pulses for ~~generator output~~interchange metering kWh
- Status of all low and high side breakers
- 10-minute ramp rate, limited by capacity
- Pmax and Pmin
- Ramp Rate MW/min
- Status – Active/Inactive
- ~~PMax~~Deploy and Deploy Acknowledge Signals

~~Testing and Disqualification for Self-Supply of Reserves in the PacifiCorp Balancing Authority Areas~~

~~Resources designated for self-supply of reserves, spinning or supplemental, may be tested by PacifiCorp at any time throughout the year. The test will be performed upon the physical response of resources designated for self-supply via e-Tag.~~

~~Resources called upon to supply reserves and responding to meet Western Electricity Coordinating Council ("WECC") and PacifiCorp requirements for time, output, and power quality, during the calendar year shall be deemed as passing the test. PacifiCorp will monitor resources designated and accepted for self-supply and log the date of successful operation. Failure to respond when called upon to supply reserves may disqualify the resource from self-supplying reserves as described here:~~

3.4 Failure to Meet Requirements or Failure to Perform

In the event that any of the requirements set forth in this Attachment U fail to be met, PacifiCorp will resume billing the Transmission Customer for the specific Ancillary Service(s) for which the Transmission Customer has failed to meet the requirements. Beginning on the date of the failure, PacifiCorp will bill the Transmission Customer until such failure is cured. This may include any penalties, charges or other consequences to which PacifiCorp is subject related to the failure. Further detail regarding the process and protocol for addressing failure to meet eligibility requirements or failure to self-supply is set forth below or in the relevant transmission service agreement.

3.5 Requests for Additional Information

PacifiCorp may, consistent with Good Utility Practice, request such additional information, beyond what is specifically required by this Attachment U, from the Transmission Customer regarding the self-supply or third-party supply of an Ancillary Service as is reasonably necessary to ensure that the Ancillary Service is supplied in a reliable manner. All such requests shall be limited to reliability specific data.

PacifiCorp shall treat any information designated as confidential by the Transmission Customer as confidential except to the extent that disclosure of this information is required by another provision of the PacifiCorp OATT, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice. Further, PacifiCorp shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

3.6 Rejection of Requests or Termination of Existing Self-Supply or Third-Party Supply Arrangements

PacifiCorp may, consistent with Good Utility Practice, reject a request for self-supply or third-party supply of Ancillary Service(s) or suspend operation of an existing arrangement for self-supply or third-party supply in the event that such self-supply or third-party supply will impair reliability of the relevant PacifiCorp Balancing Authority Area or the interconnected electric system. Prior to rejecting a request for self- or third-party supply or suspending an existing arrangement for self- or third-party supply, PacifiCorp shall provide reasonable advance notice to the Transmission Customer and shall discuss the rejection or termination, as applicable, with the Transmission Customer.

3.7 Responsibility for Necessary Equipment Installation

The Transmission Customer is responsible for the installation of all equipment (including but not limited to metering and telecommunications equipment) necessary to meet the requirements to self-supply or purchase third-party supply as specified in this Attachment U. The Transmission Customer will reimburse PacifiCorp or its affiliates for any expenses prudently incurred to accommodate the request for self-supply or third-party supply. The equipment to be installed for self-supply or third-party supply shall be specified in the agreement required by section 3.1.

4. SPECIFIC ANCILLARY SERVICE ALTERNATIVE SUPPLY REQUIREMENTS

4.1 SCHEDULE 3/3A – REGULATION AND FREQUENCY RESPONSE SERVICE

This section sets forth the resource eligibility requirements for self-supply or third-party supply of Schedules 3/3A – Regulation and Frequency Response Service. Additional detail regarding the self-supply or third-party supply of this service will be set forth in the transmission service agreement between the Transmission Customer and PacifiCorp. The agreement may cover, among other things, the Transmission Customer's reserve obligation, elections to self-supply or third-party supply, pooling arrangements, and processes for forecasting, deployment, and performance verification of self-supply or third-party supply of Schedules 3/3A.

A. Generating Resource Eligibility Requirements

The following resource eligibility requirements apply for the self-supply or third-party supply of Schedules 3/3A (Regulation and Frequency Response Service) where the resource supplying the service and the Network Load or resource requiring this service are in the same PacifiCorp Balancing Authority Areas.

1. The Network Load or resource receiving Schedule 3/3A service through self-supply or third-party supply must have real time metering observable by the Balancing Authority.

2. The resource providing self-supply or third-party supply must be deliverable on transmission within the applicable PacifiCorp BAA.

3. The Transmission Customer must have dedicated capacity for the provision of this service which may not be used to satisfy any other capacity obligations.

4. The resource providing self-supply or third-party supply must have a point of contact that is available any time the resource is designated for Schedule 3/3A.

5. An Energy Imbalance Market ("EIM") non-participating resource must be placed under automatic generation control ("AGC"), which is required to satisfy all Schedule 3/3A requirements in real time and to compensate for instantaneous load swings or resource losses within the PacifiCorp BAA. PacifiCorp reserves the right to determine the quantity and resource priority on AGC within the PacifiCorp BAA to meet the requirements under this section or those set forth in the transmission service agreement.

6. An EIM participating resources providing self-supply or third-party supply must follow the California Independent System Operator ("CAISO") Dispatch Operating Point or grid operator instruction to satisfy all reserve requirements in real time.

In addition to requirements 1 and 3-6 above, the following resource eligibility requirements apply where the resource providing self-supply or third-party supply is located in a non-PacifiCorp Balancing Authority Area (i.e., external resource) and the load or resource requiring this service is in a PacifiCorp BAA.

1. The BAA where the external resource is located ("External Balancing Authority") must be a certified BAA by NERC or its successor organization.

2. The resource providing self-supply or third-party supply must be deliverable on transmission to the applicable PacifiCorp BAA.

3. The external resource must be pseudo-tied to the PacifiCorp BAA. The pseudo-tie must meet the requirements in PacifiCorp Business Practice #25. In addition, the external resource must have observable real-time metering. The customer must provide: (i) documentation of a firm

transmission path from the external resource to a PacifiCorp BAA; and a letter from the External Balancing Authority which certifies that Regulation and Frequency Response Service is supplied in accordance with all current policies and guidelines of the NERC Operating Manual, NERC Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Schedule 3/3A to loads that are located physically in another BAA.

4. The External Balancing Authority must make arrangements to appropriately account for the resource in its own reserve obligations.

5. If the pseudo-tie equipment providing the external resource's data to PacifiCorp is not used or not useable, PacifiCorp will bill the Transmission Customer for this service for the duration of the period in which the signal was unavailable, including any and all costs or penalties incurred by PacifiCorp associated with its provision of the service. Inability of the External Balancing Authority to receive the signal by means of the pseudo-tie equipment shall not give rise to charges for this service, unless PacifiCorp also is not able to receive the resource signal and is therefore unable to include the resource in the PacifiCorp BAA Schedule 3/3A obligation. The External Balancing Authority must correct the failure to receive the signal as soon as practicable. If the signal to the External Balancing Authority is not restored expeditiously within the operating day, the self-supply or third-party supply may be terminated and the Transmission Customer will be billed for Schedule 3/3A service for the impacted operating day(s).

4.2 SCHEDULE 5 & 6 – OPERATING RESERVES – SPINNING RESERVE SERVICE & SUPPLEMENTAL RESERVE SERVICE

A. Resource Eligibility Requirements

The following resource eligibility requirements apply for the self-supply or third-party supply of Schedules 5 & 6 (Operating Reserves – Spinning Reserve Service & Supplemental Reserve Service) where the resource and the Network Load or resource

requiring this service are in the same PacifiCorp Balancing Authority Areas.

1. The Network Load or resource receiving Schedules 5 & 6 service through self-supply or third-party supply must have real time metering observable by the Balancing Authority.

2. The resource providing self-supply or third-party supply must be deliverable on transmission within the applicable PacifiCorp BAA.

3. The Transmission Customer must have dedicated capacity for the provision of this service which may not be used to satisfy any other capacity obligations.

4. The resource providing self-supply or third-party supply must have a point of contact that is available any time the resource is designated for operating reserve service.

5. For Schedule 5 – Operating Reserves – Spinning Reserve Service, the resource must have uncommitted available capacity which is on-line and loaded at less than maximum output and which may be used to satisfy the Transmission Customer's Schedule 5 obligation.

6. For Schedule 6 – Operating Reserves – Supplemental Reserve Service, the service may be self-supplied or purchased from any resource or interruptible load to meet the Transmission Customer's Schedule 6 obligation. The resource must be capable of serving demand in 10 minutes, or consist of uncommitted available capacity that is on-line and loaded at less than maximum output which can be fully applied in 10 minutes. To provide self-supply, the interruptible load must be located within a PacifiCorp BAA and must be capable of being interrupted and fully deployed within 10 minutes. If the Transmission Customer seeks to use interruptible load for self-supply or third-party supply, the Transmission Customer must provide a detailed description of the load curtailment method, measurement of the deployment, and process utilized to trigger the curtailment.

7. Transmission Customer must provide, upon request, access to logs, dispatch records or SCADA data to verify

that a resource providing self-supply is not fully loaded and has reserves that are actually spinning, and that the reserves are capable of being applied as reported.

8. Each resource must be capable of being evaluated consistent with the performance test described in Section D below. This requirement applies to the self-supplying Transmission Customer's ownership share or resource capacity rights for a jointly owned resource.

9. The resource must be capable of responding to automated deployment signals.

Requirements 1, 3-8 above also apply for the self-supply or third-party supply of Schedules 5 and 6 where the resource is located in an External Balancing Authority and the Network Load or resource receiving this service are in a PacifiCorp BAA. Requirements 2 and 9 do not apply to a generating resource located in an External Balancing Authority.

B. Scheduling Self-Supply or Third-Party Supply of Schedule 5 and 6

The following scheduling requirements apply for the self-supply or third-party supply of Schedules 5 & 6 where the resource and the load or resource receiving this service are in the same PacifiCorp BAA.

1. The resource providing self-supply or third-party supply must be deliverable on transmission to the applicable PacifiCorp BAA.

2. Transmission Customers must submit day-ahead information that identifies the specific resources and capacity levels designated for Schedule 5 and 6 through the Base Schedule Aggregation Portal ("BSAP"), or other means mutually acceptable to both parties.

3. Schedule 5 and 6 requirements must be scheduled using the CAISO BSAP scheduling portal through Day Ahead rolling seven-day submissions, or other means mutually acceptable to both parties. These submissions can be updated up to 57 minutes before the operating hour.

4. Forecast submissions for resources providing self-supply or third-party supply should be at the unit level if PacifiCorp's network model includes the resource

by unit, or at the resource level if PacifiCorp's network model includes the resource at the resource level.

5. BSAP submissions should be entered as "AS-SP" for spin (Schedule 5) or "AS-NS" for non-spin (Schedule 6) values, as appropriate.

External Resources

The following scheduling requirements apply for the self-supply or third-party supply of Schedules 5 & 6 (Operating Reserves – Spinning Reserve Service and Operating Reserves – Supplemental Reserve Service) where the resource providing self-supply or third-party supply and the load or resource receiving this service are in different Balancing Authority Areas.

6. For a resource in an External Balancing Authority, Schedule 5 and 6 requirements must be scheduled using a Capacity e-Tag consistent with PacifiCorp Business Practice #39, E-tagging Reserves or a Dynamic e-Tag consistent with PacifiCorp Business Practice #25.

7. When e-Tagging Schedule 5 and 6 requirements, the Transmission Customer will include one of the following in the comment field to identify the specific type of reserve being e-Tagged:

- RES-SPIN-PUR = Purchased Spinning Reserves
- RES-SPIN-SP = Self-Provided Spinning Reserves
- RES-NS-PUR = Purchased Non-Spinning Reserves
- RES-NS-SP = Self-Provided Non-Spinning Reserves

8. Every day at midnight (PPT), PacifiCorp will capture and record e-Tagged forecast values.

C. Deployment of Self-Supply or Third-Party Supply of Schedule 5 and 6

The following deployment requirements apply for the self-supply or third-party supply of Schedules 5 & 6 where the resource providing self-supply or third-party supply and the load or resource receiving this service are in the same PacifiCorp Balancing Authority Area.

1. Schedule 5 and 6 deployment will occur through an automated process enabled by an interface between PacifiCorp

and the Transmission Customer. The interface will be facilitated by a third-party vendor selected by the Transmission Customer. The Transmission Customer is responsible for engaging with a vendor to create an appropriate interface.

2. Deployment signals will be sent automatically through an electronic interface between PacifiCorp, Transmission Customer, and the vendor providing the electronic interface. The signal will identify the amount of Schedule 5 and 6 reserves to deploy. The Transmission Customer must have a point of contact available, all hours and every day, to be used to communicate the deployment of the reserves, when necessary.

3. During a contingency event, the amount of Schedule 5 and 6 reserves called upon for each self-supplying Transmission Customer will be calculated as follows:

> (Customer scheduled self-supply / Total PacifiCorp BAA (PACE or PACW) Contingency Reserve Obligation) * Generation Loss

4. For each self-supplying Transmission Customer, the deployment obligation is for 60 minutes.

External Resources

In addition to items 3 and 4 above, the following deployment requirements apply for the self-supply or third-party supply of Schedules 5 & 6 where the resource providing self-supply or third-party supply and the load or resource receiving this service are in different Balancing Authority Areas.

5. Consistent with Business Practice #39, when the service is needed, the Schedule 5 and 6 reserves must be deployed by the Transmission Customer. PacifiCorp will confirm that the Transmission Customer's Schedule 5 and 6 reserves are being held via e-Tag. Once confirmation is validated, PacifiCorp will provide an automatic signal to communicate a loss of resource in the appropriate BAA and request deployment of Schedule 5 and 6 reserves. The Transmission Customer will make arrangements for the External Balancing Authority to communicate its Automatic Control Error ("ACE") and an acknowledgement signal to

inform PacifiCorp that Schedule 5 and 6 reserves are being deployed.

6. During periods within the hour when Schedule 5 and 6 reserves are required, when using a Capacity e-Tag the Transmission Customer must submit an adjustment of the energy profile on the e-Tag within 7 minutes reflecting the amount of energy flow anticipated for the balance of the hour and subsequent hours. If the Transmission Customer is using a Dynamic e-Tag, then the Transmission Customer must submit updates to the Dynamic e-Tag energy profile with the integrated value (MWh) within 30 minutes after the completion of the operating hour, the e-Tag shall use the value obtained from a common agreed on source, and the e-Tag data must be submitted into the CAISO EIM as part of the base schedules for interchange.

D. Performance Verification & Failure Events

The following performance requirements apply for the self-supply or third-party supply of Schedules 5 & 6 – Operating Reserves – Spinning Reserve Service and Operating Reserves – Supplemental Reserve Service – where the resource and the Network Load or resource requiring this service are in the same PacifiCorp Balancing Authority Area. Failure of a self-supply resource to physically respond to a call to deploy Schedule 5 or 6 reserves may result in Failure Event and/or an assessment of a strike.

~~•~~ PacifiCorp will count as a single failure event (each a "Failure Event"), any hour or consecutive group of hours that a resource does not successfully respond when ~~called by PacifiCorp~~deployed to provide reserves and that occurs before PacifiCorp provides written notice of the Failure Event to the resource owner and all Transmission Customers relying on the resource for reserves. ~~Upon and with such written notice, a Failure Event may be assessed a "strike," the assessment of which shall be included in the written notice of the underlying Failure Event. "Written notice" for purposes of this Attachment U includes notice given electronically.~~

To determine whether a Failure Event has occurred, a performance test will be conducted associated with each call for deployment of Schedule 5 or 6 reserves. The test will be performed for each resource or group of resources in the following manner:

1. The resource's starting generation (average generation at the time the signal for deployment is sent) will be compared to the average generation 10 minutes following the deployment signal and during minutes 11-60 following the deployment signal.

2. Failure of the 10-minute test results if the average generation value is not greater than or equal to starting generation plus the identified Schedule 5 or 6 reserve obligation.

3. Failure of the 60-minute test results if the average generation value at during minutes 11-60 minutes is not greater than or equal to starting generation plus the identified Schedule 5 or 6 reserve obligation.

4. Failure of either the 10-minute or 60-minute test results in a Failure Event.

5. If the Transmission Customer has indicated that self-supply is available on more than a single resource or a group of resources, the performance test described above will be applied to the total available resources as compared to the average generation of the resource or group of resources.

External Resources

The following performance requirements apply for the self-supply or third-party supply of Schedules 5 & 6 – Operating Reserves – Spinning Reserve Service and Operating Reserves – Supplemental Reserve Service – where the resource and the Network Load or resource requiring this service are in different Balancing Authority Areas.

6. Failure of a self-supply resource to physically respond to a call to deploy Schedule 5 or 6 reserves may result in Failure Event. To determine whether a Failure Event has occurred, a performance test will be conducted associated with each call for deployment of Schedule 5 or 6 reserves. For Transmission Customers using an external resource to self-supply, the test will be performed for each resource or group of resources in the following manner:

7. PacifiCorp will review whether the e-Tag was implemented within the specified time listed in section

C.6 per the e-Tag type, and verify an associated change to the net-scheduled-interchange (NSI) with the External Balancing Authority. If the e-Tag was not implemented and there was not change to NSI, a strike will be issued.

E. Assessment of Strikes

Upon written notice, a Failure Event may be assessed a "strike." The written notice will inform the Transmission Customer of the underlying Failure Event and the strike. "Written notice" for purposes of this Attachment U includes notice given electronically.

- Upon each written ~~notice~~assessment of a ~~Failure Event~~strike as provided above, and before another strike may be assessed to the same resource, PacifiCorp will allow the affected Transmission Customer(s) up to three business days in which to provide written notice to PacifiCorp of the specific remedy to the resource failure that has been implemented, of alternative self-supply arrangements that have been made, or of the intent to take the applicable reserve service(s) from PacifiCorp. Absent any such written notice to PacifiCorp, the affected Customer(s) shall be subject to the applicable reserve service(s) as defined in Schedule 5 and/or Schedule 6 of PacifiCorp's OATT for the duration of the failure.

- A resource that accumulates three strikes within a rolling 12-month period will be disqualified for the balance of the month in which the third ~~Failure Event~~strike occurs and the entirety of the following month. PacifiCorp will give affected Transmission Customer(s) written notice of the third strike and resource disqualification ~~and~~. PacifiCorp will allow Transmission Customer(s) up to ~~three~~five business days in which to formally notify PacifiCorp of alternative self-supply arrangements or be subject to the applicable reserve service(s) as defined in Schedule 5 and/or Schedule 6 of PacifiCorp's OATT. No Transmission Customer may designate or utilize a disqualified resource to provide self-supply service. Following the disqualification period, strikes for the resource shall be reset to zero and the resource will be again eligible to provide self-supply service subject to the provisions herein.

~~PacifiCorp will only test resources that are carrying operating reserves at the time the test is commenced. A resource that is experiencing a unit trip shall not be subject to the test for the operating hour during which the trip occurs. This will be~~

accomplished with PacifiCorp calling on reserves, monitoring results and logging the test. PacifiCorp will provide written reports of all test results to the resource owner and the Customer(s) using the resource for self-supply, if different.

Operating Reserve - Spinning Reserve Service (Schedule 5):
This service may be self-supplied or purchased from any unit or system that has uncommitted available capacity which is on-line and loaded at less than maximum owned or contracted output and which may be used to satisfy the Transmission Customer's reserve obligation. The specific resources from which the service is being provided must be identified and have observable telemetry. The party requesting to self-supply or arranging for third-party purchase shall, at its own expense, install the necessary equipment (including but not limited to metering and telecommunications equipment) for providing the service. The party requesting to self-supply or arranging for third-party purchase shall also reimburse PacifiCorp or its affiliates for any expenses incurred to accommodate the request for self-supply or third-party supply.

A. Use of an External Resource:
For generation external to PacifiCorp's BAAs to qualify for self-supply or third-party supply service, a dynamic transfer coming into PacifiCorp's energy management system ("EMS") as a dynamic schedule into the balancing authority area where the obligation originates, represented on a dynamic e-Tag, is sufficient for communication with PacifiCorp's EMS. The author of the e-Tag is responsible for adjusting the energy profile to match the resource output for self-supply until such time as an automated process can be developed and implemented to relieve the author of this responsibility.

B. The following information will be required to demonstrate the self-supply or third-party purchase of spinning reserve service for Internal Resources:

- The generation resources providing the service must be located in the same PacifiCorp Balancing Authority Area as the Network Load or contractual point of receipt and must have observable telemetry.
- Requirements for self-supply or third-party purchase of spinning reserve service shall apply at the unit level if PacifiCorp's network model includes the resource by unit, or at the plant level if

~~PacifiCorp's network model includes the resource at the plant level.~~

- ~~Documentation that the generation resources are deliverable Network Resources as defined by a current Network Integration Transmission Service Agreement, a legacy load service agreement on file at FERC, or other firm PTP agreement, which may be reported on PacifiCorp's Electric Quarterly Report ("EQR").~~

- ~~For self-supply arrangements through a power purchase agreement, a copy of the capacity agreement(s) or contract(s) that can be used to verify that the capacity used for this service is dedicated to serve the designated metered Network Load, and is not being used to satisfy any other capacity obligations.~~

- ~~Access to logs, dispatch records and test data that can be used to verify that spinning reserves are actually spinning and not fully loaded and are capable of being applied as reported. Resource capability for self-supply of reserves shall mean the operational capability of the unit to actually deliver the reserve energy in the event of a deployment based on the operational capability characteristics of the self-supply resource (i.e., ramp rates, PMax).~~

- ~~Self-suppliers must provide a monthly reserve supply forecast no less than thirty (30) calendar days before the beginning of the month with amounts (MWs) in all hours for that month based on the forecasted percentage of reserve obligation. This 30-day forecast requirement does not replace or satisfy separate seven-day forecast requirements established by Peak Reliability and the California Independent System Operator ("CAISO").~~

- ~~Self-suppliers must provide day-ahead information via e-Tag. In the day-ahead, the reserve supply forecast must be updated for the next operating day with the amount (MWs) of reserve obligation the self-supplier expects to actually be providing in all hours.~~

- ~~A point of contact is always available, all hours, every day to be used to deploy the reserves.~~

C. For self-supply and third-party purchases of this service, reserves must be scheduled using a capacity e-Tag consistent with PacifiCorp Business Practice #39, E-tagging Reserves. Also, consistent with Business Practice #39, when the service is needed, the reserves must be deployed by the Customer through a mid-hour tag adjustment to the energy profile. PacifiCorp will confirm customer reserves are being held via e-Tag.

Once confirmation is validated, PacifiCorp will place a phone call or adjust a capacity tag through an automated process to communicate a loss of generation in the appropriate Balancing Authority and request deployment of reserves for the appropriate length of time. PacifiCorp will provide an annual report to Customers demonstrating non-discriminatory deployment of reserves.

D. In the event that any of the above requirements fail to be met, then PacifiCorp reserves the right to bill the responsible party for this service as supplied by PacifiCorp for the duration of the failure, including reimbursement for any compliance-related penalties, charges, or other consequences, to which PacifiCorp is subject related to the failure. If the Customer fails to self-supply its spinning reserves as defined in this section and fails to notify PacifiCorp to make arrangements for service, the Customer will be subject to spinning reserve service as defined in Schedule 5 of PacifiCorp's OATT.

E. The service hereunder must be available to be called on by PacifiCorp to comply with NERC Standard BAL-002-WECC-2 (or any successor Reliability Standard thereto), and any such other related criteria or standards which may be imposed by a national or regional reliability council or governing regulatory body. The service will also be used by PacifiCorp to comply with its obligations under the Northwest Power Pool Reserve Sharing Group Contract and any future Reserve Sharing Group of which PacifiCorp is a member. The supplying party must, at its own expense, make the necessary arrangements, in coordination with PacifiCorp, to be able to respond to a reserve sharing event. The supplying party is not required to have a separate relationship or agreement with the Northwest Power Pool Reserve Sharing Group.

~~F. PacifiCorp reserves the right to request more information from the party requesting self-supply or third-party supply and/or its supplier of spinning reserve service, in addition to the above-listed information, to ensure that this service is supplied in a reliable manner, PacifiCorp shall make best efforts to request further information no later than thirty (30) calendar days from the customer's request to self-supply or third-party supply.~~

~~Further, PacifiCorp reserves the right to reject the request to self-supply such service, or purchase it from another source, in the event that PacifiCorp, in its reasonable judgement, concludes that such self-supply or third-party purchase would impair reliability in the relevant PacifiCorp BAA or the interconnected system. PacifiCorp also reserves the right to terminate the self-supply or third-party purchase if, in its reasonable judgement, PacifiCorp concludes that such self-supply or third-party purchase is impairing reliability in the relevant PacifiCorp BAA or the interconnected system.~~

~~In the event that PacifiCorp rejects the request to self-supply or third-party purchase, or concludes that an existing self-supply or third-party purchase is impairing reliability, PacifiCorp will provide in writing detailed explanations for such determination and proposed remedy not less than thirty (30) calendar days from the customer's request to self-supply or third-party supply. Notice of rejection to self-supply or third-party purchase does not preclude a customer from reapplication.~~

~~G. If the metered Network Load requiring the spinning reserve service has been moved electronically into another BAA, certified by NERC or its successor organization, by means of a pseudo-tie, this Section G shall apply. The pseudo-tie requires identification and observable telemetry of the specific Network Loads for which the service is to be provided. PacifiCorp requires a letter in advance from the BAA that is supplying the spinning reserve ("Supplying Balancing Authority") which certifies that this service is supplied in accordance with all current policies and guidelines of the NERC Operating Manual and/or the North American Energy Standards Board ("NAESB") standards, or any successor~~

~~manual or standards, that apply to supplying Ancillary Services to loads that are located physically in another Balancing Authority Area.~~

1. ~~PacifiCorp will accept, in lieu of the showing required in Section A.1 above, a letter in advance from the Supplying Balancing Authority which certifies that this service is supplied in accordance with all current policies and guides of the NERC Operating Manual and/or NAESB standards, or any successor manual or standards, that apply to supplying Ancillary Services to loads that are physically located in another Balancing Authority Area.~~

2. ~~Whenever the pseudo-tie equipment providing the Network Load's data to PacifiCorp and/or the Supplying Balancing Authority is not used and/or not useable, the dispatcher for the entity that is not receiving the load signal shall immediately contact the dispatcher for the other entity to inform it of the loss of the signal. Thereafter, until both entities are again receiving the load signal through the pseudo-tie equipment, PacifiCorp may call upon the Supplying Balancing Authority to provide (or, if it is not the supplier of the Network Load's spinning reserves, call upon the supplier of such spinning reserves to provide) spinning reserves when and to the extent requested.~~

3. ~~If the Supplying Balancing Authority or the supplier of spinning reserves fails to meet the requirements set forth in Section G.2 (i.e., fails to notify PacifiCorp of the Supplying Balancing Authority's loss of its ability to receive the Network Load's signal and/or fails to supply spinning reserves when called upon by PacifiCorp), PacifiCorp reserves the right to bill the responsible party for this service for the duration of the failure, including reimbursement for any penalties, charges, or other consequences to which PacifiCorp is subject related to the failure.~~

4. ~~PacifiCorp reserves the right to request more information from the Supplying Balancing Authority and/or the Network Load's supplier of spinning reserve service, in addition to the above referenced letter, to ensure that this service is supplied in a reliable manner. PacifiCorp shall make best efforts to request~~

further information no later than thirty (30) calendar days from the customer's request.

Further, PacifiCorp reserves the right to reject the request to self-supply such service, or purchase it from another source, in the event that PacifiCorp, in its reasonable judgement, concludes that such self-supply or third-party purchase would impair reliability in the relevant PacifiCorp Balancing Authority Area or the interconnected system.

PacifiCorp also reserves the right to terminate the self-supply or third-party purchase if, in its reasonable judgement, PacifiCorp concludes that such self-supply or third-party purchase is impairing reliability in the relevant PacifiCorp Balancing Authority Area or the interconnected system.

In the event that PacifiCorp rejects the request to self-supply or third-party purchase, or concludes that an existing self-supply or third-party purchase is impairing reliability, PacifiCorp will provide in writing detailed explanations for such determination, proposed remedy not less than thirty (30) calendar days from the customer's request to self-supply or third-party supply. Notice of rejection to self-supply or third-party purchase does not preclude customer from reapplication.

H. During periods when reserve deployment is required, PacifiCorp will notify the Customer either through electronic means or by phone call that reserves are required, the amount of reserves to deploy and the appropriate length of time of deployment. Specific notice arrangements will be agreed to between the Customer and PacifiCorp during the certification process.

Energy supplied by a Customer during periods of reserve deployment will be settled financially for the amount of energy deployed as represented on the Customer adjusted energy profile of the capacity tag(s) for External Resources and for Internal Resources not represented in the network model. Resources supplying reserves that are represented in the network model will not receive

~~separate energy settlement. These resources will receive settlements per Schedule 9 of PacifiCorp's OATT for Non-Participating Resources or directly from CAISO for Participating Resources.~~

~~Financial settlement for Internal Resources not in the network model and External Resources will be settled based on the integrated tag value multiplied by the hourly settled PACE or PACW ELAP price, adjusted for losses consistent with PacifiCorp's OATT.~~

Operating Reserve - Supplemental Reserve Service (Schedule 6): This service may be self-supplied or purchased from any qualifying unit, system, or qualifying interruptible load to meet the Network Load Transmission Customer's reserve obligation. The unit or system must consist of one or more quick-start units that are off-line but capable of serving demand in 10 minutes, or uncommitted available capacity that is on-line and loaded at less than maximum owned or contracted output which can be fully applied in 10 minutes. The interruptible load must be located within PacifiCorp Balancing Authority Area and must be capable of being interrupted within 10 minutes in the reasonable judgement of PacifiCorp. The specific resources for which the service is being provided must be identified and have observable telemetry. The party requesting to self-supply or arranging for third-party purchase shall, at its own expense, install the necessary equipment (including but not limited to metering and telecommunications equipment) for providing the service. The party requesting to self-supply or arranging for third-party purchase shall also reimburse PacifiCorp or its affiliates for any expenses incurred to accommodate the request for self-supply or third-party supply.

A. Use of an External Resource:

For generation external to PacifiCorp's BAAs to qualify for self-supply or third-party supply service, a dynamic transfer coming into PacifiCorp's EMS as a dynamic schedule into the balancing authority area where the obligation originates, represented on a dynamic e-Tag is sufficient for communication with PacifiCorp's EMS. The author of the e-Tag is responsible for adjusting the energy profile to match the resource output for self-supply until such time as an automated process can be developed and implemented to relieve the author of this responsibility.

B. The following information will be required to demonstrate the self-supply or third-party purchase of supplemental reserve service for Internal Resources:

- The generation resources providing the service must be located in the same PacifiCorp Balancing Authority Area as the Network Load or contractual point of receipt and must have observable telemetry.

- ~~Requirements for self-supply or third-party purchase of supplemental reserve service shall apply at the unit level if PacifiCorp's network model includes the resource by unit or at the plant level if PacifiCorp's network model includes the resource at the plant level.~~

- ~~Documentation that the generation resources are deliverable Network Resources as defined by a current Network Integration Transmission Service Agreement, a legacy load service agreement on file at FERC, or other firm PTP agreement, which may be reported on PacifiCorp's Electric Quarterly Report ("EQR").~~

- ~~For self-supply arrangements through a power purchase agreement, a copy of the capacity agreement(s) or contract(s) that can be used to verify that the capacity used for this service is dedicated to serve the designated metered Network Load, and is not being used to satisfy any other capacity obligations.~~

- ~~If interruptible load is used, explicit description of the load, curtailment method, process utilized to trigger the curtailment and interruptible contract.~~

- ~~Deployment capability must be proven by the self-supply Customer in a fashion acceptable to PacifiCorp. Requirements will depend on the type resource claimed as supplemental reserves and may include load trip testing or requesting an unplanned start on a reserve generator. Procedures must be validated prior to certification and also may require at least bi-annual validation.~~

- ~~Access to logs, dispatch records and test data that can be used to verify that supplemental reserves are available and not fully loaded, and are capable of being applied as reported. Resource capability for self-supply of reserves shall mean the operational capability of the unit to actually deliver the reserve energy in the event of a deployment based on the operational capability characteristics of the self-supply resource (i.e., ramp rates, PMax).~~

- ~~Self-suppliers must provide a monthly reserve supply forecast no less than thirty (30) calendar days before the beginning of the month with amounts (MWs) in all hours for that month based on the forecasted percentage of reserve obligation. This 30-day forecast requirement does not replace or satisfy separate seven-day forecast requirements established by Peak Reliability and the California Independent System Operator ("CAISO").~~

- ~~Self-suppliers must provide day-ahead information via e-Tag. In the day-ahead, the reserve supply forecast must be updated for the next operating day with the amount (MWs) of reserve obligation the self-supplier expects to actually be providing in all hours.~~

- ~~A point of contact is always available, all hours, every day to be used to call on the reserves.~~

C. ~~For self-supply and third-party purchases of this service, reserves must be scheduled using a capacity e-Tag consistent with PacifiCorp Business Practice #39, E-Tagging of Reserves. Also, consistent with Business Practice #39, when the service is needed, the reserves must be deployed by the Customer through a mid-hour tag adjustment to the energy profile. PacifiCorp will confirm customer reserves are being held via e-Tag.~~

~~Once confirmation is validated, PacifiCorp will place a phone call or adjust a capacity tag through an automated process to communicate a loss of generation in the appropriate Balancing Authority and request deployment of reserves for the appropriate length of time. PacifiCorp will provide an annual report to Customers demonstrating non-discriminatory deployment of reserves.~~

D. ~~In the event that any of the above requirements fail to be met, then PacifiCorp reserves the right to bill the responsible party for this service as supplied by PacifiCorp for the duration of the failure, including reimbursement for any compliance-related penalties, charges or other consequences which PacifiCorp is subject to related to the failure. If the Customer fails to self-supply its supplemental reserves as defined in this section and fails to notify PacifiCorp to make arrangements for service, the Customer will be subject to~~

~~supplemental reserve service as defined in Schedule 6 of PacifiCorp's OATT.~~

~~E. The service hereunder must be available to be called on by PacifiCorp to comply with the NERC Disturbance Control Standard (NERC BAL-002-2 or any successor Reliability Standard thereto), and any such other related criteria or standards which may be imposed by a national or regional reliability council or governing regulatory body. The service will also be used by PacifiCorp to comply with its obligations under the Northwest Reserve Sharing Group Contract and any future Reserve Sharing Group of which PacifiCorp or its affiliates are a member. The supplying party must, at its own expense, make the necessary arrangements, in coordination with PacifiCorp, to be able to respond to a Reserve Sharing event. The supplying party is not required to have a separate relationship or agreement with the Northwest Power Pool Reserve Sharing Group.~~

If a Failure Event is caused by an unplanned outage of a self-supplying resource or transmission line, no strike will be issued for the operating hour in which the unplanned outage occurs. Unless the Transmission Customer is able to meet its self-supply obligation through a different resource or group of resources, the Transmission Customer will be billed for Schedules 5 & 6 for the duration of the unplanned outage if an unplanned outage prevents the Transmission Customer from fulfilling its self-supply obligation. The Transmission Customer may be required to supply documentation of the unplanned outage and demonstration that the Failure Event was caused by that outage.

PacifiCorp will provide written reports of all performance evaluation results to the resource owner and the Transmission Customer(s) using the resource for self-supply, if different.

F. ~~PacifiCorp reserves the right to request more information from the party requesting self-supply or third-party supply and/or its supplier of supplemental reserve service, in addition to the above-listed information, to ensure that this service is supplied in a reliable manner. PacifiCorp shall make best efforts to request further information no later than thirty (30) calendar days from the customer's request to self-supply or third-party~~

~~supply.~~ **Settlement of Self-Supply or Third-Party Supply of Schedule 5 and 6**

~~Further, PacifiCorp reserves the right to reject the request to self-supply such service, or purchase it from another source, in the event that PacifiCorp, in its reasonable judgement, concludes that such self-supply or third-party purchase would impair reliability in the relevant PacifiCorp BAA or the interconnected system. PacifiCorp also reserves the right to terminate the self-supply or third-party purchase if, in its reasonable judgement, PacifiCorp concludes that such self-supply or third-party purchase is impairing reliability in the relevant PacifiCorp BAA or the interconnected system.~~

~~In the event that PacifiCorp rejects the request to self-supply or third-party purchase, or concludes that an existing self-supply or third-party purchase is impairing reliability, PacifiCorp will provide in writing detailed explanations for such determination, proposed remedy not less than thirty (30) calendar days from the customer's request to self-supply or third-party supply. Notice of rejection to self-supply or third-party purchase does not preclude customer from reapplication.~~

Energy supplied by a Transmission Customer during periods of Schedule 5 or 6 reserve deployment for resources located within a PacifiCorp BAA will be settled financially for the amount of energy deployed by the Transmission Customer's resource in accordance with Schedule 9 of PacifiCorp's OATT.

Energy supplied by a Transmission Customer during periods of Schedule 5 or 6 reserve deployment for resources located outside of a PacifiCorp BAA will be settled financially for the amount of energy deployed by the Transmission Customer's resource in accordance with Attachment T of PacifiCorp's OATT.

G. ~~If the metered Network Load requiring the reserves has been moved electronically into another BAA, certified by NERC or its successor, by means of a pseudo-tie, this Section G shall apply. The pseudo-tie requires identification and observable telemetry of the specific Network Loads for which the service is to be provided.~~**Monthly Report To Customers Regarding Schedule 5 and 6 Deployment**

1. ~~PacifiCorp will accept, in lieu of the showing required in Section A above, a letter in advance from the BAA that is supplying the supplemental reserve ("Supplying Balancing Authority"), which certifies that this service is supplied in accordance with all current policies of the NERC Operating Manual and/or NAESB standards, or any successor manual or standards, that apply to supplying Ancillary Services to loads that are located physically in another Balancing Authority Area.~~

2. ~~Whenever the pseudo-tie equipment providing the Network Load's data to PacifiCorp and/or the Supplying Balancing Authority is not used and/or not useable, the dispatcher for the entity that is not receiving the load signal shall immediately contact the dispatcher for the other entity to inform it of the loss of the signal. Thereafter, until both entities are again receiving load signal through the pseudo-tie equipment, PacifiCorp may call upon the Supplying Balancing Authority to provide supplemental reserves when and to the extent requested.~~

3. ~~If the Supplying Balancing Authority or the supplier of spinning reserves fails to meet the requirements set forth in Section G.2 (i.e., fails to notify PacifiCorp of the Supplying Balancing Authority's loss of its ability to receive the load signal and/or fails to supply supplemental reserves when called upon by PacifiCorp), PacifiCorp reserves the right to bill the responsible party for this service for the duration of the failure, including reimbursement for any penalties, charges, or other consequences which PacifiCorp is subject to related to the failure.~~

4. ~~PacifiCorp reserves the right to request more information from the Supplying Balancing Authority and/or the Network Load's supplier of the supplemental reserves, in addition to the above referenced letter, to ensure that this service is supplied in a reliable manner. PacifiCorp shall make best efforts to request further information no later than thirty (30) calendar days from the customer's request.~~

   ~~Further, PacifiCorp reserves the right to reject the request to self-supply such service, or purchase it from another source, in the event that PacifiCorp, in~~

~~its reasonable judgement, concludes that such self-supply or third-party purchase would impair reliability in PacifiCorp's Balancing Authority Area or the interconnected system. PacifiCorp also reserves the right to terminate the self-supply or third-party purchase if, in its reasonable judgement, PacifiCorp concludes that such self-supply or third-party purchase is impairing reliability in the relevant PacifiCorp Balancing Authority Area or the interconnected system.~~

PacifiCorp will provide a monthly report to all self-supplying Transmission Customers that includes the following information for each deployment of Schedule 5 or 6 reserves:

- Contingency ID number
- North West Power Pool Reserves (committed or requested)
- Date, Event Start Time
- Reason for Deployment that identifies the regional event declared, or other reason why the deployment occurred (transmission or generator)
- Total MW Loss

~~In the event that PacifiCorp rejects the request to self-supply or third-party purchase, or concludes that an existing self-supply or third-party purchase is impairing reliability, PacifiCorp will provide in writing detailed explanations for such determination, proposed remedy not less than thirty (30) calendar days from the customer's request to self-supply or third-party supply. Notice of rejection to self-supply or third-party purchase does not preclude customer from reapplication.~~

Customers may request additional information beyond that provided in the monthly report. PacifiCorp shall provide such information or explain why it believes that it may not properly do so.

H. ~~During periods when reserve deployment is required, PacifiCorp will notify the Customer either through electronic means or by phone call that reserves are required, the amount of reserves to deploy and the appropriate length of time of deployment. Specific notice arrangements will be agreed to between the Customer and PacifiCorp during the certification process.~~**Exclusion of Certain Jointly Owned Units**

~~Energy supplied by a Customer during periods of reserve deployment will be settled financially for the amount of energy deployed as represented on the Customer adjusted energy profile of the capacity tag(s) for External Resources and for Internal Resources not represented in the network model. Resources supplying reserves that are represented in the network model will not receive separate energy settlement. These resources will receive settlements as uninstructed imbalances per Schedule 9 of PacifiCorp's OATT for Non-Participating Resources or direct from CAISO for Participating Resources.~~

~~Financial settlement for Internal Resources not in the network model and External Resources will be settled based on the integrated tag value multiplied by the hourly settled PACE or PACW ELAP price, adjusted for losses consistent with PacifiCorp's OATT.~~

PacifiCorp agrees to continue to allow Utah Associated Municipal Power Systems ("UAMPS"), the Utah Municipal Power Agency ("UMPA"), and Deseret Generation and Transmission Co-operative, Inc. ("Deseret") to self-supply from jointly owned units without performance evaluations through October 1, 2021 to allow the parties to work toward mutual agreement on self-supply arrangements specific to jointly owned units. If the parties succeed in agreeing on an approach, the parties will agree to an implementation date that provides a reasonable amount of time to ready their systems for compliance with any agreed-upon approach. If mutual agreement is not reached by September 1, 2021, PacifiCorp and each of UAMPS, UMPA, and Deseret may thereafter make a unilateral filing with FERC pursuant to Sections 205 and 206 of the FPA, respectively.

4.3 SCHEDULE 4 – ENERGY IMBALANCE SERVICE

A. Eligibility Requirements

The following eligibility requirements apply for the self-supply or third-party supply of Schedule 4 – Energy Imbalance Service

1. The specific Network Loads for which the service is to be provided must be the total Network Load obligation within the PacifiCorp Balancing Authority Area and have observable real-time metering and telemetry.

2. The resources providing the service must be located in the same PacifiCorp Balancing Authority Area as the Network Load and must have observable real time metering.

3. The resource providing the service must be deliverable resources as defined by a current transmission service agreement or resources that are interconnected to PacifiCorp's system and have an active generation interconnection agreement with PacifiCorp.

4. The capacity used for this service must be dedicated to Network Load service requirements and may not being used to satisfy any other capacity obligations.

5. The resource (or a resource dispatch center) must have a point of contact that is available any time the resource is designated for regulation and frequency response service.

6. The Transmission Customer must designate adequate resources to satisfy the Network Load obligation at all times. The designated resources must be under automatic generation control, satisfying all reserve requirements in real time and as required to compensate for instantaneous load swings or generation losses within the PacifiCorp BAA. The Transmission Provider reserves the right to determine the quantity and location of resources placed under AGC within the PacifiCorp BAA.

B. Resources Moved Electronically to External Balancing Authority

If the metered Network Load requiring imbalance service has been moved electronically into an External Balancing Authority, certified by NERC or its successor organization, by means of a pseudo-tie, this Section B shall apply.

1. The pseudo-tie requires identification and observable real-time metering of the specific Network Loads for which the service is to be provided. PacifiCorp requires a letter in advance from the External Balancing Authority which certifies that this service is supplied in accordance with all current policies and guidelines of the NERC Operating Manual, NERC Reliability Standards, or NAESB standards, or any successor manual or standards,

that apply to supplying Ancillary Services to loads that are located physically in an External Balancing Authority Area.

2. PacifiCorp will accept, in lieu of the showing required in Section A.1 above, a letter in advance from the External Balancing Authority which certifies that this service is supplied in accordance with all current policies and guides of the NERC Operating Manual, NERC Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Ancillary Services to loads that are physically located in an External Balancing Authority Area.

3. Whenever the pseudo-tie equipment providing the Network Load's data to PacifiCorp or the External Balancing Authority is not used or not useable, the dispatcher for the entity that is not receiving the load signal shall immediately contact the dispatcher for the other entity to inform it of the loss of the signal. Thereafter, until both entities are again receiving the load signal through the pseudo-tie equipment, the Transmission Customer should provide fixed schedules from the External Balancing Authority each hour to minimize the impact of load imbalance.

4. If the External Balancing Authority or the supplier of imbalance service fails to meet the requirements set forth in Section B.2 (i.e., fails to notify PacifiCorp of the External Balancing Authority's loss of its ability to receive the Network Load's signal or fails to supply fixed schedule adjustments when called upon by PacifiCorp), PacifiCorp reserves the right to bill the Transmission Customer for this service for the duration of the failure, including reimbursement for any penalties according to Schedules 4 or 9 in the PacifiCorp OATT, charges or other consequences which PacifiCorp is subject to, related to the failure.

5. PacifiCorp reserves the right to request more information from the External Balancing Authority or the Network Load's supplier of imbalance service, in addition to the above referenced letter, to ensure that this service is supplied in a reliable manner. Further, PacifiCorp reserves the right to reject the request to self-supply or third-party supply such service, in the

event that PacifiCorp, in its reasonable judgment, concludes that such self-supply or third-party purchase would impair reliability in the relevant PacifiCorp BAA or the interconnected system. PacifiCorp also reserves the right to terminate the self-supply or third-party supply if, in its reasonable judgment, PacifiCorp concludes that such self-supply or third- party supply is impairing reliability in the relevant PacifiCorp Balancing Authority Area or the interconnected system.

4.4 SCHEDULE 9 – GENERATOR IMBALANCE SERVICE

A. Self-Supply Under Schedule 3 Entities

For load serving entities who have certified as a self-supply entity for regulation and frequency response service (Schedule 3) under the requirements of this Attachment U and request generator imbalance self-certification, this Section A shall apply. Generator Imbalance Service may be self-supplied from Resources or undesignated Network Resources located within the PacifiCorp BAA under the limited set of conditions defined below. Self-supply of Generator Imbalance service created by fixed point-to-point schedules can only be provided for resources located in the PacifiCorp BAA.

The following information will be required to demonstrate that the self-supply of generator imbalance service created by point-to-point schedules during generator derates or unit tripping:

1. The resources providing the service must have observable real time metering. In addition, PacifiCorp will define specific OASIS scheduling points of receipt which will apply to Customer's requesting self-supply. Customers will be obligated to demonstrate self-supply from these specific OASIS points of receipt within the PacifiCorp BAA for purposes of this section. The current list of OASIS points of receipt for section is ("PACE", "PACEW", and "PACW"). PacifiCorp reserves the right to modify this list without notice as required to maintain transmission system reliability and compliance with the PacifiCorp OATT.

2. Documentation that the resources are deliverable Resources or Network Resources and are defined by a current Network Integration Transmission Service Agreement, interconnection agreement, or legacy load service agreement on file at FERC.

3. Any Network Resources used to supply point-to-point imbalance service must be undesignated according to the PacifiCorp business practice, "Termination of Network Resources", consistent with section 30.3 of the PacifiCorp OATT. The resources utilized must be undesignated from within specified OASIS points of receipt to self-supply point-to-point transactions originating from that particular point of receipt.

4. Resources or undesignated Network Resources must be on-line, spinning, and responsive to the loss of another undesignated unit.

5. The hourly quantity of resources or undesignated Network Resources with a point of receipt plus the purchases made and delivered on point-to-point service into each PacifiCorp point of receipt must exceed the total quantity of point-to-point transactions exiting the defined point of receipt and PacifiCorp BAA for each hour.

6. Adequate resources must remain 'designated' and available for load service as required to satisfy the Customer's Network Load obligation at all times during any period of point-to-point self-supply.

7. The party claiming generation imbalance self-supply must be previously certified as self-providing, or purchasing from third parties, regulation and frequency response service (Schedule 3) as specified in this Attachment U.

8. A point of contact is always available, all hours, every day to be used to call on resources necessary for load coverage.

B. Resources Moved Electronically to External Balancing Authority

If the Resource requiring imbalance service has been moved electronically into an External Balancing Authority Area, certified by NERC or its successor organization, by means of a pseudo-tie, this Section B shall apply. The point-to-point transmission service for the pseudo-tie resource will be established. Intra-hour transfers and the associated transmission service provided will be defined as the instantaneous output of the resource, therefore imbalance will be deemed to be self-supplied. End of hour true-ups of actual hourly integrated values are required for Balancing Authority Area energy accounting purposes.

1. The pseudo-tie requires identification and observable real-time metering of the specific Resource for which the service is to be provided. PacifiCorp requires a letter in advance from the External Balancing Authority which certifies that this service is supplied in accordance with all current policies and guidelines of the NERC Operating Manual, NERC Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Ancillary Services to loads that are located physically in another Balancing Authority Area.

2. PacifiCorp will accept, in lieu of the showing required in Section A.1 above, a letter in advance from the External Balancing Authority which certifies that this service is supplied in accordance with all current policies and guides of the NERC Operating Manual, NERC Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Ancillary Services to resources that are electronically transferred into another Balancing Authority.

3. Whenever the pseudo-tie equipment providing the Resource's data to PacifiCorp or the External Balancing Authority is not used or not useable, the dispatcher for the entity that is not receiving the load signal shall immediately contact the dispatcher for the other entity to inform it of the loss of the signal. Thereafter, until both entities are again receiving the load signal through the pseudo-tie equipment, the Transmission Customer should provide fixed schedules from the External Balancing Authority each hour to minimize the impact of generator imbalance.

Attachment A

The 2020 Settlement Agreement

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp	**)**	**Docket No. ER21-___-000**

SETTLEMENT AGREEMENT

This Settlement Agreement ("Settlement Agreement") is entered into between and among PacifiCorp; Utah Associated Municipal Power Systems ("UAMPS"); Deseret Generation and Transmission Co-operative, Inc. ("Deseret'); the Utah Municipal Power Agency ("UMPA") (UAMPS, Deseret and UMPA are, collectively, the "Legacy Customers"); Bonneville Power Administration ("Bonneville"); Avangrid Renewables, LLC ("Avangrid"); EDP Renewables North America LLC ("EDP Renewables"); and NextEra Energy Marketing, LLC (Avangrid, EDP Renewables and NextEra are, collectively, the "Renewable Customers"; the Legacy Customers, Bonneville and the Renewable Customers are, collectively, the "Joint Customers"; and the Joint Customers and PacifiCorp are all, collectively, the "Settling Parties").

The Settling Parties have been engaged in a collaborative effort contemplated by a prior settlement approved by the Federal Energy Regulatory Commission ("FERC" or "Commission") in 2018 in Docket Nos. ER17-219, et al. to address PacifiCorp proposals for updated revenue requirements and rates, as well as self-supply options, under Schedules 3 and 3A (Regulation and Frequency Response Service), Schedule 5 (Operating Reserves – Spinning) and Schedule 6 (Operating Reserves – Supplemental) of the PacifiCorp Open Access Transmission Tariff ("OATT"). The Settling Parties have also engaged in discussions regarding a proposal by PacifiCorp to submit a filing to the Commission pursuant to Section 205 of the Federal Power Act ("FPA") to amend rates, terms and conditions set out in Schedule 2 (Reactive Supply and Voltage Control) of the PacifiCorp OATT. The Settling Parties thereafter entered into a Settlement Discussion, Confidentiality and Non-Disclosure Agreement, whereby the parties

could engage in confidential negotiations pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, and Rule 408 of the Federal Rules of Evidence. As a result of these confidential settlement discussions, the Settling Parties have entered into this Settlement Agreement, which resolves issues regarding the rates, terms, and conditions of Schedules 2, 3, 3A, 5, and 6, Attachment U to the PacifiCorp OATT, and associated business practices without an extensive and resource-intensive Commission proceeding.

ARTICLE I

BACKGROUND

On October 28, 2016, in Docket No. ER17-219-000, PacifiCorp filed with the Commission tariff revisions to update its rates for Schedules 3, 3A, 5 and 6, and to clarify Schedule 11, Unauthorized Use of Transmission Service. Motions to intervene and protests were filed by several parties. On February 2, 2017, the Commission accepted PacifiCorp's proposed tariff revisions for filing, and, as relevant here, accepted the Schedule 11 revisions but established hearing and settlement judge procedures concerning the justness and reasonableness of PacifiCorp's proposed rates for Schedules 3, 3A, 5 and 6.[1] During the settlement judge procedures, PacifiCorp and the other active parties reached a settlement in the case, and PacifiCorp filed the settlement agreement with the Commission on January 31, 2018.[2] On April 19, 2018, the Commission approved the Docket No. ER17-219 Settlement Agreement.[3]

[1] *PacifiCorp*, 158 FERC ¶ 61,121 (2017).

[2] *PacifiCorp*, Offer of Settlement, Docket Nos. ER17-219, *et al.* (Jan. 31, 2018) ("Docket No. ER17-219 Settlement Agreement"). The parties to the ER17-219 Settlement included PacifiCorp, UAMPS, Deseret, UMPA, Bonneville, Avangrid, and NextEra Energy Resources, LLC.

[3] *PacifiCorp*, 163 FERC ¶ 61,035 (2018).

The Docket No. ER17-219 Settlement Agreement, which was uncontested, resolved all issues in that case. Article 4 of the Docket No. ER17-219 Settlement Agreement established black box rates for Schedules 3, 3A, 5, and 6 for two periods: July 13, 2017 through December 31, 2018, and then prospectively from January 1, 2018 (to recognize the decrease in the federal tax rate that became effective on that date). In addition, Article 6 of the Settlement Agreement provided for a moratorium period with respect to any further changes to ancillary service rates extending until June 30, 2020. Relevant here, Article 6.3 of the Docket No. ER17-219 Settlement Agreement required that PacifiCorp and stakeholders collaborate in good faith to develop a consensus regarding the methodology and associated data used to calculate the applicable regulation and operating reserves to be used in any future update of the Schedules 3 and 3A rates. The Settlement Agreement also provided that during the moratorium period, existing billing practices applicable to the affected ancillary services under the Legacy Customers' transmission service and operating agreements, as amended and restated (the "ARTSOAs"), would remain unchanged from existing practices.

Pursuant to the process described in Article 6.3 of the Docket No. ER17-219 Settlement Agreement, in December 2019, PacifiCorp began a stakeholder process in which all the Joint Customers participated. The collaborative process addressed updated revenue requirements and rates, as well as self-supply options, proposed by PacifiCorp for Schedules 3 and 3A, 5 and 6 of the PacifiCorp OATT. During the collaborative process, PacifiCorp added to the discussion proposed changes to the rates contained in Schedule 2 of the OATT, informing the Joint Customers that a Section 205 rate filing proposing new Schedule 2 rates was forthcoming. The Settling Parties entered into the Settlement Discussion, Confidentiality and Non-Disclosure Agreement, described above, and after extensive negotiations reached a settlement in principle on September 29, 2020, regarding certain rates, terms, and conditions of these ancillary services.

This Settlement Agreement shall be implemented through revisions to Schedules 2, 3/3A, 5 and 6 and Attachment U of PacifiCorp's OATT and through related modifications to PacifiCorp's business practices, including but not limited to PacifiCorp business practices 34, 39 and 63. It is acknowledged that PacifiCorp may seek to support the Settlement Agreement and business practice changes through certain cost support, including testimony and exhibits of PacifiCorp witnesses, that PacifiCorp may deem necessary to support this Settlement Agreement. This Settlement Agreement does not address the substance of, represent support for, or suggest agreement by the Joint Customers to such materials. This Settlement Agreement does, however, explicitly set out in Article VIII the process by which PacifiCorp will seek acceptance of the rates, terms and conditions set out in this Settlement Agreement, which are to be implemented through the ancillary service rate schedules, Attachment U and business practices attached as Exhibits hereto. This Settlement Agreement further provides that if the revised terms reflected in the ancillary service rate schedules and Attachment U are not accepted without condition or modification by the Commission, PacifiCorp shall withdraw its rate application without prejudice; provided, however, that if no party objects within fifteen days of the Commission's order directing such condition or modification, the conditioned or modified approval shall become effective.

The obligation imposed on PacifiCorp in Section 8.4 of this Settlement Agreement, requiring it to withdraw this filing without prejudice to making a new rate filing is of essential importance to protecting the Joint Customers' respective rights to protest any proposed rate, term or condition that differs from the rates, terms and conditions of the Settlement Agreement. This is because the Joint Customers have agreed not to protest PacifiCorp's filing to implement the Settlement Agreement. If the Commission does not accept PacifiCorp's filing related to the Settlement Agreement without condition or modification, the Settling Parties have agreed that

PacifiCorp shall withdraw its filing, without prejudice to PacifiCorp's right to make a new filing that may propose rates, terms or conditions that differ from those contemplated by the Settlement Agreement, and without prejudice to the rights of each Joint Customer under Section 205 of the FPA to protest or otherwise contest any such filing.

ARTICLE II

REVISED RATES, TERMS, AND CONDITIONS

FOR CERTAIN ANCILLARY SERVICES

2.1. Rates. Effective January 1, 2021, or the date specified by the Commission, the existing rates of Schedule 2, Schedule 3, Schedule 3A, Schedule 5 and Schedule 6 of PacifiCorp's OATT shall be superseded and replaced with the "Settlement Rates" shown in Table 1 below:

Table 1

Schedule	Settlement Rates
Schedule 2 (kW-year)	
Reactive	$1.603
Schedule 3 (per kW-year)	
Load	$1.3859
Schedule 3/3A (per kW-year)	
VERS Wind	$6.6922
VERS Wind – Committed Scheduling Discount	$6.2171
VERS Solar	$5.5836
VERS Solar - Committed Scheduling Discount	$5.1872
Non-VERS Non-Dispatchable	$3.1483
Schedule 5 (per MWh)	
Spinning Reserves	$0.1677
Schedule 6 (per MWh)	
Supplemental Reserves	$0.1677

2.2. Committed Scheduling Discount. PacifiCorp shall retain a committed scheduling rate that reflects a discount from the otherwise applicable rate (the "Committed Scheduling Discount") available to Variable Energy Resource- ("VER-") Wind and VER-solar customers pursuant to the terms and conditions of Schedules 3 and 3A of the OATT. The Committed Scheduling Discount is shown in Table 1 and reflects a 7.1% reduction from the otherwise applicable rate.

ARTICLE III

LEGACY AGREEMENTS

3.1 All billing for ancillary services under the Legacy Customers' respective ARTSOAs will continue pursuant to current practices as specified in sections 3.1.1 through 3.1.3 below.

3.1.1 In accordance with the Sixth ARTSOA between UMPA and PacifiCorp (the "UMPA ARTSOA"), PacifiCorp shall bill UMPA under Schedule 3/3A based only on its Aggregate Peak Demand ("APD"), as such term is defined in the UMPA ARTSOA, and shall not charge or seek to charge UMPA for generation at all under Schedule 3/3A or otherwise during the term of the ARTSOA Moratorium Period defined in Section 4.4. However, to the extent PacifiCorp seeks to charge UMPA for generation under Schedule 3/3A or otherwise in a rate filing after the ARTSOA Moratorium Period, PacifiCorp and UMPA each reserve their respective rights and positions regarding whether the UMPA ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UMPA's generation.

3.1.2 In accordance with the Seventh ARTSOA between Deseret and PacifiCorp (the "Deseret ARTSOA"), PacifiCorp shall bill Deseret under Schedule 3/3A based only on its

Aggregate Peak Demand plus the Deseret Area Load for which Deseret has the obligation to supply Regulation Reserve Service, and shall only charge or seek to charge Deseret under Schedule 3/3A for off-system sales associated with Deseret Resources, as all such terms are defined in the Deseret ARTSOA, during the term of the TSOA Moratorium Period defined in Section 4.4. However, to the extent PacifiCorp seeks to charge Deseret for generation under Schedule 3/3A or otherwise in a subsequent rate filing after the ARTSOA Moratorium Period, PacifiCorp and Deseret each reserve their respective rights and positions regarding whether the Deseret ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to Deseret's generation.

3.1.3 In accordance with the Fifth ARTSOA between UAMPS and PacifiCorp (the "UAMPS ARTSOA"), PacifiCorp shall bill UAMPS under Schedule 3/3A based only on its Monthly Coincident Peak Demand as such term is defined in the UAMPS ARTSOA and shall not charge or seek to charge UAMPS for generation under Schedule 3/3A or otherwise during the term of the TSOA Moratorium Period defined in Section 4.4. However, to the extent PacifiCorp seeks to charge UAMPS for generation under Schedule 3/3A or otherwise in a subsequent rate filing after the ARTSOA Moratorium Period, PacifiCorp and UAMPS each reserve their respective rights and positions regarding whether the UAMPS ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UAMPS' generation.

ARTICLE IV

MORATORIA

4.1 Except as specifically provided in Sections 4.5, 4.6, and 4.7 below, no Settling Party shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedules 2, 3, 3A, 5 and/or 6 or Attachment U, or seek any change to PacifiCorp's business practices under or applicable to the same, including but not limited to PacifiCorp business practices 39 and 63, that differ from those provided in this Settlement Agreement and propose an effective date prior to January 1, 2023 (the "Rate Schedule Moratorium Period").

4.2 Upon expiration of the Rate Schedule Moratorium Period: (a) PacifiCorp may make a Section 205 filing with the Commission that updates Schedules 2, 3, 3A, 5, and/or 6 and/or Attachment U; and (b) any Joint Customer may file a complaint regarding Schedules 2, 3, 3A, 5 and/or 6 and/or Attachment U pursuant to Section 206 of the FPA. Each Settling Party reserves their respective rights under the FPA to protest or otherwise contest any such filing.

4.3 PacifiCorp is currently contesting an application by Airport Solar, LLC ("Airport Solar") for a proposed rate schedule for Reactive Supply and Voltage Control from Generation Sources Services in FERC Docket No. ER20-2528. During the Rate Schedule Moratorium Period, PacifiCorp shall not seek to recover or pass-through costs it may incur as a result of Airport Solar's application or revenue requirement. Similarly, during the Rate Schedule Moratorium Period, PacifiCorp shall neither propose to recover nor pass through any costs it may incur as a result of any other generator that receives a FERC-approved Schedule 2 rate, including any resulting revenue requirement, nor shall PacifiCorp, after the expiration of the Rate Schedule Moratorium Period, seek to recover any such costs incurred during the Rate Schedule Moratorium Period (including any such costs incurred as a result of Airport Solar's or any other generator's application or revenue requirement). Finally, none of the Joint Customers

shall make a filing with FERC seeking compensation from PacifiCorp pursuant to a Schedule 2 rate for reactive power during the Rate Schedule Moratorium Period. Consistent with Section 4.2 above, nothing in this Settlement Agreement prohibits PacifiCorp from making a section 205 filing with the Commission, after the expiration of the Rate Schedule Moratorium Period, seeking to recover or pass-through prospectively costs that PacifiCorp incurs after the Rate Schedule Moratorium Period as a result of Airport Solar's Schedule 2 charges or any other resource that has a Schedule 2 rate on file with the Commission, and each Joint Customer expressly reserves its rights to challenge any such recovery or pass-through.

4.4 PacifiCorp shall not file any proposed change to the ARTSOA billing provisions or practices referenced in Article III with an effective date prior to December 1, 2025 (the "ARTSOA Moratorium Period"). Upon expiration of the ARTSOA Moratorium Period: (a) PacifiCorp may make a Section 205 filing at FERC to propose changes to the ARTSOA provisions or practices referenced in Article III, and (b) the Joint Customers may file a complaint regarding the ARTSOAs pursuant to Section 206 of the FPA related to those same provisions. Each Joint Customer and PacifiCorp reserve their respective rights to protest or otherwise contest a filing made by the other.

4.5 The Rate Schedule Moratorium Period shall not preclude PacifiCorp from proposing tariff or business practice changes that PacifiCorp believes are needed to accommodate and implement the Extended Day-Ahead Market ("EDAM") currently being developed by the California Independent System Operator ("CAISO"). Each Joint Customer reserves its rights to protest or otherwise challenge any such filing.

4.6 The Rate Schedule Moratorium does not preclude PacifiCorp from proposing a reduction in the rate set forth in the Schedule 2 attached to this Settlement Agreement. PacifiCorp shall provide notice to each Joint Customer of any proposal to modify the Schedule 2

rate schedule at least thirty (30) days in advance of any Section 205 filing. Each Joint Customer reserves its rights under the FPA to protest or otherwise challenge any such filing.

4.7 The parties will negotiate in good faith to attempt to reach agreement on self-supply arrangements relating to jointly owned units. PacifiCorp agrees to continue to allow UAMPS, UMPA, and Deseret to self-supply from jointly owned units without performance evaluations through October 1, 2021 to allow the parties to work toward mutual agreement on self-supply arrangements specific to jointly owned units. If the parties succeed in agreeing on an approach, the parties will agree to an implementation date that provides a reasonable amount of time to ready their systems for compliance with any agreed-upon approach. If mutual agreement is not reached by September 1, 2021, PacifiCorp and each Legacy Customer may thereafter make a unilateral filing with FERC pursuant to Sections 205 and 206 of the FPA, respectively.

ARTICLE V

NON-VER PARTICIPATING RESOURCES

5.1 The Settling Parties have reached the following understandings regarding certain aspects of the treatment of Non-VER resources under Schedules 3 and 3A of the OATT. A Non-VER Participating Resource in the Energy Imbalance Market ("EIM") qualifies as a dispatchable Non-VER resource. Additionally, Non-VER resources dispatchable by PacifiCorp qualify as dispatchable Non-VERS. PacifiCorp will not charge Non-VER Participating Resources or Non-VER resources dispatchable by PacifiCorp for Schedules 3 and 3A services. PacifiCorp shall consider, on a good faith basis, requests by customers to identify a resource that should qualify as a dispatchable Non-VER in this context due to its ability to follow PacifiCorp instructions, notwithstanding the fact that the resource is not directly dispatchable by PacifiCorp.

ARTICLE VI

SELF-SUPPLY

6.1 PacifiCorp shall reasonably and in good faith consider for acceptance customer requests for self-supply, third party supply and/or pooling agreements among customers under Schedules 3, 3A, 5 and 6 of its OATT on a case-by-case and non-discriminatory basis.

ARTICLE VII

EDAM COLLABORATION

7.1 Implementation of the proposed EDAM– should such a market be developed and filed with the Commission – may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedules 3, 3A, 5 and 6 and Attachment U. Joint Customers and PacifiCorp agree to engage in good faith discussions regarding potential changes to PacifiCorp's OATT and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with the Joint Customers in good faith; (2) state to CAISO that it supports direct access to CAISO by the Joint Customers in connection with that collaboration; (3) request that CAISO provide such access; and (4) take no action to prevent, inhibit or limit such direct access. The Joint Customers acknowledge that PacifiCorp cannot guarantee a particular "direct access" to CAISO for the Joint Customers.

ARTICLE VIII

FILING TO IMPLEMENT THIS SETTLEMENT AGREEMENT

8.1 The commitments set out in Articles II to VII of this Settlement Agreement are incorporated in the rate schedules, attachment and business practices attached as Exhibits A to G hereto. The rate schedules, attachment and business practices are an integrated part of the

settlement package negotiated among the parties pursuant to the Settlement Discussion, Confidentiality and Non-Disclosure Agreement identified above. None of the terms of the Settlement Agreement are agreed to without each of the others. The various provisions of this Settlement Agreement are not severable.

8.2 Promptly after execution of this Settlement Agreement, PacifiCorp shall file revisions to its OATT to implement this Settlement Agreement, including exhibits, pursuant to Section 205 of the FPA and shall request an effective date of January 1, 2021 for the revisions to Schedules 2, 3, 3A, 5 and 6, and an effective date of July 1, 2021 for the revisions to Attachment U. The Section 205 filing will request that the Commission accept the revisions to Schedules 2, 3, 3A, 5 and 6 and Attachment U of the PacifiCorp OATT that implement this Settlement Agreement without condition or modification. By signing this Settlement Agreement, the Settling Parties confirm support for its terms, including but not limited to, the requested effective date and any requests for waivers of FERC regulations to allow the effective dates. A Settling Party may intervene and participate in any proceeding before the Commission on or affecting the Section 205 filing but must do so consistent with the substantive terms set out in this Settlement Agreement.

8.3 The Joint Customers acknowledge that with its Section 205 filing to implement this Settlement Agreement and associated rate schedules and business practices attached hereto, PacifiCorp will provide testimony, certain "base case" documents, and other cost support materials that were previously prepared by PacifiCorp and discussed during the negotiations that resulted in this Settlement Agreement. Consistent with Sections 9.3 and 9.4 below, nothing in this Settlement Agreement represents an acceptance, endorsement, or agreement by any of the Joint Customers of or to statements contained in testimony or the methodologies, assumptions, calculations, or results of PacifiCorp's "base case" documents or other cost support. In its filing to implement this

Settlement Agreement and associated rate schedules, attachment and business practices attached hereto, PacifiCorp shall not propose or otherwise seek acceptance under Section 205 of the FPA of rates higher than those stated in this Settlement Agreement, or terms and conditions of service different from those specified under this Settlement Agreement.

8.4 This Settlement Agreement and the OATT and business practice revisions described herein shall become effective on the date specified by the Commission in an order that accepts the OATT revisions for filing without condition or modification, or, if such sections are approved with condition or modification, if no Settling Party files notice with the Commission, within fifteen (15) days of the Commission's order on the Section 205 Filing, stating that it objects to such conditions or modifications.

8.5 If any Settling Party files notice of its unwillingness to accept any condition or modification imposed by the Commission, and unless the Settling Parties otherwise agree in writing, then the rates, terms and conditions of this Settlement Agreement shall be null and void and PacifiCorp shall within ten (10) business days make the appropriate filings with the Commission to withdraw the filing from further consideration before the Commission, without prejudice to refiling. Each Settling Party specifically reserves its right(s) under the FPA to protest and otherwise contest the methodologies, approaches, or results of PacifiCorp's "base case" filing or related cost support or materials if such materials are presented in a subsequent filing with the Commission.

ARTICLE IX

MISCELLANEOUS

9.1 It is agreed by all Settling Parties that until this Settlement Agreement is submitted with PacifiCorp's filing as described in section 8.1, this Settlement Agreement shall be

privileged and shall not be admissible in evidence or made a part of the record in any proceeding, consistent with the terms set out in the Settlement Discussion, Confidentiality and Non-Disclosure Agreement.

9.2 It is specifically understood and agreed that this Settlement Agreement represents a "black box" negotiated settlement in the public interest with respect to the matters agreed to herein for the sole purpose of the settlement of such matters agreed to herein, and the Settling Parties shall not be prejudiced or bound thereby in any separate proceeding, except as specifically provided herein. The Settling Parties shall not be deemed to have approved, accepted, agreed or consented to any concept, theory or principle underlying or supposed to underlie any of the matters provided for herein. Further, this Settlement Agreement cannot be used, and no part hereof shall be used, to advance or support a position taken before the Commission or the courts by any party to this proceeding except to enforce the Settlement Agreement. Nothing in this Settlement Agreement shall be deemed a "settled practice" as interpreted by the court in *Pub. Serv. Comm'n of N.Y. v. FERC*, 645 F.2d 1335 (D.C. Cir. 1980).

9.3 This Settlement Agreement, together with all Exhibits hereto, constitutes the full and complete agreement of the Settling Parties with respect to the subject matter hereof and supersedes all prior negotiations, understandings, and agreements, whether written or oral, between the Settling Parties with respect to the subject matter thereof, and there are no warranties or representations among the Parties in connection with the subject matter hereof except as set forth specifically herein.

9.4 The titles and headings of the various Articles of this Settlement Agreement are for reference and convenience purposes only and are not to be construed or taken into account in interpreting the Settlement Agreement and do not qualify, modify, or explain the effects of the Settlement Agreement.

9.5 Each person executing this Settlement Agreement represents and warrants that he or she is duly authorized and empowered to act on behalf of, and to sign for, the party for whom he or she has signed.

9.6 This Settlement Agreement is binding upon and for the benefit of the Settling Parties and their successors and assigns.

9.7 This Settlement Agreement may be executed in any number of counterparts, each of which shall constitute an original and all of which together shall constitute one and the same Settlement.

[SIGNATURES ON NEXT PAGE]

PACIFICORP

By: Mary Wieneke

Title: VP, market + transmission policy

Date: 1/20/2021

UTAH ASSOCIATED MUNICIPAL POWER SYSTEMS

By:

Title: Chief Operations Officer

Date: January 29, 2021

UTAH MUNICIPAL POWER AGENCY

By:

Title: President & CEO

Date: January 26, 2021

DESERET GENERATION AND TRANSMISSION CO-OPERATIVE, INC.

By: Clay MacArthur

Digitally signed by Clay MacArthur
Date: 2021.01.26 13:16:28 -07'00'

Title: VP, Power Marketing

Date: January 26, 2021

BONNEVILLE POWER ADMINISTRATION

By: Digitally signed by KIM THOMPSON
Date: 2021.01.25 08:35:09 -08'00'

Title: Vice President, NW Requirements Marketing

Date:

DocuSign Envelope ID: C86DD803-A912-4108-A230-6F10DE6F13BF

AVANGRID RENEWABLES, LLC

By: DocuSigned by: Jorge Pedroza 4FD673E1F6A6401...

Title: Authorized Representative

Date: 1/26/2021

DS JH

DocuSigned by: Jose Diaz 5C499CD70B9E4C9...

Authorized Representative

1/27/2021

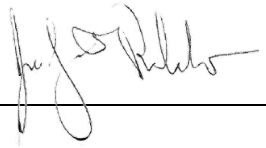
EDP RENEWABLES NORTH AMERICA LLC

By: DocuSigned by: 9D5B9C9DDAA0452... DS KS

Title: Steve Irvin

Date: Executive Vice President, Western and Central Regions & Mexico

NEXTERA ENERGY MARKETING, LLC

By: 

Title: Vice President

Date: January 25, 2021

EXHIBIT A

CLEAN AND MARKED VERSIONS OF PACIFICORP OPEN ACCESS TRANSMISSION TARIFF SCHEDULE 2

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator subject to any credits provided pursuant to applicable PacifiCorp business practices. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

Transmission Customers Obligated to acquire Reactive Supply and Voltage Control from Generation Sources Service: All Transmission Customers purchasing Long-Term Firm Point-to-Point Transmission Service, Short-Term Firm Point-to-Point Transmission Service, Non-Firm Point-to-Point Transmission Service, or Network Integration Transmission Service from the Transmission Provider shall be required to acquire Reactive Supply and Voltage Control from Generation Sources Service from the Transmission Provider.

Charge for Reactive Supply and Voltage Control from Generation Sources Service: For Point-To-Point Transmission Service, the rate shall be applied to the Transmission Customer's Reserved Capacity. For purposes of charging the rates set forth in this Schedule 2 to Transmission Customers purchasing Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff. For Network Integration Transmission Service, the rate shall be applied to the Transmission Customer's Monthly Network Load.

1.	Yearly Rate	$1.603/kW/Year
2.	Monthly Rate	$0.134/kW/Month
3.	Weekly Rate	$0.031/kW/Week
4.	Daily Rate	$0.004/kW/Day
5.	Hourly Rate	$0.183/MWh

The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 2 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 2 times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Rate Schedule Moratorium Period:

The rates and charges under this Schedule 2 cannot be changed with any effective date prior to January 1, 2023 unless the Transmission Provider proposes a reduction in the rates or charges under this Schedule 2. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 2 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

In addition, during this rate schedule moratorium period, the Transmission Provider will not propose to recover or pass-through any costs, including those in Docket No. ER20-2528, it

may incur as a result of any generator that receives a FERC approved Schedule 2 rate, including any resulting revenue requirement. Following this rate schedule moratorium period, the Transmission Provider shall not propose to recover or pass-through any such reactive power costs it incurs during the rate schedule moratorium period. None of the parties to the settlement agreement included with the filing in Docket No. [*TBD*] shall make a filing with FERC seeking compensation from the Transmission Provider pursuant to a Schedule 2 rate for reactive power during this rate schedule moratorium period. After the expiration of this rate schedule moratorium period, the Transmission Provider is not prohibited from seeking authorization to recover or pass-through future costs that the Transmission Provider incurs after this rate schedule moratorium period as a result of a Schedule 2 rate filed by a third party with the Commission.

Reactive Supply and Voltage Control from Generation Sources Service to be Provided: The Transmission Provider shall ensure that generation interconnected with its Transmission System meets the voltage support and reactive control requirements of the Western Electricity Coordinating Council.

SCHEDULE 2

Reactive Supply and Voltage Control from Generation or Other Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities and non-generation resources capable of providing this service that are under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation or Other Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation or Other Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation or Other Sources Service is to be provided directly by the Transmission Provider (if the Transmission Provider is the Control Area operator) or indirectly by the Transmission Provider making arrangements with the Control Area operator that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the Control Area operator subject to any credits provided pursuant to applicable PacifiCorp business practices. The charges for such service will be based on the rates set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by the Control Area operator.

Transmission Customers Obligated to acquire Reactive Supply and Voltage Control from Generation Sources Service: All Transmission Customers purchasing Long-Term Firm Point-to-Point Transmission Service, Short-Term Firm Point-to-Point Transmission Service, Non-Firm Point-to-Point Transmission Service, or Network Integration Transmission Service from the Transmission Provider shall be required to acquire Reactive Supply and Voltage Control from Generation Sources Service from the Transmission Provider.

Charge for Reactive Supply and Voltage Control from Generation Sources Service: For Point-To-Point Transmission Service, the rate shall be applied to the Transmission Customer's Reserved Capacity. For purposes of charging the rates set forth in this Schedule 2 to Transmission Customers purchasing Point-to-Point Transmission Service, the billing determinants shall be the amount at system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff. For Network Integration Transmission Service, the rate shall be applied to the Transmission Customer's Monthly Network Load.

1.	Yearly Rate	$~~0.55~~1.603/kW/Year
2.	Monthly Rate	$0.~~046~~134/kW/Month
3.	Weekly Rate	$0.~~011~~031/kW/Week
4.	Daily Rate	$0.~~001~~004/kW/Day
5.	Hourly Rate	$0.~~063~~183/MWh

The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 2 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 2 times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Rate Schedule Moratorium Period:

The rates and charges under this Schedule 2 cannot be changed with any effective date prior to January 1, 2023 unless the Transmission Provider proposes a reduction in the rates or charges under this Schedule 2. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 2 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

In addition, during this rate schedule moratorium period, the Transmission Provider will not propose to recover or pass-through any costs, including those in Docket No. ER20-2528, it

may incur as a result of any generator that receives a FERC approved Schedule 2 rate, including any resulting revenue requirement. Following this rate schedule moratorium period, the Transmission Provider shall not propose to recover or pass-through any such reactive power costs it incurs during the rate schedule moratorium period. None of the parties to the settlement agreement included with the filing in Docket No. [*TBD*] shall make a filing with FERC seeking compensation from the Transmission Provider pursuant to a Schedule 2 rate for reactive power during this rate schedule moratorium period. After the expiration of this rate schedule moratorium period, the Transmission Provider is not prohibited from seeking authorization to recover or pass-through future costs that the Transmission Provider incurs after this rate schedule moratorium period as a result of a Schedule 2 rate filed by a third party with the Commission.

Reactive Supply and Voltage Control from Generation Sources Service to be Provided: The Transmission Provider shall ensure that generation interconnected with its Transmission System meets the voltage support and reactive control requirements of the Western Electricity Coordinating Council.

EXHIBIT B

CLEAN AND MARKED VERSIONS OF PACIFICORP OPEN ACCESS TRANSMISSION TARIFF SCHEDULE 3

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the BA that performs this function for the Transmission Provider).

The Transmission Provider must offer this service when the Transmission Service is used to serve load within its BAA. The Transmission Customer must purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation as further described in applicable PacifiCorp business practices. The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements.

For purposes of serving load under this schedule, the amount of and charges for Regulation and Frequency Response Service are differentiated by load, Variable Energy Resources (VERs), and resources that are not VERs (Non-VERs). The Transmission Customer shall pay a total Regulation and Frequency Response Service charge under this tariff equal to the sum of the charges applicable to the customer’s load, VERs, and Non-VERs, as set forth below. To the extent the BA performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA.

Charge for Regulation and Frequency Response Service:

The load charges below apply to all load served by Network Integration Transmission Service or by Point-To-Point Transmission Service. Firm imports do not reduce the load obligation.

The rates below are applied to the Transmission Customer's Monthly Network Load for Network Integration Transmission Service or to the load served by Point-To-Point Transmission Service.

Load

1. Yearly Rate		$1.3859 per kW-Year
2. Monthly Rate		$0.1155 per kW-Month

The charges below apply to all generators serving Network Load and are differentiated by the type of resources (VERs or Non-VERs) serving that load. The Transmission Provider shall charge the Transmission Customer the monthly rate times the lesser of the nameplate capacity of the generator, the capacity in a MOD-25 report, or the interconnection capacity of the resource set forth in an Interconnection Agreement.

Each year by December 1, the Transmission Customer shall provide to the Transmission Provider an attestation of the nameplate capacity, the interconnection capacity set forth in an Interconnection Agreement, or the capacity shown in a MOD-25 report for each VER and Non-VER resource owned or controlled by the Transmission Customer and located within the BAA.

VERs (Solar)- Uncommitted Scheduling

1. Yearly Rate		$5.5836 per kW-Year
2. Monthly Rate		$0.4653 per kW-Month

VERs (Wind)- Uncommitted Scheduling

1. Yearly Rate		$6.6922 per kW-Year
2. Monthly Rate		$0.5577 per kW-Month

VERs - Committed Scheduling

To qualify for this committed scheduling rate for a month, the VER customer must: (i) provide notification to PacifiCorp in advance of the month that it intends to engage in Committed Scheduling; and (ii) during every hour of that month (except as specified below), a VER customer must utilize and submit into BSAP by 57 minutes prior to the operating hour (T-57), consistent with PacifiCorp's EIM Business Practice, hour-ahead base schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of no more than 72 minutes prior to the operating hour (T-72) without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule. In any calendar month for up to two operating hour intervals, a VER customer may utilize and submit into BSAP by T-57, hour-ahead schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of up to 90 minutes prior to the operating hour (T-90), without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule, and still be eligible for this rate. Use and submission into BSAP of hour-ahead schedules older than PacifiCorp's VER forecast vendor's forecast at T-90 in any hour during a calendar month will make a VER customer ineligible for this rate in that month. Upon notification by the PacifiCorp EIM Entity, the VER customer is required to submit a manual override or modification to the PacifiCorp VER forecast vendor's forecast to reflect a known or expected system constraint and ensure the submission of a balanced Base Schedule consistent with the requirements set forth in Attachment T.

VERs (Solar) - Committed Scheduling

1. Yearly Rate		$5.1872 per kW-Year
2. Monthly Rate		$0.4323 per kW-Month

VERs (Wind) - Committed Scheduling

1. Yearly Rate		$6.2171 per kW-Year
2. Monthly Rate		$0.5181 per kW-Month

Non-VERs

1. Yearly Rate		$3.1483 per kW-Year
2. Monthly Rate		$0.2624 per kW-Month

Rate Schedule Moratorium Period:

The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 3 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California Independent System Operator.[1] Each party to the Docket No. [TBD] Settlement Agreement reserves its rights to protest or otherwise challenge any such filing.

ARTSOA Moratorium Period:

The Amended and Restated Transmission Service and Operating Agreement ("ARTSOA") billing provisions referenced below shall not be changed with an effective date prior to December 1, 2025 (the "ARTSOA Moratorium Period"):

1. In accordance with the Sixth Amended and Restated Transmission Service and Operating Agreement between Utah Municipal Power Agency ("UMPA") and PacifiCorp (the "UMPA

[1] Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedules 3, 3A, 5 and 6. The parties to the Docket No. [TBD] Settlement Agreement agree to engage with PacifiCorp in good faith discussions regarding potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (4) take no action to prevent, inhibit or limit such direct access.

ARTSOA"), the Transmission Provider shall bill UMPA under Schedule 3/3A based only on its Aggregate Peak Demand ("APD"), as such term is defined in the UMPA ARTSOA, and shall not charge or seek to charge UMPA for generation at all under Schedule 3/3A or otherwise during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UMPA for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UMPA each reserve their respective rights and positions regarding whether the UMPA ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UMPA's generation.

2. In accordance with the Seventh Amended and Restated Transmission Service and Operating Agreement between Deseret Generation & Transmission Co-Operative, Inc. ("Deseret") and PacifiCorp (the "Deseret ARTSOA"), the Transmission Provider shall bill Deseret under Schedule 3/3A based only on its Aggregate Peak Demand plus the Deseret Area Load for which Deseret has the obligation to supply Regulation Reserve Service, and shall only charge or seek to charge Deseret under Schedule 3/3A for off-system sales associated with Deseret Resources, as all such terms are defined in the Deseret ARTSOA, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge Deseret for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and Deseret each reserve their respective rights and positions regarding whether the Deseret ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to Deseret's generation.

3. In accordance with the Fifth Amended and Restated Transmission Service and Operating Agreement between Utah Associated Municipal Power Systems ("UAMPS") and PacifiCorp (the "UAMPS ARTSOA"), the Transmission Provider shall bill UAMPS under Schedule 3/3A based only on its Monthly Coincident Peak Demand as such term is defined in the UAMPS ARTSOA, and shall not charge or seek to charge UAMPS for generation under Schedule 3/3A or otherwise, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UAMPS for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UAMPS each reserve their respective rights and positions regarding whether the UAMPS ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UAMPS' generation.

Self-Supply, Third-Party Supply and Pooling:

A Transmission Customer may choose to supply all or a portion of its Regulation and Frequency Response Service obligation through self-supply or third-party supply consistent with the requirements herein, Attachment U, and PacifiCorp's business practices. A Transmission Customer may request to supply all or a portion of its Regulation and Frequency Response Service through pooling agreement, which the Transmission Provider shall consider on a case-by-case and non-discriminatory basis.

For a Transmission Customer that chooses to supply its Regulation and Frequency Response Obligation through self-supply, third-party supply, or pooling agreements, the total charge for failure to supply its Regulation and Frequency Response Service obligation shall not exceed the Monthly Rate pursuant to this Schedule 3 times the highest amount in megawatts not covered under self-supply, third-party supply or pooling agreements.

Clarifications regarding Non-VER Participating Resources:

A Non-VER Participating Resource in the Energy Imbalance Market ("EIM") qualifies as a dispatchable Non-VER resource. Additionally, Non-VER resources dispatchable by the Transmission Provider qualify as dispatchable Non-VERS. The Transmission Provider will not charge Non-VER Participating Resources or Non-VER resources dispatchable by the Transmission Provider for Schedules 3 and 3A services. PacifiCorp shall consider, on a good faith basis, requests by customers to identify a resource that should qualify as a dispatchable Non-VER in this context due to its ability to follow PacifiCorp instructions, notwithstanding the fact that the resource is not directly dispatchable by PacifiCorp.

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) and by other non-generation resources capable of providing this service as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider (or the BA that performs this function for the Transmission Provider).

The Transmission Provider must offer this service when the Transmission Service is used to serve load within its BAA. The Transmission Customer must purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation as further described in applicable PacifiCorp business practices. The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements.

For purposes of serving load under this schedule, the amount of and charges for Regulation and Frequency Response Service are differentiated by load, Variable Energy Resources (VERs), and resources that are not VERs (Non-VERs). The Transmission Customer shall pay a total Regulation and Frequency Response Service charge under this tariff equal to the sum of the charges applicable to the customer’s load, VERs, and Non-VERs, as set forth below. To the extent the BA performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA.

Charge for Regulation and Frequency Response Service:

The load charges below apply to all load served by Network Integration Transmission Service or by Point-To-Point Transmission Service. Firm imports do not reduce the load obligation.

The rates below are applied to the Transmission Customer's Monthly Network Load for Network Integration Transmission Service or to the load served by Point-To-Point Transmission Service.

Load

	~~Effective rates July 13, 2017 through December 31, 2017~~	~~Effective rates beginning January 1, 2018~~
1. Yearly Rate	~~$2.25 per kW-Year~~	$~~2.124~~1.3859 per kW-Year
2. Monthly Rate	~~$0.188 per kW-Month~~	$0.~~177~~1155 per kW-Month

The charges below apply to all generators serving Network Load and are differentiated by the type of resources (VERs or Non-VERs) serving that load. The ~~applicable differentiated rate below is applied to customers by charging~~Transmission Provider shall charge the Transmission Customer the monthly rate times the lesser of the nameplate capacity of the generator, the capacity in a MOD-25 report, or the interconnection capacity of the resource set forth in an Interconnection Agreement.

Each year by December 1, the Transmission Customer shall provide to the Transmission Provider~~,~~ an attestation of the nameplate capacity~~ of VERs~~, the interconnection capacity set forth in an Interconnection Agreement, or the capacity shown in a MOD-25 report for each VER and Non-~~VERs~~VER resource owned or controlled by the Transmission Customer and located within the BAA.

VERs ~~-~~(Solar)~~-~~ Uncommitted Scheduling

~~Effective Rates from July 13, 2017 through December 31, 2017Effective Rates beginning January 1, 2018~~		

1. Yearly Rate	~~$6.984 per kW-Year~~	$~~6.593~~5.5836 per kW-Year
2. Monthly Rate	~~$0.582 per kW-Month~~	$0.~~5494~~4653 per kW-Month

VERs (Wind)- Uncommitted Scheduling

1. Yearly Rate		$6.6922 per kW-Year
2. Monthly Rate		$0.5577 per kW-Month

VERs - Committed Scheduling

To qualify for this committed scheduling rate for a month, the VER customer must: (i) provide notification to PacifiCorp in advance of the month that it intends to engage in Committed Scheduling; and (ii) during every hour of that month (except as specified below), a VER customer must utilize and submit into BSAP by 57 minutes prior to the operating hour (T-57), consistent with PacifiCorp's EIM Business Practice, hour-ahead base schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of no more than 72 minutes prior to the operating hour (T-72) without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule. In any calendar month for up to two operating hour intervals, a VER customer may utilize and submit into BSAP by T-57, hour-ahead schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of up to 90 minutes prior to the operating hour (T-90), without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule, and still be eligible for this rate. Use and submission into BSAP of hour-ahead schedules older than PacifiCorp's VER forecast vendor's forecast at T-90 in any hour during a calendar month will make a VER customer ineligible for this rate in that month. Upon notification by the PacifiCorp EIM Entity, the VER customer is required to submit a manual override or modification to the PacifiCorp VER forecast vendor's forecast to reflect a known or expected system constraint and ensure the submission of a balanced Base Schedule consistent with the requirements set forth in Attachment T.

VERs (Solar) - Committed Scheduling

~~Effective Rates from July 13, 2017 through December 31, 2017Effective~~		

~~Rates beginning January 1, 2018~~		
1. Yearly Rate	~~$5.965 per kW-Year~~	$5.~~631~~1872 per kW-Year
2. Monthly Rate	~~$0.497 per kW-Month~~	$0.~~4694~~4323 per kW-Month

VERs (Wind) - Committed Scheduling

1. Yearly Rate		$6.2171 per kW-Year
2. Monthly Rate		$0.5181 per kW-Month

Non-VERs

~~Effective Rates from July 13, 2017 through December 31, 2017Effective Rates beginning January 1, 2018~~		
1. Yearly Rate	~~$1.90 per kW-Year~~	$~~1.794~~3.1483 per kW-Year
2. Monthly Rate	~~$0.158 per kW-Month~~	$0.~~150~~2624 per kW-Month

Rate Schedule Moratorium Period:

The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 3 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are

needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California Independent System Operator.[1] Each party to the Docket No. [TBD] Settlement Agreement reserves its rights to protest or otherwise challenge any such filing.

ARTSOA Moratorium Period:

The Amended and Restated Transmission Service and Operating Agreement ("ARTSOA") billing provisions referenced below shall not be changed with an effective date prior to December 1, 2025 (the "ARTSOA Moratorium Period"):

1. In accordance with the Sixth Amended and Restated Transmission Service and Operating Agreement between Utah Municipal Power Agency ("UMPA") and PacifiCorp (the "UMPA ARTSOA"), the Transmission Provider shall bill UMPA under Schedule 3/3A based only on its Aggregate Peak Demand ("APD"), as such term is defined in the UMPA ARTSOA, and shall not charge or seek to charge UMPA for generation at all under Schedule 3/3A or otherwise during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UMPA for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UMPA each reserve their respective rights and positions regarding whether the UMPA ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UMPA's generation.

2. In accordance with the Seventh Amended and Restated Transmission Service and Operating Agreement between Deseret Generation & Transmission Co-Operative, Inc. ("Deseret") and PacifiCorp (the "Deseret ARTSOA"), the Transmission Provider shall bill Deseret under Schedule 3/3A based only on its Aggregate Peak Demand plus the Deseret Area Load for which Deseret has the obligation to supply Regulation Reserve Service, and shall only charge or seek to charge Deseret under Schedule

[1] Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedules 3, 3A, 5 and 6. The parties to the Docket No. [TBD] Settlement Agreement agree to engage with PacifiCorp in good faith discussions regarding potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (4) take no action to prevent, inhibit or limit such direct access.

3/3A for off-system sales associated with Deseret Resources, as all such terms are defined in the Deseret ARTSOA, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge Deseret for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and Deseret each reserve their respective rights and positions regarding whether the Deseret ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to Deseret's generation.

3. In accordance with the Fifth Amended and Restated Transmission Service and Operating Agreement between Utah Associated Municipal Power Systems ("UAMPS") and PacifiCorp (the "UAMPS ARTSOA"), the Transmission Provider shall bill UAMPS under Schedule 3/3A based only on its Monthly Coincident Peak Demand as such term is defined in the UAMPS ARTSOA, and shall not charge or seek to charge UAMPS for generation under Schedule 3/3A or otherwise, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UAMPS for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UAMPS each reserve their respective rights and positions regarding whether the UAMPS ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UAMPS' generation.

Self-Supply, Third-Party Supply and Pooling:

A ~~Network~~Transmission Customer may choose to ~~self-~~supply all or a portion of its Regulation and Frequency Response Service obligation through self-supply or third-party supply consistent with the requirements herein, Attachment U, and PacifiCorp's business practices. A Transmission Customer may request to supply all or a portion of its Regulation and ~~consistent with~~Frequency Response Service through pooling agreement, which the ~~settlement in Docket Nos. ER17-219~~Transmission Provider shall consider on a case-by-case and ~~EL17-27~~non-discriminatory basis.

~~The total charge for failure to self-supply~~For a Transmission Customer that chooses to supply its Regulation and Frequency Response Obligation through self-supply, third-party supply, or pooling agreements, the total charge for failure to supply its Regulation and Frequency Response Service obligation shall not exceed the Monthly Rate pursuant to this Schedule 3 times the highest amount in megawatts not covered under self-supply, third-party supply or pooling agreements.

Clarifications regarding Non-VER Participating Resources:

A Non-VER Participating Resource in the Energy Imbalance Market ("EIM") qualifies as a dispatchable Non-VER resource. Additionally, Non-VER resources dispatchable by the Transmission Provider qualify as dispatchable Non-VERS. The Transmission Provider will not charge Non-VER Participating Resources or Non-VER resources dispatchable by the Transmission Provider for Schedules 3 and 3A services. PacifiCorp shall consider, on a good faith basis, requests by customers to identify a resource that should qualify as a dispatchable Non-VER in this context due to its ability to follow PacifiCorp instructions, notwithstanding the fact that the resource is not directly dispatchable by PacifiCorp.

EXHIBIT C

CLEAN AND MARKED VERSIONS OF PACIFICORP OPEN ACCESS TRANSMISSION TARIFF SCHEDULE 3A

SCHEDULE 3A

Generator Regulation and Frequency Response Service

Generator Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Generator Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes for a generator located within the BAA. The obligation to maintain this balance between resources and the generator's schedule lies with the Transmission Provider (or the BAA that performs this function for the Transmission Provider).

The Transmission Provider must offer this service when transmission service is provided for a generator physically or electrically located in the Transmission Provider's BAA. Generator Regulation and Frequency Response Service applies to the extent that a Transmission Customer is not already subject to Regulation and Frequency Response Service provided under Schedule 3. When applicable, the Transmission Customer must purchase Generator Regulation and Frequency Response Service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements, as further described in applicable PacifiCorp business practices which may include self-supplying regulation reserve capacity from generation or non-generation resources or through dynamically scheduling its generation to another BAA. The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Generator Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements.

For purposes of exports or Third-Party Sales, the amount of and charges for Generator Regulation and Frequency Response Service are differentiated by the type of exporting resource (Variable Energy Resources (VERs) or resources that are not VERs (Non-VERs)) and are set forth below. To the extent a BA performs this service for the Transmission Provider, charges to

the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA. The Transmission Provider may not charge a Transmission Customer for regulation reserves under both Schedule 3 and Schedule 3A for the same transaction.

Charge for Generator Regulation and Frequency Response Service:

The charges below apply to generation that originates in the PacifiCorp BAA and terminates in another BAA or for any resource not designated as a Network Resource. The Transmission Provider shall charge the Transmission Customer the monthly rate times the lesser of the nameplate capacity of the generator, the capacity in a MOD-25 report, or the interconnection capacity of the resource set forth in an Interconnection Agreement

Each year by December 1, the Transmission Customer shall provide to the Transmission Provider attestation of the nameplate capacity, the interconnection capacity set forth in an Interconnection Agreement, or the capacity shown in a MOD-25 report for each VER and Non-VER resource owned or controlled by the Transmission Customer and located within the BAA.

VERs (Solar) - Uncommitted Scheduling

1. Yearly Rate		$5.5836 per kW-Year
2. Monthly Rate		$0.4653 per kW-Month

VERs (Wind) - Uncommitted Scheduling

1. Yearly Rate		$6.6922 per kW-Year
2. Monthly Rate		$0.5577 per kW-Month

VERs - Committed Scheduling

To qualify for this committed scheduling rate for a month, the VER customer must: (i) provide notification to PacifiCorp in advance of the month that it intends to engage in Committed Scheduling; and (ii) during every hour of that month (except as specified below), a VER customer must utilize and submit into BSAP by 57 minutes prior to the operating hour (T-57), consistent with PacifiCorp's EIM Business Practice, hour-ahead base schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of no more than 72 minutes prior to the

operating hour (T-72) without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule. In any calendar month for up to two operating hour intervals, a VER customer may utilize and submit into BSAP by T-57, hour-ahead schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of up to 90 minutes prior to the operating hour (T-90), without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule, and still be eligible for this rate. Use and submission into BSAP of hour-ahead schedules older than PacifiCorp's VER forecast vendor's forecast at T-90 in any hour during a calendar month will make a VER customer ineligible for this rate in that month. Upon notification by the PacifiCorp EIM Entity, the VER customer is required to submit a manual override or modification to the PacifiCorp VER forecast vendor's forecast to reflect a known or expected system constraint and ensure the submission of a balanced Base Schedule consistent with the requirements set forth in Attachment T.

VERs (Solar) – Committed Scheduling

1. Yearly Rate		$5.1872 per kW-Year
2. Monthly Rate		$0.4323 per kW-Month

VERs (Wind) – Committed Scheduling

1. Yearly Rate		$6.2171 per kW-Year
2. Monthly Rate		$0.5181 per kW-Month

Non-VERs - Committed Scheduling

1. Yearly Rate		$3.1483 per kW-Year
2. Monthly Rate		$0.2624 per kW-Month

Rate Schedule Moratorium Period:

The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 3A as provided in the Docket No. [TBD] Settlement

Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California Independent System Operator.[1] Each party to the Docket No. [TBD] Settlement Agreement reserves its rights to protest or otherwise challenge any such filing.

ARTSOA Moratorium Period:

The Amended and Restated Transmission Service and Operating Agreement ("ARTSOA") billing provisions referenced below shall not be changed with an effective date prior to December 1, 2025 (the "ARTSOA Moratorium Period"):

1. In accordance with the Sixth Amended and Restated Transmission Service and Operating Agreement between Utah Municipal Power Agency ("UMPA") and PacifiCorp (the "UMPA ARTSOA"), the Transmission Provider shall bill UMPA under Schedule 3/3A based only on its Aggregate Peak Demand ("APD"), as such term is defined in the UMPA ARTSOA, and shall not charge or seek to charge UMPA for generation at all under Schedule 3/3A or otherwise during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UMPA for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UMPA each reserve their respective rights and positions regarding whether the UMPA ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UMPA's generation.

2. In accordance with the Seventh Amended and Restated

[1] Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedules 3, 3A, 5 and 6. The parties to the Docket No. [TBD] Settlement Agreement agree to engage with PacifiCorp in good faith on potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (3) take no action to prevent, inhibit or limit such direct access.

Transmission Service and Operating Agreement between Deseret Generation & Transmission Co-Operative, Inc. ("Deseret") and PacifiCorp (the "Deseret ARTSOA"), the Transmission Provider shall bill Deseret under Schedule 3/3A based only on its Aggregate Peak Demand plus the Deseret Area Load for which Deseret has the obligation to supply Regulation Reserve Service, and shall only charge or seek to charge Deseret under Schedule 3/3A for off-system sales associated with Deseret Resources, as all such terms are defined in the Deseret ARTSOA, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge Deseret for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and Deseret each reserve their respective rights and positions regarding whether the Deseret ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to Deseret's generation.

3. In accordance with the Fifth Amended and Restated Transmission Service and Operating Agreement between Utah Associated Municipal Power Systems ("UAMPS") and PacifiCorp (the "UAMPS ARTSOA"), the Transmission Provider shall bill UAMPS under Schedules 3 and 3A based only on its Monthly Coincident Peak Demand as such term is defined in the UAMPS ARTSOA, and shall not charge or seek to charge UAMPS for generation under Schedule 3/3A or otherwise, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UAMPS for generation under Schedules 3 and 3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UAMPS each reserve their respective rights and positions regarding whether the UAMPS ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UAMPS' generation.

Self-Supply, Third-Party Supply and Pooling:

A Transmission Customer may choose to supply all or a portion of its Generator Regulation and Frequency Response Service obligation through self-supply or third-party supply consistent with the requirements herein, Attachment U, and PacifiCorp's business practices. A Transmission Customer may request to supply all or a portion of its Generator Regulation and Frequency Response Service obligation through pooling agreements, which the Transmission Provider shall consider on a case-by-case and non-discriminatory basis.

For a Transmission Customer that chooses to supply its Generator Regulation and Frequency Response Service obligation

through self-supply, third-party supply, or pooling agreements, the total charge for failure to supply its Generator Regulation and Frequency Response Service obligation shall not exceed the Monthly Rate pursuant to this Schedule 3A times the highest amount in megawatts not covered under self-supply, third-party supply or pooling agreements.

Clarifications regarding Non-VER Participating Resources:

A Non-VER Participating Resource in the Energy Imbalance Market ("EIM") qualifies as a dispatchable Non-VER resource. Additionally, Non-VER resources dispatchable by the Transmission Provider qualify as dispatchable Non-VERS. The Transmission Provider will not charge Non-VER Participating Resources or Non-VER resources dispatchable by PacifiCorp for Schedules 3 and 3A services. PacifiCorp shall consider, on a good faith basis, requests by customers to identify a resource that should qualify as a dispatchable Non-VER in this context due to its ability to follow PacifiCorp instructions, notwithstanding the fact that the resource is not directly dispatchable by PacifiCorp.

SCHEDULE 3A

Generator Regulation and Frequency Response Service

Generator Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Generator Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes for a generator located within the BAA. The obligation to maintain this balance between resources and the generator's schedule lies with the Transmission Provider (or the BAA that performs this function for the Transmission Provider).

The Transmission Provider must offer this service when transmission service is provided for a generator physically or electrically located in the Transmission Provider's BAA. Generator Regulation and Frequency Response Service applies to the extent that a Transmission Customer is not already subject to Regulation and Frequency Response Service provided under Schedule 3. When applicable, the Transmission Customer must purchase Generator Regulation and Frequency Response Service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements, as further described in applicable PacifiCorp business practices which may include self-supplying regulation reserve capacity from generation or non-generation resources or through dynamically scheduling its generation to another BAA. The Transmission Provider will take into account the speed and accuracy of regulation resources in its determination of Generator Regulation and Frequency Response reserve requirements, including as it reviews whether a self-supplying Transmission Customer has made alternative comparable arrangements. Upon request by the self-supplying Transmission Customer, the Transmission Provider will share with the Transmission Customer its reasoning and any related data used to make the determination of whether the Transmission Customer has made alternative comparable arrangements.

For purposes of exports or Third-Party Sales, the amount of and charges for Generator Regulation and Frequency Response Service are differentiated by the type of exporting resource (Variable Energy Resources (VERs) or resources that are not VERs (Non-VERs)) and are set forth below. To the extent a BA performs this service for the Transmission Provider, charges to

the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA. The Transmission Provider may not charge a Transmission Customer for regulation reserves under both Schedule 3 and Schedule 3A for the same transaction.

Charge for Generator Regulation and Frequency Response Service:

The charges below apply to generation that originates in the PacifiCorp BAA and terminates in another BAA or for any resource not designated as a Network Resource. The ~~applicable differentiated rate below is applied to customers by charging~~Transmission Provider shall charge the Transmission Customer the monthly rate times the lesser of the nameplate capacity of the generator~~.~~, the capacity in a MOD-25 report, or the interconnection capacity of the resource set forth in an Interconnection Agreement

Each year by December 1, the Transmission Customer shall provide to the Transmission Provider~~,~~ attestation of the nameplate capacity~~ of VERs~~, the interconnection capacity set forth in an Interconnection Agreement, or the capacity shown in a MOD-25 report for each VER and Non-~~VERs~~VER resource owned or controlled by the Transmission Customer and located within the BAA.

VERs (Solar) - Uncommitted Scheduling

	~~Effective Rates from July 13, 2017 through December 31, 2017~~	~~Effective Rates beginning January 1, 2018~~
1. Yearly Rate	~~$6.984 per kW-Year~~	$~~6.593~~5.5836 per kW-Year
2. Monthly Rate	~~$0.582 per kW-Month~~	$0.~~549~~4653 per kW-Month

VERs (Wind) - Uncommitted Scheduling

1. Yearly Rate		$6.6922 per kW-Year
2. Monthly Rate		$0.5577 per kW-Month

VERs - Committed Scheduling

To qualify for this committed scheduling rate for a month,

the VER customer must: (i) provide notification to PacifiCorp in advance of the month that it intends to engage in Committed Scheduling; and (ii) during every hour of that month (except as specified below), a VER customer must utilize and submit into BSAP by 57 minutes prior to the operating hour (T-57), consistent with PacifiCorp's EIM Business Practice, hour-ahead base schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of no more than 72 minutes prior to the operating hour (T-72) without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule. In any calendar month for up to two operating hour intervals, a VER customer may utilize and submit into BSAP by T-57, hour-ahead schedules consistent with PacifiCorp's VER forecast vendor's forecast available as of up to 90 minutes prior to the operating hour (T-90), without modification or manual override of the hour-ahead forecast, fifteen-minute schedule, and five-minute schedule, and still be eligible for this rate. Use and submission into BSAP of hour-ahead schedules older than PacifiCorp's VER forecast vendor's forecast at T-90 in any hour during a calendar month will make a VER customer ineligible for this rate in that month. Upon notification by the PacifiCorp EIM Entity, the VER customer is required to submit a manual override or modification to the PacifiCorp VER forecast vendor's forecast to reflect a known or expected system constraint and ensure the submission of a balanced Base Schedule consistent with the requirements set forth in Attachment T.

VERs (Solar) – Committed Scheduling

~~Effective Rates from July 13, 2017 through December 31, 2017~~Effective ~~Rates beginning January 1, 2018~~		
1. Yearly Rate	~~$5.965 per kW-Year~~	$5.~~631~~1872 per kW-Year
2. Monthly Rate	~~$0.497 per kW-Month~~	$0.~~469~~4323 per kW-Month

~~Non-VERs~~

VERs (Wind) – Committed Scheduling

~~Effective Rates from July 13, 2017 through December~~		

~~31, 2017Effective Rates beginning January 1, 2018~~		
1. Yearly Rate	~~$1.90 per kW-Year~~	$~~1.794~~6.2171 per kW-Year
2. Monthly Rate	~~$0.158 per kW-Month~~	$0.~~150~~5181 per kW-Month

Non-VERs - Committed Scheduling

1. Yearly Rate		$3.1483 per kW-Year
2. Monthly Rate		$0.2624 per kW-Month

Rate Schedule Moratorium Period:

The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 3A as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California Independent System Operator.[1] Each party to the Docket No. [TBD] Settlement Agreement reserves its rights to

[1] Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedules 3, 3A, 5 and 6. The parties to the Docket No. [TBD] Settlement Agreement agree to engage with PacifiCorp in good faith on potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (3) take no action to prevent, inhibit or limit such direct access.

protest or otherwise challenge any such filing.

ARTSOA Moratorium Period:

The Amended and Restated Transmission Service and Operating Agreement ("ARTSOA") billing provisions referenced below shall not be changed with an effective date prior to December 1, 2025 (the "ARTSOA Moratorium Period"):

1. In accordance with the Sixth Amended and Restated Transmission Service and Operating Agreement between Utah Municipal Power Agency ("UMPA") and PacifiCorp (the "UMPA ARTSOA"), the Transmission Provider shall bill UMPA under Schedule 3/3A based only on its Aggregate Peak Demand ("APD"), as such term is defined in the UMPA ARTSOA, and shall not charge or seek to charge UMPA for generation at all under Schedule 3/3A or otherwise during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UMPA for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UMPA each reserve their respective rights and positions regarding whether the UMPA ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UMPA's generation.

2. In accordance with the Seventh Amended and Restated Transmission Service and Operating Agreement between Deseret Generation & Transmission Co-Operative, Inc. ("Deseret") and PacifiCorp (the "Deseret ARTSOA"), the Transmission Provider shall bill Deseret under Schedule 3/3A based only on its Aggregate Peak Demand plus the Deseret Area Load for which Deseret has the obligation to supply Regulation Reserve Service, and shall only charge or seek to charge Deseret under Schedule 3/3A for off-system sales associated with Deseret Resources, as all such terms are defined in the Deseret ARTSOA, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge Deseret for generation under Schedule 3/3A, or otherwise, in a subsequent rate filing, the Transmission Provider and Deseret each reserve their respective rights and positions regarding whether the Deseret ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to Deseret's generation.

3. In accordance with the Fifth Amended and Restated Transmission Service and Operating Agreement between Utah Associated Municipal Power Systems ("UAMPS") and PacifiCorp (the "UAMPS ARTSOA"), the Transmission Provider shall bill UAMPS

under Schedules 3 and 3A based only on its Monthly Coincident Peak Demand as such term is defined in the UAMPS ARTSOA, and shall not charge or seek to charge UAMPS for generation under Schedule 3/3A or otherwise, during the term of the ARTSOA Moratorium Period defined above. However, to the extent the Transmission Provider seeks to charge UAMPS for generation under Schedules 3 and 3A, or otherwise, in a subsequent rate filing, the Transmission Provider and UAMPS each reserve their respective rights and positions regarding whether the UAMPS ARTSOA provides, or can be amended to provide, for application of Schedule 3/3A charges to UAMPS' generation.

Self-Supply, Third-Party Supply and Pooling:

A ~~Network~~ Transmission Customer may choose to ~~self-~~supply all or a portion of its Generator Regulation and Frequency Response Service obligation through self-supply or third-party supply consistent with the requirements herein, Attachment U, and PacifiCorp's business practices. A Transmission Customer may request to supply all or a portion of its Generator Regulation and ~~consistent with~~Frequency Response Service obligation through pooling agreements, which the ~~settlement in Docket Nos. ER17-219~~Transmission Provider shall consider on a case-by-case and ~~EL17-27~~non-discriminatory basis.

~~The total charge for failure to self-supply~~For a Transmission Customer that chooses to supply its Generator Regulation and Frequency Response Service obligation through self-supply, third-party supply, or pooling agreements, the total charge for failure to supply its Generator Regulation and Frequency Response Service obligation shall not exceed the Monthly Rate pursuant to this Schedule 3A times the highest amount in megawatts not covered under self-supply, third-party supply or pooling agreements.

Clarifications regarding Non-VER Participating Resources:

A Non-VER Participating Resource in the Energy Imbalance Market ("EIM") qualifies as a dispatchable Non-VER resource. Additionally, Non-VER resources dispatchable by the Transmission Provider qualify as dispatchable Non-VERS. The Transmission Provider will not charge Non-VER Participating Resources or Non-VER resources dispatchable by PacifiCorp for Schedules 3 and 3A services. PacifiCorp shall consider, on a good faith basis, requests by customers to identify a resource that should qualify as a dispatchable Non-VER in this context due to its ability to follow PacifiCorp instructions, notwithstanding the fact that

the resource is not directly dispatchable by PacifiCorp.

EXHIBIT D

CLEAN AND MARKED VERSIONS OF PACIFICORP OPEN ACCESS TRANSMISSION TARIFF SCHEDULE 5

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load in the BAA and to support other transmission usage sourced from generation in the BAA including exports and sales. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its BAA and to support other transmission usage sourced from generation in the BAA including exports and sales. The Transmission Customer must purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the BA performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA.

Charges for Spinning Reserve Service:

Under the current NERC Regional Reliability Standard BAL-002-WECC, the Transmission Provider is required to maintain a minimum amount of contingency reserve equal to the sum of three percent of hourly integrated load plus three percent of hourly integrated generation with at least half as spinning. Consistent with the Transmission Provider operating in accordance with this reliability standard, the charges for Schedule 5 below apply one and one-half percent to load and one and one-half percent to generation.

For load, the rates below are charged to a Network Customer's hourly integrated load (including losses).

For generation, the rates below are applied to customers by charging actual hourly generation delivered to the Transmission Provider at the Point of Receipt.

The rate shall be an Hourly Rate of:

Schedule 5 (Spinning Reserves)		$0.1677 per MWh

Rate Schedule Moratorium Period:

The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 5 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California Independent System Operator.[1]

Self-Supply, Third-Party Supply and Pooling:

A Transmission Customer may choose to supply all or a portion of its reserve obligation through self-supply or third-party supply consistent with the procedures set forth in Attachment U to the Tariff. A Transmission Customer may request to supply all or a portion of its reserve obligation through pooling agreements, which the Transmission Provider shall consider on a case-by-case and non-discriminatory basis.

For a Transmission Customer choosing to supply a portion of its reserve obligation through self-supply, third-party supply or pooling agreements, detailed hourly calculation procedures are set forth in Attachment V to the Tariff.

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[1] Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedule 5. The parties to the Docket No. [TBD] Settlement Agreement agree to engage with PacifiCorp in good faith on potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (4) take no action to prevent, inhibit or limit such direct access.

Spinning Reserve Service to be Provided:

The Transmission Provider, using its generators controlled by automatic generation control, will provide the capacity required to provide Spinning Reserve Service for a Transmission Customer. Upon an outage of a generation resource for which Spinning Reserve Service has been purchased from the Transmission Provider, the Transmission Provider will provide replacement capacity commencing immediately upon such outage until the earlier of (1) the restoration of such resource to service by the Transmission Customer or (2) the end of ten (10) full minutes after the occurrence of such outage.

To the extent that the Transmission Provider determines that a Transmission Customer's specific Spinning Reserve Requirements are not being fully met through the purchase of Spinning Reserve Service as provided above, the Transmission Provider reserves the right (upon filing with the Commission) to require such Transmission Customer to purchase a greater amount of Spinning Reserve Service.

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load in the BAA and to support other transmission usage sourced from generation in the BAA including exports and sales. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its BAA and to support other transmission usage sourced from generation in the BAA including exports and sales. The Transmission Customer must purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The amount of and charges for Spinning Reserve Service are set forth below. To the extent the BA performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA.

Charges for Spinning Reserve Service:

Under the current NERC Regional Reliability Standard BAL-002-WECC, the Transmission Provider is required to maintain a minimum amount of contingency reserve equal to the sum of three percent of hourly integrated load plus three percent of hourly integrated generation with at least half as spinning. Consistent with the Transmission Provider operating in accordance with this reliability standard, the charges for Schedule 5 below apply one and one-half percent to load and one and one-half percent to generation.

For load, the rates below are charged to a Network Customer's hourly integrated load (including losses).

For generation, the rates below are applied to customers by charging actual hourly generation delivered to the Transmission Provider at the Point of Receipt.

The rate shall be an Hourly Rate of:

	~~Effective Rates from February 13, 2017 through December 31, 2017~~	~~Effective Rates beginning January 1, 2018~~

Schedule 5 (Spinning Reserves)	~~$0.16 per MWh~~	$0.~~151~~1677 per MWh

Rate Schedule Moratorium Period:

The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 5 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California Independent System Operator.[1]

Self-Supply, Third-Party Supply and Pooling:

A Transmission Customer may choose to ~~self-~~supply all or a portion of its reserve obligation~~.~~ through self-supply or third-party supply consistent with the procedures set forth in Attachment U to the Tariff. A Transmission Customer may request to supply all or a portion of its reserve obligation through pooling agreements, which the Transmission Provider shall consider on a case-by-case and non-discriminatory basis.

For a Transmission Customer choosing to ~~self-~~supply a portion of its reserve obligation through self-supply, third-party supply

[1] Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedule 5. The parties to the Docket No. [TBD] Settlement Agreement agree to engage with PacifiCorp in good faith on potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (4) take no action to prevent, inhibit or limit such direct access.

or pooling agreements, detailed hourly calculation procedures are set forth in Attachment V to the Tariff.

~~The Transmission Customer shall schedule that portion which it will self-supply and/or supply from third parties pursuant to procedures set forth in Attachment U to the Tariff.~~

Spinning Reserve Service to be Provided:

The Transmission Provider, using its generators controlled by automatic generation control, will provide the capacity required to provide Spinning Reserve Service for a Transmission Customer. Upon an outage of a generation resource for which Spinning Reserve Service has been purchased from the Transmission Provider, the Transmission Provider will provide replacement capacity commencing immediately upon such outage until the earlier of (1) the restoration of such resource to service by the Transmission Customer or (2) the end of ten (10) full minutes after the occurrence of such outage.

To the extent that the Transmission Provider determines that a Transmission Customer's specific Spinning Reserve Requirements are not being fully met through the purchase of Spinning Reserve Service as provided above, the Transmission Provider reserves the right (upon filing with the Commission) to require such Transmission Customer to purchase a greater amount of Spinning Reserve Service.

EXHIBIT E

CLEAN AND MARKED VERSIONS OF PACIFICORP OPEN ACCESS TRANSMISSION TARIFF SCHEDULE 6

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the BAA and to support other transmission usage sourced from generation in the BAA including exports and sales; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its BAA and to support other transmission usage sourced from generation in the BAA including exports and sales. The Transmission Customer must purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the BA performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA.

Charges for Supplemental Reserve Service:

Under the current NERC Regional Reliability Standard BAL-002-WECC, the Transmission Provider is required to maintain a minimum amount of contingency reserve equal to the sum of three percent of hourly integrated load plus three percent of hourly integrated generation with at least half as spinning. Consistent with the Transmission Provider operating in accordance with this reliability standard, the charges for Schedule 6 below apply one and one-half percent to load and one and one-half percent to generation.

For load, the rates below are charged to a Network Customer’s hourly integrated load (including losses).

For generation, the rates below are applied to customers by charging actual hourly generation delivered to the Transmission Provider at the Point of Receipt.

The rate shall be an Hourly Rate of:

Schedule 6 (Supplemental)		$0.1677 per MWh

Rate Schedule Moratorium Period:

The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 6 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California Independent System Operator.[1] Each party to the Docket No. [TBD] Settlement Agreement reserves its rights to protest or otherwise challenge any such filing.

Self-Supply:

A Transmission Customer may choose to supply all or a portion of its reserve obligation through self-supply or third-party supply consistent with the procedures set forth in Attachment U to the Tariff. A Transmission Customer may request to supply all or a portion of its reserve obligation through pooling agreements, which the Transmission Provider shall consider on a case-by-case and non-discriminatory basis.

[1] Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedule 6. The parties to the Docket No. [TBD] Settlement Agreement settlement agreement included with the filing in Docket No. [TBD] agree to engage with PacifiCorp in good faith on potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (4) take no action to prevent, inhibit, or limit such direct access.

For a Transmission Customer choosing to supply a portion of its reserve obligation through self-supply, third-party supply or pooling agreements, detailed hourly calculation procedures are set forth in Attachment V to the Tariff.

Supplemental Reserve Service to be Provided:

The Transmission Provider, using its generators controlled by automatic generation control, will provide the capacity required to provide Supplemental Reserve Service for a Transmission Customer. Upon an outage of a generation resource for which Supplemental Reserve Service has been purchased from the Transmission Provider, the Transmission Provider will provide replacement capacity commencing at the end of ten (10) full minutes after such outage until the earlier of (1) the restoration of such resource to service by the Transmission Customer or (2) the end of the first full hour immediately following such outage.

To the extent that the Transmission Provider determines that a Transmission Customer's specific Supplemental Reserve Requirements are not being fully met through the purchase of Supplemental Reserve Service as provided above, the Transmission Provider reserves the right (upon filing with the Commission) to require such Transmission Customer to purchase a greater amount of Supplemental Reserve Service.

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the BAA and to support other transmission usage sourced from generation in the BAA including exports and sales; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service. The Transmission Provider must offer this service when the transmission service is used to serve load within its BAA and to support other transmission usage sourced from generation in the BAA including exports and sales. The Transmission Customer must purchase this service from the Transmission Provider, self-supply the service, or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. The amount of and charges for Supplemental Reserve Service are set forth below. To the extent the BA performs this service for the Transmission Provider; charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that BA.

Charges for Supplemental Reserve Service:

Under the current NERC Regional Reliability Standard BAL-002-WECC, the Transmission Provider is required to maintain a minimum amount of contingency reserve equal to the sum of three percent of hourly integrated load plus three percent of hourly integrated generation with at least half as spinning. Consistent with the Transmission Provider operating in accordance with this reliability standard, the charges for Schedule 6 below apply one and one-half percent to load and one and one-half percent to generation.

For load, the rates below are charged to a Network Customer's hourly integrated load (including losses).

For generation, the rates below are applied to customers by charging actual hourly generation delivered to the Transmission Provider at the Point of Receipt.

The rate shall be an Hourly Rate of:

	~~Effective Rates~~	~~Effective Rates~~

	~~from February 13, 2017 through December 31, 2017~~	~~beginning January 1, 2018~~
Schedule 6 (Supplemental)	~~$0.16 per MWh~~	$0.~~151~~1677 per MWh

Rate Schedule Moratorium Period:

The rates and charges under this Schedule cannot be changed with any effective date prior to January 1, 2023. During this rate schedule moratorium period, neither the Transmission Provider nor any other party to the settlement agreement included with the filing in Docket No. [TBD] ("Docket No. [TBD] Settlement Agreement"), shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedule 6 as provided in the Docket No. [TBD] Settlement Agreement, or seek any change to PacifiCorp's business practices under or applicable to the same that differ from those provided in the Docket No. [TBD] Settlement Agreement and propose an effective date prior to January 1, 2023.

The foregoing rate schedule moratorium period does not apply to any tariff or business practice manual changes that are needed to accommodate and implement the Extended Day-Ahead Market that, as of the date of the settlement agreement included with the filing in Docket No. [*TBD*], is being developed by the California Independent System Operator.[1] Each party to the Docket No. [TBD] Settlement Agreement reserves its rights to protest or otherwise challenge any such filing.

Self-Supply:

A Transmission Customer may choose to ~~self-~~supply all or a portion of its reserve obligation~~.~~ through self-supply or third-party supply consistent with the procedures set forth in Attachment U to the Tariff. A Transmission Customer may request to supply all or a portion of its reserve obligation through

[1] Implementation of EDAM may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedule 6. The parties to the Docket No. [TBD] Settlement Agreement settlement agreement included with the filing in Docket No. [TBD] agree to engage with PacifiCorp in good faith on potential changes to PacifiCorp's tariff and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with such parties in good faith; (2) state to CAISO that it supports direct access to CAISO by such parties in connection with that collaboration; (3) request that CAISO provide such access; and (4) take no action to prevent, inhibit, or limit such direct access.

pooling agreements, which the Transmission Provider shall consider on a case-by-case and non-discriminatory basis.

For a Transmission Customer choosing to supply a portion of its reserve obligation through self-supply ~~a portion of its reserve obligation~~, third-party supply or pooling agreements, detailed hourly calculation procedures are set forth in Attachment V to the Tariff.

~~The Transmission Customer shall schedule that portion which it will self-supply and/or supply from third parties pursuant to procedures set forth in Attachment U of the Tariff.~~

Supplemental Reserve Service to be Provided:

The Transmission Provider, using its generators controlled by automatic generation control, will provide the capacity required to provide Supplemental Reserve Service for a Transmission Customer. Upon an outage of a generation resource for which Supplemental Reserve Service has been purchased from the Transmission Provider, the Transmission Provider will provide replacement capacity commencing at the end of ten (10) full minutes after such outage until the earlier of (1) the restoration of such resource to service by the Transmission Customer or (2) the end of the first full hour immediately following such outage.

To the extent that the Transmission Provider determines that a Transmission Customer's specific Supplemental Reserve Requirements are not being fully met through the purchase of Supplemental Reserve Service as provided above, the Transmission Provider reserves the right (upon filing with the Commission) to require such Transmission Customer to purchase a greater amount of Supplemental Reserve Service.

EXHIBIT F

CLEAN AND MARKED VERSIONS OF PACIFICORP OPEN ACCESS TRANSMISSION TARIFF ATTACHMENT U

ATTACHMENT U

Requirements for Self-Supply Ancillary Services

1. Purpose
2. Practice
3. Generally Applicable Provisions
   - 3.1 Service Agreement
   - 3.2 Operating Tests
   - 3.3 SCADA (metering) requirements for reserves
   - 3.4 Failure to Meet Requirements or Failure to Perform
   - 3.5 Requests for Additional Information
   - 3.6 Rejection of Requests or Termination of Existing Self-Supply or Third-Party Supply Arrangements
   - 3.7 Responsibility for Necessary Equipment Installation
4. SPECIFIC ANCILLARY SERVICE ALTERNATIVE SUPPLY REQUIREMENTS
   - 4.1 SCHEDULE 3/3A – REGULATION AND FREQUENCY RESPONSE SERVICE
     - A. Generating Resource Eligibility Requirements
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     - A. Resource Eligibility Requirements
     - B. Scheduling Self-Supply or Third-Party Supply of Schedules 5 and 6
     - C. Deployment of Self-Supply or Third-Party Supply of Schedules 5 and 6
     - D. Performance Verification and Failure Events
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   - 4.3 SCHEDULE 4 – ENERGY IMBALANCE SERVICE
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     - A. Self-Supply by Entities Self-Supplying Schedule 3
     - B. Resources Moved Electronically to Supplying Balancing Authority

1. Purpose

The purpose of this Attachment U is to clarify certain practices pertaining to self-supply or third-party supply of Schedule 3 – Regulation and Frequency Response Service, Schedule 3A – Generator Regulation and Frequency Response Service, Schedule 4 – Energy Imbalance Service, Schedule 5 – Operating Reserve – Spinning Reserve Service, Schedule 6 – Operating Reserve – Supplemental Reserve Service, and Schedule 9 – Generator Imbalance Service under the OATT. Self-supply and third-party supply may include pooling agreements, which PacifiCorp shall consider for approval in good faith and on a reasonable, non-discriminatory, case-by-case basis.

2. Practice

The following are the requirements of PacifiCorp, which is the Balancing Authority and Transmission Operator, for Transmission Customers who wish to self-supply or to arrange for third-party purchase of OATT Schedule 3 – Regulation and Frequency Response Service, Schedule 3A – Generator Regulation and Frequency Response Service, Schedule 4 – Energy Imbalance Service, Schedule 5 – Operating Reserve – Spinning Reserve Service, Schedule 6 – Operating Reserve – Supplemental Reserve Service, and Schedule 9 – Generator Imbalance Service. PacifiCorp requires that self-supplied or third-party supplied Ancillary Services satisfy the requirements for the above-referenced schedules under the currently effective PacifiCorp OATT and satisfy the relevant reliability standards of NERC or any successor organization.

3. Generally Applicable Provisions

3.1 Service Agreement

A Transmission Customer requesting to self-supply or to arrange for third-party supply of Schedules 3/3A, 4, 5, 6, or 9 shall execute a revision to its existing transmission service agreement or a separate service agreement with PacifiCorp specifying, as applicable: (1) the detailed arrangements made to supply the services including, but not limited to, specification of the amount of service required to meet the party’s Ancillary Services obligation, identification of the resource(s) supplying the service and the Balancing Authority Area where the resource(s) are located; (2) metering and communications equipment; (3) procedures for data exchange or automation; (4) the calculation of the Transmission Customer’s obligation; and (5) processes for

forecasting, deploying, and verifying performance of self-supply or third-party supply.

3.2 Operating Tests

PacifiCorp may, after providing notice fifteen (15) business days in advance, require operational testing of the resources identified as providing self-supply or third-party supply of Schedules 3/3A, 4, 5, 6, or 9, in addition to testing performed by the Generation Owner to meet NERC reliability standards or Western Electricity Coordinating Council ("WECC") regional criterion. PacifiCorp will monitor resources designated and accepted for self-supply to ensure compliance with NERC reliability standards, WECC regional criterion, and PacifiCorp requirements for time, output and power quality.

Resources that do not fully comply with NERC reliability standards, WECC regional criterion, and PacifiCorp requirements will be disqualified as self-supply or third-party supply resources until such a time as an operating test establishes that the resource(s) can respond in accordance with NERC reliability standards, WECC regional criterion, and PacifiCorp requirements.

3.3 SCADA (metering) requirements for reserves

For resources to qualify for self-supply or third-party supply of Schedules 3/3A, 4, 5, 6, or 9, the following data must be supplied by the designated self-supply or third-party supply resource. Real time data must be supplied through telemetry acceptable to PacifiCorp.

- Net Generation MW
- Net Generator MVAr
- Real power flow through each of the low side feeder breakers
- Reactive power flow through each of the low side feeder breakers
- Reactive power flow from each of the shunt capacitor banks
- A phase high side transmission voltage
- B phase high side transmission voltage
- C phase high side transmission voltage
- Accumulator pulses for interchange metering kWh
- Status of all low and high side breakers

- 10-minute ramp rate, limited by capacity
- Pmax and Pmin
- Ramp Rate MW/min
- Status – Active/Inactive
- Deploy and Deploy Acknowledge Signals

3.4 Failure to Meet Requirements or Failure to Perform

In the event that any of the requirements set forth in this Attachment U fail to be met, PacifiCorp will resume billing the Transmission Customer for the specific Ancillary Service(s) for which the Transmission Customer has failed to meet the requirements. Beginning on the date of the failure, PacifiCorp will bill the Transmission Customer until such failure is cured. This may include any penalties, charges or other consequences to which PacifiCorp is subject related to the failure. Further detail regarding the process and protocol for addressing failure to meet eligibility requirements or failure to self-supply is set forth below or in the relevant transmission service agreement.

3.5 Requests for Additional Information

PacifiCorp may, consistent with Good Utility Practice, request such additional information, beyond what is specifically required by this Attachment U, from the Transmission Customer regarding the self-supply or third-party supply of an Ancillary Service as is reasonably necessary to ensure that the Ancillary Service is supplied in a reliable manner. All such requests shall be limited to reliability specific data.

PacifiCorp shall treat any information designated as confidential by the Transmission Customer as confidential except to the extent that disclosure of this information is required by another provision of the PacifiCorp OATT, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice. Further, PacifiCorp shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

3.6 Rejection of Requests or Termination of Existing Self-Supply or Third-Party Supply Arrangements

PacifiCorp may, consistent with Good Utility Practice, reject a request for self-supply or third-party supply of Ancillary Service(s) or suspend operation of an existing arrangement for self-supply or third-party supply in the event that such self-

supply or third-party supply will impair reliability of the relevant PacifiCorp Balancing Authority Area or the interconnected electric system. Prior to rejecting a request for self- or third-party supply or suspending an existing arrangement for self- or third-party supply, PacifiCorp shall provide reasonable advance notice to the Transmission Customer and shall discuss the rejection or termination, as applicable, with the Transmission Customer.

3.7 Responsibility for Necessary Equipment Installation

The Transmission Customer is responsible for the installation of all equipment (including but not limited to metering and telecommunications equipment) necessary to meet the requirements to self-supply or purchase third-party supply as specified in this Attachment U. The Transmission Customer will reimburse PacifiCorp or its affiliates for any expenses prudently incurred to accommodate the request for self-supply or third-party supply. The equipment to be installed for self-supply or third-party supply shall be specified in the agreement required by section 3.1.

4. SPECIFIC ANCILLARY SERVICE ALTERNATIVE SUPPLY REQUIREMENTS

4.1 SCHEDULE 3/3A – REGULATION AND FREQUENCY RESPONSE SERVICE

This section sets forth the resource eligibility requirements for self-supply or third-party supply of Schedules 3/3A – Regulation and Frequency Response Service. Additional detail regarding the self-supply or third-party supply of this service will be set forth in the transmission service agreement between the Transmission Customer and PacifiCorp. The agreement may cover, among other things, the Transmission Customer's reserve obligation, elections to self-supply or third-party supply, pooling arrangements, and processes for forecasting, deployment, and performance verification of self-supply or third-party supply of Schedules 3/3A.

A. Generating Resource Eligibility Requirements

The following resource eligibility requirements apply for the self-supply or third-party supply of Schedules 3/3A (Regulation and Frequency Response Service) where the resource supplying the service and the Network Load or resource requiring this service are in the same PacifiCorp Balancing Authority Areas.

1. The Network Load or resource receiving Schedule 3/3A service through self-supply or third-party supply must have real time metering observable by the Balancing Authority.

2. The resource providing self-supply or third-party supply must be deliverable on transmission within the applicable PacifiCorp BAA.

3. The Transmission Customer must have dedicated capacity for the provision of this service which may not be used to satisfy any other capacity obligations.

4. The resource providing self-supply or third-party supply must have a point of contact that is available any time the resource is designated for Schedule 3/3A.

5. An Energy Imbalance Market ("EIM") non-participating resource must be placed under automatic generation control ("AGC"), which is required to satisfy all Schedule 3/3A requirements in real time and to compensate for instantaneous load swings or resource losses within the PacifiCorp BAA. PacifiCorp reserves the right to determine the quantity and resource priority on AGC within the PacifiCorp BAA to meet the requirements under this section or those set forth in the transmission service agreement.

6. An EIM participating resources providing self-supply or third-party supply must follow the California Independent System Operator ("CAISO") Dispatch Operating Point or grid operator instruction to satisfy all reserve requirements in real time.

In addition to requirements 1 and 3-6 above, the following resource eligibility requirements apply where the resource providing self-supply or third-party supply is located in a non-PacifiCorp Balancing Authority Area (i.e., external resource) and the load or resource requiring this service is in a PacifiCorp BAA.

1. The BAA where the external resource is located ("External Balancing Authority") must be a certified BAA by NERC or its successor organization.

2. The resource providing self-supply or third-party supply must be deliverable on transmission to the applicable PacifiCorp BAA.

3. The external resource must be pseudo-tied to the PacifiCorp BAA. The pseudo-tie must meet the requirements in PacifiCorp Business Practice #25. In addition, the external resource must have observable real-time metering. The customer must provide: (i) documentation of a firm transmission path from the external resource to a PacifiCorp BAA; and a letter from the External Balancing Authority which certifies that Regulation and Frequency Response Service is supplied in accordance with all current policies and guidelines of the NERC Operating Manual, NERC Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Schedule 3/3A to loads that are located physically in another BAA.

4. The External Balancing Authority must make arrangements to appropriately account for the resource in its own reserve obligations.

5. If the pseudo-tie equipment providing the external resource's data to PacifiCorp is not used or not useable, PacifiCorp will bill the Transmission Customer for this service for the duration of the period in which the signal was unavailable, including any and all costs or penalties incurred by PacifiCorp associated with its provision of the service. Inability of the External Balancing Authority to receive the signal by means of the pseudo-tie equipment shall not give rise to charges for this service, unless PacifiCorp also is not able to receive the resource signal and is therefore unable to include the resource in the PacifiCorp BAA Schedule 3/3A obligation. The External Balancing Authority must correct the failure to receive the signal as soon as practicable. If the signal to the External Balancing Authority is not restored expeditiously within the operating day, the self-supply or third-party supply may be terminated and the Transmission Customer will be billed for Schedule 3/3A service for the impacted operating day(s).

4.2 SCHEDULE 5 & 6 – OPERATING RESERVES – SPINNING RESERVE SERVICE & SUPPLEMENTAL RESERVE SERVICE

A. Resource Eligibility Requirements

The following resource eligibility requirements apply for the self-supply or third-party supply of Schedules 5 & 6 (Operating Reserves – Spinning Reserve Service & Supplemental Reserve Service) where the resource and the Network Load or resource requiring this service are in the same PacifiCorp Balancing Authority Areas.

1. The Network Load or resource receiving Schedules 5 & 6 service through self-supply or third-party supply must have real time metering observable by the Balancing Authority.

2. The resource providing self-supply or third-party supply must be deliverable on transmission within the applicable PacifiCorp BAA.

3. The Transmission Customer must have dedicated capacity for the provision of this service which may not be used to satisfy any other capacity obligations.

4. The resource providing self-supply or third-party supply must have a point of contact that is available any time the resource is designated for operating reserve service.

5. For Schedule 5 – Operating Reserves – Spinning Reserve Service, the resource must have uncommitted available capacity which is on-line and loaded at less than maximum output and which may be used to satisfy the Transmission Customer's Schedule 5 obligation.

6. For Schedule 6 – Operating Reserves – Supplemental Reserve Service, the service may be self-supplied or purchased from any resource or interruptible load to meet the Transmission Customer's Schedule 6 obligation. The resource must be capable of serving demand in 10 minutes, or consist of uncommitted available capacity that is on-line and loaded at less than maximum output which can be fully applied in 10 minutes. To provide self-supply, the interruptible load must be located within a PacifiCorp BAA and must be capable of being interrupted and fully deployed within 10 minutes. If the Transmission Customer

seeks to use interruptible load for self-supply or third-party supply, the Transmission Customer must provide a detailed description of the load curtailment method, measurement of the deployment, and process utilized to trigger the curtailment.

7. Transmission Customer must provide, upon request, access to logs, dispatch records or SCADA data to verify that a resource providing self-supply is not fully loaded and has reserves that are actually spinning, and that the reserves are capable of being applied as reported.

8. Each resource must be capable of being evaluated consistent with the performance test described in Section D below. This requirement applies to the self-supplying Transmission Customer's ownership share or resource capacity rights for a jointly owned resource.

9. The resource must be capable of responding to automated deployment signals.

Requirements 1, 3-8 above also apply for the self-supply or third-party supply of Schedules 5 and 6 where the resource is located in an External Balancing Authority and the Network Load or resource receiving this service are in a PacifiCorp BAA. Requirements 2 and 9 do not apply to a generating resource located in an External Balancing Authority.

B. Scheduling Self-Supply or Third-Party Supply of Schedule 5 and 6

The following scheduling requirements apply for the self-supply or third-party supply of Schedules 5 & 6 where the resource and the load or resource receiving this service are in the same PacifiCorp BAA.

1. The resource providing self-supply or third-party supply must be deliverable on transmission to the applicable PacifiCorp BAA.

2. Transmission Customers must submit day-ahead information that identifies the specific resources and capacity levels designated for Schedule 5 and 6 through the Base Schedule Aggregation Portal ("BSAP"), or other means mutually acceptable to both parties.

3. Schedule 5 and 6 requirements must be scheduled using the CAISO BSAP scheduling portal through Day Ahead rolling seven-day submissions, or other means mutually acceptable to both parties. These submissions can be updated up to 57 minutes before the operating hour.

4. Forecast submissions for resources providing self-supply or third-party supply should be at the unit level if PacifiCorp's network model includes the resource by unit, or at the resource level if PacifiCorp's network model includes the resource at the resource level.

5. BSAP submissions should be entered as "AS-SP" for spin (Schedule 5) or "AS-NS" for non-spin (Schedule 6) values, as appropriate.

External Resources

The following scheduling requirements apply for the self-supply or third-party supply of Schedules 5 & 6 (Operating Reserves – Spinning Reserve Service and Operating Reserves – Supplemental Reserve Service) where the resource providing self-supply or third-party supply and the load or resource receiving this service are in different Balancing Authority Areas.

6. For a resource in an External Balancing Authority, Schedule 5 and 6 requirements must be scheduled using a Capacity e-Tag consistent with PacifiCorp Business Practice #39, E-tagging Reserves or a Dynamic e-Tag consistent with PacifiCorp Business Practice #25.

7. When e-Tagging Schedule 5 and 6 requirements, the Transmission Customer will include one of the following in the comment field to identify the specific type of reserve being e-Tagged:

- RES-SPIN-PUR = Purchased Spinning Reserves
- RES-SPIN-SP = Self-Provided Spinning Reserves
- RES-NS-PUR = Purchased Non-Spinning Reserves
- RES-NS-SP = Self-Provided Non-Spinning Reserves

8. Every day at midnight (PPT), PacifiCorp will capture and record e-Tagged forecast values.

C. Deployment of Self-Supply or Third-Party Supply of Schedule 5 and 6

The following deployment requirements apply for the self-supply or third-party supply of Schedules 5 & 6 where the resource providing self-supply or third-party supply and the load or resource receiving this service are in the same PacifiCorp Balancing Authority Area.

1. Schedule 5 and 6 deployment will occur through an automated process enabled by an interface between PacifiCorp and the Transmission Customer. The interface will be facilitated by a third-party vendor selected by the Transmission Customer. The Transmission Customer is responsible for engaging with a vendor to create an appropriate interface.

2. Deployment signals will be sent automatically through an electronic interface between PacifiCorp, Transmission Customer, and the vendor providing the electronic interface. The signal will identify the amount of Schedule 5 and 6 reserves to deploy. The Transmission Customer must have a point of contact available, all hours and every day, to be used to communicate the deployment of the reserves, when necessary.

3. During a contingency event, the amount of Schedule 5 and 6 reserves called upon for each self-supplying Transmission Customer will be calculated as follows:

   (Customer scheduled self-supply / Total PacifiCorp BAA (PACE or PACW) Contingency Reserve Obligation) * Generation Loss

4. For each self-supplying Transmission Customer, the deployment obligation is for 60 minutes.

External Resources

In addition to items 3 and 4 above, the following deployment requirements apply for the self-supply or third-party supply of Schedules 5 & 6 where the resource providing self-supply or third-party supply and the load or resource receiving this service are in different Balancing Authority Areas.

5. Consistent with Business Practice #39, when the service is needed, the Schedule 5 and 6 reserves must be deployed by the Transmission Customer. PacifiCorp will confirm that the Transmission Customer’s Schedule 5 and 6

reserves are being held via e-Tag. Once confirmation is validated, PacifiCorp will provide an automatic signal to communicate a loss of resource in the appropriate BAA and request deployment of Schedule 5 and 6 reserves. The Transmission Customer will make arrangements for the External Balancing Authority to communicate its Automatic Control Error ("ACE") and an acknowledgement signal to inform PacifiCorp that Schedule 5 and 6 reserves are being deployed.

6. During periods within the hour when Schedule 5 and 6 reserves are required, when using a Capacity e-Tag the Transmission Customer must submit an adjustment of the energy profile on the e-Tag within 7 minutes reflecting the amount of energy flow anticipated for the balance of the hour and subsequent hours. If the Transmission Customer is using a Dynamic e-Tag, then the Transmission Customer must submit updates to the Dynamic e-Tag energy profile with the integrated value (MWh) within 30 minutes after the completion of the operating hour, the e-Tag shall use the value obtained from a common agreed on source, and the e-Tag data must be submitted into the CAISO EIM as part of the base schedules for interchange.

D. Performance Verification & Failure Events

The following performance requirements apply for the self-supply or third-party supply of Schedules 5 & 6 – Operating Reserves – Spinning Reserve Service and Operating Reserves – Supplemental Reserve Service – where the resource and the Network Load or resource requiring this service are in the same PacifiCorp Balancing Authority Area. Failure of a self-supply resource to physically respond to a call to deploy Schedule 5 or 6 reserves may result in Failure Event and/or an assessment of a strike.

PacifiCorp will count as a single failure event (each a "Failure Event"), any hour or consecutive group of hours that a resource does not successfully respond when deployed to provide reserves and that occurs before PacifiCorp provides written notice of the Failure Event to the resource owner and all Transmission Customers relying on the resource for reserves.

To determine whether a Failure Event has occurred, a performance test will be conducted associated with each call for deployment of Schedule 5 or 6 reserves. The test will be

performed for each resource or group of resources in the following manner:

1. The resource's starting generation (average generation at the time the signal for deployment is sent) will be compared to the average generation 10 minutes following the deployment signal and during minutes 11-60 following the deployment signal.

2. Failure of the 10-minute test results if the average generation value is not greater than or equal to starting generation plus the identified Schedule 5 or 6 reserve obligation.

3. Failure of the 60-minute test results if the average generation value at during minutes 11-60 minutes is not greater than or equal to starting generation plus the identified Schedule 5 or 6 reserve obligation.

4. Failure of either the 10-minute or 60-minute test results in a Failure Event.

5. If the Transmission Customer has indicated that self-supply is available on more than a single resource or a group of resources, the performance test described above will be applied to the total available resources as compared to the average generation of the resource or group of resources.

External Resources

The following performance requirements apply for the self-supply or third-party supply of Schedules 5 & 6 – Operating Reserves – Spinning Reserve Service and Operating Reserves – Supplemental Reserve Service – where the resource and the Network Load or resource requiring this service are in different Balancing Authority Areas.

6. Failure of a self-supply resource to physically respond to a call to deploy Schedule 5 or 6 reserves may result in Failure Event. To determine whether a Failure Event has occurred, a performance test will be conducted associated with each call for deployment of Schedule 5 or 6 reserves. For Transmission Customers using an external resource to self-supply, the test will be performed for each resource or group of resources in the following manner:

7. PacifiCorp will review whether the e-Tag was implemented within the specified time listed in section C.6 per the e-Tag type, and verify an associated change to the net-scheduled-interchange (NSI) with the External Balancing Authority. If the e-Tag was not implemented and there was not change to NSI, a strike will be issued.

E. Assessment of Strikes

Upon written notice, a Failure Event may be assessed a "strike." The written notice will inform the Transmission Customer of the underlying Failure Event and the strike. "Written notice" for purposes of this Attachment U includes notice given electronically.

Upon each written assessment of a strike as provided above, and before another strike may be assessed to the same resource, PacifiCorp will allow the affected Transmission Customer(s) up to three business days in which to provide written notice to PacifiCorp of the specific remedy to the resource failure that has been implemented, of alternative self-supply arrangements that have been made, or of the intent to take the applicable reserve service(s) from PacifiCorp. Absent any such written notice to PacifiCorp, the affected Customer(s) shall be subject to the applicable reserve service(s) as defined in Schedule 5 and/or Schedule 6 of PacifiCorp's OATT for the duration of the failure.

A resource that accumulates three strikes within a rolling 12-month period will be disqualified for the balance of the month in which the third strike occurs and the entirety of the following month. PacifiCorp will give affected Transmission Customer(s) written notice of the third strike and resource disqualification. PacifiCorp will allow Transmission Customer(s) up to five business days in which to formally notify PacifiCorp of alternative self-supply arrangements or be subject to the applicable reserve service(s) as defined in Schedule 5 and/or Schedule 6 of PacifiCorp's OATT. No Transmission Customer may designate or utilize a disqualified resource to provide self-supply service. Following the disqualification period, strikes for the resource shall be reset to zero and the resource will be again eligible to provide self-supply service subject to the provisions herein.

If a Failure Event is caused by an unplanned outage of a self-supplying resource or transmission line, no strike will be

issued for the operating hour in which the unplanned outage occurs. Unless the Transmission Customer is able to meet its self-supply obligation through a different resource or group of resources, the Transmission Customer will be billed for Schedules 5 & 6 for the duration of the unplanned outage if an unplanned outage prevents the Transmission Customer from fulfilling its self-supply obligation. The Transmission Customer may be required to supply documentation of the unplanned outage and demonstration that the Failure Event was caused by that outage.

PacifiCorp will provide written reports of all performance evaluation results to the resource owner and the Transmission Customer(s) using the resource for self-supply, if different.

F. Settlement of Self-Supply or Third-Party Supply of Schedule 5 and 6

Energy supplied by a Transmission Customer during periods of Schedule 5 or 6 reserve deployment for resources located within a PacifiCorp BAA will be settled financially for the amount of energy deployed by the Transmission Customer's resource in accordance with Schedule 9 of PacifiCorp's OATT.

Energy supplied by a Transmission Customer during periods of Schedule 5 or 6 reserve deployment for resources located outside of a PacifiCorp BAA will be settled financially for the amount of energy deployed by the Transmission Customer's resource in accordance with Attachment T of PacifiCorp's OATT.

G. Monthly Report To Customers Regarding Schedule 5 and 6 Deployment

PacifiCorp will provide a monthly report to all self-supplying Transmission Customers that includes the following information for each deployment of Schedule 5 or 6 reserves:

- Contingency ID number
- North West Power Pool Reserves (committed or requested)
- Date, Event Start Time
- Reason for Deployment that identifies the regional event declared, or other reason why the deployment occurred (transmission or generator)
- Total MW Loss

Customers may request additional information beyond that provided in the monthly report. PacifiCorp shall provide such information or explain why it believes that it may not properly do so.

H. Exclusion of Certain Jointly Owned Units

PacifiCorp agrees to continue to allow Utah Associated Municipal Power Systems ("UAMPS"), the Utah Municipal Power Agency ("UMPA"), and Deseret Generation and Transmission Co-operative, Inc. ("Deseret") to self-supply from jointly owned units without performance evaluations through October 1, 2021 to allow the parties to work toward mutual agreement on self-supply arrangements specific to jointly owned units. If the parties succeed in agreeing on an approach, the parties will agree to an implementation date that provides a reasonable amount of time to ready their systems for compliance with any agreed-upon approach. If mutual agreement is not reached by September 1, 2021, PacifiCorp and each of UAMPS, UMPA, and Deseret may thereafter make a unilateral filing with FERC pursuant to Sections 205 and 206 of the FPA, respectively.

4.3 SCHEDULE 4 – ENERGY IMBALANCE SERVICE

A. Eligibility Requirements

The following eligibility requirements apply for the self-supply or third-party supply of Schedule 4 – Energy Imbalance Service

1. The specific Network Loads for which the service is to be provided must be the total Network Load obligation within the PacifiCorp Balancing Authority Area and have observable real-time metering and telemetry.

2. The resources providing the service must be located in the same PacifiCorp Balancing Authority Area as the Network Load and must have observable real time metering.

3. The resource providing the service must be deliverable resources as defined by a current transmission service agreement or resources that are interconnected to PacifiCorp's system and have an active generation interconnection agreement with PacifiCorp.

4. The capacity used for this service must be dedicated to Network Load service requirements and may not being used to satisfy any other capacity obligations.

5. The resource (or a resource dispatch center) must have a point of contact that is available any time the resource is designated for regulation and frequency response service.

6. The Transmission Customer must designate adequate resources to satisfy the Network Load obligation at all times. The designated resources must be under automatic generation control, satisfying all reserve requirements in real time and as required to compensate for instantaneous load swings or generation losses within the PacifiCorp BAA. The Transmission Provider reserves the right to determine the quantity and location of resources placed under AGC within the PacifiCorp BAA.

B. Resources Moved Electronically to External Balancing Authority

If the metered Network Load requiring imbalance service has been moved electronically into an External Balancing Authority, certified by NERC or its successor organization, by means of a pseudo-tie, this Section B shall apply.

1. The pseudo-tie requires identification and observable real-time metering of the specific Network Loads for which the service is to be provided. PacifiCorp requires a letter in advance from the External Balancing Authority which certifies that this service is supplied in accordance with all current policies and guidelines of the NERC Operating Manual, NERC Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Ancillary Services to loads that are located physically in an External Balancing Authority Area.

2. PacifiCorp will accept, in lieu of the showing required in Section A.1 above, a letter in advance from the External Balancing Authority which certifies that this service is supplied in accordance with all current policies and guides of the NERC Operating Manual, NERC

Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Ancillary Services to loads that are physically located in an External Balancing Authority Area.

3. Whenever the pseudo-tie equipment providing the Network Load's data to PacifiCorp or the External Balancing Authority is not used or not useable, the dispatcher for the entity that is not receiving the load signal shall immediately contact the dispatcher for the other entity to inform it of the loss of the signal. Thereafter, until both entities are again receiving the load signal through the pseudo-tie equipment, the Transmission Customer should provide fixed schedules from the External Balancing Authority each hour to minimize the impact of load imbalance.

4. If the External Balancing Authority or the supplier of imbalance service fails to meet the requirements set forth in Section B.2 (i.e., fails to notify PacifiCorp of the External Balancing Authority's loss of its ability to receive the Network Load's signal or fails to supply fixed schedule adjustments when called upon by PacifiCorp), PacifiCorp reserves the right to bill the Transmission Customer for this service for the duration of the failure, including reimbursement for any penalties according to Schedules 4 or 9 in the PacifiCorp OATT, charges or other consequences which PacifiCorp is subject to, related to the failure.

5. PacifiCorp reserves the right to request more information from the External Balancing Authority or the Network Load's supplier of imbalance service, in addition to the above referenced letter, to ensure that this service is supplied in a reliable manner. Further, PacifiCorp reserves the right to reject the request to self-supply or third-party supply such service, in the event that PacifiCorp, in its reasonable judgment, concludes that such self-supply or third-party purchase would impair reliability in the relevant PacifiCorp BAA or the interconnected system. PacifiCorp also reserves the right to terminate the self-supply or third-party supply if, in its reasonable judgment, PacifiCorp concludes that such self-supply or third- party supply is impairing reliability in the relevant PacifiCorp Balancing Authority Area or the interconnected system.

4.4 SCHEDULE 9 – GENERATOR IMBALANCE SERVICE

A. Self-Supply Under Schedule 3 Entities

For load serving entities who have certified as a self-supply entity for regulation and frequency response service (Schedule 3) under the requirements of this Attachment U and request generator imbalance self-certification, this Section A shall apply. Generator Imbalance Service may be self-supplied from Resources or undesignated Network Resources located within the PacifiCorp BAA under the limited set of conditions defined below. Self-supply of Generator Imbalance service created by fixed point-to-point schedules can only be provided for resources located in the PacifiCorp BAA.

The following information will be required to demonstrate that the self-supply of generator imbalance service created by point-to-point schedules during generator derates or unit tripping:

1. The resources providing the service must have observable real time metering. In addition, PacifiCorp will define specific OASIS scheduling points of receipt which will apply to Customer's requesting self-supply. Customers will be obligated to demonstrate self-supply from these specific OASIS points of receipt within the PacifiCorp BAA for purposes of this section. The current list of OASIS points of receipt for section is ("PACE", "PACEW", and "PACW"). PacifiCorp reserves the right to modify this list without notice as required to maintain transmission system reliability and compliance with the PacifiCorp OATT.

2. Documentation that the resources are deliverable Resources or Network Resources and are defined by a current Network Integration Transmission Service Agreement, interconnection agreement, or legacy load service agreement on file at FERC.

3. Any Network Resources used to supply point-to-point imbalance service must be undesignated according to the PacifiCorp business practice, "Termination of Network Resources", consistent with section 30.3 of the PacifiCorp OATT. The resources utilized must be undesignated from

within specified OASIS points of receipt to self-supply point-to-point transactions originating from that particular point of receipt.

4. Resources or undesignated Network Resources must be on-line, spinning, and responsive to the loss of another undesignated unit.

5. The hourly quantity of resources or undesignated Network Resources with a point of receipt plus the purchases made and delivered on point-to-point service into each PacifiCorp point of receipt must exceed the total quantity of point-to-point transactions exiting the defined point of receipt and PacifiCorp BAA for each hour.

6. Adequate resources must remain 'designated' and available for load service as required to satisfy the Customer's Network Load obligation at all times during any period of point-to-point self-supply.

7. The party claiming generation imbalance self-supply must be previously certified as self-providing, or purchasing from third parties, regulation and frequency response service (Schedule 3) as specified in this Attachment U.

8. A point of contact is always available, all hours, every day to be used to call on resources necessary for load coverage.

B. Resources Moved Electronically to External Balancing Authority

If the Resource requiring imbalance service has been moved electronically into an External Balancing Authority Area, certified by NERC or its successor organization, by means of a pseudo-tie, this Section B shall apply. The point-to-point transmission service for the pseudo-tie resource will be established. Intra-hour transfers and the associated transmission service provided will be defined as the instantaneous output of the resource, therefore imbalance will be deemed to be self-supplied. End of hour true-ups of actual hourly integrated values are required for Balancing Authority Area energy accounting purposes.

1. The pseudo-tie requires identification and observable real-time metering of the specific Resource for which the service is to be provided. PacifiCorp requires a letter in advance from the External Balancing Authority which certifies that this service is supplied in accordance with all current policies and guidelines of the NERC Operating Manual, NERC Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Ancillary Services to loads that are located physically in another Balancing Authority Area.

2. PacifiCorp will accept, in lieu of the showing required in Section A.1 above, a letter in advance from the External Balancing Authority which certifies that this service is supplied in accordance with all current policies and guides of the NERC Operating Manual, NERC Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Ancillary Services to resources that are electronically transferred into another Balancing Authority.

3. Whenever the pseudo-tie equipment providing the Resource's data to PacifiCorp or the External Balancing Authority is not used or not useable, the dispatcher for the entity that is not receiving the load signal shall immediately contact the dispatcher for the other entity to inform it of the loss of the signal. Thereafter, until both entities are again receiving the load signal through the pseudo-tie equipment, the Transmission Customer should provide fixed schedules from the External Balancing Authority each hour to minimize the impact of generator imbalance.

ATTACHMENT U

Requirements for Self-Supply Ancillary Services

1. Purpose
2. Practice
3. Generally Applicable Provisions
   - 3.1 Service Agreement
   - 3.2 Operating Tests
   - 3.3 SCADA (metering) requirements for reserves
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     - C. Deployment of Self-Supply or Third-Party Supply of Schedules 5 and 6

~~**Definitions**~~

~~No definitions other than the following, those provided hereinafter, and those currently contained in PacifiCorp's Open Access Transmission Tariff ("OATT") or North American Electric Reliability Corporation ("NERC") reliability standards are required for this Attachment U.~~

~~***Customer*** – Reference for the purpose of this Attachment U, refers to a customer that has successfully met qualifications to self-supply Ancillary Services.~~

~~***Internal Resource*** – A resource in a PacifiCorp Balancing Authority Area ("BAA") including one that is dynamically scheduled or pseudo-tied into a PacifiCorp BAA. These resources are classified as either Participating or Non-Participating Resources.~~

~~***External Resource*** – A resource that does not meet the definition of an Internal Resource but provides self-supply (or third-party supply) service via a capacity tag.~~

D. Performance Verification and Failure Events
E. Assessment of Strikes
F. Settlement of Self-Supply or Third-Party Supply of Schedules 5 and 6
G. Monthly Report to Customers Regarding Schedules 5 and 6 Deployment
H. Exclusion of Certain Jointly Owned Units
4.3 SCHEDULE 4 – ENERGY IMBALANCE SERVICE
A. Eligibility Requirements
B. Resources Moved Electronically to Supplying Balancing Authority
4.4 SCHEDULE 9 – GENERATOR IMBALANCE SERVICE
A. Self-Supply by Entities Self-Supplying Schedule 3
B. Resources Moved Electronically to Supplying Balancing Authority

1. Purpose

The purpose of this Attachment U is to clarify ~~the~~certain practices ~~outlined in the OATT~~ pertaining to self-supply or third-party supply of ~~ancillary services certification process and requirements.~~Schedule 3 – Regulation and Frequency Response Service, Schedule 3A – Generator Regulation and Frequency Response Service, Schedule 4 – Energy Imbalance Service, Schedule 5 – Operating Reserve – Spinning Reserve Service, Schedule 6 – Operating Reserve – Supplemental Reserve Service, and Schedule 9 – Generator Imbalance Service under the OATT. Self-supply and third-party supply may include pooling agreements, which PacifiCorp shall consider for approval in good faith and on a reasonable, non-discriminatory, case-by-case basis.

2. Practice

The following are the requirements of PacifiCorp, which is the Balancing Authority and Transmission Operator, for Transmission Customers who wish to self-supply or to arrange for third-party purchase of ~~specific Ancillary Services.~~OATT Schedule 3 – Regulation and Frequency Response Service, Schedule 3A – Generator Regulation and Frequency Response Service, Schedule 4 – Energy Imbalance Service, Schedule 5 – Operating Reserve – Spinning Reserve Service, Schedule 6 – Operating Reserve – Supplemental Reserve Service, and Schedule 9 – Generator Imbalance Service. PacifiCorp requires that ~~these~~self-supplied or third-party supplied Ancillary Services satisfy the requirements for ~~Schedules 5 and 6~~the above-referenced schedules under the currently effective PacifiCorp OATT and satisfy the relevant reliability standards of NERC or any successor organization. ~~In addition to these requirements and the requirements listed below, the party~~

3. Generally Applicable Provisions

3.1 Service Agreement

A Transmission Customer requesting to self-supply or to arrange for third-party ~~purchase~~supply of Schedules 3/3A, 4, 5, 6, or 9 shall ~~also~~ execute ~~an Umbrella Service Agreement or~~ a revision to ~~an~~its existing transmission service agreement~~, as applicable,~~ or a separate service agreement with PacifiCorp specifying, as applicable: (1) the detailed arrangements made to supply the services including, but not limited to, specification of the amount of service required to meet the party's Ancillary Services

obligation, identification of the ~~generation~~ resource(s) ~~or system~~ supplying the service and ~~its~~the Balancing Authority Area~~, specification of~~ where the resource(s) are located; (2) metering and communications equipment~~, and~~; (3) procedures for data exchange~~. In addition, PacifiCorp reserves the right to require pre-acceptance testing of the units identified and periodic testing, at such times determined by PacifiCorp, thereafter to ensure that~~ or automation; (4) the ~~service can be provided in accordance with reliability standards and~~ calculation of the ~~contractual agreement.~~Transmission Customer's obligation; and (5) processes for forecasting, deploying, and verifying performance of self-supply or third-party supply.

3.2 Operating Tests

PacifiCorp may, after providing notice fifteen (15) business days in advance, require operational testing of the resources identified as providing self-supply or third-party supply of Schedules 3/3A, 4, 5, 6, or 9, in addition to testing performed by the Generation Owner to meet NERC reliability standards or Western Electricity Coordinating Council ("WECC") regional criterion. PacifiCorp will monitor resources designated and accepted for self-supply to ensure compliance with NERC reliability standards, WECC regional criterion, and PacifiCorp requirements for time, output and power quality.

Resources ~~**Telemetry**~~that do not fully comply with NERC reliability standards, WECC regional criterion, and PacifiCorp requirements will be disqualified as self-supply or third-party supply resources until such a time as an operating test establishes that the resource(s) can respond in accordance with NERC reliability standards, WECC regional criterion, and PacifiCorp requirements.

3.3 SCADA (metering) requirements for reserves

For ~~an Internal Resource~~ resources to qualify for self-supply ~~of Operating Reserve-Spinning Reserve Service (Schedule 5) or Operating Reserve - Supplemental Reserve Service (Schedule 6)~~or third-party supply of Schedules 3/3A, 4, 5, 6, or 9, the following ~~four-second, industry-standard~~ data must be supplied by the designated self-supply or third-party supply resource. Real time data must be supplied through telemetry acceptable to PacifiCorp.

- Net Generation MW

- Net Generator MVAr
- Real power flow through each of the low side feeder breakers
- Reactive power flow through each of the low side feeder breakers
- Reactive power flow from each of the shunt capacitor banks
- A phase high side transmission voltage
- B phase high side transmission voltage
- C phase high side transmission voltage
- Accumulator pulses for interchange metering kWh
- Status of all low and high side breakers
- 10-minute ramp rate, limited by capacity~~In general, an example of an~~
- Pmax and Pmin
- Ramp Rate MW/min
- Status – Active/Inactive
- Deploy and Deploy Acknowledge Signals

3.4 Failure to Meet Requirements or Failure to Perform

In the event that any of the requirements set forth in this Attachment U fail to be met, PacifiCorp will resume billing the Transmission Customer for the specific Ancillary Service(s) for which the Transmission Customer has failed to meet the requirements. Beginning on the date of the failure, PacifiCorp will bill the Transmission Customer until such failure is cured. This may include any penalties, charges or other consequences to which PacifiCorp is subject related to the failure. Further detail regarding the process and protocol for addressing failure to meet eligibility requirements or failure to self-supply is set forth below or in the relevant transmission service agreement.

3.5 Requests for Additional Information

PacifiCorp may, consistent with Good Utility Practice, request such additional information, beyond what is specifically required by this Attachment U, from the Transmission Customer regarding the self-supply or third-party supply of an Ancillary Service as is reasonably necessary to ensure that the Ancillary Service is supplied in a reliable manner. All such requests shall be limited to reliability specific data.

PacifiCorp shall treat any information designated as confidential by the Transmission Customer as confidential except to the extent that disclosure of this information is required by another provision of the PacifiCorp OATT, by regulatory or judicial order, or for reliability purposes pursuant to Good Utility Practice. Further, PacifiCorp shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

3.6 Rejection of Requests or Termination of Existing Self-Supply or Third-Party Supply Arrangements

PacifiCorp may, consistent with Good Utility Practice, reject a request for self-supply or third-party supply of Ancillary Service(s) or suspend operation of an existing arrangement for self-supply or third-party supply in the event that such self-supply or third-party supply will impair reliability of the relevant PacifiCorp Balancing Authority Area or the interconnected electric system. Prior to rejecting a request for self- or third-party supply or suspending an existing arrangement for self- or third-party supply, PacifiCorp shall provide reasonable advance notice to the Transmission Customer and shall discuss the rejection or termination, as applicable, with the Transmission Customer.

3.7 Responsibility for Necessary Equipment Installation

The Transmission Customer is responsible for the installation of all equipment (including but not limited to metering and telecommunications equipment) necessary to meet the requirements to self-supply or purchase third-party supply as specified in this Attachment U. The Transmission Customer will reimburse PacifiCorp or its affiliates for any expenses prudently incurred to accommodate the request for self-supply or third-party supply. The equipment to be installed for self-supply or third-party supply shall be specified in the agreement required by section 3.1.

4. SPECIFIC ANCILLARY SERVICE ALTERNATIVE SUPPLY REQUIREMENTS

4.1 SCHEDULE 3/3A – REGULATION AND FREQUENCY RESPONSE SERVICE

This section sets forth the resource eligibility requirements for self-supply or third-party supply of Schedules 3/3A – Regulation and Frequency Response Service. Additional detail regarding the self-supply or third-party supply of this service will be set forth in the transmission service agreement between

the Transmission Customer and PacifiCorp. The agreement may cover, among other things, the Transmission Customer's reserve obligation, elections to self-supply or third-party supply, pooling arrangements, and processes for forecasting, deployment, and performance verification of self-supply or third-party supply of Schedules 3/3A.

A. Generating Resource Eligibility Requirements

The following resource eligibility requirements apply for the self-supply or third-party supply of Schedules 3/3A (Regulation and Frequency Response Service) where the resource supplying the service and the Network Load or resource requiring this service are in the same PacifiCorp Balancing Authority Areas.

1. The Network Load or resource receiving Schedule 3/3A service through self-supply or third-party supply must have real time metering observable by the Balancing Authority.

2. The resource providing self-supply or third-party supply must be deliverable on transmission within the applicable PacifiCorp BAA.

3. The Transmission Customer must have dedicated capacity for the provision of this service which may not be used to satisfy any other capacity obligations.

4. The resource providing self-supply or third-party supply must have a point of contact that is available any time the resource is designated for Schedule 3/3A.

5. An Energy Imbalance Market ("EIM") non-participating resource must be placed under automatic generation control ("AGC"), which is required to satisfy all Schedule 3/3A requirements in real time and to compensate for instantaneous load swings or resource losses within the PacifiCorp BAA. PacifiCorp reserves the right to determine the quantity and resource priority on AGC within the PacifiCorp BAA to meet the requirements under this section or those set forth in the transmission service agreement.

6. An EIM participating resources providing self-supply or third-party supply must follow the California Independent System Operator ("CAISO") Dispatch Operating Point or grid operator instruction to satisfy all reserve requirements in real time.

In addition to requirements 1 and 3-6 above, the following resource eligibility requirements apply where the resource providing self-supply or third-party supply is located in a non-PacifiCorp Balancing Authority Area (i.e., external resource) and the load or resource requiring this service is in a PacifiCorp BAA.

1. The BAA where the external resource is located ("External Balancing Authority") must be a certified BAA by NERC or its successor organization.

2. The resource providing self-supply or third-party supply must be deliverable on transmission to the applicable PacifiCorp BAA.

3. The external resource must be pseudo-tied to the PacifiCorp BAA. The pseudo-tie must meet the requirements in PacifiCorp Business Practice #25. In addition, the external resource must have observable real-time metering. The customer must provide: (i) documentation of a firm transmission path from the external resource to a PacifiCorp BAA; and a letter from the External Balancing Authority which certifies that Regulation and Frequency Response Service is supplied in accordance with all current policies and guidelines of the NERC Operating Manual, NERC Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Schedule 3/3A to loads that are located physically in another BAA.

4. The External Balancing Authority must make arrangements to appropriately account for the resource in its own reserve obligations.

5. If the pseudo-tie equipment providing the external resource's data to PacifiCorp is not used or not useable, PacifiCorp will bill the Transmission Customer for this service for the duration of the period in which the signal was unavailable, including any and all costs or penalties incurred by PacifiCorp associated with its provision of the service. Inability of the External Balancing Authority to receive the signal by means of the pseudo-tie equipment shall not give rise to charges for this service, unless PacifiCorp also is not able to receive the resource signal

and is therefore unable to include the resource in the PacifiCorp BAA Schedule 3/3A obligation. The External Balancing Authority must correct the failure to receive the signal as soon as practicable. If the signal to the External Balancing Authority is not restored expeditiously within the operating day, the self-supply or third-party supply may be terminated and the Transmission Customer will be billed for Schedule 3/3A service for the impacted operating day(s).

4.2 SCHEDULE 5 & 6 – OPERATING RESERVES – SPINNING RESERVE SERVICE & SUPPLEMENTAL RESERVE SERVICE

A. Resource Eligibility Requirements

The following resource eligibility requirements apply for the self-supply or third-party supply of Schedules 5 & 6 (Operating Reserves – Spinning Reserve Service & Supplemental Reserve Service) where the resource and the Network Load or resource requiring this service are in the same PacifiCorp Balancing Authority Areas.

1. The Network Load or resource receiving Schedules 5 & 6 service through self-supply or third-party supply must have real time metering observable by the Balancing Authority.

2. The resource providing self-supply or third-party supply must be deliverable on transmission within the applicable PacifiCorp BAA.

3. The Transmission Customer must have dedicated capacity for the provision of this service which may not be used to satisfy any other capacity obligations.

4. The resource providing self-supply or third-party supply must have a point of contact that is available any time the resource is designated for operating reserve service.

5. For Schedule 5 – Operating Reserves – Spinning Reserve Service, the resource must have uncommitted available capacity which is on-line and loaded at less than maximum output and which may be used to satisfy the Transmission Customer's Schedule 5 obligation.

6. For Schedule 6 – Operating Reserves – Supplemental Reserve Service, the service may be self-supplied or purchased from any resource or interruptible load to meet the Transmission Customer's Schedule 6 obligation. The resource must be capable of serving demand in 10 minutes, or consist of uncommitted available capacity that is on-line and loaded at less than maximum output which can be fully applied in 10 minutes. To provide self-supply, the interruptible load must be located within a PacifiCorp BAA and must be capable of being interrupted and fully deployed within 10 minutes. If the Transmission Customer seeks to use interruptible load for self-supply or third-party supply, the Transmission Customer must provide a detailed description of the load curtailment method, measurement of the deployment, and process utilized to trigger the curtailment.

7. Transmission Customer must provide, upon request, access to logs, dispatch records or SCADA data to verify that a resource providing self-supply is not fully loaded and has reserves that are actually spinning, and that the reserves are capable of being applied as reported.

8. Each resource must be capable of being evaluated consistent with the performance test described in Section D below. This requirement applies to the self-supplying Transmission Customer's ownership share or resource capacity rights for a jointly owned resource.

9. The resource must be capable of responding to automated deployment signals.

Requirements 1, 3-8 above also apply for the self-supply or third-party supply of Schedules 5 and 6 where the resource is located in an External Balancing Authority and the Network Load or resource receiving this service are in a PacifiCorp BAA. Requirements 2 and 9 do not apply to a generating resource located in an External Balancing Authority.

B. Scheduling Self-Supply or Third-Party Supply of Schedule 5 and 6

The following scheduling requirements apply for the self-supply or third-party supply of Schedules 5 & 6 where the resource and the load or resource receiving this service are in the same PacifiCorp BAA.

1. The resource providing self-supply or third-party supply must be deliverable on transmission to the applicable PacifiCorp BAA.

2. Transmission Customers must submit day-ahead information that identifies the specific resources and capacity levels designated for Schedule 5 and 6 through the Base Schedule Aggregation Portal ("BSAP"), or other means mutually acceptable ~~telemetry method is a Remote Terminal Unit ("RTU") or Inter-Control Center Communication Protocol ("ICCP"). The latter is subject to WECC Operations Network ("WON") guidelines. To the extent any data~~to both parties.

3. Schedule 5 and 6 requirements must be scheduled using the CAISO BSAP scheduling portal through Day Ahead rolling seven-day submissions, or other means mutually acceptable to both parties. These submissions can be updated up to 57 minutes before the operating hour.

4. Forecast submissions for resources providing self-supply or third-party supply should be at the unit level if PacifiCorp's network model includes the resource by unit, or at the resource level if PacifiCorp's network model includes the resource at the resource level.

5. BSAP submissions should be entered as "AS-SP" for spin (Schedule 5) or "AS-NS" for non-spin (Schedule 6) values, as appropriate.

External Resources

The following scheduling requirements apply for the self-supply or third-party supply of Schedules 5 & 6 (Operating Reserves – Spinning Reserve Service and Operating Reserves – Supplemental Reserve Service) where the resource providing self-supply or third-party supply and the load or resource receiving this service are in different Balancing Authority Areas.

6. For a resource in an External Balancing Authority, Schedule 5 and 6 requirements must be scheduled using a Capacity e-Tag consistent with PacifiCorp Business Practice #39, E-tagging Reserves or a Dynamic e-Tag consistent with PacifiCorp Business Practice #25.

7. When e-Tagging Schedule 5 and 6 requirements, the Transmission Customer will include one of the following in the comment field to identify the specific type of reserve being e-Tagged:

- RES-SPIN-PUR = Purchased Spinning Reserves
- RES-SPIN-SP = Self-Provided Spinning Reserves
- RES-NS-PUR = Purchased Non-Spinning Reserves
- RES-NS-SP = Self-Provided Non-Spinning Reserves

8. Every day at midnight (PPT), PacifiCorp will capture and record e-Tagged forecast values.

C. Deployment of Self-Supply or Third-Party Supply of Schedule 5 and 6

The following deployment requirements apply for the self-supply or third-party supply of Schedules 5 & 6 where the resource providing self-supply or third-party supply and the load or resource receiving this service are in the same PacifiCorp Balancing Authority Area.

1. Schedule 5 and 6 deployment will occur through an automated process enabled by an interface between PacifiCorp and the Transmission Customer. The interface will be facilitated by a third-party vendor selected by the Transmission Customer. The Transmission Customer is responsible for engaging with a vendor to create an appropriate interface.

2. Deployment signals will be sent automatically through an electronic interface between PacifiCorp, Transmission Customer, and the vendor providing the electronic interface. The signal will identify the amount of Schedule 5 and 6 reserves to deploy. The Transmission Customer must have a point of contact available, all hours and every day, to be used to communicate the deployment of the reserves, when necessary.

3. During a contingency event, the amount of Schedule 5 and 6 reserves called upon for each self-supplying Transmission Customer will be calculated as follows:

(Customer scheduled self-supply / Total PacifiCorp BAA (PACE or PACW) Contingency Reserve Obligation) * Generation Loss

4. For each self-supplying Transmission Customer, the deployment obligation is for 60 minutes.

External Resources

In addition to items ~~are not applicable to a particular resource, they are not required. To the extent applicable data items are already provided through an effective interconnection agreement, they are not separately required~~3 and 4 above, the following deployment requirements apply for the self-supply or third-party supply of Schedules 5 & 6 where the resource providing self-supply or third-party supply and the load or resource receiving this service are in different Balancing Authority Areas.

~~•~~ 5. Consistent with Business Practice #39, when the service is needed, the Schedule 5 and 6 reserves must be deployed by the Transmission Customer. PacifiCorp will confirm that the Transmission Customer's Schedule 5 and 6 reserves are being held via e-Tag. Once confirmation is validated, PacifiCorp will provide an automatic signal to communicate a loss of resource in the appropriate BAA and request deployment of Schedule 5 and 6 reserves. The Transmission Customer will make arrangements for the External Balancing Authority to communicate its Automatic Control Error ("ACE") and an acknowledgement signal to inform PacifiCorp that Schedule 5 and 6 reserves are being deployed.

6. During periods within the hour when Schedule 5 and 6 reserves are required, when using a Capacity e-Tag the Transmission Customer must submit an adjustment of the energy profile on the e-Tag within 7 minutes reflecting the amount of energy flow anticipated for the balance of the hour and subsequent hours. If the Transmission Customer is using a Dynamic e-Tag, then the Transmission Customer must submit updates to the Dynamic e-Tag energy profile with the integrated value (MWh) within 30 minutes after the completion of the operating hour, the e-Tag shall use the value obtained from a common agreed on source, and the e-Tag data must be submitted into the CAISO EIM as part of the base schedules for interchange.

D. Performance Verification & Failure Events

The following performance requirements apply for the self-supply or third-party supply of Schedules 5 & 6 – Operating Reserves – Spinning Reserve Service and Operating Reserves – Supplemental Reserve Service – where the resource and the Network Load or resource requiring this service are in the same PacifiCorp Balancing Authority Area. Failure of a self-supply resource to physically respond to a call to deploy Schedule 5 or 6 reserves may result in Failure Event and/or an assessment of a strike.

- ~~Net Generation MW~~
- ~~Net Generator MVAr~~
- ~~Real power flow through each of the low side feeder breakers~~
- ~~Reactive power flow through each of the low side feeder breakers~~
- ~~Reactive power flow from each of the shunt capacitor banks~~
- ~~A phase high side transmission voltage~~
- ~~B phase high side transmission voltage~~
- ~~C phase high side transmission voltage~~
- ~~Accumulator pulses for generator output metering kWh~~
- ~~Status of all low and high side breakers~~
- ~~10 minute ramp rate, limited by capacity~~
- ~~PMax~~

~~Testing and Disqualification for Self-Supply of Reserves in the PacifiCorp Balancing Authority Areas~~

~~Resources designated for self-supply of reserves, spinning or supplemental, may be tested by PacifiCorp at any time throughout the year. The test will be performed upon the physical response of resources designated for self-supply via e-Tag.~~

~~Resources called upon to supply reserves and responding to meet Western Electricity Coordinating Council ("WECC") and PacifiCorp requirements for time, output, and power quality, during the calendar year shall be deemed as passing the test. PacifiCorp will monitor resources designated and accepted for self-supply and log the date of successful operation. Failure to respond when called upon to supply reserves may disqualify the resource from self-supplying reserves as described here:~~

- PacifiCorp will count as a single failure event (each a "Failure Event"), any hour or consecutive group of hours that a

resource does not successfully respond when ~~called by PacifiCorp~~deployed to provide reserves and that occurs before PacifiCorp provides written notice of the Failure Event to the resource owner and all Transmission Customers relying on the resource for reserves. ~~Upon and with such written notice, a Failure Event may be assessed a "strike," the assessment of which shall be included in the written notice of the underlying Failure Event. "Written notice" for purposes of this Attachment U includes notice given electronically.~~

To determine whether a Failure Event has occurred, a performance test will be conducted associated with each call for deployment of Schedule 5 or 6 reserves. The test will be performed for each resource or group of resources in the following manner:

1. The resource's starting generation (average generation at the time the signal for deployment is sent) will be compared to the average generation 10 minutes following the deployment signal and during minutes 11-60 following the deployment signal.

2. Failure of the 10-minute test results if the average generation value is not greater than or equal to starting generation plus the identified Schedule 5 or 6 reserve obligation.

3. Failure of the 60-minute test results if the average generation value at during minutes 11-60 minutes is not greater than or equal to starting generation plus the identified Schedule 5 or 6 reserve obligation.

4. Failure of either the 10-minute or 60-minute test results in a Failure Event.

5. If the Transmission Customer has indicated that self-supply is available on more than a single resource or a group of resources, the performance test described above will be applied to the total available resources as compared to the average generation of the resource or group of resources.

External Resources

- ~~Upon each written notice of a Failure Event~~

The following performance requirements apply for the self-supply or third-party supply of Schedules 5 & 6 – Operating Reserves – Spinning Reserve Service and Operating Reserves – Supplemental Reserve Service – where the resource and the Network Load or resource requiring this service are in different Balancing Authority Areas.

6. Failure of a self-supply resource to physically respond to a call to deploy Schedule 5 or 6 reserves may result in Failure Event. To determine whether a Failure Event has occurred, a performance test will be conducted associated with each call for deployment of Schedule 5 or 6 reserves. For Transmission Customers using an external resource to self-supply, the test will be performed for each resource or group of resources in the following manner:

7. PacifiCorp will review whether the e-Tag was implemented within the specified time listed in section C.6 per the e-Tag type, and verify an associated change to the net-scheduled-interchange (NSI) with the External Balancing Authority. If the e-Tag was not implemented and there was not change to NSI, a strike will be issued.

E. Assessment of Strikes

Upon written notice, a Failure Event may be assessed a "strike." The written notice will inform the Transmission Customer of the underlying Failure Event and the strike. "Written notice" for purposes of this Attachment U includes notice given electronically.

Upon each written assessment of a strike as provided above, and before another strike may be assessed to the same resource, PacifiCorp will allow the affected Transmission Customer(s) up to three business days in which to provide written notice to PacifiCorp of the specific remedy to the resource failure that has been implemented, of alternative self-supply arrangements that have been made, or of the intent to take the applicable reserve service(s) from PacifiCorp. Absent any such written notice to PacifiCorp, the affected Customer(s) shall be subject to the applicable reserve service(s) as defined in Schedule 5 and/or Schedule 6 of PacifiCorp's OATT for the duration of the failure.

- A resource that accumulates three strikes within a rolling 12-month period will be disqualified for the balance of the month in which the third Failure Event strike occurs and the entirety of the following month. PacifiCorp will give affected Transmission Customer(s) written notice of the third strike and resource disqualification and. PacifiCorp will allow Transmission Customer(s) up to threefive business days in which to formally notify PacifiCorp of alternative self-supply arrangements or be subject to the applicable reserve service(s) as defined in Schedule 5 and/or Schedule 6 of PacifiCorp's OATT. No Transmission Customer may designate or utilize a disqualified resource to provide self-supply service. Following the disqualification period, strikes for the resource shall be reset to zero and the resource will be again eligible to provide self-supply service subject to the provisions herein.

PacifiCorp will only test resources that are carrying operating reserves at the time the testIf a Failure Event is commenced. A caused by an unplanned outage of a self-supplying resource that is experiencing a unit trip shall not or transmission line, no strike will be subject to the testissued for the operating hour duringin which the tripunplanned outage occurs. This Unless the Transmission Customer is able to meet its self-supply obligation through a different resource or group of resources, the Transmission Customer will be accomplished with PacifiCorp calling on reserves, monitoring resultsbilled for Schedules 5 & 6 for the duration of the unplanned outage if an unplanned outage prevents the Transmission Customer from fulfilling its self-supply obligation. The Transmission Customer may be required to supply documentation of the unplanned outage and logging the test. demonstration that the Failure Event was caused by that outage.

PacifiCorp will provide written reports of all testperformance evaluation results to the resource owner and the Transmission Customer(s) using the resource for self-supply, if different.

Operating Reserve - Spinning Reserve Service (Schedule 5):
This service may be self-supplied or purchased from any unit or system that has uncommitted available capacity which is on-line and loaded at less than maximum owned or contracted output and which may be used to satisfy the Transmission Customer's reserve obligation. The specific resources from

~~which the service is being provided must be identified and have observable telemetry. The party requesting to self-supply or arranging for third-party purchase shall, at its own expense, install the necessary equipment (including but not limited to metering and telecommunications equipment) for providing the service. The party requesting to self-supply or arranging for third-party purchase shall also reimburse PacifiCorp or its affiliates for any expenses incurred to accommodate the request for self-supply or third-party supply.~~

~~A. Use of an External Resource:~~

~~For generation external to PacifiCorp's BAAs to qualify for self-supply or third-party supply service, a dynamic transfer coming into PacifiCorp's energy management system ("EMS") as a dynamic schedule into the balancing authority area where the obligation originates, represented on a dynamic e-Tag, is sufficient for communication with PacifiCorp's EMS. The author of the e-Tag is responsible for adjusting the energy profile to match the resource output for self-supply until such time as an automated process can be developed and implemented to relieve the author of this responsibility.~~

~~B.~~ ~~The~~ **F. Settlement of Self-Supply or Third-Party Supply of Schedule 5 and 6**

Energy supplied by a Transmission Customer during periods of Schedule 5 or 6 reserve deployment for resources located within a PacifiCorp BAA will be settled financially for the amount of energy deployed by the Transmission Customer's resource in accordance with Schedule 9 of PacifiCorp's OATT.

Energy supplied by a Transmission Customer during periods of Schedule 5 or 6 reserve deployment for resources located outside of a PacifiCorp BAA will be settled financially for the amount of energy deployed by the Transmission Customer's resource in accordance with Attachment T of PacifiCorp's OATT.

G. Monthly Report To Customers Regarding Schedule 5 and 6 Deployment

PacifiCorp will provide a monthly report to all self-supplying Transmission Customers that includes the following information for each deployment of Schedule 5 or 6 reserves:

- Contingency ID number

- North West Power Pool Reserves (committed or requested)
- Date, Event Start Time
- Reason for Deployment that identifies the regional event declared, or other reason why the deployment occurred (transmission or generator)
- Total MW Loss

Customers may request additional information beyond that provided in the monthly report. PacifiCorp shall provide such information or explain why it believes that it may not properly do so.

H. ~~will be required to demonstrate~~**Exclusion of Certain Jointly Owned Units**

PacifiCorp agrees to continue to allow Utah Associated Municipal Power Systems ("UAMPS"), the Utah Municipal Power Agency ("UMPA"), and Deseret Generation and Transmission Co-operative, Inc. ("Deseret") to self-supply from jointly owned units without performance evaluations through October 1, 2021 to allow the parties to work toward mutual agreement on self-supply arrangements specific to jointly owned units. If the parties succeed in agreeing on an approach, the parties will agree to an implementation date that provides a reasonable amount of time to ready their systems for compliance with any agreed-upon approach. If mutual agreement is not reached by September 1, 2021, PacifiCorp and each of UAMPS, UMPA, and Deseret may thereafter make a unilateral filing with FERC pursuant to Sections 205 and 206 of the FPA, respectively.

4.3 SCHEDULE 4 – ENERGY IMBALANCE SERVICE

A. Eligibility Requirements

The following eligibility requirements apply for the self-supply or third-party ~~purchase of spinning reserve service for Internal Resources:~~supply of Schedule 4 – Energy Imbalance Service

- ~~The generation~~1. The specific Network Loads for which the service is to be provided must be the total Network Load obligation within the PacifiCorp Balancing Authority Area and have observable real-time metering and telemetry.

2. The resources providing the service must be located in the same PacifiCorp Balancing Authority Area as the Network Load ~~or contractual point of receipt~~ and must have observable ~~telemetry~~real time metering.

- ~~Requirements for self-supply or third-party purchase of spinning reserve service shall apply at the unit level if PacifiCorp's network model includes the~~3. The resource ~~by unit, or at the plant level if PacifiCorp's network model includes the resource at the plant level.~~

- ~~Documentation that the generation resources are~~ providing the service must be deliverable ~~Network Resources~~ resources as defined by a current ~~Network Integration Transmission Service Agreement, a legacy load~~transmission service agreement ~~on file at FERC,~~ or ~~other firm PTP agreement, which may be reported on~~resources that are interconnected to PacifiCorp's ~~Electric Quarterly Report ("EQR").~~

~~• For self-supply arrangements through a power purchase agreement, a copy of the capacity~~system and have an active generation interconnection agreement~~(s) or contract(s) that can be used to verify that the~~ with PacifiCorp.

4. The capacity used for this service ~~is~~must be dedicated to ~~serve the designated metered~~ Network Load~~,~~ service requirements and ~~is~~may not being used to satisfy any other capacity obligations.

- ~~Access to logs, dispatch records and test data that can be used to verify that spinning reserves are actually spinning and not fully loaded and are capable of being applied as reported. Resource capability for self-supply of reserves shall mean the operational capability of the unit to actually deliver the reserve energy in the event of a deployment based on the operational capability characteristics of the self-supply resource (i.e., ramp rates, PMax).~~

- ~~Self-suppliers must provide a monthly reserve supply forecast no less than thirty (30) calendar days before the beginning of the month with amounts (MWs) in all hours for that month based on the forecasted percentage of reserve obligation. This 30-day forecast requirement does not replace or satisfy~~

~~separate seven-day forecast requirements established by Peak Reliability and the California Independent System Operator ("CAISO").~~

- ~~Self-suppliers must provide day-ahead information via e-Tag. In the day-ahead, the reserve supply forecast must be updated for the next operating day with the amount (MWs) of reserve obligation the self-supplier expects to actually be providing in all hours.~~

- ~~A point of contact is always available, all hours, every day to be used to deploy the reserves.~~

~~C. For self-supply and third-party purchases of this service, reserves must be scheduled using a capacity e-Tag consistent with PacifiCorp Business Practice #39, E-tagging Reserves. Also, consistent with Business Practice #39, when the service is needed, the reserves must be deployed by the Customer through a mid-hour tag adjustment to the energy profile. PacifiCorp will confirm customer reserves are being held via e-Tag.~~

~~Once confirmation is validated, PacifiCorp will place a phone call or adjust a capacity tag through an automated process to communicate a loss of generation in the appropriate Balancing Authority and request deployment of reserves for the appropriate length of time. PacifiCorp will provide an annual report to Customers demonstrating non-discriminatory deployment of reserves.~~

~~D. In the event that any of the above requirements fail to be met, then PacifiCorp reserves the right to bill the responsible party for this service as supplied by PacifiCorp for the duration of the failure, including reimbursement for any compliance-related penalties, charges, or other consequences, to which PacifiCorp is subject related to the failure. If the Customer fails to self-supply its spinning reserves as defined in this section and fails to notify PacifiCorp to make arrangements for service, the Customer will be subject to spinning reserve service as defined in Schedule 5 of PacifiCorp's OATT.~~

~~E. The service hereunder must be available to be called on by PacifiCorp to comply with NERC Standard BAL-002-WECC-2 (or any successor Reliability Standard thereto), and any such other related criteria or standards which may be~~

~~imposed by a national or regional reliability council or governing regulatory body. The service will also be used by PacifiCorp to comply with its obligations under the Northwest Power Pool Reserve Sharing Group Contract and any future Reserve Sharing Group of which PacifiCorp is a member. The supplying party must, at its own expense, make the necessary arrangements, in coordination with PacifiCorp, to be able to respond to a reserve sharing event. The supplying party is not required to have a separate relationship or agreement with the Northwest Power Pool Reserve Sharing Group.~~

~~F. PacifiCorp reserves the right to request more information from the party requesting self-supply or third-party supply and/or its supplier of spinning reserve service, in addition to the above-listed information, to ensure that this service is supplied in a reliable manner, PacifiCorp shall make best efforts to request further information no later than thirty (30) calendar days from the customer's request to self-supply or third-party supply.~~

~~Further, PacifiCorp reserves the right to reject the request to self-supply such service, or purchase it from another source, in the event that PacifiCorp, in its reasonable judgement, concludes that such self-supply or third-party purchase would impair reliability in the relevant PacifiCorp BAA or the interconnected system. PacifiCorp also reserves the right to terminate the self-supply or third-party purchase if, in its reasonable judgement, PacifiCorp concludes that such self-supply or third-party purchase is impairing reliability in the relevant PacifiCorp BAA or the interconnected system.~~

~~In the event that PacifiCorp rejects the request to self-supply or third-party purchase, or concludes that an existing self-supply or third-party purchase is impairing reliability, PacifiCorp will provide in writing detailed explanations for such determination and proposed remedy not less than thirty (30) calendar days from the customer's request to self-supply or third-party supply. Notice of rejection to self-supply or third-party purchase does not preclude a customer from reapplication.~~

~~G. If the~~ 5. The resource (or a resource dispatch center) must have a point of contact that is available any time the resource is designated for regulation and frequency response service.

6. The Transmission Customer must designate adequate resources to satisfy the Network Load obligation at all times. The designated resources must be under automatic generation control, satisfying all reserve requirements in real time and as required to compensate for instantaneous load swings or generation losses within the PacifiCorp BAA. The Transmission Provider reserves the right to determine the quantity and location of resources placed under AGC within the PacifiCorp BAA.

B. Resources Moved Electronically to External Balancing Authority

If the metered Network Load requiring ~~the spinning reserve~~imbalance service has been moved electronically into ~~another BAA~~an External Balancing Authority, certified by NERC or its successor organization, by means of a pseudo-tie, this Section ~~G~~B shall apply.

1. The pseudo-tie requires identification and observable ~~telemetry~~real-time metering of the specific Network Loads for which the service is to be provided. PacifiCorp requires a letter in advance from the ~~BAA that is supplying the spinning reserve ("Supplying~~External Balancing Authority~~")~~ which certifies that this service is supplied in accordance with all current policies and guidelines of the NERC Operating Manual~~ and/or the North American Energy~~, NERC Reliability Standards~~ Board (", or~~ NAESB~~")~~ standards, or any successor manual or standards, that apply to supplying Ancillary Services to loads that are located physically in ~~another~~an External Balancing Authority Area.

~~1~~2. PacifiCorp will accept, in lieu of the showing required in Section A.1 above, a letter in advance from the ~~Supplying~~External Balancing Authority which certifies that this service is supplied in accordance with all current policies and guides of the NERC Operating Manual ~~and/~~, NERC Reliability Standards, or NAESB standards, or

any successor manual or standards, that apply to supplying Ancillary Services to loads that are physically located in ~~another~~an External Balancing Authority Area.

~~2~~3. Whenever the pseudo-tie equipment providing the Network Load's data to PacifiCorp ~~and/~~or the ~~Supplying~~External Balancing Authority is not used ~~and/~~or not useable, the dispatcher for the entity that is not receiving the load signal shall immediately contact the dispatcher for the other entity to inform it of the loss of the signal. Thereafter, until both entities are again receiving the load signal through the pseudo-tie equipment, ~~PacifiCorp may call upon the Supplying Balancing Authority to provide (or, if it is not the supplier of the Network Load's spinning reserves, call upon the supplier of such spinning reserves to provide) spinning reserves when and to the extent requested~~the Transmission Customer should provide fixed schedules from the External Balancing Authority each hour to minimize the impact of load imbalance.

~~3~~4. If the ~~Supplying~~External Balancing Authority or the supplier of ~~spinning reserves~~ imbalance service fails to meet the requirements set forth in Section ~~G~~B.2 (i.e., fails to notify PacifiCorp of the ~~Supplying~~External Balancing Authority's loss of its ability to receive the Network Load's signal ~~and/~~or fails to supply ~~spinning reserves~~fixed schedule adjustments when called upon by PacifiCorp), PacifiCorp reserves the right to bill the ~~responsible party~~Transmission Customer for this service for the duration of the failure, including reimbursement for any penalties according to Schedules 4 or 9 in the PacifiCorp OATT, charges~~,~~ or other consequences ~~to~~ which PacifiCorp is subject to, related to the failure.

~~4~~5. PacifiCorp reserves the right to request more information from the ~~Supplying~~External Balancing Authority ~~and/~~or the Network Load's supplier of ~~spinning reserve~~imbalance service, in addition to the above referenced letter, to ensure that this service is supplied in a reliable manner. ~~PacifiCorp shall make best efforts to request further information no later than thirty (30) calendar days from the customer's request.~~

Further, PacifiCorp reserves the right to reject the request to self-supply or third-party supply such service, ~~or purchase it from another source,~~ in the event that PacifiCorp, in its reasonable ~~judgement~~judgment, concludes that such self-supply or third-party purchase would impair reliability in the relevant PacifiCorp ~~Balancing Authority Area~~BAA or the interconnected system. PacifiCorp also reserves the right to terminate the self-supply or third-party ~~purchase~~supply if, in its reasonable ~~judgement~~judgment, PacifiCorp concludes that such self-supply or third- party ~~purchase~~supply is impairing reliability in the relevant PacifiCorp Balancing Authority Area or the interconnected system.

~~In the event that PacifiCorp rejects the request to self-supply or third-party purchase, or concludes that an existing self-supply or third-party purchase is impairing reliability, PacifiCorp will provide in writing detailed explanations for such determination, proposed remedy not less than thirty (30) calendar days from the customer's request to self-supply or third-party supply. Notice of rejection to self-supply or third-party purchase does not preclude customer from reapplication.~~

~~H. During periods when reserve deployment is required, PacifiCorp will notify the Customer either through electronic means or by phone call that reserves are required, the amount of reserves to deploy and the appropriate length of time of deployment. Specific notice arrangements will be agreed to between the Customer and PacifiCorp during the certification process.~~

~~Energy supplied by a Customer during periods of reserve deployment will be settled financially for the amount of energy deployed as represented on the Customer adjusted energy profile of the capacity tag(s) for~~

4.4 SCHEDULE 9 – GENERATOR IMBALANCE SERVICE

A. Self-Supply Under Schedule 3 Entities

For load serving entities who have certified as a self-supply entity for regulation and frequency response service (Schedule 3) under the requirements of this Attachment U and request generator imbalance self-certification, this Section A shall

apply. Generator Imbalance Service may be self-supplied from Resources or undesignated Network Resources located within the PacifiCorp BAA under the limited set of conditions defined below. Self-supply of Generator Imbalance service created by fixed point-to-point schedules can only be provided for resources located in the PacifiCorp BAA.

~~**External Resources** and for Internal Resources not represented in the network model. Resources supplying reserves that are represented in the network model will not receive separate energy settlement. These resources will receive settlements per Schedule 9 of PacifiCorp's OATT for Non-Participating Resources or directly from CAISO for Participating Resources.~~

~~Financial settlement for Internal Resources not in the network model and External Resources will be settled based on the integrated tag value multiplied by the hourly settled PACE or PACW ELAP price, adjusted for losses consistent with PacifiCorp's OATT.~~

~~**Operating Reserve - Supplemental Reserve Service (Schedule 6):**~~ ~~This service may be self-supplied or purchased from any qualifying unit, system, or qualifying interruptible load to meet the Network Load Transmission Customer's reserve obligation. The unit or system must consist of one or more quick-start units that are off-line but capable of serving demand in 10 minutes, or uncommitted available capacity that is on-line and loaded at less than maximum owned or contracted output which can be fully applied in 10 minutes. The interruptible load must be located within PacifiCorp Balancing Authority Area and must be capable of being interrupted within 10 minutes in the reasonable judgement of PacifiCorp. The specific resources for which the service is being provided must be identified and have observable telemetry. The party requesting to self-supply or arranging for third-party purchase shall, at its own expense, install the necessary equipment (including but not limited to metering and telecommunications equipment) for providing the service. The party requesting to self-supply or arranging for third-party purchase shall also reimburse PacifiCorp or its affiliates for any expenses incurred to accommodate the request for self-supply or third-party supply.~~

~~A. Use of an External Resource:~~

~~For generation external to PacifiCorp's BAAs to qualify for self-supply or third-party supply service, a dynamic transfer coming into PacifiCorp's EMS as a dynamic schedule into the balancing authority area where the obligation originates, represented on a dynamic e-Tag is sufficient for communication with PacifiCorp's EMS. The author of the e-Tag is responsible for adjusting the energy profile to match the resource output for self-supply until such time as an automated process can be developed and implemented to relieve the author of this responsibility.~~

~~**B.**~~ The following information will be required to demonstrate that the self-supply ~~or third-party purchase~~ of ~~supplemental reserve~~generator imbalance service ~~for Internal Resources~~created by point-to-point schedules during generator derates or unit tripping:

- ~~The generation resources providing the service must be located in the same PacifiCorp Balancing Authority Area as the Network Load or contractual~~

~~point of receipt and must have observable telemetry.~~

- ~~Requirements for self-supply or third-party purchase of supplemental reserve service shall apply at the unit level if PacifiCorp's network model includes the resource by unit or at the plant level if PacifiCorp's network model includes the resource at the plant level.~~

1. The resources providing the service must have observable real time metering. In addition, PacifiCorp will define specific OASIS scheduling points of receipt which will apply to Customer's requesting self-supply. Customers will be obligated to demonstrate self-supply from these specific OASIS points of receipt within the PacifiCorp BAA for purposes of this section. The current list of OASIS points of receipt for section is ("PACE", "PACEW", and "PACW"). PacifiCorp reserves the right to modify this list without notice as required to maintain transmission system reliability and compliance with the PacifiCorp OATT.

2. Documentation that the ~~generation~~ resources are deliverable ~~Network~~ Resources ~~as~~or Network Resources and are defined by a current Network Integration Transmission Service Agreement, ~~a~~interconnection agreement, or legacy load service agreement on file at FERC~~, or other firm PTP agreement, which may be reported on PacifiCorp's Electric Quarterly Report ("EQR").~~.

- ~~For self-supply arrangements through a power purchase agreement, a copy of the capacity agreement(s) or contract(s) that can be used to verify that the capacity used for this service is dedicated to serve the designated metered Network Load, and is not being used to satisfy any other capacity obligations.~~

- ~~If interruptible load is used, explicit description of the load, curtailment method, process utilized to trigger the curtailment and interruptible contract.~~

- ~~Deployment capability must be proven by the self-supply Customer in a fashion acceptable to PacifiCorp. Requirements will depend on the type resource claimed as supplemental reserves and may~~

~~include load trip testing or requesting an unplanned start on a reserve generator. Procedures must be validated prior to certification and also may require at least bi-annual validation.~~

- ~~Access to logs, dispatch records and test data that can be used to verify that supplemental reserves are available and not fully loaded, and are capable of being applied as reported. Resource capability for self-supply of reserves shall mean the operational capability of the unit to actually deliver the reserve energy in the event of a deployment based on the operational capability characteristics of the self-supply resource (i.e., ramp rates, PMax).~~

- ~~Self-suppliers must provide a monthly reserve supply forecast no less than thirty (30) calendar days before the beginning of the month with amounts (MWs) in all hours for that month based on the forecasted percentage of reserve obligation. This 30-day forecast requirement does not replace or satisfy separate seven-day forecast requirements established by Peak Reliability and the California Independent System Operator ("CAISO").~~

- ~~Self-suppliers must provide day-ahead information via e-Tag. In the day-ahead, the reserve supply forecast must be updated for the next operating day with the amount (MWs) of reserve obligation the self-supplier expects to actually be providing in all hours.~~

- 3. Any Network Resources used to supply point-to-point imbalance service must be undesignated according to the PacifiCorp business practice, "Termination of Network Resources", consistent with section 30.3 of the PacifiCorp OATT. The resources utilized must be undesignated from within specified OASIS points of receipt to self-supply point-to-point transactions originating from that particular point of receipt.

4. Resources or undesignated Network Resources must be on-line, spinning, and responsive to the loss of another undesignated unit.

5. The hourly quantity of resources or undesignated Network Resources with a point of receipt plus the

purchases made and delivered on point-to-point service into each PacifiCorp point of receipt must exceed the total quantity of point-to-point transactions exiting the defined point of receipt and PacifiCorp BAA for each hour.

6. Adequate resources must remain 'designated' and available for load service as required to satisfy the Customer's Network Load obligation at all times during any period of point-to-point self-supply.

7. The party claiming generation imbalance self-supply must be previously certified as self-providing, or purchasing from third parties, regulation and frequency response service (Schedule 3) as specified in this Attachment U.

8. A point of contact is always available, all hours, every day to be used to call on ~~the reserves~~resources necessary for load coverage.

~~C. For self-supply and third-party purchases of this service, reserves must be scheduled using a capacity e-Tag consistent with PacifiCorp Business Practice #39, E-Tagging of Reserves. Also, consistent with Business Practice #39, when the service is needed, the reserves must be deployed by the Customer through a mid-hour tag adjustment to the energy profile. PacifiCorp will confirm customer reserves are being held via e-Tag.~~

~~Once confirmation is validated, PacifiCorp will place a phone call or adjust a capacity tag through an automated process to communicate a loss of generation in the appropriate Balancing Authority and request deployment of reserves for the appropriate length of time. PacifiCorp will provide an annual report to Customers demonstrating non-discriminatory deployment of reserves.~~

~~D. In the event that any of the above requirements fail to be met, then PacifiCorp reserves the right to bill the responsible party for this service as supplied by PacifiCorp for the duration of the failure, including reimbursement for any compliance-related penalties, charges or other consequences which PacifiCorp is subject to related to the failure. If the Customer fails to self-supply its supplemental reserves as defined in this section and fails to notify PacifiCorp to make arrangements for service, the Customer will be subject to~~

supplemental reserve service as defined in Schedule 6 of PacifiCorp's OATT.

E. The service hereunder must be available to be called on by PacifiCorp to comply with the NERC Disturbance Control Standard (NERC BAL-002-2 or any successor Reliability Standard thereto), and any such other related criteria or standards which may be imposed by a national or regional reliability council or governing regulatory body. The service will also be used by PacifiCorp to comply with its obligations under the Northwest Reserve Sharing Group Contract and any future Reserve Sharing Group of which PacifiCorp or its affiliates are a member. The supplying party must, at its own expense, make the necessary arrangements, in coordination with PacifiCorp, to be able to respond to a Reserve Sharing event. The supplying party is not required to have a separate relationship or agreement with the Northwest Power Pool Reserve Sharing Group.

F. PacifiCorp reserves the right to request more information from the party requesting self-supply or third-party supply and/or its supplier of supplemental reserve service, in addition to the above-listed information, to ensure that this service is supplied in a reliable manner. PacifiCorp shall make best efforts to request further information no later than thirty (30) calendar days from the customer's request to self-supply or third-party supply.

Further, PacifiCorp reserves the right to reject the request to self-supply such service, or purchase it from another source, in the event that PacifiCorp, in its reasonable judgement, concludes that such self-supply or third-party purchase would impair reliability in the relevant PacifiCorp BAA or the interconnected system. PacifiCorp also reserves the right to terminate the self-supply or third-party purchase if, in its reasonable judgement, PacifiCorp concludes that such self-supply or third-party purchase is impairing reliability in the relevant PacifiCorp BAA or the interconnected system.

In the event that PacifiCorp rejects the request to self-supply or third-party purchase, or concludes that an existing self-supply or third-party purchase is impairing reliability, PacifiCorp will provide in writing detailed explanations for such determination, proposed remedy not less than thirty (30) calendar days from the customer's request to self-supply or third-party supply. Notice of

~~rejection to self-supply or third-party purchase does not preclude customer from reapplication.~~

~~G. If the metered Network Load~~

B. Resources Moved Electronically to External Balancing Authority

If the Resource requiring ~~the reserves~~imbalance service has been moved electronically into ~~another BAA~~an External Balancing Authority Area, certified by NERC or its successor organization, by means of a pseudo-tie, this Section ~~G shall apply. B~~ shall apply. The point-to-point transmission service for the pseudo-tie resource will be established. Intra-hour transfers and the associated transmission service provided will be defined as the instantaneous output of the resource, therefore imbalance will be deemed to be self-supplied. End of hour true-ups of actual hourly integrated values are required for Balancing Authority Area energy accounting purposes.

1. The pseudo-tie requires identification and observable ~~telemetry~~real-time metering of the specific ~~Network Loads~~Resource for which the service is to be provided.

~~1.~~ PacifiCorp ~~will accept, in lieu of the showing required in Section A above,~~requires a letter in advance from the ~~BAA that is supplying the supplemental reserve ("Supplying~~ External Balancing Authority~~"),~~ which certifies that this service is supplied in accordance with all current policies and guidelines of the NERC Operating Manual ~~and/~~, NERC Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Ancillary Services to loads that are located physically in another Balancing Authority Area.

~~2~~2. PacifiCorp will accept, in lieu of the showing required in Section A.1 above, a letter in advance from the External Balancing Authority which certifies that this service is supplied in accordance with all current policies and guides of the NERC Operating Manual, NERC Reliability Standards, or NAESB standards, or any successor manual or standards, that apply to supplying Ancillary Services to resources that are electronically transferred into another Balancing Authority.

3. Whenever the pseudo-tie equipment providing the ~~Network Load's~~Resource's data to PacifiCorp ~~and/~~or the

~~Supplying~~External Balancing Authority is not used ~~and/~~or not useable, the dispatcher for the entity that is not receiving the load signal shall immediately contact the dispatcher for the other entity to inform it of the loss of the signal. Thereafter, until both entities are again receiving the load signal through the pseudo-tie equipment, ~~PacifiCorp may call upon the Supplying~~the Transmission Customer should provide fixed schedules from the External Balancing Authority each hour to ~~provide supplemental reserves when and to the extent requested~~minimize the impact of generator imbalance.

~~3. If the Supplying Balancing Authority or the supplier of spinning reserves fails to meet the requirements set forth in Section G.2 (i.e., fails to notify PacifiCorp of the Supplying Balancing Authority's loss of its ability to receive the load signal and/or fails to supply supplemental reserves when called upon by PacifiCorp), PacifiCorp reserves the right to bill the responsible party for this service for the duration of the failure, including reimbursement for any penalties, charges, or other consequences which PacifiCorp is subject to related to the failure.~~

~~4. PacifiCorp reserves the right to request more information from the Supplying Balancing Authority and/or the Network Load's supplier of the supplemental reserves, in addition to the above referenced letter, to ensure that this service is supplied in a reliable manner. PacifiCorp shall make best efforts to request further information no later than thirty (30) calendar days from the customer's request.~~

~~Further, PacifiCorp reserves the right to reject the request to self-supply such service, or purchase it from another source, in the event that PacifiCorp, in its reasonable judgement, concludes that such self-supply or third-party purchase would impair reliability in PacifiCorp's Balancing Authority Area or the interconnected system. PacifiCorp also reserves the right to terminate the self-supply or third-party purchase if, in its reasonable judgement, PacifiCorp concludes that such self-supply or third-party purchase is impairing reliability in the relevant PacifiCorp Balancing Authority Area or the interconnected system.~~

~~In the event that PacifiCorp rejects the request to self-supply or third-party purchase, or concludes that an existing self-supply or third-party purchase is impairing reliability, PacifiCorp will provide in writing detailed explanations for such determination, proposed remedy not less than thirty (30) calendar days from the customer's request to self-supply or third-party supply. Notice of rejection to self-supply or third-party purchase does not preclude customer from reapplication.~~

~~H. During periods when reserve deployment is required, PacifiCorp will notify the Customer either through electronic means or by phone call that reserves are required, the amount of reserves to deploy and the appropriate length of time of deployment. Specific notice arrangements will be agreed to between the Customer and PacifiCorp during the certification process.~~

~~Energy supplied by a Customer during periods of reserve deployment will be settled financially for the amount of energy deployed as represented on the Customer adjusted energy profile of the capacity tag(s) for External Resources and for Internal Resources not represented in the network model. Resources supplying reserves that are represented in the network model will not receive separate energy settlement. These resources will receive settlements as uninstructed imbalances per Schedule 9 of PacifiCorp's OATT for Non-Participating Resources or direct from CAISO for Participating Resources.~~

~~Financial settlement for Internal Resources not in the network model and External Resources will be settled based on the integrated tag value multiplied by the hourly settled PACE or PACW ELAP price, adjusted for losses consistent with PacifiCorp's OATT.~~

EXHIBIT G

CLEAN AND MARKED VERSIONS OF PACIFICORP BUSINESS PRACTICE NO. 39

Business Practice #39: Electronic Tagging of Reserves ("e-Tags")

Posted: ***TBD***
Effective: ***TBD***
Revision No.: 6.0

NOTICE
A redline version showing the latest revision to this business practice is available at:
https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/BP39red.pdf

Policy Reference

PacifiCorp's Open Access Transmission Tariff ("OATT"), Schedule 5 ("Operating Reserve – Spinning Reserve Service) and Schedule 6 ("Operating Reserve – Supplemental Reserve Service).

Definitions

The following definitions and those currently contained in the OATT, North American Electric Reliability Corporation ("NERC") Reliability Standards, North American Energy Standards Board ("NAESB") Business Practice Standards and the NAESB Electronic Tagging Functional Specification document, and Western Electricity Coordinating Council ("WECC") Regional Criteria are required for this business practice.

Capacity e-Tag – A tag type used for the specific purpose of importing operating reserves. A Capacity e-Tag will define a level of transmission capacity set aside for the use of operating reserve transfers, mid-hour, when required. Available Transfer Capability ("ATC") in the opposite direction to an established and tagged Capacity e-Tag will not be incremented for firm and non-firm use for the duration of the e-Tag. Capacity e-Tags are required to be activated upon contingency with zero ramp durations.

Dynamic e-Tag - A dynamic schedule is scheduled using an expected value but the actual energy transfer is determined in real time by separate communications external to the e-Tag system. The Dynamic e-Tag should contain the expected average energy in the energy profile and contain the maximum expected energy in the Transmission Allocation prior to the operating hour. The energy profile of the Dynamic e-Tag(s) must be adjusted by the e-Tag Author to the actual interchange value within10 minutes after completion of the operating hour using values obtained from a common agreed on source.

Purpose

The purpose of this business practice is to define the process for the use of e-Tags (both Capacity and Dynamic e-Tags) to deliver operating reserves across posted paths. This business practice applies to all Transmission Customers unless explicitly contradicted by contract terms.

Practice

The following are the requirements of PacifiCorp, for Transmission Customers that wish to self-supply or to arrange for third-party purchase of Schedule 5 – Operating Reserve – Spinning Reserve Service and Schedule 6 – Operating Reserve – Supplemental Reserve Service. PacifiCorp requires that the self-supplied or third-party supplied Ancillary Services satisfy the requirements of this business practice, Attachment U in the PacifiCorp OATT, and the relevant reliability standards of NERC or any successor organization.

Request for e-Tag:

Capacity e-Tag:
Transmission Customers may utilize Capacity e-Tag to supply Schedule 5 and 6 services with resources located externally to the PacifiCorp Balancing Authority Area by selecting Capacity as the transaction type.

Dynamic e-Tag:
Transmission Customers may utilize a Dynamic e-Tag to supply Schedule 5 and 6 services with resources located externally to the PacifiCorp Balancing Authority Area by applying to, and meeting requirements for, use of a Dynamic e-Tag. The application process is explained in Business Practice #25.

Use of e-Tags by Type:

PacifiCorp will communicate the reserves needed to respond to a contingency event by sending an automatic signal of the reserve amount to the Transmission Customer. During a contingency event, the amount of Schedule 5 and 6 reserves called upon for each self-supplying Transmission Customer will be calculated as follows:

(Customer scheduled self-supply / Total PacifiCorp BAA (PACE or PACW) Contingency Reserve Obligation) * Generation Loss

If the calculation results in a fraction of a MW, then the resulting fraction or decimal will be rounded up to the nearest MW.

Capacity e-Tags:
The following information will be required to demonstrate the self-supply or third-party purchase of spinning reserve service for External Resources using a Capacity e-Tag:

1. During periods within the hour when contingency reserves are required, the Transmission Customer must submit an adjustment of the energy profile on the e-Tag reflecting the amount of energy flow anticipated for the balance of the hour and subsequent hour. The adjustment must be made within 7 minutes upon the need to call on spinning or non-spinning reserves.

2. Transmission Customers who self-supply or arrange for third-party purchase of ancillary services (i.e. spinning or supplemental reserves) must keep PacifiCorp informed of any change in their ability to supply the required ancillary services. PacifiCorp will consider an advance adjustment or withdrawal of the Transmission Customer's previously submitted Capacity e-Tag as such notification.

Dynamic e-Tags:
The following information will be required to demonstrate the self-supply or third-party purchase of spinning reserve service for External Resources using a Dynamic e-Tag:

1. The generating resource Balancing Authority must have the ability to provide an automated after the fact e-Tag adjustment within 30 minutes following the completion of the operating hour where the spinning or non-spinning reserve service was deployed. The e-Tag shall use the value obtained from a common agreed on source, and contingent on the transmission path used for the Dynamic e-Tag, the e-Tag data will be submitted into the CAISO EIM as part of the base schedules for interchange.

2. Transmission Customers who self-supply or arrange for third-party purchase of ancillary services (i.e. spinning or supplemental reserves) must keep PacifiCorp informed of any change in their ability to supply the required ancillary services. PacifiCorp will consider an advance adjustment or withdrawal of the Transmission Customer's previously submitted Dynamic e-Tag as such notification.

Specification of Reserve Type
When e-Tagging reserves, please include one of the following in the comment field to identify the specific type of reserve being e-Tagged:

- RES-SPIN-PUR = Purchased Spinning Reserves
- RES-SPIN-SP = Self-Provided Spinning Reserves
- RES-NS-PUR = Purchased Non-Spinning Reserves
- RES-NS-SP = Self-Provided Non-Spinning Reserves

Contacts for Assistance: businesspractices@pacificorp.com

Revision History

Version	Date	Change Summary
6.0	TBD	Updated e-Tags used to support an automated self-supply process and removed the use of a capacity e-tag for regulation self-supply.
5.0	12/13/13	Added bullet to explain to Self-Supplying Customers what to do if they lose their ability to Self-Supply
4.0	11/21/12	Revised to add further clarity and formatted the business practice to standard template. Notice section updated with new web OASIS link.
3.0	9-24-10	Per customer comment, removed bullet under "Use of Capacity e-Tags" section that allowed intra-hour e-Tag adjustments to not be required for use internal to PacifiCorp Balancing Area for certain uses
2.0	7-2-09	"Specification of Reserve Type" section
1.0	7-8-08	No changes made to draft – Post to OASIS
1.0	5-12-08	Modification to eliminate capacity reservations and re-direct requirements. Use of capacity tags is substituted.
0.0	3-21-08	

Business Practice #39: Electronic Tagging of Reserves ("e-Tags")

Posted: ~~December 13, 2013~~***TBD***
Effective: ~~December 31, 2013~~***TBD***
Revision No.: ~~5~~6.0

NOTICE
A redline version showing the latest revision to this business practice is available at:
https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/BP39red.pdf

Policy Reference

PacifiCorp's Open Access Transmission Tariff ("OATT"), Schedule 5 ("Operating Reserve – Spinning Reserve Service) and Schedule 6 ("Operating Reserve – Supplemental Reserve Service).

Definitions

~~No~~The following definitions ~~other than the following~~ and those currently contained in the OATT, North American Electric Reliability Corporation ("NERC") Reliability Standards, North American Energy Standards Board ("NAESB") Business Practice Standards and the NAESB Electronic Tagging Functional Specification document, and Western Electricity Coordinating Council ("WECC") Regional Criteria are required for this business practice.
~~practice.~~

Capacity e-Tag – A tag type used for the specific purpose of ~~accommodating~~importing operating ~~or regulating~~ reserves ~~across a constrained transmission path.~~. A Capacity e-Tag will define a level of transmission capacity set aside for the use of operating ~~or regulating~~ reserve transfers, mid-hour, when required. Available Transfer Capability ("ATC") in the opposite direction to an established and tagged Capacity e-Tag will not be incremented for firm and non-firm use for the duration of the e-Tag. Capacity e-Tags are required to be activated upon contingency with zero ramp durations.

Dynamic e-Tag - A dynamic schedule is scheduled using an expected value but the actual energy transfer is determined in real time by separate communications external to the e-Tag system. The Dynamic e-Tag should contain the expected average energy in the energy profile and contain the maximum expected energy in the Transmission Allocation prior to the operating hour. The energy profile of the Dynamic e-Tag(s) must be adjusted by the e-Tag Author to the actual interchange value within10 minutes after completion of the operating hour using values obtained from a common agreed on source.

Purpose

The purpose of this business practice is to define the ~~processing~~process for the use of e-Tags (both Capacity and Dynamic e-Tags) to deliver operating reserves across posted ~~and/or constrained transmission~~ paths. This business practice applies to all Transmission Customers unless explicitly contradicted by contract terms.

Practice

The following are the requirements of PacifiCorp, for Transmission Customers that wish to self-supply or to arrange for third-party purchase of Schedule 5 – Operating Reserve – Spinning Reserve Service and Schedule 6 – Operating Reserve – Supplemental Reserve Service. PacifiCorp requires that the self-supplied or third-party supplied Ancillary Services satisfy the requirements of this business practice, Attachment U in the PacifiCorp OATT, and the relevant reliability standards of NERC or any successor organization.

Request for ~~Capacity~~ e-Tag:

Capacity e-Tag:

Transmission Customers may utilize Capacity e-Tag to supply Schedule 5 and 6 services with resources located externally to the PacifiCorp Balancing Authority Area by selecting Capacity as the transaction type.

Dynamic e-Tag:

Transmission Customers may utilize a Dynamic e-Tag to supply Schedule 5 and 6 services with resources located externally to the PacifiCorp Balancing Authority Area by applying to, and meeting requirements for, use of a Dynamic e-Tag. The application process is explained in Business Practice #25.

Use of ~~Capacity~~ e-Tags by Type:

PacifiCorp will communicate the reserves needed to respond to a contingency event by sending an automatic signal of the reserve amount to the Transmission Customer. During a contingency event, the amount of Schedule 5 and 6 reserves called upon for each self-supplying Transmission Customer will be calculated as follows:

(Customer scheduled self-supply / Total PacifiCorp BAA (PACE or PACW) Contingency Reserve Obligation) * Generation Loss

If the calculation results in a fraction of a MW, then the resulting fraction or decimal will be rounded up to the nearest MW.

Capacity e-Tags ~~will be accepted consistent with all other~~:

The following information will be required to demonstrate the self-supply or third-party purchase of spinning reserve service for External Resources using a Capacity e-~~Tags with limited exceptions. These exceptions include~~Tag:

1. During periods within the hour when contingency reserves are required, the Transmission Customer must submit an adjustment of the energy profile on the e-Tag reflecting the amount of energy flow anticipated for the balance of the hour and subsequent ~~hours~~hour. The adjustment must be made ~~immediately~~within 7 minutes upon the need to call on spinning or non-spinning reserves.

2. Transmission Customers who self-supply or arrange for third-party purchase of ancillary services (~~I~~i.e. spinning or supplemental reserves) must keep PacifiCorp informed of any change in their ability to supply the required ancillary services. PacifiCorp will consider an advance adjustment or withdrawal of the Transmission Customer's previously submitted Capacity e-Tag as such notification. ~~In the event of a disturbance, where the Transmission Customer is not able to provide its own ancillary services, PacifiCorp will supply such ancillary services and bill the Transmission Customer at the full rate as described in OATT Schedules 5 – Spinning Reserve Service and 6 – Supplemental Reserves Service.~~

- ~~Regulating reserves external~~

Dynamic e-Tags:

The following information will be required to demonstrate the ~~PacifiCorp~~ self-supply or third-party purchase of spinning reserve service for External Resources using a Dynamic e-Tag:

1. The generating resource Balancing Authority ~~Area will require a dynamic signal from~~ must have the ~~resource~~ability to ~~PacifiCorp automatic generation control system (AGC). Regulating reserves will be transferred via dynamic e-Tag and require hourly updates of energy flow~~provide an automated after the fact e-Tag adjustment within ~~60~~30 minutes following the completion of the ~~close of the~~operating hour ~~for all hours~~where the spinning or non-spinning reserve service was deployed. The e-Tag shall use the value obtained from a common agreed on source, and contingent on the transmission path used for the Dynamic e-Tag, the e-Tag data will be submitted into the CAISO EIM as part of the base schedules for interchange.

~~1.~~2. Transmission Customers who self-supply or arrange for third-party purchase of ~~scheduled use~~ancillary services (i.e. spinning or supplemental reserves) must keep PacifiCorp informed of any change in their ability to supply the required ancillary services. PacifiCorp will consider an advance adjustment or withdrawal of the Transmission Customer's previously submitted Dynamic e-Tag as such notification.

Specification of Reserve Type

When e-Tagging reserves, please include one of the following in the comment field to identify the specific type of reserve being e-Tagged:

- RES-SPIN-PUR = Purchased Spinning Reserves
- RES-SPIN-SP = Self-Provided Spinning Reserves
- RES-NS-PUR = Purchased Non-Spinning Reserves

- RES-NS-SP = Self-Provided Non-Spinning Reserves

Contacts for Assistance: businesspractices@pacificorp.com

Revision History

Version	Date	Change Summary
6.0	TBD	Updated e-Tags used to support an automated self-supply process and removed the use of a capacity e-tag for regulation self-supply.
5.0	12/13/13	Added bullet to explain to Self-Supplying Customers what to do if they lose their ability to Self-Supply
4.0	11/21/12	Revised to add further clarity and formatted the business practice to standard template. Notice section updated with new web OASIS link.
3.0	9-24-10	Per customer comment, removed bullet under "Use of Capacity e-Tags" section that allowed intra-hour e-Tag adjustments to not be required for use internal to PacifiCorp Balancing Area for certain uses
2.0	7-2-09	"Specification of Reserve Type" section
1.0	7-8-08	No changes made to draft – Post to OASIS
1.0	5-12-08	Modification to eliminate capacity reservations and re-direct requirements. Use of capacity tags is substituted.

~~0.0~~	3-21-08	

EXHIBIT H

CLEAN AND MARKED VERSIONS OF PACIFICORP BUSINESS PRACTICE NO. 63

Business Practice #63: Transmission Customer Provision of Reactive Supply and Voltage Control from Generation or Other Sources Service

Posted: ***TBD***
Effective: **TBD**
Revision No.: 2.0

NOTICE
A redline version of the most recent revisions to this business practice is available at:
https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/BP63red.pdf

Policy Reference

PacifiCorp's Open Access Transmission Tariff ("OATT"), Schedule 2 – Reactive Supply and Voltage Control from Generation or Other Sources Service ("Reactive Supply and Voltage Control Service"), and PacifiCorp Planning Policy No. 139 – Facility Connection Requirements for Transmission Systems (46 kV and Higher Voltages).

Definitions

No definitions other than those currently contained in PacifiCorp's OATT are required for this business practice.

Purpose

The purpose of this business practice is to establish a Transmission Customer's option to self-supply Schedule 2, Reactive Supply and Voltage Control Service, for its own transactions, including the eligibility requirements that a Transmission Customer must satisfy to self-supply Schedule 2 service and receive a corresponding credit from Transmission Provider. Any Transmission Customer or Interconnection Customer that has a rate schedule for Reactive Supply and Voltage Control on file with the Federal Energy Regulatory Commission for any generator or other resource located within PacifiCorp BAA will not be eligible to receive this credit from the Transmission Provider.

Practice

All transactions requiring Transmission Service over Transmission Provider's transmission facilities require the provision of Reactive Supply and Voltage Control Service in accordance with Schedule 2. Pursuant to Schedule 2 of PacifiCorp's OATT, Reactive Supply and Voltage Control Service is to be provided directly by the Transmission Provider (if the Balancing Authority ("BA")) or indirectly by the Transmission Provider making arrangements with the BA that performs this service for

the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the BA.

A Transmission Customer may be eligible to provide all or a portion of its reactive supply and voltage control obligations from a qualifying resource. Qualifying resources must meet the minimum criteria described in this business practice to self-supply all or a portion of its Reactive Supply and Voltage Control obligations. To the extent a Transmission Customer can self-supply Reactive Supply and Voltage Control Service for at least a portion of its Schedule 2 transactions through a qualifying resource, it will be eligible to receive a Schedule 2 credit through the mechanism described in this business practice.

Qualifying Resource Requirements to supply Reactive Supply and Voltage Control Service

The Transmission Customer must make an application (in the attached form) to the Transmission Provider requesting approval of its use of a qualifying resource to self-supply Reactive Supply and Voltage Control Service to offset all or a part of its obligations under Schedule 2. Qualifying resources must demonstrate the following characteristics, among other things, as set forth in the Application for Provision of Reactive Supply and Voltage Control from Generation and Other Sources Service, to be eligible for a Schedule 2 credit:

1) The resource must be able to provide reactive power within the power factor range of 0.95 leading to 0.95 lagging.

2) All qualifying resources shall be controlled by an automatic voltage regulator system having the capability for both voltage regulation and net power factor regulation operating modes.

3) All qualifying resources shall be accurately modeled within the PacifiCorp EMS system to ensure real-time visibility of the resource from the resource's RTU.

4) The generator must follow the voltage schedule supplied by the Transmission Provider. If no voltage schedule is provided, the generator must operate at the nominal voltage level, unless called upon by the BA to do otherwise. Additionally, if there is a voltage event on the system, then the resource must be able to respond due to the local change in voltage.

5) The resource must be capable of responding automatically to voltage or reactive control settings and to manual directives from the BA, as defined

in the OATT, when called upon to supply reactive support (either to generate or absorb reactive energy) to PacifiCorp's Transmission System. Automatic response must be immediate and manual response must occur within five minutes of notice. Transmission Customers whose resources fail to respond as directed by the BA two times within a rolling twelve month period will be disqualified from the self-supply credit for that month and future months until such time as the Transmission Customer demonstrates to the BA that its resource can be relied upon to generate or absorb reactive energy, as described above. The Transmission Customer shall coordinate a test of its resource with PacifiCorp to demonstrate that the resource is capable of providing voltage support.

6) The resource must be located within the PacifiCorp BA and interconnected to PacifiCorp's Transmission System or connected to a PacifiCorp Network transmission customer-owned transmission system within PacifiCorp's Balancing Authority Area ("BAA").

7) At least every five years (with no more than 66 calendar months between verifications), each Transmission Customer shall certify to PacifiCorp that the resource(s) it uses to self-supply its Schedule 2 requirements can operate at nameplate MVA, MW and MVAR ratings through performing a MOD-25 or comparable test. The test results shall be sent to PacifiCorp with the application below to demonstrate the resource's capability. In the event that the resource(s) are unable to operate at nameplate ratings, such ratings will be adjusted downward to reflect the degradation in the operation of the resource(s), and the adjusted real power values (MWs) will be used in the crediting process, until such time that the Transmission Customer can re-certify to PacifiCorp that that the resource(s) it uses to self-supply its Schedule 2 requirements can operate at nameplate MVA, MW and MVAR ratings.

Any resources jointly owned by PacifiCorp and a Transmission Customer subject to Schedule 2 charges and for which PacifiCorp's costs are included in the calculation of Reactive Supply and Voltage Control Service rates, shall be deemed qualified. If a Transmission Customer jointly owns a resource and/or only wants to qualify part of a resource, the Transmission Customer must specifically state the resource parameters for what will be applied towards the Schedule 2 credit. Specifically, the Transmission Customer will need to provide the resource and accompanying characteristics, the generator unit interactions with other generating units (if applicable), ownership share information (if applicable), or any other information as determined by PacifiCorp as relevant.

Credit Mechanism

The self-supply credit is based upon the capability of the qualifying resource. To qualify for this credit mechanism, the Transmission Customer's qualifying resource shall meet the Qualifying Resource Requirements to supply Reactive Supply and Voltage Control Service described above. The Schedule 2 credit shall be based upon the real power (MW) capability of the resource. The Transmission Customer will be charged the difference between its Schedule 2 obligations for its Network Load or point-to-point transmission service and the resource's capability times the currently effective Schedule 2 rate. The total Reactive Supply and Voltage Control Service self-supply credit shall not exceed the total amount of the Schedule 2 charge which otherwise would be assessed to the Transmission Customer for load located within the BAA or for point-to-point transmission service. Notwithstanding, any resource that is used to reduce a Transmission Customer's Network Load is not eligible to receive a Schedule 2 credit, as the resource is already reducing the Network Load upon which Schedule 2 is assessed. However, if that resource is tracked in the network model and not netted against load, then the resource would be eligible to receive a credit against Schedule 2 charges subject to the required operating requirements outlined in this business practice. Upon approval by the Transmission Provider, the details for the specific qualifying resource and crediting mechanisms will be described in the Transmission Customer's agreement for Transmission Service with the Transmission Provider.

Contact for Assistance: BusinessPractices@PacifiCorp.com

Revision History

Version	Posted Date	Change Summary
2.0	TBD	Added qualifying resource language to include renewable resources and add capability testing requirements. Updated the credit mechanism for the credit to be based on the reactive power capability of the resource.
1.0	3/6/2017	Clarifications to Qualifying Generator Requirements and the attached Application for Provision of Reactive Supply and Voltage Control from Generation or Other Sources Service to clarify generator requirements and information needed to evaluate requests submitted pursuant to this Business Practice.
0.0	5/1/13	In the attached Application for Provision of Reactive Supply and Voltage Control from Generation or Other Sources Service, specified that the completed application and documentation should be sent to the BusinessPractices@PacifiCorp.com e-mail address and added a footnote to clarify when PacifiCorp considers the documentation requirement fulfilled.
DRAFT	2/22/13	Initial draft posted for public comment

Application for Provision of Reactive Supply and Voltage Control from Generation or Other Sources Service

Transmission Customer Name: _____

Address: _____

Contact Name: _____

Contact Phone: _____

Pursuant to PacifiCorp OATT's and Business Practice #63, the above-listed Transmission Customer requests to provide all or a portion of the following Ancillary Service:

_____ **Reactive Supply and Voltage Control from Generation or Other Sources Service – Schedule 2**

Transmission Customer shall complete this application for each generator it seeks to qualify. Transmission Customer certifies it has one or more resources qualified to provide a portion or all of its obligations for the Ancillary Service selected above in conformance with the requirements in PacifiCorp's OATT and outlined in PacifiCorp Business Practice #63 – Transmission Customer Provision of Reactive Supply and Voltage Control from Generation or Other Sources Service. Transmission Customer submits the attached completed form for each such resource. Submission of this application and any supporting documentation should be sent to BusinessPractices@PacifiCorp.com. In addition, Transmission Customer understands that Transmission Provider may request additional information as needed to further support the documentation given herein.

Application for Provision of Reactive Supply and Voltage Control from Generation or Other Sources Services (cont'd)

1. Please list resource providing the service along with its nameplate capacity; will the full facility be used or only part?

_____

_____

2. Please indicate by what means the resource listed above are deliverable. Please list applicable transmission service agreement for the resource identified above.

_____

_____

3. Please provide a point of contact for the resource listed above (or a resource dispatch center) that is available any time the resource is providing reactive supply and voltage control from generation or other sources service.

_____

_____

_____

4. Provide documentation demonstrating that each generator or other sources service providing reactive supply and voltage control meets the qualifications described in PacifiCorp's Business Practice #63 – Transmission Customer Provision of Reactive Supply and Voltage Control from Generation or Other Sources Service[1].
    a. An attestation that the resource meets the requirements stated in PacifiCorp's Business Practice #63.

[1] PacifiCorp will consider this requirement fulfilled if the generator owner/operator attests compliance with the currently effective North American Electric Reliability Corporation ("NERC") VAR-002 Reliability Standard. Upon PacifiCorp's acceptance of a qualified generator, the generator owner/operator must also comply with the PacifiCorp Voltage Schedule provided at least annually to each generator owner/operator.

b. MOD-25 or comparable test results illustrating the resource capability. In the event that the resource(s) are unable to operate at its nameplate ratings, such ratings will be adjusted downward to reflect the degradation in the operation of the resource(s), and the adjusted real power values (MWs) will be used in the crediting process.

_____

_____

_____

Transmission Customer attests to the following:

- The information and documentation provided to section 4a-e is current and accurate
  OR
- Transmission Customer is a registered entity with NERC following VAR-002

Name _____ Title _____

Signature _____ Date _____

Business Practice #63: Transmission Customer Provision of Reactive Supply and Voltage Control from Generation or Other Sources Service

Posted: ~~February 20, 2017~~***TBD***
Effective: ~~March 6, 2017~~**TBD**
Revision No.: ~~1~~2.0

NOTICE
A redline version of the most recent revisions to this business practice is available at:
https://www.oasis.oati.com/woa/docs/PPW/PPWdocs/BP63red.pdf

Policy Reference

PacifiCorp's Open Access Transmission Tariff ("OATT"), Schedule 2 – Reactive Supply and Voltage Control from Generation or Other Sources Service ("Reactive Supply and Voltage Control Service"), and PacifiCorp Planning Policy No. 139 – Facility Connection Requirements for Transmission Systems (46 kV and Higher Voltages).

Definitions

No definitions other than those currently contained in PacifiCorp's OATT are required for this business practice.

Purpose

The purpose of this business practice is to establish a Transmission Customer's option to self-supply Schedule 2, Reactive Supply and Voltage Control Service, for its own transactions, including the eligibility requirements that a Transmission Customer must satisfy to self-supply Schedule 2 service and receive a corresponding credit from Transmission Provider. Any Transmission Customer or Interconnection Customer that has a rate schedule for Reactive Supply and Voltage Control on file with the Federal Energy Regulatory Commission for any generator or other resource located within PacifiCorp BAA will not be eligible to receive this credit from the Transmission Provider.

Practice

All transactions requiring Transmission Service over Transmission Provider's transmission facilities require the provision of Reactive Supply and Voltage Control Service~~. The purpose of this business practice is to establish a Transmission Customer's option to provide Reactive Supply and Voltage Control Service for its own transactions, including the eligibility requirements that a Transmission Customer's generator must~~

~~satisfy in order to supply such service and receive a corresponding credit from Transmission Provider.~~ in accordance with Schedule 2.

~~**Practice**~~

Pursuant to Schedule 2 of PacifiCorp's OATT, Reactive Supply and Voltage Control Service is to be provided directly by the Transmission Provider (if the Balancing Authority ("BA")) or indirectly by the Transmission Provider making arrangements with the BA that performs this service for the Transmission Provider's Transmission System. The Transmission Customer must purchase this service from the Transmission Provider or the BA.

A Transmission Customer may be eligible to provide all or a portion of its reactive supply and voltage control obligations from a qualifying ~~generator~~resource. Qualifying ~~generators~~resources must meet the minimum criteria described in this business practice~~.~~ to self-supply all or a portion of its Reactive Supply and Voltage Control obligations. To the extent a Transmission Customer can self-supply Reactive Supply and Voltage Control Service for at least a portion of its Schedule 2 transactions through a qualifying ~~generator~~resource, it will be eligible to receive a Schedule 2 credit through the mechanism described in this business practice.

Qualifying ~~Generator~~Resource Requirements

~~The following is required for a Transmission Customer~~ ***to*** ~~demonstrate the ability to provide~~***supply Reactive Supply and Voltage Control Service*** ~~for its own transactions on Transmission Provider's Transmission System:~~

The Transmission Customer must make an application (in the attached form) to the Transmission Provider requesting approval of its use of a qualifying ~~generator.~~resource to self-supply Reactive Supply and Voltage Control Service to offset all or a part of its obligations under Schedule 2. Qualifying ~~generators~~resources must demonstrate ~~all of~~ the following characteristics, among other things, as set forth in the Application for Provision of Reactive Supply and Voltage Control from Generation and Other Sources Service, to be eligible for a Schedule 2 credit:

~~1) The generator has an exciter and can be operated in the *Automatic Voltage Regulator (AVR)* mode.~~

1) The resource must be able to provide reactive power within the power factor range of 0.95 leading to 0.95 lagging.

2) All qualifying resources shall be controlled by an automatic voltage regulator system having the capability for both voltage regulation and net power factor regulation operating modes.

3) All qualifying resources shall be accurately modeled within the PacifiCorp EMS system to ensure real-time visibility of the resource from the resource's RTU.

~~2)~~4) The generator must follow the voltage schedule supplied by the Transmission Provider. ~~For lack of~~ If no voltage schedule is provided, the generator must operate at the nominal voltage level, unless called upon by the BA to do otherwise. Additionally, if there is a voltage ~~schedule, the generator must demonstrate the power factor requirements as written in PacifiCorp's Facility Connection Requirements attached and included as part of the Generation Interconnection Agreement.~~event on the system, then the resource must be able to respond due to the local change in voltage.

~~3)~~5) The ~~generator is~~resource must be capable of responding automatically to voltage ~~and/~~or reactive control settings and to manual directives from the BA, as defined in the OATT, when called upon to supply reactive support (either to generate ~~and~~or absorb reactive energy) to PacifiCorp's Transmission System. Automatic response must be immediate and manual response must occur within ~~5~~five minutes of notice. ~~Generators which~~Transmission Customers whose resources fail to respond as directed by the BA two times within a rolling twelve month period will be disqualified from the self-supply credit for that month and future months until such time as the ~~Control Area operator can be assured the unit~~Transmission Customer demonstrates to the BA that its resource can be relied upon~~.~~ to generate or absorb reactive energy, as described above. The Transmission Customer shall coordinate a test of its resource with PacifiCorp to demonstrate that the resource is capable of providing voltage support.

~~4)~~6) ~~The generator is~~The resource must be located within the PacifiCorp BA and interconnected to PacifiCorp's Transmission System or connected to a PacifiCorp Network transmission customer-owned transmission system within PacifiCorp's Balancing Authority Area ("BAA"). ~~If the Generator is interconnected to the PacifiCorp Transmission System, it must meet current PacifiCorp Policy 139 ("Facility Connection Requirements for Transmission Systems") standards.~~

7) At least every five years (with no more than 66 calendar months between verifications), each Transmission Customer shall certify to PacifiCorp that

the resource(s) it uses to self-supply its Schedule 2 requirements can operate at nameplate MVA, MW and MVAR ratings through performing a MOD-25 or comparable test. The test results shall be sent to PacifiCorp with the application below to demonstrate the resource's capability. In the event that the resource(s) are unable to operate at nameplate ratings, such ratings will be adjusted downward to reflect the degradation in the operation of the resource(s), and the adjusted real power values (MWs) will be used in the crediting process, until such time that the Transmission Customer can re-certify to PacifiCorp that that the resource(s) it uses to self-supply its Schedule 2 requirements can operate at nameplate MVA, MW and MVAR ratings.

Any ~~generators~~resources jointly owned by PacifiCorp and a Transmission Customer subject to Schedule 2 charges and for which PacifiCorp's costs are included in the calculation of Reactive Supply and Voltage Control Service rates, shall be deemed qualified. If a Transmission Customer jointly owns a ~~generating facility~~resource and/or only wants to qualify part of a ~~facility~~resource, the Transmission Customer must specifically state the ~~generator~~resource parameters for what will be applied towards the ~~qualified facility.~~Schedule 2 credit. Specifically, the Transmission Customer will need to provide the ~~generator unit~~resource and accompanying characteristics, the generator unit interactions with other generating units (if applicable), ownership share information (if applicable), or any other information as determined by PacifiCorp as relevant.

Credit Mechanism

~~The total Reactive Supply and Voltage Control Service obligation for a Transmission Customer who supplies such service for its transactions shall be equal to the total amount of load served within the BAA and/or generation exported from the BAA. The billing determinants for Reactive Supply and Voltage Control Service shall be determined by:~~

~~(1) For the hour of the transmission system peak, subtracting from a Transmission Customer's full requirement the total amount supplied by qualifying generator(s) during that hour each month; and~~

~~(2) Charging the Transmission Customer the Schedule 2 rate multiplied by the difference, in MWs, calculated in item (1) to the extent the transmission customer supplied less than its full requirement during the coincident peak hour.~~

~~Upon approval by the Transmission Provider, the details for the specific qualifying generator~~The self-supply credit is based upon the capability of the qualifying resource. To qualify for this credit mechanism, the Transmission Customer's qualifying resource shall meet the Qualifying Resource Requirements to supply Reactive Supply and Voltage

Control Service described above. The Schedule 2 credit shall be based upon the real power (MW) capability of the resource. The Transmission Customer will be charged the difference between its Schedule 2 obligations for its Network Load or point-to-point transmission service and the resource's capability times the currently effective Schedule 2 rate. The total Reactive Supply and Voltage Control Service self-supply credit shall not exceed the total amount of the Schedule 2 charge which otherwise would be assessed to the Transmission Customer for load located within the BAA or for point-to-point transmission service. Notwithstanding, any resource that is used to reduce a Transmission Customer's Network Load is not eligible to receive a Schedule 2 credit, as the resource is already reducing the Network Load upon which Schedule 2 is assessed. However, if that resource is tracked in the network model and not netted against load, then the resource would be eligible to receive a credit against Schedule 2 charges subject to the required operating requirements outlined in this business practice. Upon approval by the Transmission Provider, the details for the specific qualifying resource and crediting mechanisms will be described in the Transmission Customer's agreement for Transmission Service with the Transmission Provider.

Contact for Assistance: BusinessPractices@PacifiCorp.com

Revision History

Version	Posted Date	Change Summary
2.0	TBD	Added qualifying resource language to include renewable resources and add capability testing requirements. Updated the credit mechanism for the credit to be based on the reactive power capability of the resource.
1.0	3/6/2017	Clarifications to Qualifying Generator Requirements and the attached Application for Provision of Reactive Supply and Voltage Control from Generation or Other Sources Service to clarify generator requirements and information needed to evaluate requests submitted pursuant to this Business Practice.
0.0	5/1/13	In the attached Application for Provision of Reactive Supply and Voltage Control from Generation or Other Sources Service, specified that the completed application and documentation should be sent to the BusinessPractices@PacifiCorp.com e-mail address and added a footnote to clarify when PacifiCorp considers the documentation requirement fulfilled.
DRAFT	2/22/13	Initial draft posted for public comment

Application for
Provision of Reactive Supply and Voltage Control from Generation or Other Sources Service

Transmission Customer Name: _____

Address: _____

Contact Name: _____

Contact Phone: _____

Pursuant to PacifiCorp OATT's and Business Practice #63, the above-listed ~~transmission customer~~Transmission Customer requests to provide all or a portion of the following Ancillary Service:

_____ **Reactive Supply and Voltage Control from Generation or Other Sources Service – Schedule 2**

Transmission Customer shall complete this application for each generator it seeks to qualify. Transmission Customer certifies it has one or more resources qualified to provide a portion or all of its obligations for the Ancillary Service selected above in conformance with the requirements in PacifiCorp's OATT and outlined in PacifiCorp Business Practice #63 – Transmission Customer Provision of Reactive Supply and Voltage Control from Generation or Other Sources Service. Transmission Customer submits the attached completed form for each such resource. Submission of this application and any supporting documentation should be sent to BusinessPractices@PacifiCorp.com. In addition, Transmission Customer understands that Transmission Provider may request additional information as needed to further support the documentation given herein.

Application for Provision of Reactive Supply and Voltage Control from Generation or Other Sources Services (~~con't~~cont'd)

1. Please list resource providing the service along with its nameplate capacity; will the full facility be used or only part?

_____

_____

2. Please indicate by what means the resource listed above are deliverable. Please list applicable transmission service agreement for the resource identified above.

_____

_____

3. Please provide a point of contact for the resource listed above (or a resource dispatch center) that is available any time the resource is providing reactive supply and voltage control from generation or other sources service.

_____

_____

_____

4. Provide documentation demonstrating that each generator or other sources service providing reactive supply and voltage control meets the qualifications described in PacifiCorp's Business Practice #63 – Transmission Customer Provision of Reactive Supply and Voltage Control from Generation or Other Sources Service[1].

~~a. The generator has an exciter and can be operated in the *Automatic Voltage Regulator (AVR)* mode.~~

[1] PacifiCorp will consider this requirement fulfilled if the generator owner/operator attests compliance with the currently effective North American Electric Reliability Corporation ("NERC") VAR-002 Reliability Standard. Upon PacifiCorp's acceptance of a qualified generator, the generator owner/operator must also comply with the PacifiCorp Voltage Schedule provided at least annually to each generator owner/operator.

~~b. The generator must follow the voltage schedule supplied by Transmission Provider. For lack of a voltage schedule, the generator must demonstrate the power factor requirements as mentioned in the interconnection study.~~

~~c. The generator is capable of responding automatically to voltage and/or reactive control settings and to manual directives from the BA when called upon to supply reactive support (generate and absorb reactive energy) to the Transmissions Provider's Transmission System; and~~

~~d. The generator is interconnected to the Transmission Provider's Transmission System or connected to a PacifiCorp transmission customer-owned transmission system with PacifiCorp's BAA.~~

a. ~~Proof that the generator meets current PacifiCorp Policy 139 standards.~~ An attestation that the resource meets the requirements stated in PacifiCorp's Business Practice #63.

b. MOD-25 or comparable test results illustrating the resource capability. In the event that the resource(s) are unable to operate at its nameplate ratings, such ratings will be adjusted downward to reflect the degradation in the operation of the resource(s), and the adjusted real power values (MWs) will be used in the crediting process.

_____

_____

_____

Transmission Customer attests to the following:

- The information and documentation provided to section 4a-e is current and accurate
  OR
- Transmission Customer is a registered entity with NERC following VAR-002

Name _____ Title _____

Signature _____ Date _____

Attachment B

Direct Testimony of Mary M. Wiencke, Vice President of Transmission Regulation and Market Policy

Exhibit No. PAC-0001

Exhibit No. PAC-0001

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp	**)**	**Docket No. ER21-___-000**

TESTIMONY OF

MARY M. WIENCKE

ON BEHALF OF PACIFICORP

February 1, 2021

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I. Introduction

Q. PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A. My name is Mary M. Wiencke. I am Vice President of Transmission Regulation and Market Policy for PacifiCorp (also referred to herein as the "Company"). My business address is 825 NE Multnomah Street, Suite 2000, Portland, Oregon 97232.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying in support of PacifiCorp.

Q. IN WHAT POSITION ARE YOU CURRENTLY EMPLOYED?

A. I am the Vice President of Transmission Regulation and Market Policy for PacifiCorp (also referred to herein as the "Company").

Q. PLEASE BRIEFLY OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have a B.A. in Environmental Science from Barnard College and a J.D. from Lewis & Clark Law School. I have been employed by PacifiCorp for twelve years in various positions of responsibility in both legal and policy roles. In 2018, I assumed my current position.

Q. PLEASE SUMMARIZE THE BASIS OF YOUR KNOWLEDGE AND CONCLUSIONS CONCERNING THE ISSUES TO WHICH YOU ARE TESTIFYING IN THIS CASE.

A. As the Vice President of Transmission Regulation and Market Policy for PacifiCorp, I have a strong understanding of the areas I discuss in my testimony, including: (1) PacifiCorp's

rates for ancillary services provided under Schedules 2, 3, 3A, 5, and 6; (2) the reserve requirements with which PacifiCorp must comply for Schedules 3, 3A, 5, and 6; and (3) the opportunities for customers to self-supply under Schedules 3, 3A, 5, and 6. I also have a strong understanding of PacifiCorp's Open Access Transmission Tariff ("OATT") as it relates to ancillary services and PacifiCorp's participation in the California Independent System Operator's ("CAISO") Western Energy Imbalance Market ("EIM"). In addition, I led the pre-filing collaboration efforts explained in my testimony that PacifiCorp undertook to meet its obligations under the Docket No. ER17-219 settlement agreement.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. Pursuant to the terms of the prior settlement in Docket No. ER17-219, PacifiCorp has been engaged in a collaborative process since December 2019 to address the updating of certain ancillary services under PacifiCorp's OATT. As a result of those efforts, PacifiCorp has reached a new settlement agreement ("2020 Settlement Agreement') with customers, which PacifiCorp will implement through its filing. In its filing, PacifiCorp is including cost support in the form of "base case" materials, which were PacifiCorp's starting point for negotiations with customers and which would have been the case filed by PacifiCorp if the 2020 Settlement Agreement had not been reached. The purpose of my testimony is to provide an overview of PacifiCorp's filing, including an overview of the following:

(1) The settlement agreement accepted by the Commission in Docket No. ER17-219,[1] the collaboration that was required under the Settlement Agreement and that occurred prior to this filing, and how the Settlement Agreement relates to this filing;

(2) The 2020 Settlement Agreement;

[1] *PacifiCorp,* Docket No. ER17-219-002 (Apr. 19, 2018), herein referred to as the "Settlement Agreement."

(3) The rates proposed for Schedules 3 and 3A, including: (a) an explanation of the purpose of and need for the proposed rates; (b) the proposed Schedules 3 and 3A tariff changes; and (c) compliance with Order No. 764;[2]

(4) The rates proposed for Schedule 5 and 6, including: (a) an explanation of the purpose of and need for the proposed rates, and (b) the proposed Schedules 5 and 6 tariff changes;

(5) The rates proposed for Schedule 2, including: (a) an explanation of the purpose of and need for the proposed rates, and (b) the proposed Schedule 2 tariff changes;

(6) The updates to the self-supply protocols for Schedules 5 and 6 to incorporate automation and the associated, revised Schedule 5 and 6 tariff changes and business practices; and

(7) Describe the other testimony supporting this filing.

Q. WHAT OTHER INDIVIDUALS ARE PRESENTING TESTIMONY ON BEHALF OF PACIFICORP IN THIS PROCEEDING?

A. Several individuals are providing testimony describing PacifiCorp's base case rates, which, as noted earlier, were the basis for PacifiCorp's negotiations with customers and stakeholders. Since the 2020 Settlement Agreement rates are negotiated black box rates that lower than the base case rates, PacifiCorp is providing materials with its filing that describe the base case as support for the justness and reasonableness of the lower 2020 Settlement Agreement rates. To that end, the following individuals are providing testimony on behalf of PacifiCorp regarding the development of the base case:

1. *Kelcey A. Brown*, Vice President, Energy Supply Management ("ESM") at PacifiCorp, has prepared testimony[3] that:
    a. explains the policy considerations supporting the determination in the base case of how to allocate the total amount of regulation reserve among Load, variable

[2] Integration of Variable Energy Resources, Order No. 764, FERC Stats. & Regs. ¶ 31,331 (2012) (Order No. 764), order on reh'g, Order No. 764-A, 141 FERC ¶ 61,232 (2012), order on clarification and reh'g, Order No. 764-B, 144 FERC ¶ 61,222 (2013).
[3] Direct Testimony of Kelcey Brown, Exhibit No. PAC-0002.

energy resources ("VERs"), and resources that are not VERs ("Non-VERs"), and to exclude generation that provides reserve capabilities;

b. describes the methodology used by PacifiCorp to consider VERs operational reforms such as power production forecasting and intra-hour scheduling;

c. discusses PacifiCorp's participation in the California Independent System Operator Corporation's ("CAISO") Energy Imbalance Market ("EIM") and the way that PacifiCorp's participation in the EIM reduces the amount of reserves required by PacifiCorp; and

d. describes the background of the applicable reliability standards related to PacifiCorp's filing.

2. *Daniel J. MacNeil*, Resource and Commercial Strategy Adviser at PacifiCorp, has prepared testimony[4] that:

a. explains and supports the methodology used to develop PacifiCorp's base case ancillary service rates for Regulation and Frequency Response Service (Schedule 3), Generator Regulation and Frequency Response Service (Schedule 3A), Operating Reserve – Spinning Reserve Service (Schedule 5), and Operating Reserve – Supplemental Reserve Service (Schedule 6);

b. presents the study to determine an updated base case reserve requirement for Regulation and Frequency Response Service and for Spinning Reserve Service and Supplemental Reserve Service;

c. supports the total amount of regulating reserves that are needed by PacifiCorp to provide service under revised Schedules 3 and 3A of PacifiCorp's OATT;

d. supports the allocation in the base case of the total amount of regulation reserves among Load, variable energy resources ("VERs") and resources that are not VERs ("Non-VERs");

e. supports the identification of the specific resources that supply the total amount of regulating reserves, including the proportional contributions of such resources; and

f. supports the total amount of operating reserves needed by PacifiCorp in the base case to provide service under Schedules 5 and 6.

3. *Paul A. Dumais*, Chief Executive Officer, Dumais Consulting LLC, has prepared testimony[5] that:

a. supports the rate methodologies employed for PacifiCorp's base case Ancillary Services charges for Schedules 2, 3, 3A, 5, and 6 of PacifiCorp's OATT;

b. provides cost and rate design support for the ancillary services addressed in the subject filing[6] and is sponsoring Statements BG and BH.[7] Dr. Dumais relies

[4] See Direct Testimony of Daniel J. McNeil, Exhibit No. PAC-0003.
[5] See Direct Testimony of Dr. Paul A. Dumais, Exhibit No. PAC-0010.
[6] See Exhibit Nos. PAC-–0013 – 0015.
[7] See Exhibit No. PAC-0012.

upon the work of Mr. MacNeil for identifying the necessary reserves volumes and identifying the specific units utilized to provide the reserves;

Q. PLEASE DESCRIBE PACIFICORP.

A. PacifiCorp is an investor-owned utility that serves nearly two million customers in six western states: California, Idaho, Oregon, Utah, Washington, and Wyoming. The Company serves its customers with a vast, integrated system of generation and transmission that spans 10 states and connects customers and communities across the West.

PacifiCorp's integrated system provides benefits to customers in all six states and includes generation, transmission, and distribution assets. PacifiCorp owns, or has interests in thermal, hydroelectric, wind-powered, solar, and geothermal generating facilities, with a net-owned capacity of 10,894 megawatts ("MW"). PacifiCorp buys and sells electricity on the wholesale market with other utilities, energy marketing companies, financial institutions, and other market participants to balance and optimize the economic benefits of electricity generation, retail customer loads, and existing wholesale transactions.

PacifiCorp operates two Balancing Authority Areas ("BAAs")—PacifiCorp Balancing Authority Area East ("PACE") and PacifiCorp Balancing Authority Area West ("PACW") that together comprise the largest privately owned and operated grid in the Western United States.

PacifiCorp provides transmission service under its OATT approved by the Federal Energy Regulatory Commission and owns or has interests in approximately 16,500 miles of transmission lines. Under its OATT, PacifiCorp provides Long-Term Firm Point-to-

Point ("PTP") Transmission Service to 19 transmission customers, Short-Term Firm and Non-Firm PTP Transmission Service to 66 transmission customers under umbrella service agreements, and Network Integration Transmission ("NT") Service to 14 transmission customers, including PacifiCorp ESM. PacifiCorp also provides transmission service to certain "legacy" transmission customers under transmission service agreements pre-dating the OATT and has three customers with "Direct Access" NT Service Agreements.[8]

II. Discussion of Filing

Q. WHEN WERE ANCILLARY SERVICES RATES LAST ESTABLISHED FOR PACIFICORP?

A. PacifiCorp's current ancillary services rates for Schedules 3, 3A, 5, and 6 were established through a Stipulation and Offer of Settlement ("ER17-219 Settlement") accepted by the Commission in Docket No. ER17-219-000. As a result of the ER17-219 Settlement, the current rates for Schedules 3, 3A, 5, and 6 have been in place since January 1, 2018.

Schedule 2 rates were established through a settlement agreement reached in Docket No. ER11-3643-000, and the Schedule 2 rates became effective December 25, 2011. That settlement agreement was accepted by the Commission in a May 23, 2013 letter order.[9]

As I discuss in more detail below, the ER17-219 Settlement directly impacts the timing of this new ancillary services rate case filing by PacifiCorp.

[8] The "Legacy Customers" are Utah Associated Municipal Power Systems, Utah Municipal Power Agency, and Deseret Generation and Transmission Co-Operative.
[9] *PacifiCorp*, 143 FERC ¶ 61,162 at P 5 (2013).

A. Summary of Prior Settlement Agreement, the New 2020 Settlement Agreement, and Background of Discussions with Joint Customers.

Q. PLEASE SUMMARIZE THE ER17-219 SETTLEMENT.

A. On October 28, 2016, in Docket No. ER17-219-000, PacifiCorp filed tariff revisions to update its rates for Schedules 3, 3A, 5 and 6, and to clarify Schedule 11, Unauthorized Use of Transmission Service. Motions to intervene and protests were filed by several parties. On February 2, 2017, the Commission accepted PacifiCorp's proposed tariff revisions for filing, and, relevant here, accepted the Schedule 11 revisions, but established hearing and settlement judge procedures into the justness and reasonableness of the rates for Schedules 3, 3A, 5 and 6.

The ER17-219 Settlement, which was uncontested, resolved all issues in that case. Article 4 of the ER17-219 Settlement established black box rates for Schedules 3, 3A, 5 and 6 for two periods: July 13, 2017, through December 31, 2018, and then prospectively from January 1, 2018, onward.[10] The rates that became effective on January 1, 2018, are still in effect today, and are proposed to be revised by this filing. Among other things, the ER17-219 Settlement also:

(i) Established requirements for self-supply of Schedules 5 and 6 in a new Attachment U and Attachment V to the PacifiCorp OATT;

(ii) Established a moratorium until June 30, 2020, on changes to the rates for Schedules 3, 3A, 5 and 6, and on customer self-supply under Schedules 3 and 3A; and

(iii) Required that, prior to filing the new Schedule 3, 3A, 5 and 6, PacifiCorp and Settling Parties work together to reach consensus on several concepts

[10] The reason for two sets of rates is to reflect the impacts of the lower federal tax rate from the Tax Reform and Job Acts of 2017.

in the design for new rates for Schedules 3 and 3A, and in self-supply procedures.

Q. WHO WERE THE SIGNATORIES TO THE ER17-219 SETTLEMENT?

A. The signatories were: PacifiCorp; Utah Associated Municipal Power Systems ("UAMPS"); Deseret Generation & Transmission Co-operative, Inc. ("Deseret"); Utah Municipal Power Agency ("UMPA"); Bonneville Power Administration ("BPA"); Avangrid Renewables, LLC ("Avangrid"); and NextEra Energy Resources, LLC ("NextEra"). These parties were referred to as the "Settling Parties" in the Settlement Agreement.

Q. DOES THE ER17-219 SETTLEMENT IMPACT THE TIMING OF PACIFICORP'S PRESENT FILING?

A. Yes. As noted, the ER17-219 Settlement established a "Moratorium Period" from the date of the ER17-219 Settlement until June 30, 2020. Pursuant to Section 6.1 of the ER17-219 Settlement, during the Moratorium Period, PacifiCorp could not propose any new or separate ancillary service schedule charge or other rate, term, or condition of service for Schedules 3, 3A, 5, and/or 6.

However, under Section 6.2 of the ER17-219 Settlement, following the Moratorium Period, PacifiCorp may make a Section 205 filing that updates the Regulation Reserve Study and the ancillary services rates for Schedules 3, 3A, 5, and/or 6 rates with an effective date no earlier than July 1, 2020.

Q. DID THE ER17-219 SETTLEMENT REQUIRE COLLABORATION AMONG THE SETTLING PARTIES PRIOR TO PROPOSING NEW RATES FOR SCHEDULES 3 AND 3A?

A. Yes. The collaboration is not confined to the Settling Parties, and includes all stakeholders. Under Section 6.3 of the Settlement Agreement, PacifiCorp was required to "work with stakeholders in good faith to develop consensus regarding the methodology and associated data used to calculate the applicable regulation and operating reserves to be used in the future update of the Schedule 3/3A ancillary service rates." Section 6.3 of the ER17-219 Settlement also required that the stakeholder process consider ten topics for collaboration ("10 enumerated rate topics"):

(1) Development of the ancillary services rates based on cost-causation principles and optimization of resources utilizing a least cost methodology (Section 6.3.1 of the Settlement Agreement);

(2) Calculation of the fixed charge rate using the Production Fixed Charge Rate Formula of the instant docket (Section 6.3.2);

(3) Use of coincidental one-minute data that includes EIM benefits for, at a minimum, the most recent 24-month period for which data is available (Section 6.3.3);

(4) Allocation of System-Wide Portfolio Diversity Benefits among classes (Load, Non-VERs, and VERs) according to the contribution of the deviation signals of each class to the combined deviation signal for regulation deployment during the test period (Section 6.3.4);

(5) Use of data that reflect all events that are reasonably known and measurable at the time of filing, including unit retirements, contract terminations/renewals, resource additions, changes in operational characteristics of the resources providing ancillary services, changes in load growth, etc. (Section 6.3.5);

(6) Accounting for contingencies and Disturbance Control Standard events using actual contingency data, including deployment of contingency reserves as well as other Qualifying Events under the Northwest Power Pool Agreement (Section 6.3.6);

(7) Treatment of PacifiCorp's Interruptible Contracts as providing self-supply of ancillary services to PacifiCorp's Energy Supply Management, and excluding them from the derivation of the ancillary service rates (Section 6.3.7);

(8) Use of a 1-day-in-10-years resource adequacy standard (equivalent to a 2.4 loss of load hours per year) (Section 6.3.8);

(9) Inclusion of an intra-hour scheduling discount reflecting the use of wind power production forecasts as of the later of the T-40 base schedule update or any later deadline that is established for EIM Entity updates to base schedules (Section 6.3.9); and

(10) In the calculation of the production plant revenue requirement, provision of revenue offsets (credits) of all revenues generated by PacifiCorp's EIM sales out of the Balancing Authority Area (whether short-term or long-term opportunity sales) for the purpose of serving loads other than firm native load (Section 6.3.10).

Q. DID THE ER17-219 SETTLEMENT ADDRESS THE RATE DESIGN FOR ANCILLARY SERVICE SCHEDULES 2, 5, OR 6?

A. No. The stakeholder process and 10 enumerated rate topics described above are specific to the rate design for Schedules 3 and 3A, and are not applicable to Schedules 2, 5, and 6. In terms of updating rates, the Settlement Agreement only required that PacifiCorp work with stakeholders with respect to Schedules 3 and 3A. Nevertheless, as I explain further below, given the interconnectedness of the rate design for each of the applicable schedules, PacifiCorp presented its base case rates for Schedules 2, 5 and 6 during the stakeholder process in an effort to establish as much consensus as possible on the 10 enumerated rate topics and resulting rates.

Q. DOES THE ER17-219 SETTLEMENT REQUIRE THE SETTLING PARTIES TO WORK TOGETHER REGARDING SELF-SUPPLY OF ANCILLARY SERVICES?

A. Yes. Section 3.7 of the ER17-219 Settlement memorialized the Settling Parties' agreement to work together during the Moratorium Period to create a framework for the self-supply of Schedules 3 and 3A, and to update the self-supply provisions for Schedules 5 and 6, including discussion of PacifiCorp's ability to automate self-supply of those schedules. The ER17-219 Settlement self-supply provisions are limited to Schedules 3, 3A, 5 and 6,

and does not have any requirements with respect to self-supply of other ancillary services under the OATT.

Q. FOLLOWING THE COLLABORATION EFFORTS DESCRIBED ABOVE, DOES THE ER17-219 SETTLEMENT ADDRESS WHETHER THE SECTION 205 FILING SHOULD REFLECT ANY AGREEMENTS REACHED?

A. Yes. If consensus was able to be reached regarding the 10 enumerated rate topics for Schedule 3 and 3A rates, then pursuant to Section 6.4 of the ER17-219 Settlement PacifiCorp was to conform its Section 205 filing to "all the foregoing matters on which consensus is reached."

Similarly, regarding self-supply protocols, Section 3.7 of the ER17-219 Settlement states that "if the Settling Parties agree to a final self-supply framework during the Moratorium Period for Schedules 3, 3A, 5, and 6, PacifiCorp shall make a Section 205 filing at the end of the Moratorium Period or thereafter to implement that self-supply framework."

Q. HOW DID PACIFICORP UNDERTAKE THE COLLABORATION EFFORTS WITH THE COMBINED CUSTOMERS AND STAKEHOLDERS?

A. PacifiCorp conducted a stakeholder process over the course of six months, from December 2019 through May 2020. During this time period, PacifiCorp held a series of workshops, posted extensive data and information supporting its reserve study and updated rates, responded to numerous information requests from stakeholders and Settling Parties, and conducted informal conversations with customers to assist in a comprehensive

understanding of PacifiCorp's study and proposals. Following each workshop, PacifiCorp solicited comments from stakeholders and responded to any comments received in writing.

PacifiCorp began preparing its proposal for Schedules 3 and 3A rates and self-supply in November 2019, which included assembling its internal teams to review the current rates, commence a study of the reserves needed for Schedules 3, 3A, 5 and 6, and develop stakeholder materials. On November 15, 2019, PacifiCorp posted notice of a meeting on December 13, 2019, for all customers to discuss PacifiCorp's ancillary services pursuant to the Settlement Agreement. The workshops were held on: December 13, 2019; February 18, 2020; March 24, 2020; May 4, 2020; and May 28, 2020. The first two workshops were in-person meetings in Portland, Oregon; the latter workshops were held via "Zoom" conference calls due to the coronavirus. The workshops lasted roughly between 2.5 to 4 hours each.

Prior to each workshop, PacifiCorp circulated detailed power point presentations to the Settling Parties and stakeholders. To the extent answers to the Settling Parties and stakeholder questions could not be provided during the workshops, PacifiCorp provided written responses following the workshops. The presentations and written responses were posted to PacifiCorp's OASIS.

In addition to the discussion that took place during the workshops, PacifiCorp requested written comments and questions from the Combined Customers and other stakeholders following the workshops. PacifiCorp provided written responses that were provided in advance of the subsequent workshop, and also posted to PacifiCorp's OASIS. As needed, PacifiCorp also addressed the questions and responses during the subsequent workshop, as well.

Later in my testimony I provide a summary of the workshops and other efforts undertaken to comply with the pre-filing collaboration requirements of the Settlement Agreement.

Q. DID PACIFICORP WORK WITH THE COMBINED CUSTOMERS IN GOOD FAITH TO REACH CONSENSUS, AS REQUIRED BY THE ER17-219 SETTLEMENT?

A. Yes, PacifiCorp made extensive efforts to work with and collaborate with the Combined Customers and other stakeholders in a good faith attempt to reach consensus during the Moratorium Period. These efforts took the form of multiple stakeholder workshops, the pre-publication of extensive data and analysis, offers to meet with customers informally, responses to numerous requests for information, requests for written feedback and comments, and the development of sensitivities to demonstrate the impact of various methodological approaches. PacifiCorp also clearly articulated its positions on each of the 10 enumerated rate topics, as well as self-supply protocols with the clear identification of areas in which PacifiCorp believed compromise may be possible and should be explored. These positions, as well as proposed self-supply protocols, were posted on PacifiCorp's OASIS and discussed at the workshops.

Although the information, materials, and data circulated to the Combined Customers and stakeholders reflected PacifiCorp's studies and analyses that the Company felt would meet its burden of proof under Section 205 of the FPA, PacifiCorp expressed a willingness to be flexible to reach a consensus on the 10 enumerated rate topics and self-supply protocols.

Q. DID THE COMBINED CUSTOMERS PARTICIPATE IN THE STAKEHOLDER PROCESS LED BY PACIFICORP?

A. Yes. The Combined Customers participated in the workshops. Some, but not all, customers submitted written comments and/or submitted information requests to PacifiCorp regarding its proposals or analyses.

Q. WAS A CONSENSUS REACHED BETWEEN PACIFICORP, THE COMBINED CUSTOMERS, AND THE STAKEHOLDERS?

A. Yes. As discussed in the transmittal letter accompanying this filing, the Joint Customers and PacifiCorp reached a "black box" settlement regarding rates for Schedules 2, 3, 3A, 5, and 6 ("2020 Settlement Agreement"). The settling parties to the 2020 Settlement Agreement also agreed on changes to PacifiCorp's Tariff that regard: (1) self-supply provisions for Schedules 2, 3/3A, 5 and 6; (2) automation of Schedules 5 and 6; and (3) the Committed Scheduling Discount under Schedule 3. I address these tariff revisions later in my testimony.

Q. PLEASE SUMMARIZE THE 2020 SETTLEMENT AGREEMENT.

A. The 2020 Settlement Agreement resolves issues related to the rates, terms, and conditions of PacifiCorp's Schedules 2, 3, 3A, 5 and 6 under the OATT. Article II of the 2020 Settlement Agreement provides the black box, negotiated rates for these ancillary services; I discuss the 2020 Settlement Agreement rates in more detail in a subsequent section of my testimony. Section 2.2 of the 2020 Settlement Agreement provides for the continuation of the "Committed Scheduling" discount from the ER17-219 Settlement, adjusted to 7.1%.

The Committed Scheduling discount enables customers that use VERs to obtain a 7.1% reduction in the Schedule 3 VER charge on the condition that they commit to follow their schedules submitted into the Base Schedule Aggregator Portal ("BSAP").

Article III addresses billing for Schedule 3/3A under the Legacy Customers' transmission service and operating agreements ("TSOAs"), and requires that the billing continue pursuant to current practices during the "ARTSOA Moratorium Period" and as specified in sections 3.1.1 through 3.1.3 of the 2020 Settlement Agreement. Sections 3.1.1 through 3.1.3 generally replicate similar provisions in the ER17-219 Settlement. "ARTSOA Moratorium Period" is defined and discussed in section 4.4 of the 2020 Settlement Agreement, which states that "PacifiCorp shall not file any proposed change to the ARTSOA billing provisions or practices referenced in Article III with an effective date prior to December 1, 2025 (the "ARTSOA Moratorium Period"). Upon expiration of the ARTSOA Moratorium Period: (a) PacifiCorp may make a Section 205 filing at FERC to propose changes to the ARTSOA provisions or practices referenced in Article III, and (b) the Joint Customers may file a complaint regarding the ARTSOAs pursuant to Section 206 of the FPA related to those same provisios. Each Joint Customer and PacifiCorp reserve their respective rights to protest or otherwise contest a filing made by the other."

Article IV of the 2020 Settlement Agreement provides a moratorium period until January 1, 2023, on changes to PacifiCorp's rates, terms, and conditions for Schedules 2, 3, 3A, 5 and 6. The heart of the moratorium is in section 4.1, which states: "Except as specifically provided in Sections 4.5, 4.6, and 4.7 below, no Settling Party shall file any proposed revision or addition to or affecting the rates, terms and conditions for Schedules 2, 3, 3A, 5 and/or 6 or Attachment U, or seek any change to PacifiCorp's business practices

under or applicable to the same, including but not limited to PacifiCorp business practices 39 and 63, that differ from those provided in this Settlement Agreement and propose an effective date prior to January 1, 2023."

Section 4.2 discusses potential filings after the moratorium period. Section 4.2 states: "Upon expiration of the Rate Schedule Moratorium Period: (a) PacifiCorp may make a Section 205 filing with the Commission that updates Schedules 2, 3, 3A, 5, and/or 6 and/or Attachment U; and (b) any Joint Customer may file a complaint regarding Schedules 2, 3, 3A, 5 and/or 6 and/or Attachment U pursuant to Section 206 of the FPA. Each Settling Party reserves their respective rights under the FPA to protest or otherwise contest any such filing."

Section 4.3 acknowledges a recent filing by Airport Solar, LLC ("Airport Solar") for a proposed rate schedule for Reactive Supply and Voltage Control from Generation Sources Services in FERC Docket No. ER20-2528. Section 4.3 states: During the Rate Schedule Moratorium Period, PacifiCorp shall not seek to recover or pass-through costs it may incur as a result of Airport Solar's application or revenue requirement. Similarly, during the Rate Schedule Moratorium Period, PacifiCorp shall neither propose to recover nor pass through any costs it may incur as a result of any other generator that receives a FERC-approved Schedule 2 rate, including any resulting revenue requirement, nor shall PacifiCorp, after the expiration of the Rate Schedule Moratorium Period, seek to recover any such costs incurred during the Rate Schedule Moratorium Period (including any such costs incurred as a result of Airport Solar's or any other generator's application or revenue requirement). Finally, none of the Joint Customers shall make a filing with FERC seeking compensation from PacifiCorp pursuant to a Schedule 2 rate for reactive power during the

Rate Schedule Moratorium Period. Consistent with Section 4.2 above, nothing in this Settlement Agreement prohibits PacifiCorp from making a section 205 filing with the Commission, after the expiration of the Rate Schedule Moratorium Period, seeking to recover or pass-through prospectively costs that PacifiCorp incurs after the Rate Schedule Moratorium Period as a result of Airport Solar's Schedule 2 charges or any other resource that has a Schedule 2 rate on file with the Commission, and each Joint Customer expressly reserves its rights to challenge any such recovery or pass-through."

The first exception to the moratorium period is in section 4.5, which states: "The Rate Schedule Moratorium Period shall not preclude PacifiCorp from proposing tariff or business practice changes that PacifiCorp believes are needed to accommodate and implement the Extended Day-Ahead Market ("EDAM") currently being developed by the California Independent System Operator ("CAISO"). Each Joint Customer reserves its rights to protest or otherwise challenge any such filing."

The second exception to the moratorium period is in section 4.6, which states: "The Rate Schedule Moratorium does not preclude PacifiCorp from proposing a reduction in the rate set forth in the Schedule 2 attached to this Settlement Agreement. PacifiCorp shall provide notice to each Joint Customer of any proposal to modify the Schedule 2 rate schedule at least thirty (30) days in advance of any Section 205 filing. Each Joint Customer reserves its rights under the FPA to protest or otherwise challenge any such filing."

The third exception to the moratorium period is in section 4.7, which states: "The parties will negotiate in good faith to attempt to reach agreement on self-supply arrangements relating to jointly owned units. PacifiCorp agrees to continue to allow UAMPS, UMPA, and Deseret to self-supply from jointly owned units without performance

evaluations through October 1, 2021 to allow the parties to work toward mutual agreement on self-supply arrangements specific to jointly owned units. If the parties succeed in agreeing on an approach, the parties will agree to an implementation date that provides a reasonable amount of time to ready their systems for compliance with any agreed-upon approach. If mutual agreement is not reached by September 1, 2021, PacifiCorp and each Legacy Customer may thereafter make a unilateral filing with FERC pursuant to Sections 205 and 206 of the FPA, respectively."

Article V of the 2020 Settlement Agreement provides certain clarifications regarding the treatment of Non-VER resources under Schedules 3 and 3A of the OATT. It states that a "Non-VER Participating Resource in the Energy Imbalance Market ("EIM") qualifies as a dispatchable Non-VER resource. Additionally, Non-VER resources dispatchable by PacifiCorp qualify as dispatchable Non-VERS. PacifiCorp will not charge Non-VER Participating Resources or Non-VER resources dispatchable by PacifiCorp for Schedules 3 and 3A services." In addition, Article V states that "PacifiCorp shall consider, on a good faith basis, requests by customers to identify a resource that should qualify as a dispatchable Non-VER in this context due to its ability to follow PacifiCorp instructions, notwithstanding the fact that the resource is not directly dispatchable by PacifiCorp."

Article VI of the 2020 Settlement Agreement addresses self-supply and states: "PacifiCorp shall reasonably and in good faith consider for acceptance customer requests for self-supply, third party supply and/or pooling agreements among customers under Schedules 3, 3A, 5 and 6 of its OATT on a case-by-case and non-discriminatory basis."

Article VII of the 2020 Settlement Agreement relates to collaboration on EDAM implementation. Article VII states: "Implementation of the proposed EDAM– should such a market be developed and filed with the Commission – may involve modifications to PacifiCorp's OATT and potentially material changes to the provision of ancillary services, including Schedules 3, 3A, 5 and 6 and Attachment U. Joint Customers and PacifiCorp agree to engage in good faith discussions regarding potential changes to PacifiCorp's OATT and operations required for the implementation of EDAM. PacifiCorp will: (1) engage substantively with the Joint Customers in good faith; (2) state to CAISO that it supports direct access to CAISO by the Joint Customers in connection with that collaboration; (3) request that CAISO provide such access; and (4) take no action to prevent, inhibit or limit such direct access. The Joint Customers acknowledge that PacifiCorp cannot guarantee a particular "direct access" to CAISO for the Joint Customers."

Article VIII of the 2020 Settlement Agreement discusses the filing to implement the settlement. Section 8.1 discusses the integrated nature of the settlement. Section 8.1 states that "[t]he commitments set out in Articles II to VII of this Settlement Agreement are incorporated in the rate schedules, attachment and business practices attached as Exhibits A to G." Section 8.1 further states that "[t]he rate schedules, attachment and business practices are an integrated part of the settlement package negotiated among the parties," that "[n]one of the terms of the Settlement Agreement are agreed to without each of the others," and that "[t]he various provisions of this Settlement Agreement are not severable."

Section 8.2 discusses the requested effective date. Among other things, section 8.2 states that "[p]romptly after execution of this Settlement Agreement, PacifiCorp shall file

revisions to its OATT to implement this Settlement Agreement, including exhibits, pursuant to Section 205 of the FPA and shall request an effective date of January 1, 2021 for the revisions to Schedules 2, 3, 3A, 5 and 6, and an effective date of July 1, 2021 for the revisions to Attachment U."

Section 8.3 provides that nothing in the 2020 Settlement Agreement "represents an acceptance, endorsement, or agreement by any of the Joint Customers of or to statements contained in testimony or the methodologies, assumptions, calculations, or results of PacifiCorp's 'base case' documents or other support," which PacifiCorp provides with its filing to demonstrate its justness and reasonableness.

Sections 8.4 and 8.5 address how, if the Commission does not accept the filing without condition or modification, a Settling Party may file a notice with the Commission, within 15 days of the Commission's order, that states that it objects to any conditions or modifications required by the Commission. Section 8.5 states that "If any Settling Party files notice of its unwillingness to accept any condition or modification imposed by the Commission, and unless the Settling Parties otherwise agree in writing, then the rates, terms and conditions of this Settlement Agreement shall be null and void and PacifiCorp shall within ten (10) business days make the appropriate filings with the Commission to withdraw the filing from further consideration before the Commission, without prejudice to refiling." Each Settling Party also reserves its rights to protest any of PacifiCorp's "base case" documents or other support if PacifiCorp files such materials in a subsequent filing.

Article IX contains miscellaneous provisions of settlement agreements that are typical of settlements before FERC. For example section 9.2 states that the 2020 Settlement Agreement is a "'black box' negotiated settlement."

B. Description of 2020 Settlement Agreement Rates and Non-Rate Terms and Conditions

Q. DO THE TARIFF RECORDS SUBMITTED WITH THE COMPANY'S FILING INCLUDE THE NON-RATE TERMS AND CONDITIONS OF THE 2020 SETTLEMENT AGREEMENT?

A. Yes. Each of the tariff records for Schedules 2, 3, 3A, 5, 6 and Attachment U incorporate the provisions of the 2020 Settlement Agreement that provide non-rate terms and conditions of service so that those provisions are on file with the Commission under Section 205 of the Federal Power Act. Provisions of the 2020 Settlement Agreement that do not relate to actual service, such as the provisions regarding the filing of the settlement agreement and the standard settlement language in Article IX, are not reflected in the tariff records.

For example, each of Schedules 2, 3, 3A, 5 and 6 include the applicable moratorium period language from Article III and Article IV of the 2020 Settlement Agreement, as well as the applicable exceptions. The clarifications regarding certain Non-VER resources that are found in Article V of the 2020 Settlement Agreement are reflected in the revised Schedules 3 and 3A of the OATT. Similarly, the provisions in Article VI of the 2020 Settlement Agreement regarding third-party supply and pooling are reflected in the revised Schedules 3, 3A, 5 and 6.

The provisions in Section 4.7 regarding self-supply by UAMPS, UMPA and Deseret from jointly owned units, and additional discussion among the parties on the issue, is carried forward into section 4.2(H) of Attachment U, which continues to address technical

requirements for self-supply. I discuss the revised Attachment U in later parts of my testimony, after discussing the rates of the 2020 Settlement Agreement.

Q. DOES THE FILING AND TESTIMONY THAT PACIFICORP IS SUBMITTING SPECIFICALLY TIE TO THE RATES AGREED TO IN THE 2020 SETTLEMENT AGREEMENT?

A. No. The filing and testimony that PacifiCorp is providing supports the "base case" rates that PacifiCorp would have filed but for the 2020 Settlement Agreement. The 2020 Settlement Agreement rates are lower than the base case rates that PacifiCorp can otherwise support, so the base case materials are submitted for informational purposes to demonstrate the justness and reasonableness of the 2020 Settlement Agreement.

I note that none of the Joint Customers endorse or agree with the base case filing or the resulting rates from the base case cost of service studies. The Joint Customers only support the 2020 Settlement Agreement rates, terms, and conditions, which are what is proposed in PacifiCorp's filing. Nonetheless, I have been informed by counsel that the Commission's regulations require cost support of the 2020 Settlement Agreement. To meet these requirements, PacifiCorp is submitting the base case support, which *a fortiori* supports the *lower* rates that are agreed upon under the 2020 Settlement Agreement.

1. <u>Schedule 3 and Schedule 3A Rates</u>

Q. WHAT ARE THE CURRENT RATES FOR SCHEDULES 3 AND 3A AND WHAT ARE THE 2020 SETTLEMENT AGREEMENT RATES?

A. The following table shows the current rates, as well as the new rates that are being filed pursuant to the 2020 Settlement Agreement.

Table 1 – Existing and 2020 Settlement Agreement Rates for Schedule 3 and 3A ($/MW-year)

Ancillary Service	2020 Settlement Agreement Rates	Existing Rates
Schedule 3 (Load)	$ 1.3859	$ 2.124
Schedule 3/3A (Non-VER)	$ 3.1483	$ 1.794
Schedule 3/3A -Wind (VER)	$ 6.6922	$6.593 (applicable to wind and solar)
Schedule 3/3A -Solar (VER)	$ 5.5836	

Under PacifiCorp's proposal, PacifiCorp's Schedule 3 rate for Load will decrease from a "black box" settlement rate of $2,124/MW/year to $1,578.81/MW/year. PacifiCorp proposes to continue to charge Schedule 3 rates for generation that distinguish between VERs and Non-VERs. PacifiCorp is proposing to change from a single VER category to separate Schedule 3 VER categories for wind and solar generation, with proposed rates of $8,105.70/MW/year for wind (increase from $6,593/MW/year) and $6,622.16/MW/year for solar (first time rate). PacifiCorp's current rate Schedule 3/3A rate for non-VERs will increase from $1,794/MW/year to $3,962.59/MW/year.

Mr. MacNeil's testimony discusses PacifiCorp's methodology for calculating the amount of regulation reserve required for Schedule 3 and 3A service and for identifying the units most likely to provide regulation reserve service. The testimony of Dr. Dumais discusses the cost-of-service approach applied to the units providing reserve service and the development of the base case rates.

Q. DOES THE 2020 SETTLEMENT AGREEMENT PROVIDE FOR CONTINUED ASSESSMENT OF CHARGES TO BOTH GENERATION AND LOAD?

A. Yes. For this filing, PacifiCorp separately studied and quantified the regulation reserve burden associated with the generation (VERs and Non-VERs) and Load components of a transaction. However, as I noted earlier, the differentiated rates under Schedule 3 and 3A for generation serving the balancing area will change from a single VER category to separate charges for wind and solar generation.

Q. IS IT APPROPRIATE FOR PACIFICORP TO DIFFERENTIATE SCHEDULE 3 AND SCHEDULE 3A RATES FOR VERS BETWEEN WIND AND SOLAR?

A. Yes. As discussed further by Mr. MacNeil, the reserve requirements analysis for Schedules 3 and 3A finds that wind and solar resources have significantly different impacts on regulation and frequency response needs. Mr. MacNeil concludes that, based on the test years, for PacifiCorp to maintain compliance with BAL-001, PacifiCorp needs approximately 237 MW of regulation and frequency response reserves to address impacts from Wind VERs, whereas PacifiCorp needs approximately 76 MW of reserves to address impacts from Solar VERs.

Due to the different reserve impacts of solar and wind resources, differentiating rates based on the relative regulation reserve burden of each customer class avoids one type of VER resource subsidizing the other and, therefore, aligns with cost causation principles. I discuss this topic in more detail below when I address the requirements of Order No. 764.

Q. HAVE REVISIONS TO SCHEDULES 3 AND 3A TARIFF SHEETS BEEN MADE TO REFLECT THE 2020 SETTLEMENT AGREEMENT?

A. Yes. The revisions to the Schedules 3 and 3A tariff sheets are shown in the exhibits to the 2020 Settlement Agreement.

Q. PLEASE DESCRIBE THE CHANGES MADE IN THE REVISED TARIFF SHEETS FOR SCHEDULE 3 AND SCHEDULE 3A.

A. PacifiCorp's tariff sheets for OATT Schedules 3 and 3A have been modified in this filing to reflect the 2020 Settlement Agreement revised charges for providing Regulation and Frequency Response Service and Generator Regulation and Frequency Response Service, respectively. In addition, as I discussed above, the tariff sheets for Schedules 3 and 3A incorporate the moratorium provisions of the 2020 Settlement Agreement applicable to Schedules 3 and 3A, the clarifications regarding Non-VER resources, and the provisions regarding third-party supply and pooling.

i. Consistency with Order No. 764.

Q. PLEASE SUMMARIZE THE REQUIREMENTS OF ORDER NO. 764.

A. On June 21, 2012, FERC issued Order No. 764, which is intended to remove barriers to the integration of VERs and, among other things, to promote more efficient operation of the transmission system amid increasing integration of VERs and to benefit electric consumers

by ensuring that services are provided at just and reasonable rates. In Order No. 764, the Commission provided guidance on six factors that should be considered when designing Regulation and Frequency Response Service charges that distinguish between VERs and other customers. In this filing, PacifiCorp is proposing updated Regulation and Frequency Response Service rates that continue to distinguish among load, VERs, and non-VERs (i.e., traditional fuel resources) based upon the different Regulation and Frequency Response burdens these three classes impose, and to further delineate the VER class between wind and solar. As discussed below, the design of PacifiCorp's base case rates for Regulation and Frequency Response complies with these six factors.

Q. WHAT IS THE FIRST FACTOR?

A. The first factor is:

> 1. Public utility transmission providers seeking to distinguish customers into classes for the purpose of requiring them to purchase or otherwise account for different quantities of generation regulating reserves should do so only to the extent such classes and distinctions among classes are reasonably related to operational similarities and differences among those resources.[11]

Q. HOW DOES PACIFICORP'S BASE CASE RATE DESIGN FOR REGULATION AND FREQUENCY RESPONSE SERVICE COMPLY WITH THE FIRST FACTOR?

A. The base case Schedules 3 and 3A rate design distinguishes among Load, Non-VERs, and Solar and Wind VERs based upon the differing impacts that each class has upon the Regulation and Frequency Response requirements. Load, Non-VERs, and Solar and Wind VERs each exhibit distinct patterns of variability and thus, each class creates a specific,

[11] Order No. 764 at P 318.

and different, volume of regulation reserve necessary to maintain system reliability. For example, most of PacifiCorp's Load customers have a usage pattern based on weather conditions and the day of the week, with seasonal and holiday variations. VERs exhibit a very different pattern of variability.

VERs include resources that, among other things, are renewable and have variability that is beyond the control of the facility owner or operator. As a result of these characteristics, wind and solar VERs fluctuate more than Load or Non-VERs, thereby introducing incremental variability and uncertainty, and thus increasing the amount of regulation reserves PacifiCorp must provide. Non-VERs, in contrast to both Load and VERs, tend to have little variability from their schedules when functioning properly. The Commission has recognized that VERs impose a higher regulation reserve burden on the transmission system even when their schedules are functioning properly.[12] The testimony of Mr. MacNeil supports a Schedules 3 and 3A base case rate design based upon operational differences among these resources.

Q. WHAT IS THE SECOND FACTOR?

A. The second factor is:

> 2. To the extent a public utility transmission provider proposes to break customers into specific groups based on operational characteristics, we expect public utility transmission providers to provide detailed explanations as to why such

[12] See Westar Energy, Inc., 130 FERC ¶ 61,215 at P 36 (2010) ("Westar asserts that intermittent generation places a heavier burden on its system than dispatchable generation and has provided data supporting this claim. Specifically, Westar's analysis submitted in response to the deficiency letter provides data showing, among other things, that intermittent generators' deviations from the deployment signal are more than three times greater than those of dispatchable generators. Accordingly, the Commission finds that Westar's proposal reasonably assesses intermittent generation a higher regulation requirement consistent with cost causation principles."); see also Pub. Serv. Co. of Colo., 149 FERC ¶ 61,208 at P 74 (2014) ("PSCo has distinguished between VERs, [N]on-VERs, and [L]oad, and demonstrates that these separate classes each involves a different Regulation and Frequency Response reserves burden. Therefore, we find that, consistent with the consideration given to Principle One, PSCo has shown distinguishable differences among the three customer classes that justify proposing different rates for those classes of customers").

classifications are appropriate if and when they propose to allocate different generating regulation reserve obligations to different customer classes.[13]

Q. HOW DOES PACIFICORP'S BASE CASE RATE DESIGN FOR REGULATION AND FREQUENCY RESPONSE SERVICE COMPLY WITH THE SECOND FACTOR?

A. In the context of Regulation and Frequency Response, Load, Wind VERs, Solar VERs, and Non-VERs display different operational characteristics and have distinct impacts on PacifiCorp's system. As shown by Mr. MacNeil's testimony, during the Study Period[14] each class has a unique forecast error, which is a measure of the difference between their forecasted output, represented by base schedules, and their actual output, based on metered data. Using a quantile regression, Mr. MacNeil shows the different Regulation and Frequency Response reserve obligations that would be needed for each class, based on each class's forecast error, for PacifiCorp to meet its compliance target for that class. Table 3 further illustrates the different Regulation and Frequency Response reserve obligations that would be needed for each class.

Table 3 – Regulation and Frequency Response Reserve Obligations for Each Class Evaluated Individually

Class	**Individual**
Non-VER	106 MW
Load	334 MW
Solar VER	159 MW
Wind VER	457 MW
Total	1057 MW

[13] Order No. 764 at P 319.

[14] As Mr. MacNeil discusses, PacifiCorp conducted a study to determine updated reserve requirements for Regulation and Frequency Response Service (both under Schedule 3 and Schedule 3A) and for Spinning Reserves (Schedule 5) and Supplemental Reserves (Schedule 6). The time period or "Study Period" was calendar years 2018 and 2019.

These values do not reflect an adjustment for portfolio diversity, which is discussed further below. However, Mr. MacNeil's calculations show the different operational characteristics of each of the proposed classes in the context of Regulation and Frequency Response, confirming the second factor of Order No. 764 is met.

Q. WHAT IS THE THIRD FACTOR?

A. The third factor is:

> 3. To the extent a public utility transmission provider proposes to differentiate among customers (or customer classes) in determining their relative regulating reserve responsibilities, the public utility transmission provider must demonstrate that the overall quantity of regulating reserve it requires of its transmission customers' accounts for diversity benefits among all resources and loads, and the allocations to individual customers (or customer classes) of their proportionate share is based on the operational characteristics of such customers (or customer classes).[15]

Q. PLEASE DESCRIBE HOW PACIFICORP CONSIDERED THE THIRD FACTOR.

A. The third factor requires that Regulation and Frequency Response rates consider portfolio diversity benefits.

Q. PLEASE EXPLAIN WHAT "PORTFOLIO DIVERSITY" IS, AS THAT TERM IS USED IN ORDER NO. 764.

A. In Order No. 764, FERC used the term portfolio diversity to describe diversity benefits that, in the calculation of generator regulation reserves, may result from the aggregation of the variations of all resources such that one resource's negative deviation can offset some or all of another resource's positive deviation.[16]

[15] Order No. 764 at P 320.
[16] Order No. 764 at P 279 n. 290.

Q. HOW DID PACIFICORP CONSIDER PORTFOLIO DIVERSITY IN ITS BASE CASE RATES FOR PURPOSES OF MEETING THE THIRD FACTOR?

A. Mr. MacNeil's testimony supports the assessment of portfolio diversity among wind and solar VERs, load, and Non-VERs, and how the reserve requirement is reduced to reflect that portfolio diversity. Because the largest deviations of each class do not occur at the same time, the regulation reserves held can cover the expected deviations for multiple classes at once and a reduced total quantity of reserves is sufficient to maintain the desired level of reliability. This reduction in the reserve requirement is the portfolio diversity benefit from holding a single pool of reserves to cover deviations in Load, VERs, and Non-VERs based on a portfolio-wide analysis. Table 3 showed the reserve requirements for each class. However, the portfolio diversity allows for a 36% reduction in reserve requirements. Thus, instead of 1057 MW in total, the base case total reserve requirement is reduced to 680 MW after taking portfolio diversity into consideration.

Q. WHAT IS THE FOURTH FACTOR?

A. The fourth factor is:

> 4. Weather events such as droughts may affect the required quantity of generator regulating reserves that the public utility transmission provider must have in reserve more or less during one portion of the year versus another portion of the year. In such cases, these diversity events, though perhaps characterized as anomalies, should be included in the data set so that the quantity and costs of such reserves are more reflective of actual system operations.[17]

Q. HOW DOES PACIFICORP'S BASE CASE RATE DESIGN FOR REGULATION AND FREQUENCY RESPONSE SERVICE COMPLY WITH THE FOURTH FACTOR?

[17] Order No. 764 at P 321.

A. PacifiCorp has analyzed data for the full calendar years 2018 and 2019 and has not excluded any data associated with weather events. The testimony of Mr. MacNeil explains in detail any data that were removed and the reasons for such removal; however, consistent with this factor, data were not excluded on the basis of weather events.

Q. WHAT IS THE FIFTH FACTOR?

A. The fifth factor is:

> 5. In designing any proposals for generator regulation service charges, a public utility transmission provider should consider the extent to which transmission customers are using intra-hour scheduling in evaluating whether to require different transmission customers to purchase or otherwise account for different quantities of generator regulating reserves.[18]

Q. WHEN DID PACIFICORP BEGIN ALLOWING INTRA-HOUR SCHEDULING?

A. PacifiCorp began to offer fifteen-minute scheduling in the Fall of 2013 to align with Order No. 764's effective date.

Q. IS INTRA-HOUR SCHEDULING USED FREQUENTLY ON PACIFICORP'S SYSTEM?

A. No. Although the use of intra-hour scheduling increased as a result of PacifiCorp's participation in the EIM, overall use of the intra-hour scheduling is not frequent.

Q. NOTWITHSTANDING THE LACK OF USE OF INTRA-HOUR SCHEDULING, HOW DOES PACIFICORP'S BASE CASE RATE DESIGN FOR REGULATION AND FREQUENCY RESPONSE SERVICE TAKE INTO ACCOUNT INTRA-HOUR SCHEDULING?

[18] Order No. 764 at P 322.

A. While limited intra-hour scheduling has occurred, PacifiCorp's base case rates recognize intra-hour scheduling and forecasting reforms by: (1) applying the EIM diversity benefit (discussed in more detail in the testimonies of Mr. MacNeil and Ms. Brown) to lower the regulation reserve burden for all customer classes (Load, VERs, and Non-VERs); and (2) offering, through the intra-hour Committed Scheduling discount, an additional 7.1 percent rate reduction to VERs willing to commit to submit balanced load and generation schedules on 15-minute intervals.

With regard to the latter discount, PacifiCorp's Schedule 3 and 3A offer this today, but PacifiCorp has adjusted the Committed Scheduling discount based upon the updated rates and to make the discount applicable to Solar VERs. Mr. McNeal discusses the discount further in his testimony.

Q. WHAT IS THE SIXTH FACTOR?

A. The sixth factor is:

> 6. There also is a relationship between the use of power production forecasting and the allocation of generator regulation reserve quantities to a particular class of customers. . . [T]he Commission finds that power production forecasts can provide public utility transmission providers with advanced knowledge of system conditions needed to manage the variability of VER generation through the unit commitment and dispatch process, rather than through the deployment of reserve services, such as regulation reserve. Without the increased situational awareness of projected variability provided by power production forecasts, the public utility transmission provider's ability to commit or de-commit resources providing regulation reserves efficiently can be constrained. This lack of situational awareness potentially can result in rates for generator regulation service that are unjust and unreasonable or unduly discriminatory.[19]

[19] Order No. 764 at P 323.

Q. HOW DOES PACIFICORP'S BASE CASE RATE DESIGN FOR REGULATION AND FREQUENCY RESPONSE SERVICE COMPLY WITH THE SIXTH FACTOR?

A. PacifiCorp's OATT requires customers to submit various power production forecasts. Ms. Brown's testimony describes these requirements and PacifiCorp's incorporation of these forecasts into its operations to more accurately estimate the regulation reserve needed in each hour. These actions reduce the quantity and cost of regulation reserve needed.

2. Schedules 5 and 6 Rates

Q. HOW DOES PACIFICORP CURRENTLY RECOVER ITS COSTS FOR OPERATING RESERVES UNDER SCHEDULES 5 AND 6?

A. As discussed earlier, the rates for the services provided under current Schedules 5 and 6 are the result of the ER17-219 Settlement. The current rates do not accurately reflect the costs PacifiCorp incurs to provide these services. The testimony of Mr. MacNeil discusses the base case reserve requirement and identification of the resources used to provide these services,[20] while the testimony of Dr. Dumais describes the base case calculation of the resource costs and rate for Schedules 5 and 6.[21] Under the 2020 Settlement Agreement, the rates for Schedules 5 and 6 will be lower than they would have been under the base case.

Q. WHAT ARE THE CURRENT RATES FOR SCHEDULES 5 AND 6 AND WHAT ARE THE 2020 SETTLEMENT AGREEMENT RATES?

[20] *See* Testimony of Dan MacNeil, Exhibit No. PAC-0003 at 48-50.
[21] *See* Testimony of Dr. Paul Dumais, Exhibit No. PAC-0011 at 12-36.

A. Currently, PacifiCorp charges "black box" settlement rates for Schedules 5 and 6 to transmission customers serving load in PacifiCorp's BAAs and to transmission customers exporting off-system from a generator integrated into PacifiCorp's BAAs. The table below provides the current "black box" rates and the 2020 Settlement Agreement rates for Schedules 5 and 6:

Table 5 – Current and 2020 Settlement Agreement Rates for Schedules 5 and 6 ($/MWh)

Ancillary Service	2020 Settlement Agreement Rates	Current Rates
Schedule 5 (Spinning Reserves)	$ 0.1677	$ 0.151
Schedule 6 (Supplemental Reserves)	$ 0.1677	$ 0.151

Under the 2020 Settlement Agreement, the Schedule 5 rate will increase from $0.151/MWh to $0.0167/MWh. The Schedule 6 rate will increase from $0.151/MWh to $0.167/MWh. As discussed more fully in Dr. Dumais' testimony, the base case Schedules 5 and 6 rates are $0.1820/MWh and $0.1720/MWh, respectively, and thus the 2020 Settlement Agreement rate for Schedules 5 and 6 of $0.167 is a reduction from what PacifiCorp otherwise could support.

Q. WHAT ARE THE NON-RATE TERMS AND CONDITIONS INCLUDED IN SCHEDULES 5 AND 6 FROM THE 2020 SETTLEMENT AGREEMENT?

A. As discussed earlier, the tariff records for Schedules 5 and 6 implement the service-related non-rate terms and conditions of the 2020 Settlement Agreement. The tariff sheets for Schedules 5 and 6 incorporate the moratorium provisions of the 2020 Settlement Agreement applicable to Schedules 5 and 6, and the provisions regarding third-party supply and pooling.

C. PacifiCorp's Proposed Schedule 2 Rates.

Q. HOW DOES PACIFICORP CURRENTLY RECOVER ITS COSTS FOR REACTIVE SUPPLY AND VOLTAGE CONTROL UNDER SCHEDULE 2?

A. As discussed earlier, the rates for the services provided under Schedule 2 were established as a result of a settlement agreement in Docket No. ER11-3643. The Schedule 2 rates became effective December 25, 2011.

The current rates do not accurately reflect the costs PacifiCorp incurs to provide this service. Since 2011, PacifiCorp has added significant resources to its portfolio that are providing these services. The testimony of Dr. Dumais further discusses the reactive power study, identification of the resources used to provide this service, the base case revenue requirement by resource for Schedule 2, and base case rates for Schedule 2. Under the 2020 Settlement Agreement, the rate for Schedule 2 will be lower than it would have been under the base case.

Q. WHAT ARE THE CURRENT RATES FOR SCHEDULE 2 AND WHAT IS THE 2020 SETTLEMENT AGREEMENT RATE?

A. The table below provides the current "black box" rates that resulted from the settlement agreement in Docket No. ER11-3643 and the 2020 Settlement Agreement rates for Schedule 2.

Table 6 – Proposed Rates for Schedule 2

Schedule 2	2020 Settlement Agreement Rates	Current Rates
Yearly	$1.603/kW/Year	$0.55/kW/Year

Q. PLEASE DESCRIBE THE DRIVERS FOR PACIFICORP'S BASE CASE SCHEDULE 2 RATES.

A. PacifiCorp has not proposed revisions to its Schedule 2 rates in almost a decade, and the generation mix on its system has changed. The drivers for this increase are inclusion of wind resources and significant investments in new wind resources, as well as inclusion of three power purchase arrangements. Neither wind facilities nor power purchase agreements were included in PacifiCorp's reactive power rates filed in and that resulted from the ER11-3643 settlement. Dr. Dumais addresses these topics further in his testimony.

Q. DOES THE 2020 SETTLEMENT AGREEMENT AFFECT THE NON-RATE TERMS AND CONDITIONS OF SCHEDULE 2 SERVICE?

A. Yes. First, the tariff records for Schedule 2 include the applicable moratorium provisions from the 2020 Settlement Agreement. Second, as part of the 2020 Settlement Agreement, the Settling Parties also agreed to revisions to PacifiCorp's Business Practice No. 63

("Transmission Customer Provision of Reactive Supply and Voltage Control from Generation or Other Sources Service"), which is posted to OASIS and which sets forth PacifiCorp's rules for transmission customers to receive credits for reactive power from the generation they use. Clean and redlined versions of Business Practice No. 63 are set forth in Exhibit H to the 2020 Settlement Agreement. The core principles of Business Practice No. 63 were first developed as part of PacifiCorp's settlement in Docket No. ER11-3643-000. As part of the most recent negotiations with customers, PacifiCorp and the other Settling Parties agreed to clarify and expand Business Practice No. 63 to, among other things, address how renewable customers may qualify for the revenue credit. The new Business Practice No. 63 will become effective and posted to PacifiCorp's OASIS on the effective date of the 2020 Settlement Agreement.

E. Self-Supply of Ancillary Services under Schedules 3, 3A, 5 and 6.

Q. HOW DOES THE 2020 SETTLEMENT AGREEMENT ADDRESS SELF-SUPPLY OF SCHEDULES 3, 3A, 5 AND 6?

A. The 2020 Settlement Agreement addresses self-supply of ancillary services in several ways. First, Attachment U of the PacifiCorp OATT, which today only addresses self-supply requirements for Schedules 5 and 6, has been extensively revised.

PacifiCorp's Business Practice No. 34 ("Self-Supply or Third-Party Supply of Ancillary Services – Certification Process and Requirements"), which is posted on its OASIS, describes certain minimum requirements for customers seeking to self-supply Schedule 3 and 3A, Regulation and Frequency Response Service; Schedule 4, Energy Imbalance Service; Schedule 5 – Operating Reserve-Spinning Reserve Service; Schedule

6, Operating Reserve-Supplemental Reserve Service; and Schedule 9, Generator Imbalance Service.

The current version of Business Practice No. 34 has been in effect since February 8, 2013. However, the ER17-219 Settlement Agreement included a moratorium on self-supply of Schedule 3 and 3A that expired on June 30, 2020. The Moratorium Period effectively suspended the provisions of Business Practice No. 34 as to Regulation and Frequency Response service self-supply.

Q. DOES THE 2020 SETTLEMENT ADDRESS SELF-SUPPLY OF ANCILLARY SERVICES?

A. Yes. As I discussed earlier, section 3.7 of the ER17-219 Settlement memorialized the Settling Parties' agreement to work together during the Moratorium Period to create a framework for the self-supply of Schedules 3 and 3A, and to update the self-supply provisions for Schedules 5 and 6, including discussion of PacifiCorp's ability to automate e-Tag adjustments. The Settling Parties discussed self-supply issues during the stakeholder process and their resolution is reflected in the 2020 Settlement Agreement. The 2020 Settlement Agreement addresses self-supply of Schedules 3, 3A, 5 and 6 in the following ways:

- Attachment U, which today only discusses self-supply requirements for Schedules 5 and 6, is extensively revised through the 2020 Settlement Agreement to provide greater clarity and consistency regarding self-supply. The updated Attachment U addresses self-supply requirements for Schedules 3, 3A, 4, 5 and 6. As part of the revision of Attachment U, the Settling Parties incorporated much of PacifiCorp's existing Business

Practice No. 34 ("Self-Supply or Third-Party Supply of Ancillary Services-Certification Process and Requirements") into Attachment U. As a result, Business Practice No. 34 will be retired as a separate document on July 1, 2021, the effective date of Attachment U.

- Schedules 3, 3A, 5 and 6 are revised through the 2020 Settlement Agreement to reflect that PacifiCorp shall reasonably and in good faith consider for acceptance customer requests for self-supply, third party supply and/or pooling agreements among customers under Schedules 3, 3A, 5 and 6 of its OATT on a case-by-case and non-discriminatory basis.
- PacifiCorp's Business Practice No. 39 ("Electronic Tagging of Reserves ('e-Tags')") is updated to revise the terms and conditions for use of e-Tags for self-supply of Schedules 5 and 6.

F. Background on the Collaboration with Combined Customers and Stakeholders

Q. EARLIER YOU STATED THAT PACIFICORP HELD FIVE WORKSHOPS WITH THE COMBINED CUSTOMERS AND STAKEHOLDERS. BRIEFLY DESCRIBE THE DECEMBER 13, 2019 WORKSHOP AND ANY STEPS TAKEN LEADING UP TO THE FEBRUARY 18, 2020 WORKSHOP.

A. The December 13, 2019 meeting focused on the Schedule 3 & 3A Study Methodology, Schedule 5 & 6 Self-Supply Automation, and the Schedule 3 & 3A Self-Supply.

Following the December 13, 2019 workshop, PacifiCorp issued specific questions to customers as a way of requesting feedback on the information provided at the December 13, 2019 workshop. The questions sought additional information relating to the topics discussed at the workshop, including: (1) PacifiCorp's proposed reserve requirement methodology for Schedules 3 and 3A; (2) the use of five-minute data rather than one-minute data for the reserve requirement study; (3) the use of 0.5 hours of loss of load per year in the study to meet reliability requirements and customer expectations; (4) developing ancillary services rates using a least cost rate methodology; (5) self-supply under Schedules 3 and 3A; and (6) self-supply automation under Scheduled 5 and 6. Additionally, PacifiCorp held a technical self-supply call on January 14, 2020 to allow for additional questions to be answered about the initial proposals for the self-supply of Schedules 3, 3A, 5 and 6.

Leading up to the February 18, 2020 Workshop, PacifiCorp posted a cost-of-service model and the Schedule 3/3A study data with an instruction manual for viewing the data on February 12, 2020. PacifiCorp also provided contact information for PacifiCorp representatives to walk stakeholders through the data and cost-of-service model for the rates. Several stakeholders contacted the PacifiCorp representatives for such assistance, which PacifiCorp provided.

Q. PLEASE CONTINUE TO DISCUSS EACH OF THE MEETINGS. BRIEFLY DESCRIBE THE FEBRUARY 18, 2020 WORKSHOP.

A. A primary topic discussed at the February 18, 2020 workshop were the questions and comments PacifiCorp received following the December 13, 2019 workshop, as well as PacifiCorp's responses to those questions.[22] In addition, self-supply protocols under Schedules 3 and 3A were addressed, including proposed:

- Self-Supply Principles;
- Options for election of Self-Supply;
- Requirements for Self-Supply; and
- Self-Supply scheduling for an EIM participating resource and a non-participating resource, including examples of each.

Q. BRIEFLY DESCRIBE THE MARCH 24, 2020 WORKSHOP.

A. A primary topic discussed at the March 24, 2020 workshop were the rates that PacifiCorp developed based on 2018 FERC Form 1 data. As noted, this work was undertaken by PacifiCorp to help further the collaboration by giving the Settling Parties and interested stakeholders an idea of how the revised revenue requirements would look for rates under Schedules 3, 3A, 5, and 6. Topics addressed regarding the estimated rates included: rate development under Schedules 3, 3A, 5, and 6; billing determinants; resource cost calculations; and development of the production fixed charge rate.

[22] The matrix of questions and answers can be found at: http://www.oasis.oati.com/woa/docs/PPW/PPWdocs/Revised_December_13_2019_Customer_Responses_022120.pdf.

In addition, other topics addressed were: reserve requirement methodology for Schedules 3 and 3A; the regulation reserve requirement by class; resources available to provide reserves; automated self-supply for Schedules 5 and 6; requirements to supply frequency response as a part of self-supply under Schedules 3 and 3A; real-time dispatch for self-supply; after-the-fact performance checks; and the process for strikes.

Q. BRIEFLY DESCRIBE THE MAY 4, 2020 WORKSHOP.

A. The primary discussion points during the May 4, 2020 workshop were the Schedule 3, 3A, 5 and 6 rates developed using 2019 financial data, the effects on the rates from the sensitivity analysis, and the remaining settlement elements from Section 6.3 of the ER17-219 Settlement Agreement. There was not enough time to cover the proposed rate development for Schedule 2. Therefore, PacifiCorp held an additional stakeholder workshop to discuss the rate development of Schedule 2 on May 28, 2020.

Q. WHAT HAS OCCURRED SINCE THE MAY 4, 2020 WORKSHOP?

A. Since the last of the series of workshops, the participants have been involved in a "negotiation phase." PacifiCorp and customers have been involved in many discussions and negotiations regarding the ancillary service rates, non-rate terms and conditions, and associated business practices related to ancillary services, which culminated in the 2020 Settlement Agreement and PacifiCorp's filing to implement the 2020 Settlement Agreement.

Q. HOW DID PACIFICORP CONSIDER SECTION 6.3.9 OF THE SETTLEMENT AGREEMENT, WHICH REQUIRES CONSIDERATION OF "INCLUSION OF AN

INTRA-HOUR SCHEDULING DISCOUNT REFLECTING THE USE OF WIND POWER PRODUCTION FORECASTS AS OF THE LATER OF THE T-40 BASE SCHEDULE UPDATE OR ANY LATER DEADLINE THAT IS ESTABLISHED FOR EIM ENTITY UPDATES TO BASE SCHEDULES"?

A. Pursuant to the 2020 Settlement Agreement, PacifiCorp's tariff will continue to offer a Committed Scheduling discount to VERs that provide a commitment to submit fifteen-minute schedules, and actually provide such schedules.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Mary M. Wiencke

Attachment C

Direct Testimony of Kelcey A. Brown, former Vice President of Energy Supply Management

Exhibit No. PAC-0002

Exhibit No. PAC-0002

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp	**)**	**Docket No. ER21-___-000**

TESTIMONY OF

KELCEY A. BROWN
ON BEHALF OF PACIFICORP

February 1, 2021

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I. INTRODUCTION AND EXPERIENCE

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Kelcey A. Brown. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. Up until February 25, 2021, I was employed by PacifiCorp as Vice President of Energy Supply Management. I am currently the CEO, president and director of MidAmerican Energy.

Q. PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS EXPERIENCE.

A. I have been employed by PacifiCorp since May 2011 and I have been in my current role since November 2019. Before my current role at PacifiCorp, I was the Director of Market Policy and Analytics since July 2015, wherein my responsibilities were primarily related to the California Independent System Operator ("CAISO") Energy Imbalance Market ("EIM"), contract administration, and short-term post analytics. I have also worked as the Manager of Load Forecast and as a Senior Consultant in the Regulatory Net Power Costs Department. Before joining PacifiCorp, I worked at the Public Utility Commission of Oregon from November 2007 through May 2011. From 2003 through 2007, I was the Economic Analyst with Blackfoot Telecommunications Group, where I was responsible for revenue forecasts, resource acquisition analysis, pricing, and regulatory support. I have a Bachelor of Science degree in Business Economics from the University of Wyoming, and I have completed all course work towards a Master's degree in Economics from the University of Wyoming.

Q. PLEASE SUMMARIZE THE BASIS OF YOUR KNOWLEDGE AND CONCLUSIONS CONCERNING THE ISSUES TO WHICH YOU ARE TESTIFYING IN THIS CASE.

A. Up until February 25, 2021, I served as the vice president of the organization responsible for commercially managing PacifiCorp's diverse generation portfolio. This includes the electric and natural gas hedging, term and day-ahead trading, real-time trading, and load/resource balancing.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. PacifiCorp has reached a settlement agreement ("2020 Settlement Agreement') with its customers regarding the rates for certain ancillary services under the PacifiCorp Open Access Transmission Tariff ("OATT"), and proposes to implement the settlement rates through its filing. The 2020 Settlement Agreement rates are "black box," negotiated rates. The purpose of my testimony is to explain and support certain policy considerations underlying PacifiCorp's revised ancillary service rates in the "base case," which was PacifiCorp's starting point for negotiations with customers and which would have been the case filed by PacifiCorp if settlement had not been reached.. My testimony includes the background of the applicable reliability standards, pertinent aspects of the EIM and PacifiCorp's participation in the EIM. My testimony also explains several policy considerations supporting the determination to allocate the total amount of Regulation and Frequency Response reserves among load, variable energy resources ("VERs") and generators that are not VERs ("Non-VERs"), and to exclude generation that provides reserve capabilities. I also describe power production forecasting and intra-hour scheduling. Further, I discuss several of PacifiCorp's considerations in developing reserve

requirements for Operating Reserves – Spinning under Schedule 5 of the OATT, and Operating Reserve – Supplemental under Schedule 6 of the OATT.

II. CONSIDERATIONS FOR SERVICES PROVIDED BY PACIFICORP UNDER SCHEDULES 3 AND 3A

A. Reliability Standards

Q. PLEASE DESCRIBE SCHEDULES 3 AND 3A.

A. Schedule 3 addresses Regulation and Frequency Response Service. This service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining interconnection frequency at 60 cycles per second (60 Hertz). Regulation and Frequency Response Service is accomplished by committing generation, whose output is raised or lowered predominantly through the use of automatic generation control equipment, and other non-generation resources able to provide this service. PacifiCorp has the responsibility to maintain this balance between resources and load in its balancing authority area ("BAA"). Transmission customers in the PacifiCorp BAA must purchase this service from PacifiCorp, make alternative comparable arrangements or self-supply the service.

Under Schedule 3, PacifiCorp differentiates charges to different customer classes: load, VERs and Non-VERs. By definition VERs are generation resources that are not dispatchable by the generator operator in the same way as conventional resources using fossil fuel sources. The output of VERs tends to be dependent on a fuel source that cannot be stored and which availability is difficult to predict. Examples of VERs are wind and solar generation. Non-VERs are generation resources where the output can be controlled to meet need and which output is dependent on a fuel source that can be stored and which

availability is predictable. Examples of non-VERS are combined cycle natural gas-fired generation facilities, and coal-fired generation facilities.

Schedule 3A addresses Regulation and Frequency Response Service when transmission service is provided for a generator physically or electrically located in the PacifiCorp BAA, but the electricity terminates in another BAA, or for any resource that is not a Network Resource.

Q. PLEASE DESCRIBE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION ("NERC") RELIABILITY STANDARD BAL-001-2, WHICH PERTAINS TO SCHEDULES 3 AND 3A.

A. The regulation reserve requirement for Schedules 3 and 3A are driven by NERC Reliability Standard BAL-001-2, which is a regulation reserve standard that became effective July 1, 2016. Regulation reserve and contingency reserve (which is further described below) are components of operating reserves, which NERC defines as "the capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection."

Schedules 3 and 3A reflect the cost of regulation reserve and are derived from compliance with Standard BAL-001-2. The Control Performance Criteria in BAL-001-2 require each BAA to carry regulation reserve incremental to contingency reserve to maintain reliability. Under this standard, the regulation reserve requirement is not defined by a simple formula, but instead is the amount of reserve required by each BAA to meet specified control performance standards defined in the standard. Requirement 2 of BAL-001-2 defines the compliance standard as follows:

> *Each Balancing Authority shall operate such that its clock-minute average 12 of Reporting [Area Control Error ("ACE")] does not exceed its clock minute*

Balancing Authority ACE Limit (BAAL) for more than 30 consecutive clock-minutes…

The PacifiCorp BAAs[1] have separate and distinct ACE measurements and Balancing Authority ACE Limit requirements. Each of PacifiCorp's BAAs maintains and deploys regulation reserve to ensure that its ACE does not exceed its Balancing Authority ACE Limit for more than 30 consecutive minutes.

Q. WHAT IS PACIFICORP'S UNDERSTANDING OF ITS COMPLIANCE OBLIGATIONS UNDER BAL-001-2?

A. The BAL-001-2 standard effectively requires that PacifiCorp keep its loads and resources balanced in real-time. Specifically, the BAL-001-2 standard requires one-minute ACE to be within a dynamic limit at least one full minute in 100 percent of all rolling thirty-minute intervals.

Q. WHAT IS ACE?

A. NERC defines ACE as "the instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction (ATEC), if operating in the ATEC mode."[2]. ACE is the measure of performance for an entity to balance internal demand obligations and simultaneously meet external obligations. Supply in excess to demand results in a positive ACE. Demand in excess to supply results in a negative ACE.

Q. PLEASE DESCRIBE THE LOADS AND RESOURCES PACIFICORP BALANCES IN REAL-TIME.

[1] PacifiCorp operates two BAAs in the Western Electricity Coordinating Council ("WECC") NERC region, PacifiCorp East ("PACE") and PacifiCorp West ("PACW").

[2] Glossary of Terms Used in NERC Reliability Standards (updated June 2, 2020), *available at*: https://www.nerc.com/files/glossary_of_terms.pdf

A. As I noted earlier, PacifiCorp operates two BAAs: PACE and PACW. PacifiCorp's BAAs are interconnected by a limited amount of transmission facilities owned by PacifiCorp and a third-party. The two BAAs are each separately required to maintain compliance with NERC standards, including BAL-001-2 and BAL-002-WECC-2.

In 2019, the average monthly coincident peak load ("12 CP") was 10,359 megawatts ("MW"), not including loads telemetered to other BAAs. In 2020, 15,825 MW of resources were interconnected with the PacifiCorp system, including over 3,800 MW of VERs (predominantly wind generation.

Q. PLEASE DESCRIBE THE IMPACTS DIFFERENT CLASSES OF TRANSMISSION USERS HAVE ON PACIFICORP'S COMPLIANCE OBLIGATIONS UNDER THE BAL-001-2 STANDARD.

A. As discussed in the testimony of PacifiCorp Witness Mr. Daniel J. MacNeil, the frequency, magnitude, and predictability of ACE deviations varies for different classes of transmission users, and places different compliance obligations on PacifiCorp under the BAL-001-2 standard.

Load generally follows diurnal and seasonal patterns, but has some unexpected variation due to weather and customer behavior. VERs also generally follow diurnal and seasonal patterns, but have significant unexpected variation due to weather. Non-VERs have some diurnal and seasonal patterns, and some unexpected variation, but that variation is not generally driven by weather conditions, is generally predictable, and is significantly less than VERs. As a class, dispatchable resources are Non-VERs that are dispatchable by PacifiCorp and used to balance the deviations resulting from other users of the transmission system in all hours. While non-dispatchable resources (both VERs and Non-VERs) may

happen to offset deviations in loads or other resources in some hours, they are not controlled to balance the system and in other hours they contribute to the overall requirement. Because the dispatchable resource class is a net provider rather than a user of regulation reserve service, its stand-alone regulation reserve requirement is zero (or negative), and its share of the system regulation reserve requirement is also zero.

Q. DO THE REQUIREMENTS DEVELOPED IN PACIFICORP'S REGULATION RESERVE STUDY REASONABLY REFLECT THE DIFFERENCES BETWEEN LOAD, VERS, AND NON-VERS?

A. Yes. The regulation reserve study concludes that an average of 540 MW of regulation reserve is necessary to comply with NERC Standard BAL-001-2. Of the total regulation reserve requirement, 32% is attributed to load, 58% is attributed to VERs, and 10% is attributed to Non-VERs. The load in PacifiCorp's BAAs is roughly 2.5 times larger than the VER capacity and roughly eight times larger than the Non-VER capacity in the PacifiCorp BAAs. The result of the study shows that the regulation reserve attributable to load is less than the amount required for a comparable capacity of VERs, and somewhat lower than the amount required for a comparable capacity of Non-VERs. This is consistent with the underlying uncertainty and variability of the different classes, as described above. The dispatchable resource class provides the 540 MW of regulation reserve necessary to balance the aggregate deviations of load, VERs, and Non-VERs, and ensures compliance with NERC Standard BAL-001-2. As noted above, because the dispatchable resource class doesn't make the regulation reserve requirement larger, none of the requirement is attributed to dispatchable resources.

Q. DESCRIBE ANY UNIQUE LOADS ON PACIFICORP'S SYSTEM AND WHETHER THEY WERE INCLUDED OR EXCLUDED IN THE DATA USED TO DEVELOP THE UPDATED ANCILLARY SERVICE RATES.

A. Unique loads exist in the PACE BAA including several large industrial loads with unique patterns of demand. Each of these loads is either interruptible at short notice or includes behind-the-meter generation. Due to the large size of these loads, abrupt changes in demand are magnified for these customers in a manner which is not representative of the aggregated demand of the large number of small customers, which make up the majority of PacifiCorp's loads. Additionally, interruptible loads are included in the cost of regulation reserve service and are dispatchable resources. Therefore, these loads are not allocated a regulation reserve requirement

Although the reserve requirement for the large industrial loads is not included in the analysis, these loads are still included in the denominator of PacifiCorp's regulation reserve rate, so the large industrial loads are attributed a proportionate share of the costs. Removing these loads from the denominator would increase the Schedules 3 and 3A regulation reserve rate.

In addition, interruptible loads can be curtailed if their deviations are contributing to a resource shortfall. Because of these unique characteristics, these loads are excluded from the data used to develop the updated ancillary service rates submitted in this proceeding. This treatment is consistent with that used in the CAISO load forecast methodology (used for PACE and PACW EIM operations), which also nets these interruptible customer loads out of the PACE BAA.

B. <u>Meeting the ACE Limit</u>

Q. HOW DOES PACIFICORP APPLY THE BALANCING AUTHORITY ACE LIMIT IN ACTUAL OPERATIONS?

A. The Balancing Authority ACE Limit is specific to each BAA and is dynamic, varying as a function of interconnection frequency. When WECC frequency is close to 60 Hz, the Balancing Authority ACE Limit is large and large deviations in ACE are allowed. As WECC frequency drops further and further below 60 Hz, ACE deviations are increasingly restricted for BAAs that are contributing to the shortfall, i.e., those BAAs with Net Actual Interchange less than Net Scheduled Interchange. A BAA commits a BAL-001-2 reliability violation if in any thirty-minute interval it does not have at least one minute when its ACE is within its Balancing Authority ACE Limit.

WECC-wide frequency can change rapidly and without notice, and this causes large changes in the Balancing Authority ACE Limit over short time frames. Maintaining ACE within the Balancing Authority ACE Limit under those circumstances can require rapid deployments of large amounts of operating reserve. To limit the size and speed of resource deployment necessitated by variation in the Balancing Authority ACE Limit, PacifiCorp's operating practice caps permissible ACE at the lesser of the Balancing Authority ACE Limit or four times L_{10}. L_{10} represents a bandwidth of acceptable deviation under the former BAL-001 standard (BAL-001-1) prescribed by WECC between the net scheduled interchange and the net actual electrical interchange of PacifiCorp's BAAs.

Q. DOES PACIFICORP ASSUME IT WILL SHED FIRM LOAD IN ACTUAL OPERATIONS?

A. No, not under normal conditions. However, for purposes of operational planning, PacifiCorp makes certain assumptions, including assumptions that PacifiCorp will shed

firm load under certain conditions for reliability purposes. Since its 2011 comprehensive transmission rate filing (Docket No. ER11-3643-000), PacifiCorp has not shed firm load for system reliability purposes (as opposed to local transmission problems).

As discussed in the testimony of Mr. MacNeil, the base case Schedules 3 and 3A rates assume 0.50 loss of load hours per year due to regulation reserve shortages. In actual operations, PacifiCorp may realize a lower loss of load probability because the regulation reserve requirement is a minimum, and, due to the granularity of PacifiCorp's resources and market opportunities, larger amounts of reserves are likely to be available in any given hour. However, this condition cannot be counted upon in the hour-ahead setup of the balancing area in the event it is unavailable. Finally, as discussed below, import opportunities from the EIM further reduces the likelihood that PacifiCorp would need to shed firm load for reliability reasons, but the EIM is a non-firm energy market that is not able to be leaned on or counted upon for the balancing area responsibilities.

C. Treatment of EIM Diversity Benefit

Q. PLEASE DESCRIBE THE EIM.

A. The EIM is a voluntary energy imbalance market service through the CAISO where market systems automatically balance supply and demand for electricity every 15 minutes, dispatching the least-cost resources every five minutes. PacifiCorp began participating in the EIM on November 1, 2014.

Q. HOW DOES THE EIM IMPACT PACIFICORP'S REQUIREMENTS TO CARRY RESERVES?

A. By pooling variability in load, wind, and solar output, EIM entities reduce the quantity of reserves required to balance intra-hour variations. The EIM does not relieve participants of

their reliability responsibilities. EIM entities are required to have sufficient resources to serve their load on a standalone basis each hour before participating in the EIM. Thus, each EIM participant remains independently responsible for all reliability obligations.

Q. WHAT IS THE EIM DIVERSITY BENEFIT PROVIDED BY THE EIM?

A. Variability across different BAAs may happen in opposite directions, therefore, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAAs' requirements. CAISO calculates the flexible ramping requirement for each individual balancing authority and for the entire EIM footprint. The EIM footprint flexible ramping requirement is lower than the sum of all of the participating BAAs individual requirements. This difference is known as the "EIM Diversity Benefit" in the market. This diversity benefit reflects offsetting variability and lower combined uncertainty. The EIM footprint flexible ramping requirement is in addition to, and separate from, the spinning and supplemental reserves carried against generation or transmission system contingencies under the NERC standards.

Q. HOW DOES THE CAISO CALCULATE THE EIM DIVERSITY BENEFIT?

A. The CAISO calculates the EIM diversity benefit by first calculating a flexible ramping requirement for each individual EIM BAA and then by comparing the sum of those requirements to the flexible ramping requirement for the entire EIM area. The latter amount is expected to be less than the sum of the individual BAAs due to: (1) the portfolio diversification effect of forecasting a larger pool of load and VERs, and (2) increased system visibility in the hypothetical, single-BAA EIM. Each EIM BAA is then credited with a share of the reserve benefit calculated by CAISO based on its share of the stand-alone requirement relative to the total requirement.

Q. WHAT EIM DIVERSITY BENEFIT DOES PACIFICORP PROPOSE TO INCLUDE IN ITS REGULATION RESERVE STUDY?

A. PacifiCorp is proposing the application of an EIM diversity benefit by crediting its regulation reserve forecast with average EIM diversity benefits based on historical results. The testimony of Mr. MacNeil discusses how the EIM diversity benefits are incorporated into the regulation reserve study.

Q. HOW DOES THE EIM DIVERSITY BENEFIT IMPACT PACIFICORP'S REGULATION RESERVE REQUIREMENTS?

A. The EIM diversity benefit assumes that imports from other EIM participants will be available to cover a portion of PacifiCorp's requirement, thereby reducing the probability of reserve shortfalls and, in doing so, reducing the overall regulation reserve requirement. As Mr. MacNeil discusses, the impact of the EIM diversity benefit is a 140 MW reduction of the overall regulation reserve requirement.

D. <u>Power Production Forecasting</u>

Q. PLEASE DESCRIBE HOW THE COMPANY USES FORECAST SERVICES TO DEVELOP ACCURATE FORECASTS OF LOAD AND VERS.

A. Customers with VERs are required to provide meteorological and forced outage data, as specified in PacifiCorp's *pro forma* Large Generator Interconnection Agreement. Additionally, VERs forecast data is required under Attachment T of PacifiCorp's OATT for purposes of the EIM. Customers' VERs that are not participating in EIM bidding are required to submit resource forecast data on an hourly basis, as well as resource forecast data on either a 15-minute or five-minute basis, and must update the forecast every 15 minutes or five minutes, respectively. Intra-hour updates to the load forecast (by CAISO)

and the VERs forecast (by PacifiCorp's third-party provider) provide advance notice of changing requirements, enabling the EIM to deploy lower cost resources rather than just those with faster ramping capability. This reduces imbalance costs charged to customers under Schedules 4 and 9.

Q. HOW HAS PACIFICORP ACCOUNTED FOR POWER PRODUCTION FORECASTING IN DETERMINING THE QUANTITY OF REGULATION RESERVES REQUIRED FOR SCHEDULES 3 AND 3A?

A. PacifiCorp's transmission customers submit balanced base schedules to CAISO for its load and resources by 55 minutes prior to the start of each operating hour (T-55). The base schedules for all VERs reflect data provided by a forecasting service, in accordance with PacifiCorp's OATT and EIM operational practices, and reflect the best, most up-to-date information about conditions in the upcoming hour at the time of submission.

The regulation reserve study presented by Mr. MacNeil identifies the amount of capacity in excess of the balanced load and resource base schedule submission that needs to be set aside at T-55 for compliance with NERC standard BAL-001-2. Because the regulation reserve study uses deviations in load, VERs, and Non-VERs calculated from the forecasts available at T-55, it does not include the requirements or costs of managing the larger uncertainty over longer time frames. This is appropriate as uncertainty prior to T-55 is intended to be managed by transmission customers via their submission of balanced base schedules. In addition, PacifiCorp's regulation reserve forecast for VERs utilizes the base schedule to more accurately estimate the regulation reserve needed in the upcoming hour, lowering regulation reserve requirements in periods with limited potential for deviations.

Q. HOW DOES PACIFICORP'S POWER PRODUCTION FORECASTING MINIMIZE THE NEED FOR REGULATION RESERVES ON ITS SYSTEM IN BOTH DAY-AHEAD AND REAL-TIME OPERATIONS?

A. In the day-ahead timeframe, PacifiCorp uses forecasted load, VERs, and Non-VERs to estimate its regulation reserve requirements and optimize the commitment of its gas-fired generating units. To the extent day-ahead regulation reserve needs call for must-run commitment of units to provide regulation reserve, the startup and operating costs associated with those units would be attributable to meeting the regulation reserve requirement. PacifiCorp did not include these costs in its base case rates.

As a result of EIM participation, PacifiCorp has increased system visibility and improved intra-hour operational performance. Leading up to and during the operating hour, load and VERs forecasts are updated to ensure that sufficient flexible resource capacity is maintained to compensate for both expected and unexpected changes in load or generation, while at the same time automatically dispatching the least cost resources within each five minute interval. In the absence of intra-hour power production forecasting, all changes in load and resources would be unexpected, and more rapid ramping capability would be necessary to ensure compliance with NERC Standard BAL-001-2.

III. Considerations for Development of Schedules 5 and 6

Q. PLEASE DESCRIBE SCHEDULE 5.

A. Schedule 5 addresses operating reserves, and, in particular, Spinning Reserve Service. Spinning Reserve Service is needed to serve load in the BAA and to support other transmission usage sourced from generation in the BAA, including exports and sales. Spinning Reserve Service may be provided by generating units that are on-line and loaded

at less than maximum output and by non-generation resources capable of providing this service. PacifiCorp offers Spinning Reserve Service when the transmission service is used to serve load within its BAA and to support other transmission usage sourced from generation in the BAA, including exports and sales. The Transmission Customer must purchase this service from PacifiCorp, make alternative comparable arrangements or self-supply the service to satisfy its Spinning Reserve Service obligation.

Q. PLEASE DESCRIBE SCHEDULE 6.

A. Schedule 6 addresses Supplemental Reserve Service, which is needed to serve load in the BAA and to support other transmission usage sourced from generation in the BAA including exports and sales. However, it is not available immediately to serve load, but rather is available within a ten minute period. Supplemental Reserve Service may be provided by generating units that are on-line, but unloaded, by quick-start generation, by interruptible load or other non-generation resources capable of providing this service.

PacifiCorp offers this service when the transmission service is used to serve load within its BAA and to support other transmission usage sourced from generation in the BAA, including exports and sales. The Transmission Customer must purchase this service from PacifiCorp, make alternative comparable arrangements or self-supply the service to satisfy its Supplemental Reserve Service obligation.

Q. HAS THE COMMISSION INSTITUTED ANY REQUIREMENTS FOR SCHEDULES 5 AND 6?

A. Yes. On November 21, 2013, the Commission issued Order No. 789 wherein the Commission approved the WECC regional Reliability Standard BAL-002-WECC-2 (Contingency Reserve). On January 24, 2017, the Commission accepted BAL-002-

WECC-2a, which clarified the standard in terms of the use of certain non-traditional resources to qualify as "Operating Reserve- Spinning." BAL-002-WECC-2a is still effective today.[3] As I noted above, the rates under Schedules 5 and 6 reflect the cost of contingency reserve held to ensure compliance with the Reliability Standard BAL-002-WECC-2a. Schedules 5 and 6 of the OATT expressly refer to this reliability standard, stating: "the current NERC Regional Reliability Standard BAL-002-WECC, the Transmission Provider is required to maintain a minimum amount of contingency reserve equal to the sum of three percent of hourly integrated load plus three percent of hourly integrated generation with at least half as spinning."

Q. PLEASE DESCRIBE STANDARD BAL-002-WECC-2a.

A. The WECC standard BAL-002-WECC-2a applies to balancing authorities and reserve sharing groups in the WECC Region and is meant to specify the quantity and types of operating contingency reserve required to ensure reliability under normal and abnormal conditions.

Q. WHAT IS THE AMOUNT OF OPERATING RESERVE REQUIRED UNDER THE BAL-002-WECC-2a STANDARD?

A. The amount of total operating contingency reserve—both spinning and supplemental—is the greater of either: (1) the amount of contingency reserve equal to the loss of the most severe single contingency; or (2) the amount of contingency reserve equal to the sum of three percent of hourly integrated load plus three percent of hourly integrated generation. Contingency reserve must be deployable within ten minutes, and, pursuant to Requirement

[3] NERC and WECC recently filed a new version of the standard: BAL-002-WECC-3, currently pending Federal Regulatory Energy Commission ("FERC") approval.

2 of BAL-002-WECC-2a, at least half must be from "spinning" resources that are online and immediately responsive to system fluctuations.

Q. HAS PACIFICORP TAKEN STEPS TO MINIMIZE ITS CONTINGENCY RESERVE OBLIGATIONS?

A. Yes. PacifiCorp's participation in the Northwest Power Pool Reserve Sharing Group eliminates its need to cover the most severe single contingency on its system. As a result, it holds contingency reserves equal to three percent of hourly integrated load plus three percent of hourly integrated generation.

Q. DO PACIFICORP'S SCHEDULES 5 AND 6 REFLECT THE COST OF THE RESERVE REQUIREMENT UNDER THE BAL-002-WECC-2a STANDARD?

A. Yes. Schedules 5 and 6 of the PacifiCorp OATT reflect the cost of contingency reserve for the sum of three percent of a customer's hourly integrated load and three percent of a customer's hourly integrated generation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Kelcey Brown

Kelcey A. Brown

Attachment D

Direct Testimony of Daniel J. MacNeil, Resource and Commercial Strategy Adviser, and Exhibits

Exhibit Nos. PAC-0003 – PAC-0010

Exhibit No. PAC-003

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp	**)**	**Docket No. ER21-___-000**

TESTIMONY OF

DANIEL J. MACNEIL
ON BEHALF OF PACIFICORP

February 1, 2021

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LIST OF EXHIBITS

Exhibit No.	Description
PAC-004	Table A Study Results: Schedule 5, Spinning Reserve
PAC-005	Table B Study Results: Schedule 6, Supplemental Reserve
PAC-006	Table C Study Results: Schedules 3/3A, Regulation & Frequency Response
PAC-007	Table D Adjusted Study Results: Schedule 5, Spinning Reserve
PAC-008	Table E Adjusted Study Results: Schedule 6, Supplemental Reserve
PAC-009	Table F Adjusted Study Results: Schedules 3/3A, Regulation & Frequency Response
PAC-0010	Workpaper Contents

I. INTRODUCTION AND EXPERIENCE

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Daniel J. MacNeil. My business address is 825 NE Multnomah Street, Portland, Oregon 97232.

Q. IN WHAT POSITION ARE YOU CURRENTLY EMPLOYED?

A. I am a Resource and Commercial Strategy Adviser at PacifiCorp.

Q. PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS EXPERIENCE.

A. I received a Master of Arts degree in International Science and Technology Policy from George Washington University and a Bachelor of Science degree in Materials Science and Engineering from Johns Hopkins University. Before joining the Company, I completed internships with the U.S. Department of Energy's Office of Policy and International Affairs and the World Resources Institute's Green Power Market Development Group. I have been employed by PacifiCorp since 2008, first as a member of the Net Power Costs group, then as manager of that group from June 2015 until September 2016. In my current role, I provide analytical expertise on a broad range of topics related to PacifiCorp's resource portfolio and obligations.

Q. PLEASE SUMMARIZE THE BASIS OF YOUR KNOWLEDGE AND CONCLUSIONS CONCERNING THE ISSUES TO WHICH YOU ARE TESTIFYING IN THIS CASE.

A. In the Net Power Cost group, I developed a thorough understanding of PacifiCorp's system, and the resources, requirements, and operating constraints which drive decisions, which in turn, drive costs. PacifiCorp defines net power costs as the sum of fuel expenses, wholesale purchase power expenses, and third-party wheeling expenses, less

wholesale sales revenue. In my current role I support the determination of avoided cost prices for qualifying facilities and other resources, both through production cost modeling and by refining and defending the avoided cost methodology in each of PacifiCorp's jurisdictions.

I have supported PacifiCorp's ancillary service rates in prior cases. I served as part of the internal team which reviewed the methodology originally developed for the 2012 Wind Integration Study, which was used in PacifiCorp's 2013 Schedules 3 and 3A Study—which supported PacifiCorp's 2013 filing for amended Schedules 3 and 3A rates in Docket No. ER13-1206-000, as well as the 2014 Wind Integration Study. As part of that team, I helped develop analyses and arguments defending the methodology and modeling of the results in retail rate proceedings. I was also part of the internal team that developed the 2016 Regulation Reserve Study, and I sponsored testimony supporting the methodology for determining the reserve requirements for the revised Schedule 3, 3A, 5 and 6 rates of PacifiCorp in Docket No. ER17-219-000.

I also was a member of the team that developed PacifiCorp's updated reserve study, which is presented through my testimony and is the basis for the reserve requirements for PacifiCorp's proposed rates in this case.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. PacifiCorp has reached a settlement agreement with its customers regarding the rates for certain ancillary sevices, and proposes to implement the settlement rates through its filing. The settlement rates are "black box," negotiated rates. The purpose of my testimony is to explain and support the methodology used to develop the revised ancillary service rates in PacifiCorp's "base case" for: Regulation and Frequency

Response Service ("Regulation Service") (Schedule 3); Generator Regulation and Frequency Response Service ("Generator Regulation Service") (Schedule 3A); Operating Reserve – Spinning Reserve Service (Schedule 5); and Operating Reserve – Supplemental Reserve Service (Schedule 6). During the first quarter of 2020, PacifiCorp conducted a study to determine an updated reserve requirement for Regulation and Frequency Response Service and for Spinning Reserve Service and Supplemental Reserve Service, and I present that study through my testimony and workpapers. The resulting, updated reserves requirements from the study were used in PacifiCorp's "base case," which was PacifiCorp's starting point for negotiations with customers and which would have been the case filed by PacifiCorp if settlement had not been reached. Since the settlement agreement rates are at or below the base case rates, this testimony is submitted to support the justness and reasonableness of the settlement agreement rates. My testimony supports the following features of PacifiCorp's base case:

(1) the total amount of regulating reserves that are needed by PacifiCorp to provide service under revised Schedules 3 and 3A of PacifiCorp's open access transmission tariff ("OATT");

(2) the allocation of the total amount of regulation reserves among load, variable energy resources ("VERs") and resources that are not VERs ("Non-VERs");

(3) identification of the specific resources that supply the total amount of regulating reserves, including the proportional contributions of such resources; and

(4) the total amount of operating reserves needed by PacifiCorp to provide service under Schedules 5 and 6.

Q. HAS PACIFICORP INCORPORATED ANY SIGNIFICANT ENHANCEMENTS SINCE ITS FILING IN DOCKET ER17-219-000?

A. Yes.

Q. PLEASE BRIEFLY DESCRIBE THOSE ENHANCEMENTS.

A. There are three primary areas of improvement in the current study. First, in light of the growth of utility-scale solar resources from a de minimus quantity in the 2015 study period in docket ER17-219-000 to more than 1,000 MW in this proceeding, PacifiCorp has split the VERs class so as to account for the distinct characteristics of wind and solar resources. Second, PacifiCorp's study now incorporates the hour-ahead forecast of load produced by the CAISO, replacing the proxy forecast based on conditions in the prior week used in Docket No. ER17-219-000. Improved load forecasting contributes to a significant reduction in the regulation reserve requirement for load. Finally, PacifiCorp's regulation requirement forecast is now based on a quantile regression methodology that expresses the regulation requirement as a polynomial function based on the relationship between hour ahead forecasts and hour ahead forecast errors at a certain quantile. As a result of these changes, the portfolio regulation requirement is lower than in Docket No. ER17-219-000, despite the addition of more than 1,000 MW of solar resources and more than 150 MW of wind resources.

Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes. I am sponsoring Exhibit Nos. PAC-004 through PAC-009, which provide tables summarizing the results of the reserve study calculations.

Q. ARE YOU SPONSORING ANY OTHER DOCUMENTS?

A. Yes. I am sponsoring my workpapers, which are provided both as Microsoft Excel files and R script, with my testimony. The workpapers support PacifiCorp's reserve study. The study was created in R, a statistical computing software and all calculations, with the exception of the quantile regression, have been converted into Microsoft Excel files so that they may be more easily referenced and reviewed. The contents of the workpapers are listed in Exhibit No. PAC-0010 to my testimony.

II. DETERMINATION OF RESOURCE REQUIREMENTS FOR SERVICES PROVIDED BY PACIFICORP UNDER SCHEDULES 3, 3A, 5 AND 6

A. Defining Regulation and Frequency Response Service and Spinning and Supplemental Reserves Services

Q. WHAT IS REGULATION AND FREQUENCY RESPONSE SERVICE?

A. Regulation and Frequency Response Service is a type of ancillary service that is offered under the PacifiCorp Open Access Transmission Tariff ("OATT"). Schedule 3 of the OATT provides the rates, terms, and conditions for this service. As defined in Schedule 3, Regulation and Frequency Response Service "is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz)." Under Schedule 3, PacifiCorp offers Regulation and Frequency Response Service in support of transmission service serving load within PacifiCorp's Balancing Authority Areas ("BAA"). PacifiCorp's OATT also contains a Schedule 3A, which is the same basic service, but is offered in support of transmission service that is delivering generation from within PacifiCorp's BAAs to serve load outside of the BAAs.

Regulation and Frequency Response Service consists of two basic components: a regulation reserve component that corresponds to the operations governed by NERC Reliability Standard BAL-001 and a frequency response reserve component that

corresponds to the operations governed by NERC Reliability Standard BAL-003. The testimony of Kelcey Brown provides further background on these two reliability standards. In terms of recovery of PacifiCorp's costs of providing service consistent with the reliability standards, Schedule 3 reflects the cost of providing Regulation and Frequency Response reserve sufficient to maintain compliance with reliability standard BAL-001-2 and BAL-003-1.1 to customers serving load internal to the PacifiCorp BAAs. Schedule 3A reflects the cost of providing Regulation and Frequency Response reserve sufficient to maintain compliance with reliability standard BAL-001-2 and BAL-003-1.1 to customers exporting generation from the PacifiCorp BAAs.

Q. HOW ARE REGULATION AND FREQUENCY RESPONSE RESERVE REQUIREMENTS DETERMINED?

A. The reserve requirement for Regulation and Frequency Response Service is not defined by a simple formula, but instead is the amount of reserve required by each BAA to meet specified control performance standards defined in NERC reliability standards BAL-001-2 and BAL-003-1.1.

Regulation reserve must be available within thirty minutes, which corresponds to the time limit in BAL-001-2. To comply with BAL-003-1.1, frequency response reserve must be deployed for periods under a minute to arrest frequency deviations and support the generator interconnection when frequency drops below the scheduled level. The capacity necessary to ensure compliance with BAL-003-1.1 is not expected to be additive to amounts identified for compliance with BAL-001-2. The interaction between these obligations is discussed in more detail later in my testimony.

Q. WHAT ARE OPERATING RESERVE – SPINNING RESERVE SERVICE AND OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE?

A. Operating Reserve – Spinning Reserve Service is an ancillary service that is addressed in Schedule 5 of the OATT. Schedule 5 defines Spinning Reserve Service as "needed to serve load in the BAA and to support other transmission usage sourced from generation in the BAA including exports and sales. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output and by non-generation resources capable of providing this service."

Operating Reserve – Supplemental Reserve is also an ancillary service and it is addressed in Schedule 6 of the OATT. Schedule 6 defines Supplemental Reserve Service as "needed to serve load in the BAA and to support other transmission usage sourced from generation in the BAA including exports and sales; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load or other non-generation resources capable of providing this service."

Both Spinning Reserve Service and Supplemental Reserve Service correspond to the provision of "contingency reserves" by the transmission provider. Contingency reserves are required to be provided by a transmission provider in order to comply with NERC regional reliability standard BAL-002-WECC-2a. This is discussed further below and in the testimony of Ms. Brown.

Q. HOW ARE THE CONTINGENCY RESERVE REQUIREMENTS DETERMINED?

A. The contingency reserve requirement is based on a formula defined in NERC regional reliability standard BAL-002-WECC-2a.[1] Contingency reserve must be available within ten minutes, and, pursuant to Requirement 2 of the standard, at least half must be from "spinning" resources that are online and immediately responsive to system fluctuations. Schedule 5 reflects the cost of spinning reserve necessary for compliance with reliability standard BAL-002-WECC-2a. Schedule 6 reflects the cost of supplemental (*i.e.*, non-spinning) reserve necessary for compliance with reliability standard BAL-002-WECC-2a.

Q. HAS PACIFICORP CONDUCTED A RECENT STUDY OF ITS RESERVE REQUIREMENTS TO PROVIDE SERVICE UNDER SCHEDULES 3, 3A, 5 AND 6?

A. Yes. As I noted earlier, during the first quarter of 2020, PacifiCorp conducted a study to determine updated reserve requirements for Regulation and Frequency Response Service (both under Schedule 3 and Schedule 3A) and for Spinning Reserves (Schedule 5) and Supplemental Reserves (Schedule 6). The study assessed the reserves need by PacifiCorp to provide these services in light of the most recent data and the requirements of the reliability standards, and identified the PacifiCorp resources that provide these services. I present the study through my testimony and workpapers. The most substantial part of the study is the analysis of the reserves needed for Regulation and Frequency Response Service.

[1] Available at: https://www.wecc.org/Reliability/BAL-002-WECC-2a%20-%20Effective%201-24-2017.pdf (accessed on 6/25/2020). BAL-002-WECC-2a clarified that non-traditional resources that meet technical and performance requirements for the provision of spinning reserves can be counted toward the spinning reserve obligation. This did not change the obligation relative to BAL-002-WECC-2.

Q. DATA FROM WHAT TIME PERIOD DID PACIFICORP USE TO CONDUCT ITS STUDY?

A. PacifiCorp used data from calendar years 2018 and 2019 for its study (the "Study Period").

B. Customer Class Impacts on Regulation and Frequency Response

Q. DO LOAD AND GENERATION RESOURCES HAVE DIFFERENT IMPACTS ON THE TRANSMISSION PROVIDER'S PROVISION OF REGULATION AND FREQUENCY RESPONSE SERVICE (SCHEDULE 3 AND 3A)?

A. Yes. In fact, in Order No. 764, FERC recognized that VERs may have a different impact on Regulation and Frequency Response service than load and Non-VERs. In PacifiCorp's experience, there are distinct general classes of customers that have different operational characteristics and different impacts on a transmission provider's compliance with the BAL-001 standard.

Q. WHAT CLASSES OF CUSTOMERS HAS PACIFICORP IDENTIFIED?

A. In the past, and in its recent study, PacifiCorp has identified three general classes of customers whose deviations create distinct balancing obligations for compliance with the BAL-001-2 standard: load, VERs, and Non-VERs. As I discuss later in my testimony, there are further distinctions within these classes in terms of the operational impact on PacifiCorp's provision of Regulation and Frequency Response. Within the VERs class, wind and solar resources on PacifiCorp's system had distinct impacts on Regulation and Frequency Response needs during the Study Period.

PacifiCorp's data demonstrates that VERs place a proportionately greater regulation reserve burden on PacifiCorp's system than either the load or Non-VERs customer

classes. PacifiCorp's data also demonstrates that load and Non-VERs, while each placing a lower burden on the system than VERs, each place a differing regulation reserve burden on the system, which makes it appropriate to account for these customer classes separately. Differentiating among the various classes allows regulation reserve requirements to be forecasted more accurately and ensures that each customer class is allocated costs that reflect the obligations they place on the system, consistent with cost causation principles.

Q. PLEASE DESCRIBE THE LOAD CUSTOMER CLASS.

A. The load class represents the aggregate firm demand of end users of power from the electric system. While the requirements of individual users vary, there are diurnal and seasonal patterns in aggregated demand. The load class can generally be described to include three components: (1) forecasted average load, which is the base load during a particular scheduling period; (2) the trend, or "ramp," across an hour and from hour-to-hour; and (3) the fluctuations in load that depart from the forecasted level. The need for a system response to the second and third components is the function of regulation reserve in order to ensure reliability of the system.

For the purpose of the regulation reserve study, the load class excludes several large industrial loads on PacifiCorp's system with unique patterns of demand. These loads are either interruptible at short notice or include behind-the-meter generation. Due to their large size, abrupt changes in their demand are magnified for these customers in a manner which is not representative of the aggregated demand of the large number of small customers which make up the majority of PacifiCorp's loads. In addition, interruptible loads can be curtailed if their deviations are contributing to a resource

shortfall. Because of these unique characteristics, these loads are excluded from the regulation reserve study.

Q. PLEASE DESCRIBE THE VER CUSTOMER CLASS.

A. The VER customer class includes resources that: (1) are renewable; (2) fuel cannot be stored by the facility owner or operator; and (3) have variability that is beyond the control of the facility owner or operator.[2] On PacifiCorp's system, the VER class includes both wind and solar resources. In comparison to the load class, wind and solar often have larger upward and downward fluctuations in output that impose significant and sometimes unforeseen challenges when attempting to maintain system reliability. For example, as recognized by FERC in Order No. 764, "Increasing the relative amount of [VERs] on a system can increase operational uncertainty that the system operator must manage through operating criteria, practices, and procedures, including the commitment of adequate reserves."[3] Within the VER class, wind and solar have distinct impacts from each other.

The data included in the regulation reserve study during the Study Period for the VER-wind and VER-solar classes include all utility-scale wind and solar resources in PacifiCorp's BAAs, which includes: (1) third-party resources (OATT or legacy contract transmission customers); (2) PacifiCorp-owned resources; and (3) other PacifiCorp-contracted resources, such as qualifying facilities, power purchases, and exchanges. The Study Period includes an average of 2,745 megawatts of wind and 1,080 megawatts of solar.

Q. PLEASE DESCRIBE THE NON-VER CUSTOMER CLASS.

[2] PacifiCorp OATT at Att. N, Article 1.
[3] Order No. 764 at P 20 (emphasis added).

A. The Non-VER customer class is a mix of thermal and hydroelectric resources and includes all resources which are not VERs, except the following: (i) Non-VERs that are dispatchable by PacifiCorp, as they provide the Schedule 3 and 3A service; and (ii) Non-VERs that are participating in the EIM. The Non-VER class includes geothermal and run-of-river hydro resources owned by PacifiCorp, qualifying facilities of various types that are primarily contracted to PacifiCorp, and a number of thermal and hydro resources associated with third-party transmission customers.

When Non-VERs output falls below the scheduled level, additional resources must be available to compensate. Non-VERs customers provide specific schedules of their expected resource output and are less frequently subject to changes in output from hour to hour than VERs. Like load and VERs, the Non-VERs class has reduced aggregate deviations because it consists of a significant number of geographically dispersed customers, and while more granular than load (*i.e.*, a single generating unit versus a single home), large numbers of Non-VERs are not typically impacted simultaneously in a similar manner as can be the case for VERs. In total, the Study Period includes 1,304 MWs of Non-VERs.

Q. WHAT ARE "DISPATCHABLE RESOURCES"?

A. The dispatchable resource class consists of Non-VERs that are dispatched to compensate for deviations resulting from other users of the transmission system in all hours. PacifiCorp designates a substantial portion of its dispatchable resource fleet as network resources and uses these resources to balance the deviations of all other load, VERs, and Non-VERs in its BAAs. At present, two third-party resources in PacifiCorp's BAAs are

participating in EIM, and contribute to balancing the system as part of the dispatchable resource class.

Q. WHY ARE RESOURCES THAT ARE DISPATCHABLE BY PACIFICORP EXCLUDED FROM THE NON-VER CUSTOMER CLASS?

A. Resources that are dispatchable by PacifiCorp are excluded from the non-VER class because the output of these resources reflects their provision of operating reserve services. These resources are net providers rather than users of regulation reserve service. While non-dispatchable resources may offset deviations in loads or other resources in some hours, they are not within the control of the system operator and they contribute to the overall resource requirement in other hours. As such, resources that are excluded from the Non-VER customer class have a stand-alone regulation reserve requirement of zero, and they are not allocated any of the regulation reserve requirement.

Q. WHY ARE NON-VER RESOURCES THAT ARE PARTICIPATING IN THE EIM EXCLUDED FROM THE NON-VERS CUSTOMER CLASS?

A. Non-VER resources that are participating in the EIM are excluded from the Non-VERs class because their output reflects dispatch instructions from the EIM. Under EIM operating practices, these resources can also be dispatched by PacifiCorp, if necessary. This results in benefits that are comparable to those from resources that are dispatched by PacifiCorp directly and have a stand-alone regulation reserve requirement of zero and they are not allocated any of the regulation reserve requirement for the same reasons.

C. NERC Balancing Standards

Q. WHAT IS THE GOAL OF THE REGULATION RESERVE STUDY?

A. The goal of the regulation reserve study was to develop a regulation reserve requirement forecast methodology that ensures BAL-001-2 compliance.

Q. WHAT ARE THE KEY ELEMENTS OF THE BAL-001-2 STANDARD THAT IMPACT PACIFICORP'S NEED FOR REGULATION RESERVES?

A. There are three key elements in BAL-001-2 that drive the regulation reserve need. These elements are: (1) the length of time (or "interval") used to measure compliance; (2) the percentage of intervals that a BAA must be within the limits set in the standard; and (3) the bandwidth of acceptable deviation used to determine whether an interval is considered out of compliance. I discuss each of these elements in more detail below.

Q. WHAT IS THE FIRST KEY ELEMENT UNDER STANDARD BAL-001-2?

A. The first key element is the length of time used to measure compliance. Compliance under BAL-001-2 is measured over rolling thirty-minute intervals, with sixty overlapping periods per hour, some of which include parts of two clock-hours. In effect, this means that every minute of every hour is the beginning of a new, thirty-minute compliance interval under the new BAL-001-2 standard. If the area control error ("ACE") is within the allowed limits at least once in a thirty-minute interval, that interval was in compliance, and only the minimum deviation in each thirty-minute interval is considered in determining compliance. As a result, PacifiCorp does not need to hold regulation reserves for deviations with duration less than 30 minutes.

Q. WHAT IS ACE?

A. Ms. Brown's testimony further explains ACE and notes that it is the difference between a BAA's scheduled and actual interchange, reflecting the difference between electrical generation and load within that BAA.

Q. WHAT IS THE SECOND KEY ELEMENT UNDER STANDARD BAL-001-2?

A. The second key element is the compliance percentage, or the number of intervals where deviations are allowed outside the limits set in the standard. BAL-001-2 requires 100 percent compliance, so deviations must be maintained within the requirement set by the standard for all rolling thirty-minute intervals. Because shortfalls are not permitted when the compliance requirement is 100 percent, this results in relatively high regulation reserve requirements based on uncommon events, rather than typical conditions, as further discussed herein.

Q. WHAT IS THE THIRD KEY ELEMENT UNDER STANDARD BAL-001-2?

A. The third key element is related to the bandwidth of acceptable deviation before an interval is considered out of compliance. Under BAL-001-2, the acceptable deviation for each BAA is dynamic, varying as a function of the frequency deviation for the entire interconnect. As a result, a given deviation will be out of compliance in some periods and in compliance in other periods. As a result, the acceptable deviation for a future period cannot be known in advance.

D. <u>Elements of Regulation Reserve Calculation</u>

Q. HOW HAS PACIFICORP CALCULATED THE REGULATION RESERVE REQUIRED FOR COMPLIANCE WITH BAL-001-2?

A. The calculations used to determine the regulation reserve required to ensure PacifiCorp's compliance with BAL-001-2 are described in more detail below. The five primary elements of the calculation are as follows:

- Collection of Data and Historical Deviations;
- Compliance Requirements;
- Acceptable Deviations: Historical Balancing Authority ACE Limit Data;
- Planning Reliability Target: Loss of Load Probability ("LOLP"); and
- Regulation Reserve Forecast

The regulation reserve forecast section is further broken down into specific forecasts for each class of regulation reserve contributor: load, VER-Wind, VER-Solar, and Non-VER. Finally, the calculation used to determine the regulation reserve forecast for the combined portfolio of all regulation reserve contributors is discussed.

1. Collection of Data and Historical Deviations

Q. PLEASE DESCRIBE THE HISTORICAL GENERATION DATA USED IN PACIFICORP'S ANALYSIS.

A. PacifiCorp's participation in EIM results in five-minute deviation data for each generating resource in PacifiCorp's BAAs, including both VERs and Non-VERs. Deviations reflect the difference between actual resource output based on meter data and an hourly "base schedule" submitted to the CAISO during the prior hour. These deviations are used to determine energy imbalance charges (or payments) under Schedules 4 and 9 of the PacifiCorp OATT. PacifiCorp's analysis uses EIM deviation results from January 2018 through December 2019.

Q. PLEASE DESCRIBE THE HISTORICAL LOAD DATA USED IN PACIFICORP'S ANALYSIS.

A. As part of PacifiCorp's participation in EIM, the CAISO produces a forecast of the load for each PacifiCorp BAA for the upcoming hour. This forecast excludes non-conforming loads for certain industrial customers with unique patterns of demand which are forecasted and scheduled directly by PacifiCorp. Deviations for load can be calculated from the difference between this hourly forecast and PacifiCorp's actual load data for conforming loads in the PacifiCorp BAAs for each five-minute interval from its Energy Management System ("EMS").

Q. DID PACIFICORP CONSIDER USING ALTERNATIVES TO FIVE-MINUTE DATA?

A. Yes. Section 6.3.3 of the 2017 settlement agreement (discussed in the testimony of Mary Wiencke) required PacifiCorp and stakeholders to consider the "use of coincidental one-minute data that includes Energy Imbalance Market ("EIM") benefits, for, at a minimum the most recent 24-month period for which data is available." Thus, PacifiCorp considered whether one-minute data would produce a more accurate reserve requirement. In PacifiCorp's assessment of one-minute data versus five-minute data, there was little difference in outcomes when one-minute data was used as illustrated in Figures 1 to 4 below. Moreover, CAISO uses five-minute interval data for settlement, so the five-minute data has already been analyzed to ensure accuracy. In addition, even if the resources needed to balance a deviation are available, they cannot be fully deployed immediately and need time to catch up with the changing conditions on the system. Because the interval with the lowest deviation determines the minimum requirement, the

amount needed to catch up is likely to be increasing as time goes on. PacifiCorp's analysis assumes that all available reserves are deployed and that load and resources are balanced at some point in the critical interval when the requirement is minimized. While there is potential additional flexibility in the requirements on a one-minute basis versus a five-minute basis, it is offset by the reduced flexibility of PacifiCorp's resources on a one-minute basis versus a five-minute basis. Using five-minute interval data reasonably captures both the flexibility and constraints experienced by PacifiCorp in its actual operations. For these reasons, PacifiCorp is using five-minute interval data for its analysis of regulation reserve requirements.

Figure 1

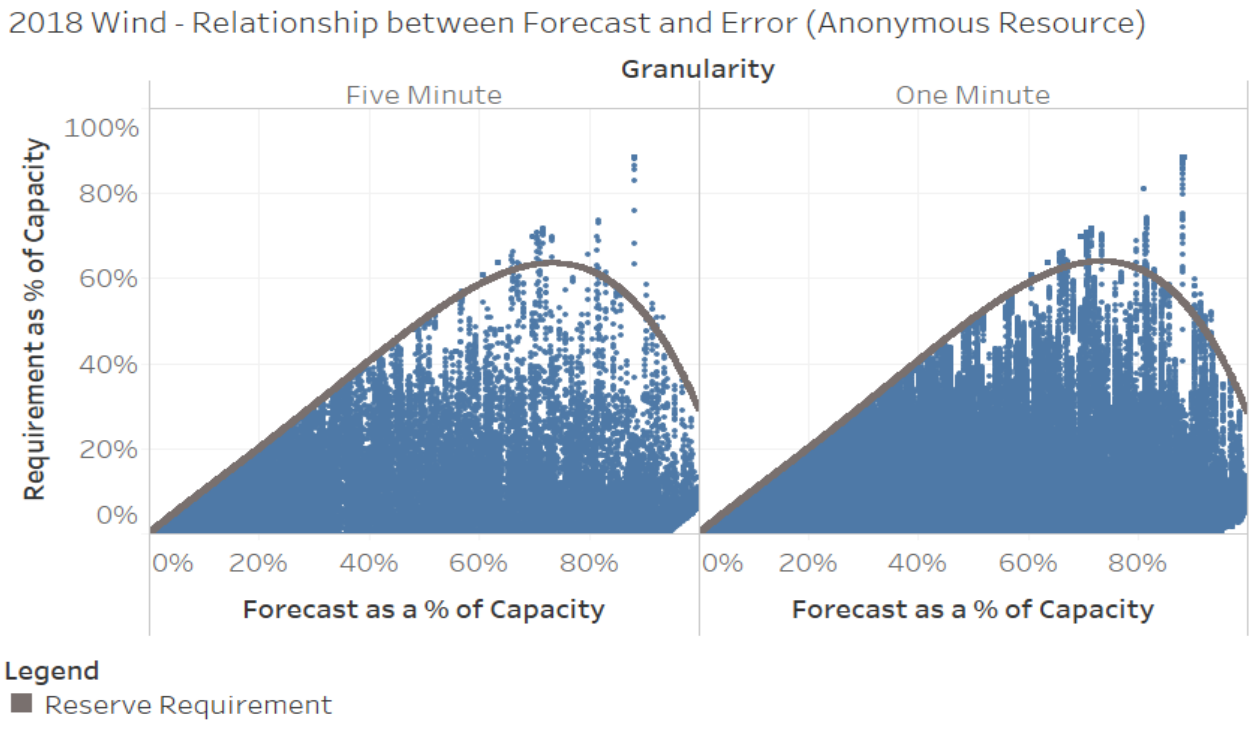


Figure 2

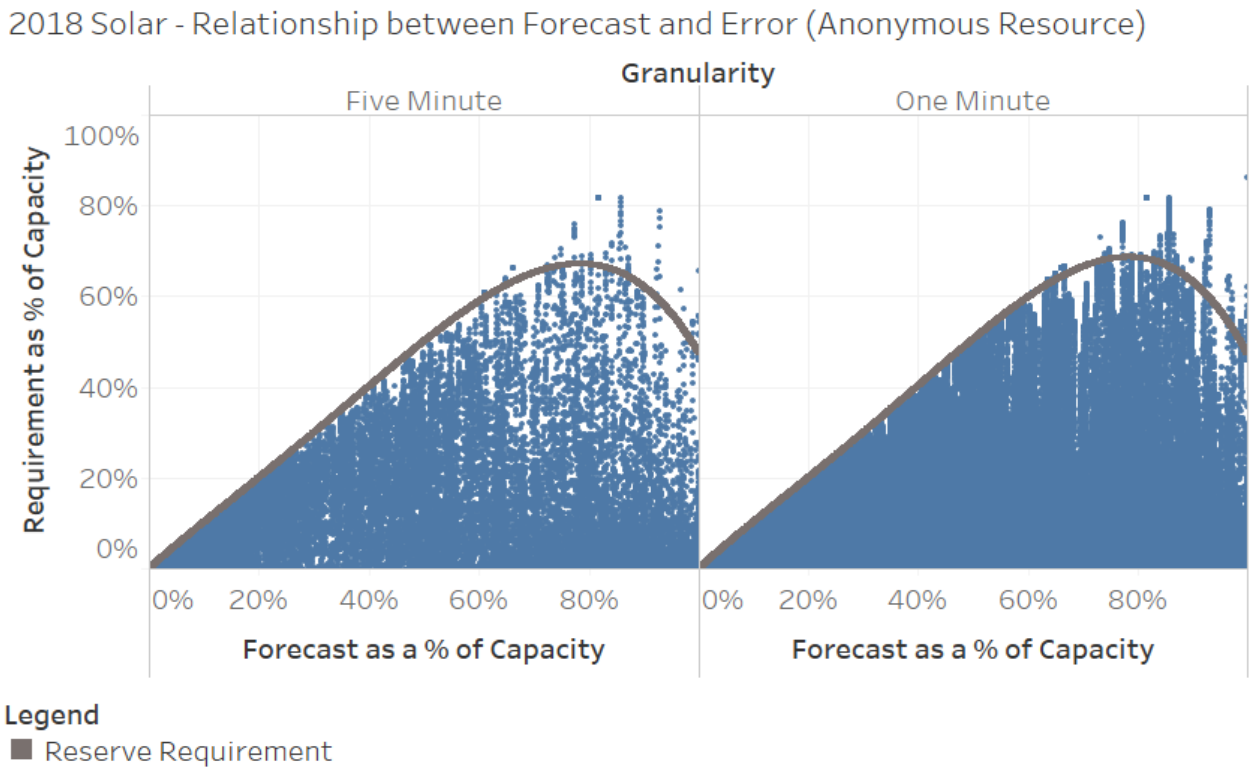


Figure 3

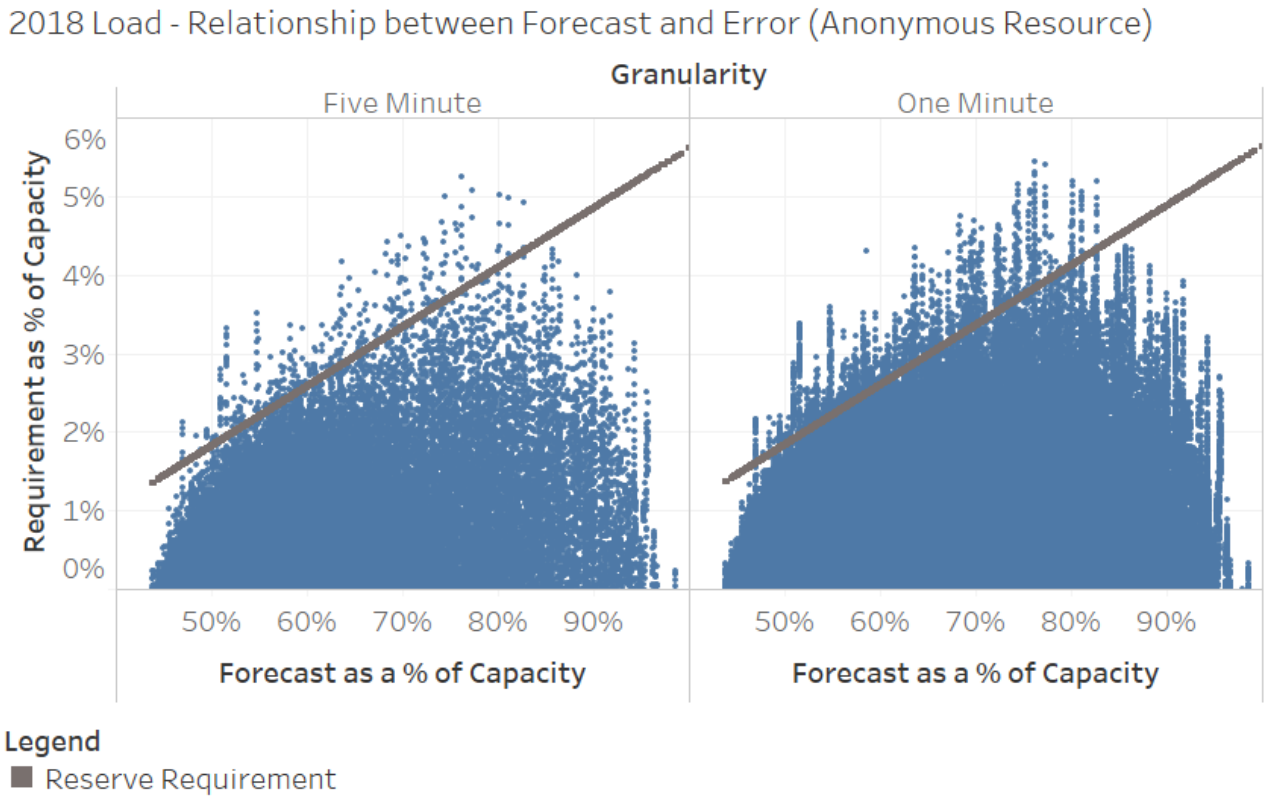
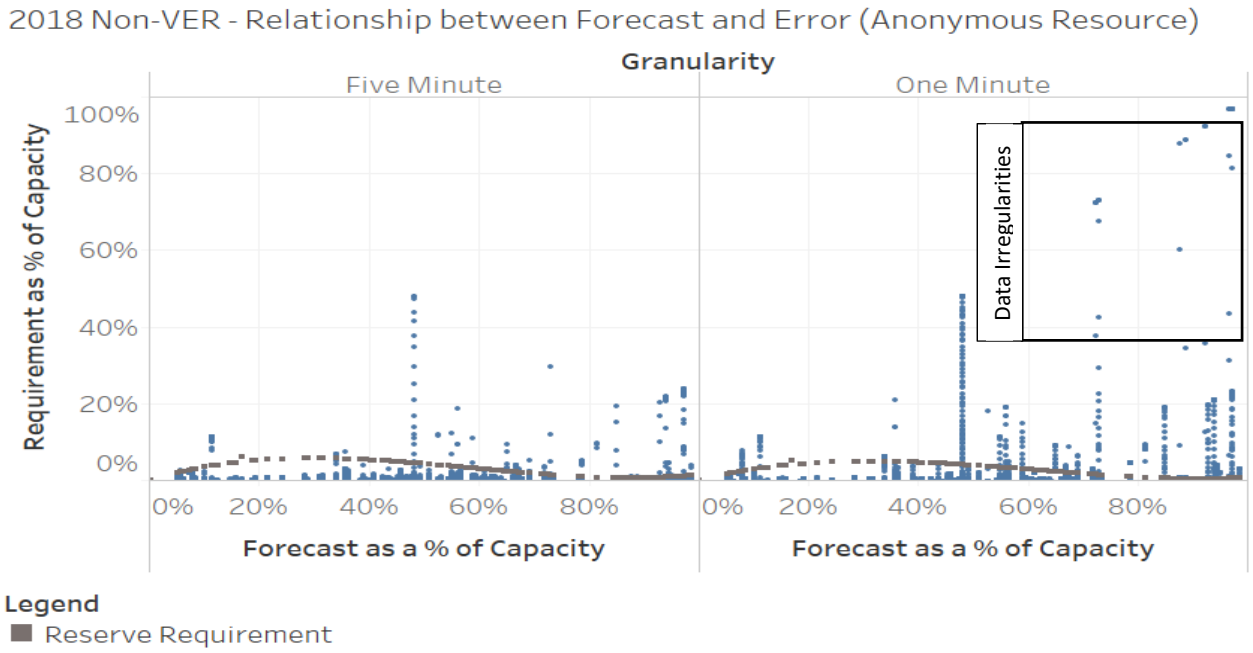


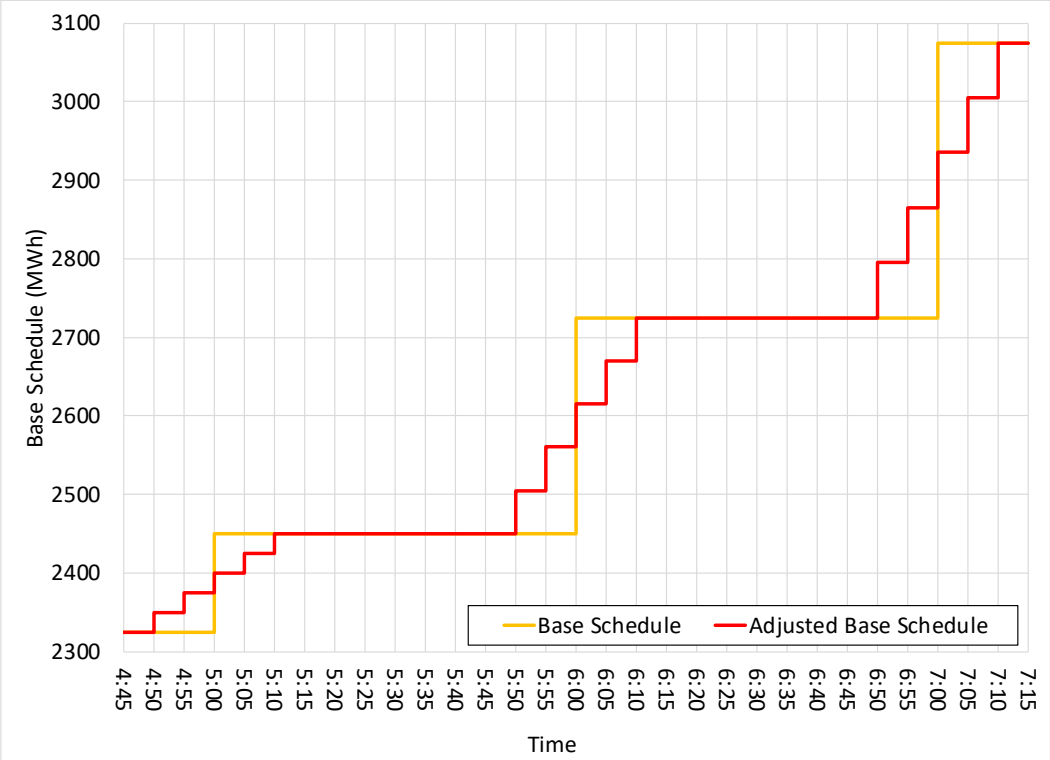
Figure 4



Q. DID PACIFICORP MAKE ANY ADJUSTMENTS TO THE HISTORICAL LOAD DATA TO BETTER REFLECT OPERATIONAL PRACTICES?

A. Yes. We made a "base schedule ramp adjustment." In actual operations, PacifiCorp's ACE calculation includes a linear ramp from the base schedule in one hour to the base schedule in the next hour, starting ten minutes before the hour and continuing until ten minutes past the hour. The hourly base schedules used in the analysis are adjusted to reflect this transition from one hour to the next. This adjustment step is important because, to the extent actual load or generation is transitioning to the levels expected in the next hour, the adjusted base schedules will result in reduced deviations during these intervals, potentially reducing the regulation reserve requirement. Figure 5 below illustrates the base schedule ramping adjustment.

Figure 5. Illustration of Base Schedule Ramping Adjustment



Q. WAS THE SOURCE DATA ADJUSTED TO REMOVE THE IMPACTS OF ABNORMAL WEATHER CONDITIONS?

A. No. The full range of weather conditions experienced during the Study Period remain in the source data, as these conditions are indicative of the range of weather conditions PacifiCorp expects to experience going forward. Including the full range of weather conditions also complies with the guidance from FERC's Order No. 764 that weather "diversity events" should be included in the data set so that the quantity and costs of such reserves are more reflective of actual system operations.[4]

[4] Order No. 764 at P 321.

Q. WERE DATA IRREGULARITIES UNRELATED TO ACTUAL REGULATION RESERVE REQUIREMENTS OBSERVED IN PACIFICORP'S SOURCE DATA?

A. Yes. The raw data extracted from PacifiCorp's systems was reviewed to identify potentially spurious data points prior to performing the regulation reserve requirement calculations discussed below. The following types of data irregularities were observed.

Load:

- Telemetry spike/poor connection to meter
- Missing meter data
- Missing base schedules

VERs:

- Curtailment events

Q. PLEASE DESCRIBE THE LOAD TELEMETRY SPIKE IRREGULARITIES.

A. Rapid spikes in load telemetry either up or down are unlikely to be the result of conditions which require deployment of regulation reserve, particularly when they are transient. Such events could be a result of a transmission or distribution outage, which would allow for the deployment of contingency reserve, and would not require deployment of regulation reserve. Such events are also likely to be a result of a single bad load measurement. Load telemetry spike irregularities were identified by examining the intervals with the largest changes from one interval to the next, either up or down. Intervals with inexplicably large and rapid changes in load, particularly where the load reverts back within a short period, were assumed to have been covered through contingency reserve deployment or to reflect inaccurate load measurements. Because

they do not reflect periods that require regulation reserve deployment, such intervals are excluded from the analysis. During the Study Period, in PACW 15 minutes' worth of telemetry spikes were excluded while no telemetry spikes were observed in PACE.

Q. PLEASE DESCRIBE THE LOAD MISSING METER DATA.

A. Simultaneously, during the Study Period in both PACE and PACW there were 10 minutes' worth of missing meter data from PacifiCorp's energy management system's data historian.

Q. PLEASE DESCRIBE THE LOAD BASE SCHEDULE IRREGULARITIES.

A. As describe above the CAISO produces a forecast of the load for each PacifiCorp BAA for the upcoming hour. This load forecast is publicly available data on the CAISO's OASIS and was sourced from there. However, the sourced OASIS data had instances of missing hours. These hours were excluded from the analysis. Simultaneously, during the Study Period in both PACE and PACW there were 82 hours' worth of missing base schedules from the CAISO's OASIS spread randomly throughout time.

Q. PLEASE DESCRIBE THE VER IRREGULARITIES.

A. The available VER data includes wind curtailment events which affect metered output. When these curtailments occur, the CAISO sends data, by generator, indicating the magnitude of the curtailment. This data is layered on top of the actual meter data to develop a proxy for what the metered output would have been were the generator not curtailed. Regulation reserve requirements are calculated based on the shortfall in actual output relative to base schedules. By adding back curtailed volumes to the actual metered output, the shortfall relative to base schedules is reduced, as is the regulation reserve

requirement. This is reasonable since the curtailment is directed by the CAISO or the transmission system operator to help maintain reliable operation, so it should not exacerbate the calculated need for regulation reserves.

2. Reliability Compliance Requirements

Q. HOW ARE THE ADJUSTED HISTORICAL DEVIATIONS USED TO DEVELOP THE BAL-001-2 COMPLIANCE REQUIREMENTS IN EACH INTERVAL?

A. First, the minimum five-minute imbalance was calculated for each thirty-minute rolling period in the Study Period. Second, for each hour, the maximum five-minute imbalance was selected from the values identified in the first step. These two calculations are explained in more detail below.

Q. WHY IS THE MINIMUM IMBALANCE CALCULATED FOR EACH THIRTY-MINUTE INTERVAL?

A. As indicated in the testimony of Ms. Brown, NERC standard BAL-001-2 requires that a balancing authority's ACE not exceed the specified limit for more than 30 consecutive minutes. In other words, compliance can be maintained by operating within the specified limit once in each rolling thirty-minute interval, and the requirement is lowest if this occurs in the interval with the smallest deviation. Using the minimum imbalance thus ensures that compliance can be achieved in at least the one interval in which that minimum occurred.

Q. WHY IS THE MAXIMUM IMBALANCE FROM ALL ROLLING THIRTY-MINUTE INTERVALS CALCULATED FOR EACH HOUR?

A. All PacifiCorp transmission customers submit hour-ahead base schedules for the resources needed to serve their load by 57 minutes before the operating hour (T-57). The maximum capacity that may be used as operating reserve at any time during the upcoming hour needs to be identified and set aside so that it is not utilized in the base schedules for resources serving PacifiCorp's own retail loads, which are also submitted at T-57. While there is an opportunity to adjust resource base schedules up to T-40, this is limited to identifying resources necessary to meet any changes to expected requirements. Therefore, the regulation reserve forecast identifying the quantity of operating reserves to be set aside for use at any time during the upcoming hour needs to be finalized by T-57. As a result, the 30-minute rolling interval with the largest minimum imbalance establishes the reserves that must be set aside for the entire hour.

Q. HOW DOES THE THIRTY-MINUTE COMPLIANCE TIMEFRAME UNDER BAL-001-2 INTERACT WITH BASE SCHEDULE SUBMISSION AT T-57?

A. The thirty-minute compliance timeframe for BAL-001-2 can reduce the regulation reserve requirement associated with deviations in the last few intervals of each hour. This period has the longest forecast horizon (*i.e.*, the furthest out from T-57), so the potential deviations are expected to be larger. However, if the change resulting in the deviation is reflected in the base schedule for the next hour, PacifiCorp's ACE will return to zero on its own a few minutes later. Thus, so long as the duration of the deviation is less than 30 minutes, any deviation in the last few intervals will not require additional regulation reserve to ensure compliance with BAL-001-2. Because compliance will occur on its own within thirty minutes, regulation reserve requirements are reduced.

3. Acceptable Deviations: Historical Balancing Authority ACE Limit

Q. DOES A VIOLATION OF BAL-001-2 NECESSARILY OCCUR IF A 30-MINUTE SUSTAINED DEVIATION EXCEEDS THE REGULATION RESERVE CAPABILITY AVAILABLE?

A. No. A violation does not occur unless the deviation also exceeds the Balancing Authority ACE Limit.

Q. PLEASE DESCRIBE THE BALANCING AUTHORITY ACE LIMIT.

A. As described by Ms. Brown's testimony, the Balancing Authority ACE Limit is specific to each BAA and is dynamic, varying as a function of interconnection frequency.

Q. DOES PACIFICORP OPERATING PRACTICE IMPACT HOW THE BALANCING AUTHORITY ACE LIMIT IS APPLIED?

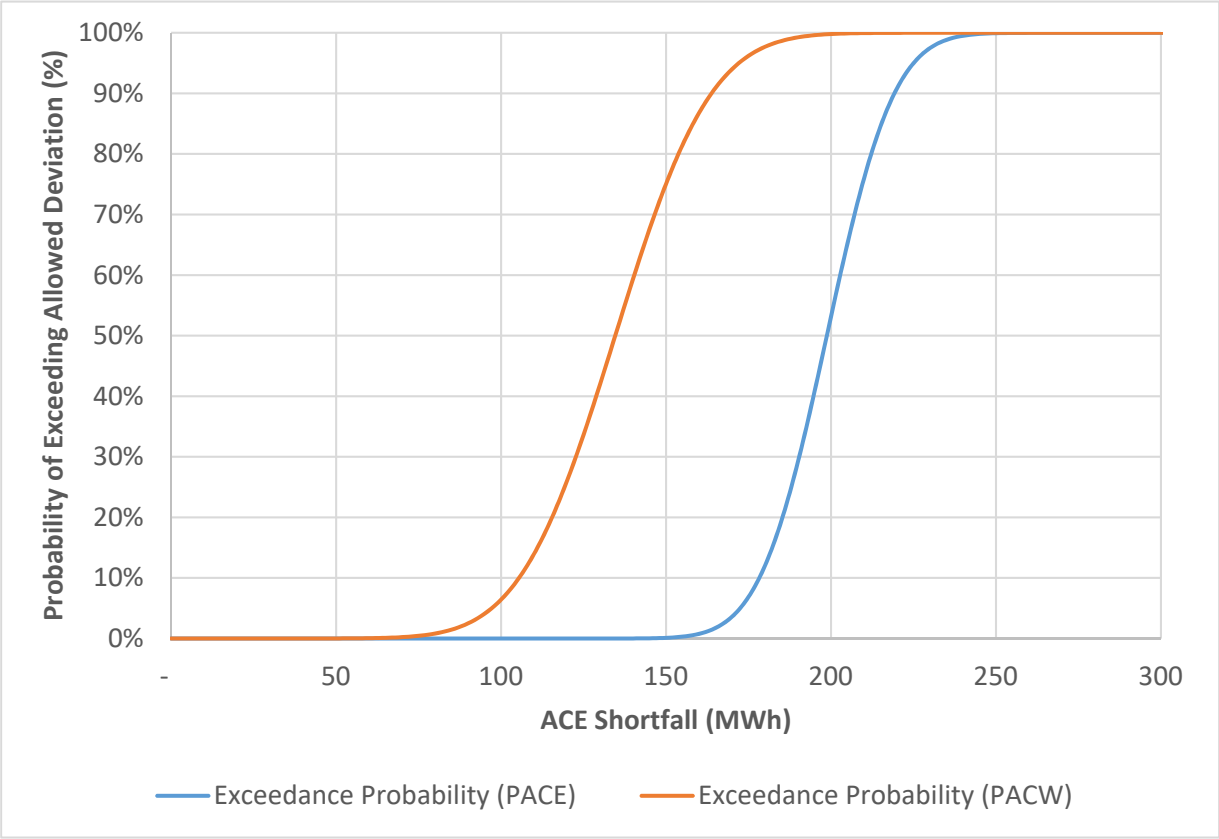
A. Again, Ms. Brown's testimony explains that, to limit the size and speed of resource deployment necessitated by variation in the Balancing Authority ACE Limit, PacifiCorp's operating practice caps permissible ACE at the lesser of the Balancing Authority ACE Limit or four times its L_{10}.[5]

Q. IF THE BALANCING AUTHORITY ACE LIMIT IS DYNAMIC AND NOT KNOWN IN ADVANCE, HOW CAN IT BE USED TO DEVELOP A REGULATION RESERVE FORECAST?

[5] L_{10} is a BAA-specific bound on ACE that varies as a function of the targeted frequency bound for the interconnection and the frequency bias setting specific to that BAA. The L_{10} for PacifiCorp's BAAs in 2019 were approximately 31.9 MW for PacifiCorp's West BAA ("PACW") and 48.8 MW for PacifiCorp's East BAA ("PACE"). For more information, please refer to: https://www.nerc.com/comm/OC/BAL0031_Supporting_Documents_2017_DL/BAL-003_Frequency_Bias_Settings_02Jul19.pdf

A. While the specific Balancing Authority ACE Limit for a given interval cannot be known in advance, the historical probability distribution of Balancing Authority ACE Limit values is known. The following figure shows the probability of exceeding the allowed deviation during a five-minute interval for a given level of ACE shortfall, up to the cap of four times L_{10}. For instance, an 82 MW ACE shortfall in PACW had a one percent chance of exceeding the Balancing Authority ACE Limit in 2018-2019.

Figure 6. Probability of Exceeding Allowed Deviation



Q. IS THERE A LINK BETWEEN PACIFICORP'S DEVIATIONS AND THE BALANCING AUTHORITY ACE LIMIT?

A. Yes. Resource shortfalls in the PacifiCorp BAAs contribute to reductions in WECC-wide frequency, which in turn reduces the Balancing Authority ACE Limit. However, in the

Study Period, PacifiCorp's deviations and Balancing Authority ACE Limits were uncorrelated, which indicates that PacifiCorp's contribution to WECC-wide frequency is small. PacifiCorp's deviations and Balancing Authority ACE Limits were also uncorrelated when periods with large deviations were examined in isolation. If PacifiCorp's large deviations made distinguishable contributions to the Balancing Authority ACE Limit, ACE shortfalls would be more likely to exceed the Balancing Authority ACE Limit during large deviations. Since this is not the case, the probability of exceeding the Balancing Authority ACE Limit is lower, and fewer regulation reserves are necessary to comply with the BAL-001-2 standard, which benefits customers.

4. Planning Reliability Target: Loss of Load Probability

Q. DOES A VIOLATION OF BAL-001-2 NECESSARILY OCCUR IF A 30-MINUTE SUSTAINED DEVIATION EXCEEDS THE REGULATION RESERVE CAPABILITY AVAILABLE BY MORE THAN THE BALANCING AUTHORITY ACE LIMIT?

A. Not necessarily. As a last resort, PacifiCorp may curtail firm load to reduce the resource shortfall to a level below the Balancing Authority ACE Limit.

Q. IS CURTAILMENT OF FIRM LOAD A TYPICAL COMPONENT OF RESOURCE PLANNING?

A. Yes. When conducting resource planning, it is common to use a reliability target that assumes a specified Loss of Load Probability ("LOLP"). The LOLP that many planners use is a "1-day-in-10-years" metric. An electric system using a 1-day-in-10 years LOLP will plan its system to maintain sufficient capacity (i.e., through a planning reserve margin) such that system peak load is not likely to exceed available supply (i.e., load is

lost) more than once in a 10-year period. If the system is planned correctly under this metric, the electric system is considered to be a "reliable" system and the probability of load exceeding supply becomes highly improbable. However, the 1-day-in-10-years planning standard accepts that in a reliably-planned electric system, firm load might be curtailed in rare circumstances, rather than acquiring resources for extremely unlikely events. Under the most-restrictive interpretation, 1-day-in-10-years would require reliable operation for nine years and 364 days out of a 10-year period, and would allow capacity shortfalls to occur on a single day. Under a less-restrictive interpretation, one day can be expressed as 24 hours, which would allow capacity shortfalls to occur in up to 24 hours spread across ten years. PacifiCorp's analysis uses this less-restrictive "loss of load hours" interpretation.

Q. WHAT DOES THE TERM "LOSS OF LOAD HOURS" MEAN?

A. Loss of load hours is a count of the expected (mean) number of hours in which load exceeds available resources over the course of a given year. Hypothetically, a system using the 1-day-in-10-years LOLP can meet that standard by planning its system to ensure that load does not exceed generation during more than 2.4 hours per year. The 2.4 loss of load hours is calculated by dividing a single day (24 hours) by the 10 years of the LOLP.

Q. WHAT RELIABILITY TARGET HAS PACIFICORP USED IN ITS ANALYSIS?

A. PacifiCorp's 2019 Integrated Resource Plan ("IRP") included an analysis of regulation reserve requirements that was similar to that conducted here.[6] In that analysis, which produced inputs used to support resource selection for long-term portfolio analysis,

[6] PacifiCorp 2019 Integrated Resource Plan Report, Vol. I at 16, 20; *available at*: https://www.pacificorp.com/energy/integrated-resource-plan.html.

regulation reserve shortfalls were allowed up to 0.50 loss of load hours per year.[7] PacifiCorp's 2019 IRP also includes a planning reserve margin study which assesses the risk of loss of load due to variations in load, thermal unit availability, and hydro conditions.[8] That study identified a planning reserve margin of 13% of coincident peak load, concluding that 1.06 loss of load hours per year from those causes was acceptable for planning purposes and reasonably balanced capacity costs with the risk of loss of load occurring. The 1.06 loss of load hours value related to PacifiCorp's ability to serve its retail load is in addition to the risk associated with regulation reserve shortfalls and outages customers might experience as a result of transmission and distribution system events. As a result, the regulation reserve shortfall represents a portion of the risk faced by PacifiCorp's retail customers. Accordingly, PacifiCorp's reserve study assumes that the same 0.50 loss of load hours per year due to regulation reserve shortages used in its 2019 IRP is also appropriate for determining regulation reserve requirements that support its OATT Schedule 3/3A rates. By assuming firm load can be curtailed in up to 0.50 hours per year, the quantity of regulation reserve needed to maintain the required 100 percent compliance with the BAL-001-2 standard and the Balancing Authority ACE Limit is reduced from the level that would be required if reserves held were required to meet or exceed the regulation reserve need in all intervals.

Q. IN THE EVENT THAT SOME LOAD WERE LOST ANNUALLY FOR UP TO 0.5 HOURS, WOULD PACIFICORP PROVIDE REGULATION AND FREQUENCY RESPONSE SERVICE DURING THAT TIME?

[7] Id., Vol. II, Appendix F – Flexible Reserve Study at 77.
[8] Id., Vol. II, Appendix I – Planning Reserve Margin Study at 137.

A. Yes. To meet the BAL-001-2 standard, PacifiCorp's regulation reserve analysis assumes that native load could be lost for up to 0.5 hours per year. But this does not mean that PacifiCorp would cease to provide regulation and frequency response under the BAL standards and its OATT to all firm transmission customers if that occurred, as curtailing load would allow PacifiCorp to continue to balance ACE during that time. Just as interruptible loads can supply capacity that provides regulation reserves, interrupting firm loads also represents a last-resort source of supply. Under current operational practice, only PacifiCorp's own loads are subject to interruption under these conditions, and the load of other load serving entities and third-party customers is not at risk.

Q. IS CURTAILMENT OF FIRM LOAD A TYPICAL COMPONENT OF SYSTEM OPERATIONS?

A. No. I have been discussing certain planning standards and presumptions. In real-time operations, curtailment of firm load would only occur as a last resort when all available alternatives had been utilized and a reliability violation was imminent. PacifiCorp has not curtailed firm load because of ACE or operating reserve shortfalls in the past ten years. PacifiCorp must maintain compliance with the BAL standards at all times and BAL-001-2 does not allow for exceptions based on planning assumptions. As a result, the study is likely understating the quantity of regulation reserve held by PacifiCorp and used to provide reliable service since it allows for loss of load events in excess of what has actually occurred in the past several years. Nonetheless, primarily for ratemaking purposes, PacifiCorp has incorporated the 0.5 LOLH into its regulation reserve study, and, from the perspective of customers, it has a beneficial effect of lowering the regulation reserve requirement and associated rates.

Q. HOW IS THE RELIABILITY TARGET APPLIED IN PACIFICORP'S ANALYSIS?

A. If the regulation reserve available is greater than the regulation reserve requirement for an hour, the LOLP is zero percent for that hour. If the regulation reserve held is less than the amount needed, the LOLP is derived from the Balancing Authority ACE Limit probability distribution. As the magnitude of the shortfall increases, the probability of exceeding the Balancing Authority ACE Limit increases. For instance, as indicated above, an 82 MW ACE shortfall in PACW has a one percent chance of exceeding the Balancing Authority ACE Limit. A one percent probability of failing to meet the Balancing Authority ACE Limit in one hour is 0.01 loss of load hours ("LOLH"). A one percent probability of failing to meet the Balancing Authority ACE Limit in 50 hours over the course of a year would be 0.5 loss of load hours per year and corresponds to the targeted level of reliability.

5. Regulation Reserve Requirement: Overview

Q. WHAT IS THE REGULATION RESERVE REQUIREMENT?

A. The regulation reserve requirement is the amount of operating reserve set aside prior to each hour for the purpose of compliance with BAL-001-2.

Q. WHAT ARE THE GOALS OF THE REGULATION RESERVE REQUIREMENT?

A. The regulation reserve requirement methodology is intended to achieve the following goals:

- Compliance with standard BAL-001-2;
- Minimize regulation reserve held; and
- Use data available at time of base schedule submission at T-57.

Q. HOW DO THE COMPONENTS DISCUSSED IN THE PREVIOUS SECTIONS RELATE TO THE REGULATION RESERVE REQUIREMENT?

A. The regulation reserve requirement is first compared to the hourly compliance requirement to determine the magnitude of the shortfall in each hour, if any. Next, the LOLP associated with each hour that has a shortfall is calculated from the Balancing Authority ACE Limit probability distribution. Finally, if the cumulative LOLP over all hours with shortfalls in the year is less than the reliability target, the regulation reserve requirement is deemed sufficient to comply with BAL-001-2 for the purpose of setting OATT rates for Regulation and Frequency Response service.

Q. HOW DO THE OTHER TWO GOALS (I.E., MINIMIZE REGULATION RESERVE HELD AND USE DATA AVAILABLE AT TIME OF BASE SCHEDULE SUBMISSION AT T-57) IMPACT THE REGULATION RESERVE REQUIREMENT?

A. Ideally, PacifiCorp would never hold more than the minimum regulation reserve required in any hour. However, requirements vary widely, and it is not possible to predict the exact requirement for an upcoming hour. Despite this, if information available at T-57 can be used to reliably distinguish between periods when requirements are likely to be low and periods when requirements are likely to be high, then fewer regulation reserves will be necessary to achieve a given reliability target.

Q. WHAT DATA IS AVAILABLE TO INFORM THE CALCULATION OF THE REGULATION RESERVE REQUIREMENTS?

A. The base schedule reflects the best, most up-to-date information about conditions in the upcoming hour as of T-57.

Q. HOW WERE THE REGULATION RESERVE REQUIREMENTS DEVELOPED?

A. To develop regulation reserve requirements for each Schedule 3 class, we use quantile regression, which is a type of regression analysis. Stated simply, a regression analysis attempts to predict the value of one variable (the response variable) on the basis of one or more variables (predictor variable). A typical regression results in estimates of the conditional mean (i.e., the 50th percentile) of the response variable given certain values of the predictor variables. A quantile regression estimates other specified percentiles (e.g., 25th percentile, 95th percentile, etc.) of the response variable. For PacifiCorp's regulation reserve study, the response variable is the reserve requirement, calculated from the deviation between the hour-ahead forecast and the actual metered output. The predictor variable is the hour-ahead forecast. The study's quantile regressions employ polynomial functions that cover a targeted percentile of all historical deviations.

Q. WERE QUANTILE REGRESSIONS PREPARED FOR EACH CUSTOMER CLASS?

A. Yes. The forecast and deviations specific to each class are used to calculate a reserve requirement for each hour. The targeted percentile in the quantile regression for each class is calculated such that the hourly reserve requirement achieves the annual reliability target of 0.5 hours per year, after accounting for the dynamic Balancing Authority ACE

Limit. These class-level reserve requirements represent the stand-alone requirements for each class, in the absence of any diversity benefits from using a shared regulation reserve supply to meet system requirements. Figures 7 to 14 below illustrate the relationship between the regulation reserve requirement, the historical forecast error and the forecasted level of output stated as a capacity factor (*i.e.*, a percentage of the nameplate VERs capacity) for each customer class in PACE and PACW during the Study Period.

Figure 7. PACE Wind

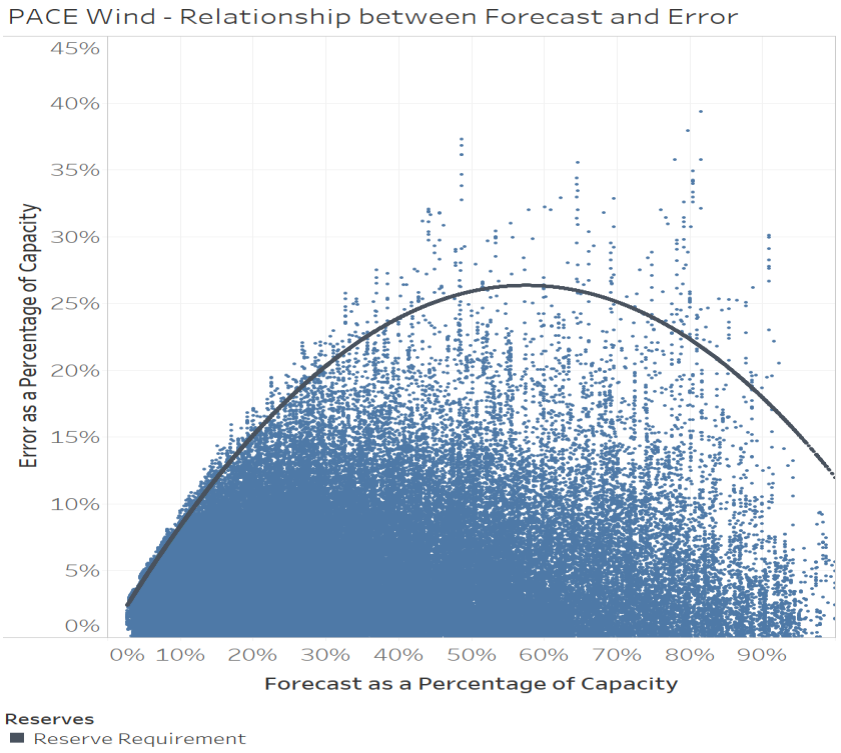


Figure 8. PACW Wind

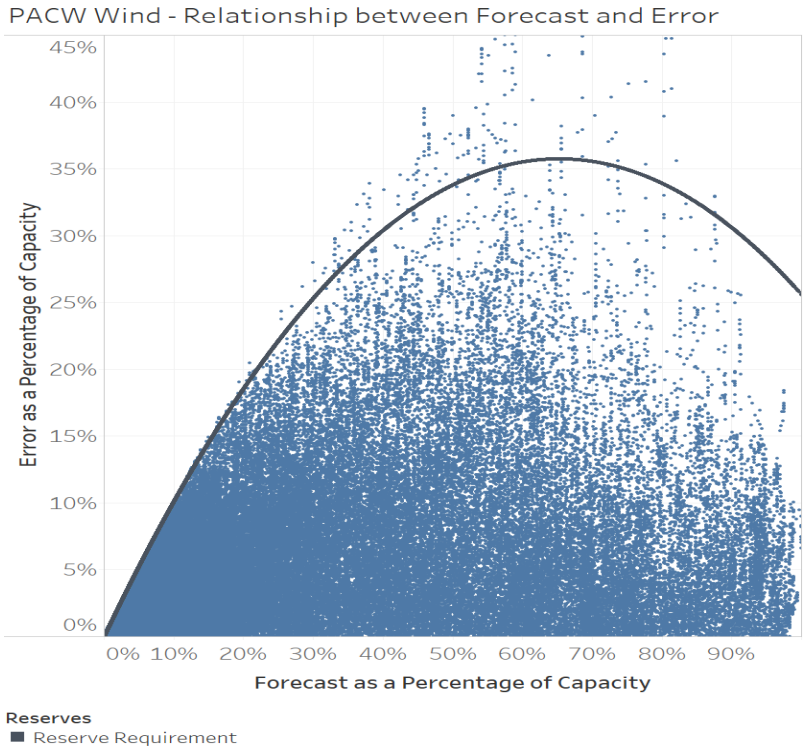


Figure 9. PACE Solar

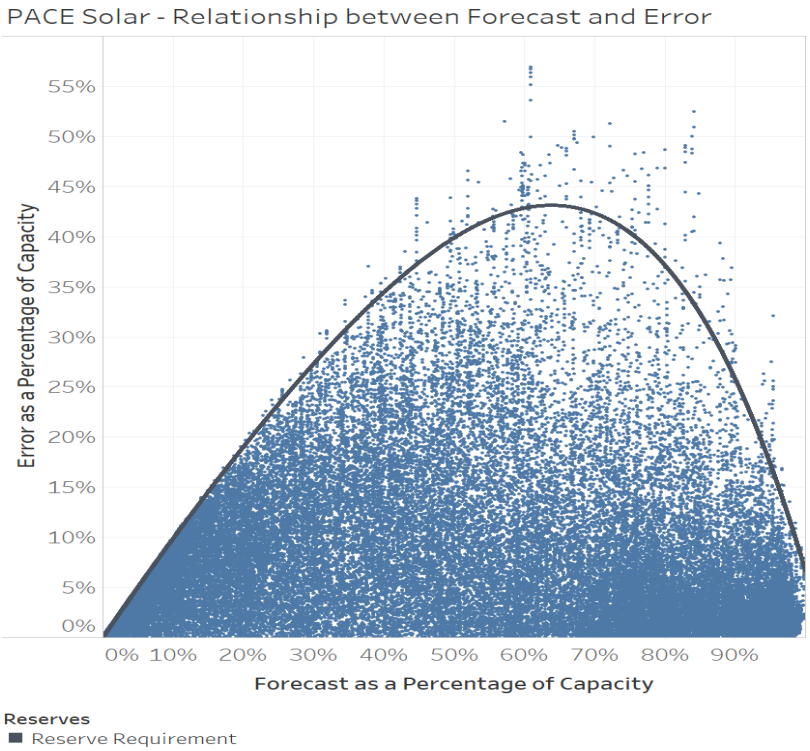


Figure 10. PACW Solar

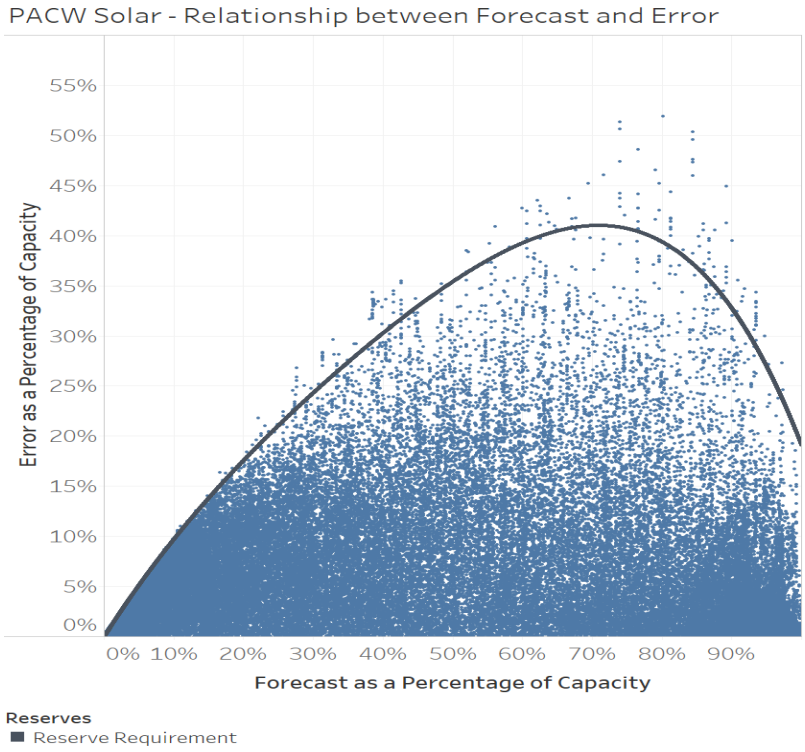


Figure 11. PACE Non-VER

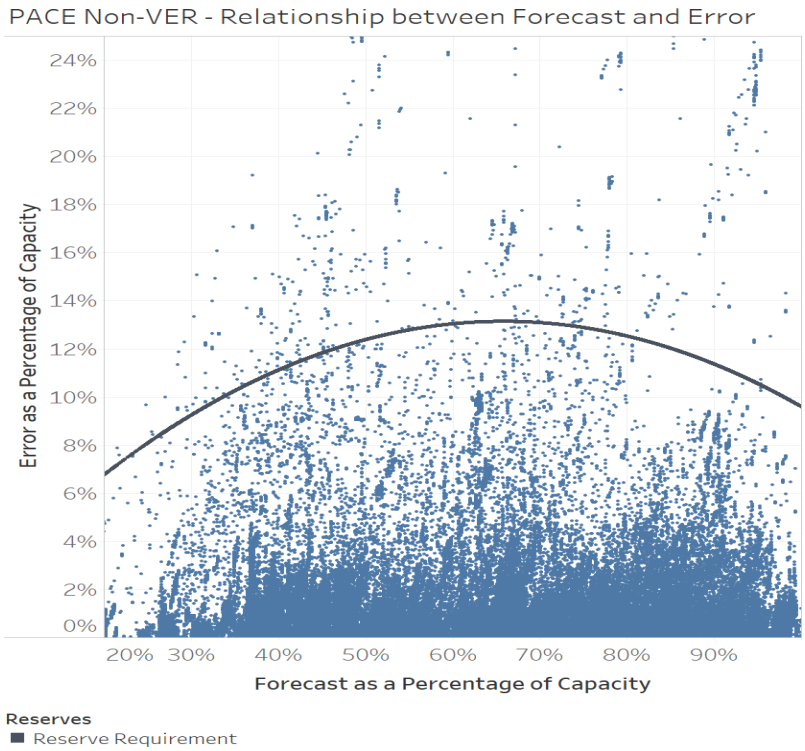


Figure 12. PACE Non-VER

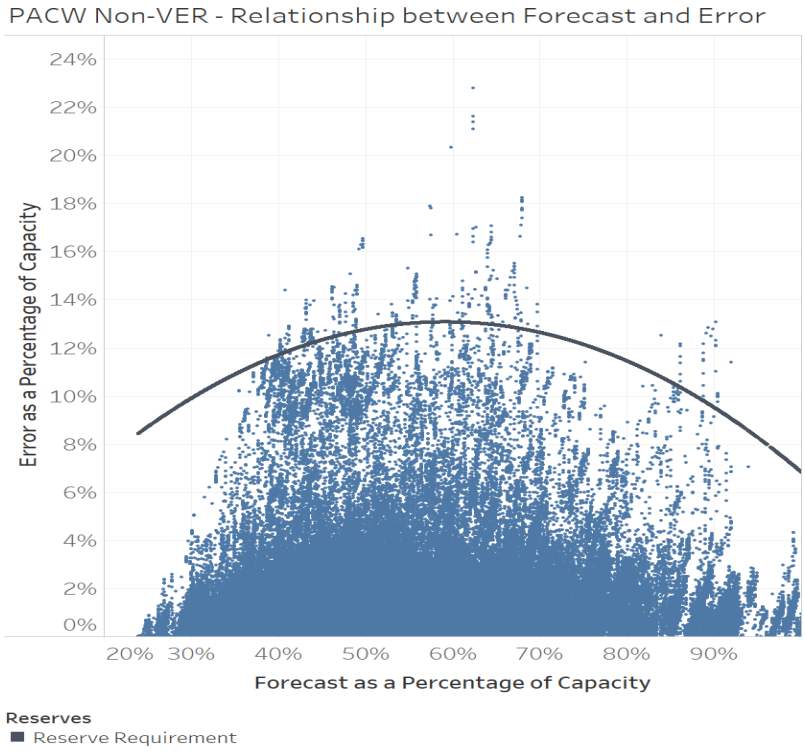


Figure 13. PACE Load

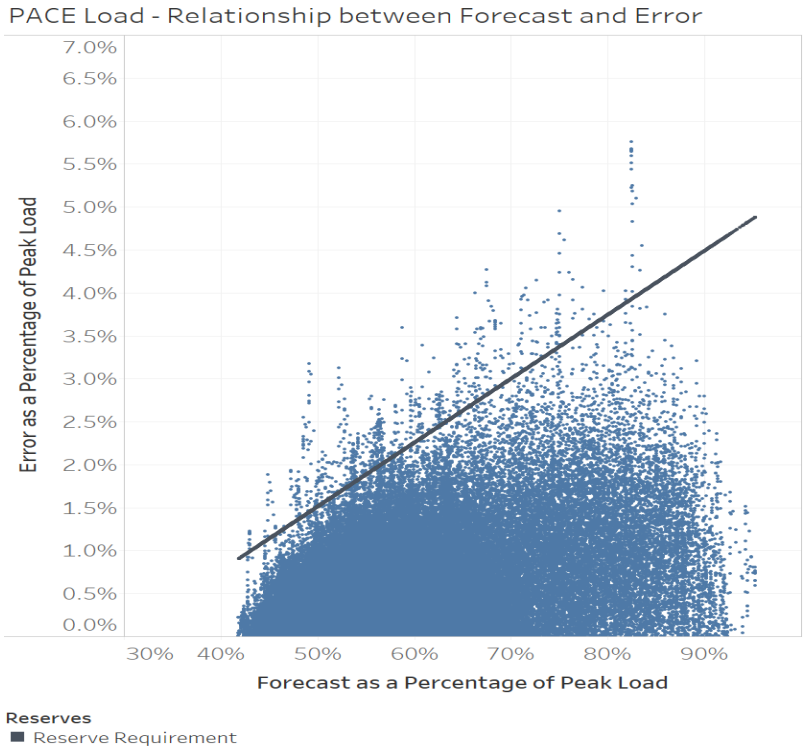
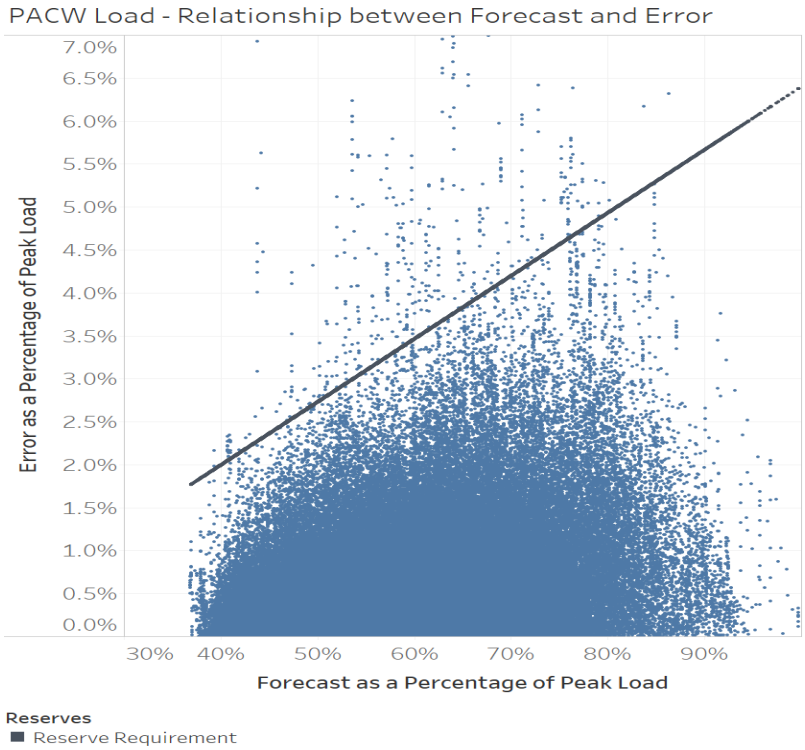


Figure 14. PACW Load



Q. WHAT ARE THE RESULTS OF THE REGULATION RESERVE REQUIREMENTS?

A. The quantile regression analysis results in an average stand-alone regulation reserve requirement for wind of 457 MW, or approximately 16.7% percent of nameplate capacity; for solar, 159 MW or approximately 14.8% percent of nameplate capacity; for non-VERs, 106 MW or approximately 8.2% percent of nameplate capacity; and for load, 334 MW or approximately 3.3% percent of monthly coincident peak loads ("12CP"). These requirements do not account for any portfolio diversity benefits from combining the deviations across classes.

6. Portfolio Diversity Benefit

Q. HOW DID PACIFICORP ACCOUNT FOR PORTFOLIO DIVERSITY BENEFITS?

A. The regulation reserve study accounts for diversity benefits attributable to the diverse users of PacifiCorp's system through an iterative process that starts with a calculation of the aggregate system-wide deviations. Because the largest deviations in each class of resources and load are not likely to occur at the same time, the regulation reserves held can cover the expected deviations for multiple classes at once and a reduced total quantity of reserves is sufficient to maintain the desired level of reliability. This reduction in the reserve requirement is the diversity benefit from holding a single pool of reserves on PacifiCorp's system to cover deviations by VERs, Non-VERs, and load.

Q. IS THERE AN INTERACTION BETWEEN THE REGULATION RESERVE REQUIREMENTS FOR VERS, NON-VERS, AND LOAD?

A. Yes. The stand-alone regulation reserve forecasts described above (459 MW for wind, 160 MW for solar, 107 MW for Non-VERs, and 336 MW for load) independently ensure that the probability of a reliability violation for each class remains within the reliability target. However, the largest deviations in each class tend not to occur simultaneously, and in some cases deviations by one class will offset deviations by another class. As a result, while the sum of the stand-alone reserve requirements for each class yields a total reserve requirement of 1057 MW, the total portfolio requirement when the deviations of all classes are combined is only 680 MW. This 36% reduction in the reserve requirement still achieves the reliability target of 0.50 loss of load hours per year. Because the regulation reserves held cover the expected deviations for multiple classes at once, a reduced total quantity of reserves is sufficient to maintain the desired level of reliability.

7. EIM Diversity Benefit

Q. HOW DOES PARTICIPATION IN THE EIM ASSIST PACIFICORP IN FULFILLING ITS RELIABILITY OBLIGATIONS?

A. In addition to the increased system visibility provided by EIM participation, as further described in Ms. Brown's testimony, EIM imports from other participating BAAs can help balance PacifiCorp's loads and resources within an hour, reducing the size of reserve shortfalls and the likelihood of a Balancing Authority ACE Limit violation. While substantial EIM imports do occur in some hours, it is only appropriate to rely on PacifiCorp's share of the reserve benefits associated with EIM, as these are derived from the structure of the EIM rather than resources contributed by other participants. These benefits are analogous to the portfolio diversity benefits from sharing reserve resources among the classes in PacifiCorp's BAAs, but instead reflect the of sharing reserve resources with other BAAs across the EIM footprint. The sharing of reserves through EIM is referred to as the EIM diversity benefit.

Q. HOW DOES PACIFICORP PROPOSE TO ACCOUNT FOR THE EIM DIVERSITY BENEFIT?

A. Using historical EIM diversity benefits, a matrix of average EIM diversity benefits was calculated by hour and season. These diversity benefits are applied as a credit to the final BAA regulation reserve requirement in each hour of the study.

Q. COULD THE EIM RESULT IN A HIGHER RESERVE OBLIGATION?

A. It is possible under certain circumstances. In order to participate fully in EIM, each participating BAA must pass a flexible ramp sufficiency test demonstrating that it has a minimum level of resources necessary to compensate for ramping or uncertainty in the

requirements across the next hour. The uncertainty component is somewhat analogous to the estimate of regulation reserve requirements in PacifiCorp's study, while the ramping component is mostly incremental. The flexible ramp sufficiency test is used by the CAISO to facilitate market operation and fairness and is not intended to ensure reliable system operation, for which all EIM participating BAAs remain individually responsible. In the current study, PacifiCorp's forecasted reserve requirements were never lower than CAISO's flexible ramp sufficiency test's requirement, but this test could be an issue if loss of load hours were set to allow a lower level of reliability.

Q. WHAT IS THE IMPACT OF INCLUDING THE EIM DIVERSITY BENEFIT IN THE REGULATION RESERVE ANALYSIS?

A. Including the EIM diversity benefit results in an average regulation reserve requirement of 540 MW. Reducing the PacifiCorp portfolio reserve requirement without the EIM diversity benefits by 140 MW, or an additional 21% reduction (after taking into account the portfolio diversity benefit).

E. Regulation Reserve Class Allocation and Billing

Q. CAN THE REGULATION RESERVES CARRIED FOR EACH CLASS BE READILY DIFFERENTIATED?

A. No. Because the regulation reserve requirement incorporates portfolio diversity resulting from the combined deviations of all classes, each increment of the portfolio reserve requirement is available to compensate for the deviations of all the classes at the same time.

Q. HOW DOES PACIFICORP PROPOSE ALLOCATING THE PORTFOLIO RESERVE REQUIREMENT AMONG THE VARIOUS CLASSES?

A. The stand-alone reserve requirements by class that were previously discussed identify the reserve requirement for each class in the absence of sharing requirements with different classes. Any reduction from this level is a result of sharing and should be allocated equitably. Therefore, PacifiCorp proposes that the difference between the sum of the stand-alone requirements and the portfolio requirement after accounting for portfolio diversity and EIM diversity for a given hour be shared pro-rata among the classes. All classes would thus receive the same percentage reduction in their reserve requirements in each hour. This is comparable to the allocation of requirements to classes proposed by PacifiCorp in Docket ER17-219-000, except that in this proceeding, diversity specific to each hour is allocated hourly among the classes' requirements, whereas in the prior proceeding diversity benefits were allocated based on the annual diversity and requirements.

Q. DOES THIS RESULT IN IDENTICAL PERCENTAGE REDUCTIONS FOR ALL CLASSES?

A. No. Classes whose requirements are highest in the hours with the greatest diversity receive the largest reductions. For example, solar resources do not have reserve requirements at night, so there are more classes contributing to requirements during the day relative to at night. As a result, the solar class receives a slightly higher diversity benefit than the other classes.

Q. PLEASE SUMMARIZE THE RESULTS OF THE REGULATION RESERVE REQUIREMENT ANALYSIS.

A. As shown in the table below reflecting the conclusions of PacifiCorp's regulation reserve study, the regulation reserve requirement for Non-VERs is 4.2 percent of resource

capacity, the requirement for load is 1.7 percent of the 12CP, the requirement for wind is 8.6 percent of resource capacity, and the requirement for solar is 7.1 percent of resource capacity. For both VERs and Non-VERs, the resource capacity refers to the lesser of a resource's nameplate capacity or its interconnection capacity, recognizing that a resource's impact on the system cannot exceeds its connection to the system.

Table 1: Regulation Reserve Study Results

Class	Stand-alone Regulation Forecast		Portfolio Regulation Forecast with Diversity		Capacity	Rate Determinant
	(aMW)	(%)	(aMW)	(%)	(aMW)	
Non-VER	**106**	**8.2%**	**55.0**	**4.2%**	**1,304**	Nameplate
Load	**334**	**3.3%**	**171.5**	**1.7%**	**10,094**	12CP
VER - Wind	**457**	**16.7%**	**236.9**	**8.6%**	**2,745**	Nameplate
VER - Solar	**159**	**14.8%**	**76.2**	**7. 1%**	**1,080**	Nameplate
Total	**1,057**		**539.7**			

F. Intra-hour Scheduling Benefits

Q. CAN INTRA-HOUR SCHEDULING REDUCE REGULATION RESERVE REQUIREMENTS?

A. Yes. Intra-hour scheduling utilizing transmission schedules (or e-tags) on a fifteen-minute basis has the potential to reduce PacifiCorp's regulation reserve requirements by ensuring a better alignment of resources and requirements within the hour. Accurate scheduling for imports and exports can result in net reductions in deviations, and a resulting improvement in PacifiCorp's ACE.

Q. HOW ARE INTRA-HOUR SCHEDULING BENEFITS ACHIEVED?

A. PacifiCorp's OATT allows for transmission scheduling on fifteen-minute intervals, so that timeframe is considered here. For intra-hour scheduling to reduce PacifiCorp's

regulating reserve requirements, the intra-hour schedules must result in a net reduction in interchange deviations, and an improvement in PacifiCorp's ACE. As a result, intra-hour scheduling adjustments for generation resources will not provide benefits unless those adjustments are also reflected in interchange schedules (for exporting generators), or the dispatch of other generation (for internal load-serving generators).

Q. HOW HAS INTRA-HOUR SCHEDULING BEEN USED ON THE PACIFICORP SYSTEM?

A. Ms. Wiencke's testimony explains that very few customers on PacifiCorp's system use intra-hour scheduling. While very limited intra-hour scheduling occurred on PacifiCorp's system during the Study Period, PacifiCorp recognizes its obligation to take intra-hour scheduling and forecasting reforms into account when developing and supporting rates for generator regulation service.

Q. GIVEN INTRA-HOUR SCHEDULING IN ACTUAL OPERATIONS HAS BEEN LIMITED, WHAT OTHER INFORMATION IS AVAILABLE TO IDENTIFY ITS POTENTIAL BENEFITS?

A. As part of EIM operations, VERs owners are required by the OATT to submit operational forecasts at five- or fifteen-minute granularity, which must be updated at each applicable interval to improve the optimization in the CAISO's EIM. If these forecasts were used to update interchange or dispatchable resource schedules, the more granular interval and shorter forecast horizon would result in lower total deviations, as well as lower maximum deviations.

Q. HOW HAVE THE IMPACTS OF INTRA-HOUR SCHEDULING ON REGULATION RESERVE REQUIREMENTS BEEN ANALYZED?

A. In order to incorporate an intra-hour scheduling and forecasting benefit in the regulation reserve study results, PacifiCorp's fifteen-minute scheduling analysis uses the fifteen-minute market schedules from the EIM for all of the VERs in the study, and the associated deviations from those schedules. The structure of the data and methodology used to determine the stand-alone regulating reserve requirements associated with VERs using fifteen-minute scheduling is the same as in PacifiCorp's primary analysis based on 60-minute scheduling, as previously described.

Q. WHAT ARE THE RESULTS OF THE REGULATION RESERVE FORECAST FOR VERS WITH INTRA-HOUR SCHEDULING?

A. If all of the VERs in the regulation reserve study submitted balanced fifteen-minute schedules, the regulation reserve requirement, after accounting for portfolio and EIM diversity, would be reduced by an average of 23 MW. This corresponds to a 7.1% reduction relative to the requirements allocated to VERs in the absence of intra-hour scheduling.

G. Spinning and Supplemental Reserve Requirements

Q. HOW ARE SPINNING AND SUPPLEMENTAL RESERVE REQUIREMENTS CALCULATED?

A. As I noted above, Spinning and Supplemental reserves correspond to contingency reserve requirements, which are based on a formula defined in NERC regional reliability standard BAL-002-WECC-2a. As discussed in the testimony of Ms. Brown, the amount of total operating contingency reserve—both spinning and supplemental—is the greater of either: (1) the amount of contingency reserve equal to the loss of the most severe single contingency; or (2) the amount of contingency reserve equal to the sum of three

percent of hourly integrated load plus three percent of hourly integrated generation. Contingency reserve must be available within ten minutes, and, pursuant to Requirement 2 of BAL-002-WECC-2a, at least half must be from "spinning" resources that are online and immediately responsive to system fluctuations. The remainder of the requirement can be met by supplemental reserves.

Q. HOW DID PACIFICORP DETERMINE THE AMOUNTS OF SPINNING AND SUPPLEMENTAL RESERVES NEEDED?

A. The reserve requirements for spinning reserves and supplemental reserves are based on actual operational data from 2018, as recorded in PacifiCorp's Energy Management System. The required annual hourly average amount of spinning reserves under BAL-002-WECC-2a in 2018 was 237.2 average megawatts (aMW), representing half the recorded contingency reserve obligation. The required annual hourly average amount of supplemental reserves under BAL-002-WECC-2a in 2018 was also 237.2 aMW. I discuss how the resources most likely to have fulfilled these reserve requirements were identified in the next section of my testimony.

H. Determination of Resource Pool

Q. DO ALL OF PACIFICORP'S RESOURCES CONTRIBUTE TO THE SUPPLY OF OPERATING RESERVE FOR SCHEDULES 3, 3A, 5, AND 6?

A. No. As discussed below, PacifiCorp used the FERC-approved, "units most likely" approach[9] in its analysis to identify which existing resources are likely to provide each particular reserve, taking into account each unit's operating characteristics and Study Period evidence of the unit's capacity factor and availability. After identifying these

[9] *Consumers Energy Co*., 86 FERC ¶ 63,004 at 65,055 (1999), *aff'd*, 98 FERC ¶ 61,333 (2002).

units, PacifiCorp then performed an analysis to determine the contribution of each of these PacifiCorp's resources to the supply of operating reserve for Schedules 3, 3A, 5 and 6, ensuring that the same capacity is not double-counted, as certain units may be capable of providing multiple types of reserves. PacifiCorp also has determined the proportionate amount each resource provides to meet Schedules 3 and 3A requirements ("Regulation Contribution Ratio"), Schedule 5 requirements ("Spinning Contribution Ratio"), and Schedule 6 requirements ("Supplemental Contribution Ratio").

Q. ARE THE RESOURCES THAT PROVIDE RESERVES LIMITED TO PACIFICORP-OWNED GENERATION?

A. No. In addition to generation owned by PacifiCorp, PacifiCorp also meets its reserve requirements with some resources committed to PacifiCorp under contract. In the reserve study, PacifiCorp included the hydro-electric generation from the Mid-Columbia system (Public Utility District No. 2 of Grant County, Washington). In addition to generation resources, PacifiCorp also can meet reserve requirements with interruptible load. PacifiCorp has interruptible load contracts with three customers – Monsanto, Nucor, and Magcorp – that PacifiCorp may use to meet reserve requirements.

Q. HOW DOES THE REGULATION CONTRIBUTION RATIO RELATE TO THE TOTAL REQUIREMENTS IDENTIFIED IN THE PACIFICORP REGULATION RESERVE STUDY?

A. The Regulation Contribution Ratio represents the proportionate contribution of PacifiCorp's resources that were available to meet regulation reserve requirements on PacifiCorp's system during 2018, but it does not have anything to do with the MW amount of the total regulation reserve requirement identified in the regulation reserve

study. Because the results of the regulation reserve study were not known during actual operations in 2018, the regulation supply available in 2018 does not correspond directly with the regulation requirements identified in the study. In general, there was more regulation supply available during 2018 from PacifiCorp's resources than is necessary for ratemaking purposes based upon PacifiCorp's updated study. However, it is reasonable to assume that the mix of resources that provided regulation reserves in 2018 would also provide regulation reserves in the future. Therefore the costs in Schedules 3 and 3A reflect the Regulation Contribution Ratio discussed below, while the volume requirements are identified in the regulation reserve study (see Table 1 on page 46 of my testimony). I discuss further below how the Regulation Contribution Ratios are used for ratemaking purposes in light of the updated reserve requirements.

Q. CAN YOU PROVIDE AN OVERVIEW OF THE METHODOLOGY USED TO IDENTIFY THE GENERATING UNITS THAT ARE MOST LIKELY TO CONTRIBUTE TO THE SUPPLY OF OPERATING RESERVE FOR SCHEDULES 3, 3A, 5, AND 6?

A. Yes. The actual capacity available to provide regulation, spinning, and supplemental service was identified by hour for each unit. The spinning reserve requirement is the most restrictive, as it is limited to 10-minute ramping capability on resources that begin to respond immediately. The supplemental reserve requirement is the next most restrictive, as it is limited to 10-minute ramping capability and doesn't require an immediate response. Finally, the regulation reserve requirement is the least restrictive, as it is limited to 30-minute ramping capability and doesn't require an immediate response. Recognizing these constraints, the available capacity is allocated first to the spinning

reserve requirement, next to the supplemental reserve requirement, and lastly to the regulation reserve requirement.

As discussed above, the spinning and supplemental requirements are formulaic, so the specific amount needed in each hour is known and that quantity of reserve can be identified for each. Because the regulation reserve requirement is not specified, for the purposes of determining the Regulation Contribution Ratio, any remaining capability that qualifies is considered available for regulation reserve. All these calculations are performed independently for PACE and PACW, since they must both separately maintain compliance with all reliability standards.

Q. HOW DID PACIFICORP IDENTIFY THE GENERATING UNITS THAT ARE MOST LIKELY TO PROVIDE THE SERVICE WHICH FORMS THE BASIS FOR THE COSTS ALLOCATED PURSUANT TO SCHEDULE 5?

A. As I noted earlier in my testimony, PacifiCorp records data in its EMS showing the amount of total ten-minute reserve credited to individual generation resources and contracts by hour. This data identifies the generation resources that provided spinning reserve capability in each hour of the Study Period. As part of EIM operations, PacifiCorp also submits schedules identifying resources that are expected to provide spinning and non-spinning reserves in the next hour. Finally, PacifiCorp's EMS also records the contingency reserve requirement for each hour, net of any contingency reserves self-supplied by third-party customers. The spinning reserve requirement and supplemental reserve requirement each represent half of the total contingency reserve requirement. The hourly spinning reserve requirement is allocated pro-rata first among resources that were scheduled to provide reserves and had spinning reserve capability in

that hour. Any remaining spinning reserve requirement is allocated pro-rata among all resources with remaining spinning reserve capability in that hour.

Specifically, two percentages are calculated related to the spinning reserve requirement under BAL-002-WECC-2a in each hour. First, I calculated the percentage of the scheduled and available spinning reserve capability that was needed to meet the spin requirement for the hour. Second, I calculated the percentage of the spinning reserve capability that was available and was not scheduled that was needed to meet the remainder of the spin requirement for the hour. These percentages are multiplied by the scheduled and/or available spinning reserve for each resource, thus determining the capability each resource contributed toward the spinning reserve requirement. The spin requirement is thus allocated among the resources with spin capability for each hour.[10] The contribution to the spinning reserve requirement is calculated for each hour in the Study Period, and then the average hourly contribution of each plant is calculated. The Spinning Contribution Ratio for each plant is the ratio of its contribution to the spinning reserve requirement to the total contribution to the spinning reserve requirement by all plants.

Q. CAN YOU PROVIDE AN EXAMPLE ILLUSTRATING HOW THE SPECIFIC GENERATING UNITS ARE IDENTIFIED?

A. Yes. In a hour, Plant A, Plant B, and Plant C provide 30 MW, 60 MW, and 70 MW of spinning reserve, respectively, such that 160 MW of spinning reserve are available in total. Each plant was scheduled to provide 30 MW of spinning reserves prior to the hour,

[10] Since May 1, 2017, PacifiCorp has been operating under a Field Trial which waives the spinning reserve obligation under BAL-002-WECC-2a. As a result, non-spinning resources provided a portion of the spinning reserve obligation in some intervals; however, for the purpose of this proceeding, spinning reserves are only allocated among qualified resources consistent with the current standard.

for a total of 90 MW of scheduled and available spinning reserve capability. In that hour, if the spin requirement is 125 MW, then 100 percent of the 90 MW of scheduled and available spinning reserve capability will be required for compliance with BAL-002-WECC-2a. The remaining spinning reserve requirement of 35 MW, represents 50% of the remaining available spinning reserve of 70 MW. In this example:

- (Spin Scheduled and Available * Scheduled and Available Spin Ratio) + (Remaining Spin Available * Remaining Spin Ratio)
- Plant A: 100 percent of its available spin.
  - 30 MW * 100 percent + 0 MW * 50 percent = 30 MW of 30 MW
- Plant B: 75 percent of its available spin.
  - 30 MW * 100 percent + 30 MW * 50 percent = 45 MW of 60 MW
- Plant C: 71 percent of its available spin.
  - 30 MW * 100 percent + 40 MW * 50 percent = 50 MW of 70 MW

The total spinning reserve contribution in that hour is 30 MW + 45 MW + 50 MW = 125 MW, which is equal to the spin requirement.

If every hour in the year were identical to the example above, the Spinning Contribution Ratio of Plant A would be 30 MW/125 MW = 24 percent, the Spinning Contribution Ratio of Plant B would be 60 MW/125 MW = 36 percent, the Spinning Contribution Ratio of Plant C would be 70 MW/125 MW = 40 percent. In other words, Schedule 5 would be 24 percent based on the unit costs of Plant A, 36 percent based on the unit costs of Plant B, and 40 percent based on the unit costs of Plant C.

Q. WHAT ARE THE RESULTS OF THE SPINNING RESERVE ALLOCATION?

A. Please refer to Table A, which is provided as Exhibit No. PAC-004.

Q. HOW DID PACIFICORP IDENTIFY THE RESOURCES THAT PROVIDE THE SERVICE WHICH FORMS THE BASIS FOR THE COSTS ALLOCATED PURSUANT TO SCHEDULE 6?

A. The supplemental reserve requirement may be met with non-spinning resources, or with remaining spinning resources. After accounting for self-supply, the hourly non-spinning reserve requirement is allocated pro-rata, first among resources that were scheduled to provide reserves and had non-spinning or remaining spinning reserve capability in that hour. Any remaining non-spinning reserve requirement is allocated pro-rata among all resources with remaining non-spinning or remaining spinning reserve capability in that hour.

Specifically, two percentages are calculated related to the non-spinning reserve requirement under BAL-002-WECC-2a in each hour. First, I calculated the percentage of the scheduled and available reserve capability that was needed to meet the non-spin requirement for the hour. Second, I calculated the percentage of the remaining reserve capability that was needed to meet the non-spin requirement for the hour. These percentages are multiplied by the scheduled and/or available reserve for each resource, thus determining the capability each resource contributed toward the non-spinning reserve requirement. The non-spin requirement is thus allocated among the resources with available spin and non-spin reserve capability for each hour.

The contribution to the supplemental reserve requirement is calculated for each hour of the Study Period, and then the average hourly contribution of each resource is calculated. The Supplemental Contribution Ratio for each plant is the ratio of its

contribution to the supplemental reserve requirement to the total contribution to the supplemental reserve requirement by all plants.

Q. CAN YOU PROVIDE AN EXAMPLE ILLUSTRATING HOW THE SPECIFIC GENERATING UNITS ARE IDENTIFIED?

A. Yes. Continuing the example above, the supplemental reserve requirement is equal to the spinning requirement at 125 MW. Plant B and Plant C have 15 MW and 20 MW of spinning reserve remaining, respectively. Assuming also that an Interruptible Load provides 110 MW of non-spinning reserve, all of which is scheduled. The total reserve contribution by scheduled and available resources is 110 MW, from the Interruptible Load, which is less than the non-spin requirement, so 100% of its capability is required for compliance with BAL-002-WECC-2a. That leaves 15 MW of non-spin capability to be met by Plants B and C, which have 35 MW of remaining capability, resulting in a ratio for remaining non-spin resources of 43% (15 MW / 35 MW). In this example:

- (Non-Spin Scheduled and Available * Scheduled and Available Non-Spin Ratio) + (Remaining Non-Spin Available * Remaining Non-Spin Ratio)
- Interruptible Load: 100 percent of its available capability.
    - 110 MW * 100 percent + 0 MW * 43 percent = 110 MW of 110 MW
- Plant B: 43 percent of its available capability.
    - 0 MW * 100 percent + 15 MW * 43 percent = 6.4 MW of 15 MW
- Plant C: 43 percent of its available capability.
    - 0 MW * 100 percent + 20 MW * 43 percent = 8.6 MW of 20 MW

If every hour in the year was identical to the example above, the Supplemental Contribution Ratio of the Interruptible Load would be 110 MW/125 MW = 88 percent, the Supplemental Contribution Ratio Plant B and C would be approximately 5 percent and 7 percent, respectively. In other words, Schedule 6 would be 88 percent based on the unit costs of the Interruptible Load, 5 percent based on the unit costs of Plant B, and 7 percent based on the unit costs of Plant C.

Q. WHAT ARE THE RESULTS OF THE SUPPLEMENTAL RESERVE ALLOCATION?

A. Please refer to Table B, which is provided as Exhibit No. PAC-005.

Q. HOW DID PACIFICORP IDENTIFY THE RESOURCES THAT PROVIDE THE SERVICE WHICH FORMS THE BASIS FOR THE COSTS ALLOCATED PURSUANT TO SCHEDULES 3 AND 3A?

A. Schedules 3 and 3A service can be provided from any of three types of resources:

- Unused 10-minute spinning reserve capability;
- Unused 10-minute non-spinning reserve capability, where not contractually precluded; or
- Incremental 30-minute ramping capability beyond that identified in the first two categories.

Data on the first two categories is readily available from the analysis performed for Schedules 5 and 6. However, the Company's EMS only records the amount of 10-minute reserve capability credited to individual generation resources and contracts in each hour. Additional calculations are thus required to identify units providing regulation reserve service in the incremental 30-minute category.

For several resources, the 10-minute capability encompasses their full capacity, so no additional regulation capability is possible beyond the unused 10-minute

capability. For other units, the regulation reserve available in a given hour is the capacity between a unit's high regulation limit (maximum available capacity for a given hour) and its base schedule for that hour that was not allocated to 10-minute reserves, capped at the unit's 30-minute ramp rate. The high regulation limit is recorded in the Company's EMS, while base schedules are available through EIM settlements.

Q. CAN YOU PROVIDE AN EXAMPLE ILLUSTRATING HOW REGULATION CAPABILITY IS IDENTIFIED?

A. Yes. Continuing the example above, Plant B held 60 MW of 10-minute reserve and was allocated 45 MW of spinning reserve and 6.4 MW of supplemental reserve, for a total of 51.4 MW of 10-minute reserve capability allocated to Schedules 5 and 6. In 30 minutes, Plant B could provide 180 MW of regulation reserve, however if it has a high regulation limit of 200 MW and was base scheduled at 110 MW, only 90 MW of total reserve capability would have been available in this example. Of the 90 MW, 51.4 MW was allocated to Schedules 5 and 6, so 38.6 MW remain available as regulation reserve.

Q. WHAT ARE THE RESULTS OF THE REGULATION RESERVE ALLOCATION?

A. Please refer to Table C, which is provided as Exhibit No. PAC-006.

Q. ARE ANY ADJUSTMENTS MADE TO THE CONTRIBUTION RATIOS FOR PURPOSES OF DEVELOPING RATES FOR SCHEDULES 3, 3A, 5, AND 6?

A. Yes. PacifiCorp's calculations utilize hourly results from the Study Period, and changes to PacifiCorp's resource portfolio have occurred since that time. Specifically, Naughton 3 ceased coal-fired operation in January 2019, and the Mid-Columbia hydro contract with the Douglas County Public Utility District expired in August 2018. In addition, the

Cool Keeper and SCL Stateline self-supply resources do not have a cost basis and are also removed from the reserve supply for the purposes of calculating rates. Please refer to Tables D, E, and F for the adjusted resource contribution ratios for spinning, supplemental, and regulation reserves used for developing rates. Tables D, E, and F are provided in Exhibit Nos. PAC-007, PAC-008, and PAC-009, respectively.

Q. HOW ARE THE ADJUSTED RESULTS USED?

A. As I explained earlier in my testimony, the Company did not use the contribution ratios to determine total reserve need. Instead, the results are used to determine a relative contribution ratio among the units that provided the service. The contribution ratio for each individual unit can then be used to allocate an appropriate amount of fixed capacity costs of that unit for purposes of developing rates. For the reserves required for Regulation and Frequency Response Service, the amount shown on Table F (PAC-009) as the "Total Capability Available for Regulation Reserve" is 763.9 aMW. Since the reserve study only identified a total need for 539.7 MW, the contribution ratios for each resource are used in a pro rata adjustment to reflect their contribution to meeting the 539.7 MW reserve requirement. These same contribution ratios are likewise used to identify the resources applicable to the reserve requirement of individual classes within the total.

I. Conclusions

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS.

A. Based upon the 2018-2019 Study Period, the total amount of the Regulation and Frequency Response reserve requirement is 539.7 MW. Of this total, 236.9 MW are allocated as the Regulation and Frequency Response reserve requirement for wind

VERs, 76.2 MW are allocated as the Regulation and Frequency Response reserve requirement for solar VERs, 55 MW are allocated as the Regulation and Frequency Response reserve requirement for Non-VERs, and 171.5 MW are allocated as the Regulation and Frequency Response reserve requirement for load. Based upon a 2018 study period, the mix of resources that were used to supply Regulation and Frequency Response reserve, Operating Reserve – Spinning, and Operating Reserve – Supplemental were also identified, as detailed in Exhibit No. PAC-004 through PAC-009.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A . Yes.

Daniel J. MacNeil

Table A
2018 Study Results
Schedule 5, Spinning Reserve

		Total 10-Minute Contingency Reserve		Spin Held for Contingency Spin Requirement		Total Reserve Held for Spinning Reserve Requirement	
Plant	**Type**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**
Dave Johnston 1	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 2	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 3	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 4	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
Gadsby 1	Steam	1.3	0.1%	0.8	0.4%	0.8	0.4%
Gadsby 2	Steam	1.9	0.2%	1.2	0.5%	1.2	0.5%
Gadsby 3	Steam	2.6	0.3%	2.3	1.0%	2.3	1.0%
Hunter 1	Steam	21.6	2.1%	10.5	4.5%	10.5	4.5%
Hunter 2	Steam	19.5	1.9%	9.9	4.2%	9.9	4.2%
Hunter 3	Steam	26.0	2.5%	13.2	5.6%	13.2	5.6%
Huntington 1	Steam	26.3	2.5%	16.8	7.2%	16.8	7.2%
Huntington 2	Steam	23.1	2.2%	12.3	5.2%	12.3	5.2%
Jim Bridger	Steam	19.3	1.8%	0.7	0.3%	0.7	0.3%
Naughton 1	Steam	5.8	0.6%	2.4	1.0%	2.4	1.0%
Naughton 2	Steam	6.2	0.6%	2.4	1.0%	2.4	1.0%
Naughton 3	Steam	8.8	0.8%	3.8	1.6%	3.8	1.6%
Wyodak	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
Cutler 1	Hydro	14.8	1.4%	7.6	3.3%	7.6	3.3%
Cutler 2	Hydro	13.6	1.3%	7.1	3.0%	7.1	3.0%
Mid-C Hydro - Douglas	Hydro	6.5	0.6%	0.0	0.0%	0.0	0.0%
Mid-C Hydro - Grant	Hydro	3.0	0.3%	0.0	0.0%	0.0	0.0%
Oneida 1	Hydro	10.2	1.0%	5.3	2.3%	5.3	2.3%
Oneida 2	Hydro	6.1	0.6%	3.2	1.4%	3.2	1.4%
Oneida 3	Hydro	0.9	0.1%	0.4	0.2%	0.4	0.2%
Swift	Hydro	129.0	12.3%	45.0	19.2%	45.0	19.2%
Yale	Hydro	90.9	8.6%	12.7	5.4%	12.7	5.4%
Chehalis	Gas	52.1	5.0%	3.1	1.3%	3.1	1.3%
Currant Creek	Gas	49.3	4.7%	20.8	8.9%	20.8	8.9%
Gadsby 4	Gas	38.1	3.6%	0.2	0.1%	0.2	0.1%
Gadsby 5	Gas	36.4	3.5%	0.2	0.1%	0.2	0.1%
Gadsby 6	Gas	37.6	3.6%	0.3	0.1%	0.3	0.1%
Hermiston	Gas	30.1	2.9%	5.2	2.2%	5.2	2.2%
Lake Side 1	Gas	47.3	4.5%	19.3	8.2%	19.3	8.2%
Lake Side 2	Gas	62.1	5.9%	27.3	11.7%	27.3	11.7%
Magcorp	Interruptible Load	84.3	8.0%	0.0	0.0%	0.0	0.0%
Monsanto	Interruptible Load	94.4	9.0%	0.0	0.0%	0.0	0.0%
Nucor	Interruptible Load	52.5	5.0%	0.0	0.0%	0.0	0.0%
Coolkeeper	Self-supply	19.4	1.8%	0.0	0.0%	0.0	0.0%
SCL Stateline	Self-supply	10.0	1.0%	0.0	0.0%	0.0	0.0%
Totals		**1051.2**	**100%**	**234.1**	**100%**	**234.1**	**100%**

Table B
2018 Study Results
Schedule 6, Supplemental Reserve

		Total 10-Minute Contingency Reserve		Supplemental Reserves Held for Supplemental Reserve Requirement		Spin Held for Supplemental Reserve Requirement		Total Reserve Held for Supplemental Reserve Requirement	
Plant	**Type**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**
Dave Johnston 1	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 2	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 3	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 4	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Gadsby 1	Steam	1.3	0.1%	0.0	0.0%	0.0	1.6%	0.0	0.0%
Gadsby 2	Steam	1.9	0.2%	0.0	0.0%	0.0	2.0%	0.0	0.0%
Gadsby 3	Steam	2.6	0.3%	0.0	0.0%	0.0	0.4%	0.0	0.0%
Hunter 1	Steam	21.6	2.1%	0.0	0.0%	0.0	6.5%	0.0	0.0%
Hunter 2	Steam	19.5	1.9%	0.0	0.0%	0.0	6.3%	0.0	0.0%
Hunter 3	Steam	26.0	2.5%	0.0	0.0%	0.0	5.1%	0.0	0.0%
Huntington 1	Steam	26.3	2.5%	0.0	0.0%	0.0	3.0%	0.0	0.0%
Huntington 2	Steam	23.1	2.2%	0.0	0.0%	0.0	4.4%	0.0	0.0%
Jim Bridger	Steam	19.3	1.8%	1.2	0.5%	0.0	0.0%	1.2	0.5%
Naughton 1	Steam	5.8	0.6%	0.0	0.0%	0.0	0.7%	0.0	0.0%
Naughton 2	Steam	6.2	0.6%	0.0	0.0%	0.0	1.2%	0.0	0.0%
Naughton 3	Steam	8.8	0.8%	0.0	0.0%	0.0	2.0%	0.0	0.0%
Wyodak	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Cutler 1	Hydro	14.8	1.4%	0.0	0.0%	0.0	4.8%	0.0	0.0%
Cutler 2	Hydro	13.6	1.3%	0.0	0.0%	0.0	4.9%	0.0	0.0%
Mid-C Hydro - Douglas	Hydro	6.5	0.6%	0.1	0.1%	0.0	0.0%	0.1	0.1%
Mid-C Hydro - Grant	Hydro	3.0	0.3%	0.1	0.1%	0.0	0.0%	0.1	0.1%
Oneida 1	Hydro	10.2	1.0%	0.0	0.0%	0.0	3.8%	0.0	0.0%
Oneida 2	Hydro	6.1	0.6%	0.0	0.0%	0.0	2.2%	0.0	0.0%
Oneida 3	Hydro	0.9	0.1%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Swift	Hydro	129.0	12.3%	37.5	15.8%	0.0	0.0%	37.5	15.8%
Yale	Hydro	90.9	8.6%	10.7	4.5%	0.0	0.0%	10.7	4.5%
Chehalis	Gas	52.1	5.0%	3.0	1.3%	0.0	0.0%	3.0	1.3%
Currant Creek	Gas	49.3	4.7%	0.0	0.0%	0.0	16.6%	0.0	0.0%
Gadsby 4	Gas	38.1	3.6%	18.9	8.0%	0.0	2.1%	18.9	8.0%
Gadsby 5	Gas	36.4	3.5%	16.8	7.1%	0.0	1.8%	16.8	7.1%
Gadsby 6	Gas	37.6	3.6%	16.5	7.0%	0.0	2.0%	16.5	7.0%
Hermiston	Gas	30.1	2.9%	4.0	1.7%	0.0	0.0%	4.0	1.7%
Lake Side 1	Gas	47.3	4.5%	0.0	0.0%	0.0	11.7%	0.0	0.0%
Lake Side 2	Gas	62.1	5.9%	0.0	0.0%	0.0	16.7%	0.0	0.0%
Magcorp	Interruptible Load	84.3	8.0%	38.9	16.5%	0.0	0.0%	38.9	16.5%
Monsanto	Interruptible Load	94.4	9.0%	50.7	21.4%	0.0	0.0%	50.7	21.4%
Nucor	Interruptible Load	52.5	5.0%	27.8	11.8%	0.0	0.0%	27.8	11.8%
Coolkeeper	Self-supply	19.4	1.8%	0.1	0.0%	0.0	0.0%	0.1	0.0%
SCL Stateline	Self-supply	10.0	1.0%	10.0	4.2%	0.0	0.0%	10.0	4.2%
	Totals	**1051.2**	**100%**	**236.4**	**100%**	**0.1**	**100%**	**236.5**	**100%**

Table C
2018 Study Results
Schedule 3 and 3A, Regulation Reserve

		Total 10-Minute & 30-Minute Reserve		Excess Spin and Supplemental Available for Regulation Reserve		30-Minute Reserves Available for Regulation Reserve		Total Capability Available for Regulation Reserve	
Plant	**Type**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**
Dave Johnston 1	Steam	5.0	0.4%	0.0	0.0%	5.0	1.9%	5.0	0.6%
Dave Johnston 2	Steam	5.5	0.4%	0.0	0.0%	5.5	2.1%	5.5	0.7%
Dave Johnston 3	Steam	16.2	1.3%	0.0	0.0%	16.2	6.2%	16.2	2.0%
Dave Johnston 4	Steam	15.6	1.2%	0.0	0.0%	15.6	6.0%	15.6	2.0%
Gadsby 1	Steam	1.3	0.1%	0.5	0.1%	0.0	0.0%	0.5	0.1%
Gadsby 2	Steam	2.1	0.2%	0.7	0.1%	0.2	0.1%	0.9	0.1%
Gadsby 3	Steam	4.6	0.4%	0.4	0.1%	2.0	0.8%	2.4	0.3%
Hunter 1	Steam	37.5	3.0%	11.1	2.1%	15.9	6.1%	27.1	3.4%
Hunter 2	Steam	25.9	2.0%	9.6	1.8%	6.4	2.5%	16.0	2.0%
Hunter 3	Steam	59.3	4.7%	12.9	2.4%	33.2	12.8%	46.1	5.8%
Huntington 1	Steam	59.8	4.7%	9.5	1.8%	33.5	12.9%	43.0	5.4%
Huntington 2	Steam	53.3	4.2%	10.8	2.0%	30.3	11.7%	41.1	5.2%
Jim Bridger	Steam	39.2	3.1%	17.5	3.3%	19.9	7.7%	37.3	4.7%
Naughton 1	Steam	6.2	0.5%	3.4	0.6%	0.4	0.2%	3.8	0.5%
Naughton 2	Steam	7.4	0.6%	3.8	0.7%	1.2	0.5%	5.0	0.6%
Naughton 3	Steam	10.5	0.8%	5.0	0.9%	1.7	0.7%	6.7	0.8%
Wyodak	Steam	16.2	1.3%	0.0	0.0%	16.2	6.2%	16.2	2.0%
Cutler 1	Hydro	14.8	1.2%	7.2	1.3%	0.0	0.0%	7.2	0.9%
Cutler 2	Hydro	13.6	1.1%	6.5	1.2%	0.0	0.0%	6.5	0.8%
Mid-C Hydro - Douglas	Hydro	6.5	0.5%	6.3	1.2%	0.0	0.0%	6.3	0.8%
Mid-C Hydro - Grant	Hydro	3.0	0.2%	2.9	0.5%	0.0	0.0%	2.9	0.4%
Oneida 1	Hydro	10.2	0.8%	4.9	0.9%	0.0	0.0%	4.9	0.6%
Oneida 2	Hydro	6.1	0.5%	2.9	0.5%	0.0	0.0%	2.9	0.4%
Oneida 3	Hydro	0.9	0.1%	0.5	0.1%	0.0	0.0%	0.5	0.1%
Swift	Hydro	129.0	10.2%	46.6	8.7%	0.0	0.0%	46.6	5.8%
Yale	Hydro	90.9	7.2%	67.4	12.6%	0.0	0.0%	67.4	8.5%
Chehalis	Gas	52.1	4.1%	46.0	8.6%	0.0	0.0%	46.0	5.8%
Currant Creek	Gas	59.2	4.7%	28.4	5.3%	9.9	3.8%	38.3	4.8%
Gadsby 4	Gas	48.0	3.8%	19.0	3.5%	9.9	3.8%	28.8	3.6%
Gadsby 5	Gas	43.9	3.5%	19.4	3.6%	7.5	2.9%	27.0	3.4%
Gadsby 6	Gas	44.8	3.5%	20.9	3.9%	7.2	2.8%	28.0	3.5%
Hermiston	Gas	30.1	2.4%	20.9	3.9%	0.0	0.0%	20.9	2.6%
Lake Side 1	Gas	54.9	4.3%	28.0	5.2%	7.6	2.9%	35.6	4.5%
Lake Side 2	Gas	76.1	6.0%	34.8	6.5%	14.0	5.4%	48.8	6.1%
Magcorp	Interruptible Load	84.3	6.7%	45.4	8.4%	0.0	0.0%	45.4	5.7%
Monsanto	Interruptible Load	50.7	4.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Nucor	Interruptible Load	52.5	4.1%	24.6	4.6%	0.0	0.0%	24.6	3.1%
Coolkeeper	Self-supply	19.4	1.5%	19.4	3.6%	0.0	0.0%	19.4	2.4%
SCL Stateline	Self-supply	10.0	0.8%	0.0	0.0%	0.0	0.0%	0.0	0.0%
	Totals	**1266.8**	**100%**	**536.9**	**100%**	**259.3**	**100%**	**796.2**	**100%**

Table D
2018 Study Adjusted Results
Schedule 5, Spinning Reserve

		Total 10-Minute Contingency Reserve		Spin Held for Contingency Spin Requirement		Total Reserve Held for Spinning Reserve Requirement	
Plant	**Type**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**
Dave Johnston 1	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 2	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 3	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 4	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
Gadsby 1	Steam	1.3	0.1%	0.8	0.4%	0.8	0.4%
Gadsby 2	Steam	1.9	0.2%	1.2	0.5%	1.2	0.5%
Gadsby 3	Steam	2.6	0.3%	2.3	1.0%	2.3	1.0%
Hunter 1	Steam	21.6	2.1%	10.5	4.5%	10.5	4.5%
Hunter 2	Steam	19.5	1.9%	9.9	4.3%	9.9	4.3%
Hunter 3	Steam	26.0	2.6%	13.2	5.7%	13.2	5.7%
Huntington 1	Steam	26.3	2.6%	16.8	7.3%	16.8	7.3%
Huntington 2	Steam	23.1	2.3%	12.3	5.3%	12.3	5.3%
Jim Bridger	Steam	19.3	1.9%	0.7	0.3%	0.7	0.3%
Naughton 1	Steam	5.8	0.6%	2.4	1.0%	2.4	1.0%
Naughton 2	Steam	6.2	0.6%	2.4	1.0%	2.4	1.0%
Naughton 3 (1)	Steam						
Wyodak	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
Cutler 1	Hydro	14.8	1.5%	7.6	3.3%	7.6	3.3%
Cutler 2	Hydro	13.6	1.4%	7.1	3.1%	7.1	3.1%
Mid-C Hydro - Douglas (2)	Hydro						
Mid-C Hydro - Grant	Hydro	3.0	0.3%	0.0	0.0%	0.0	0.0%
Oneida 1	Hydro	10.2	1.0%	5.3	2.3%	5.3	2.3%
Oneida 2	Hydro	6.1	0.6%	3.2	1.4%	3.2	1.4%
Oneida 3	Hydro	0.9	0.1%	0.4	0.2%	0.4	0.2%
Swift	Hydro	129.0	12.8%	45.0	19.5%	45.0	19.5%
Yale	Hydro	90.9	9.0%	12.7	5.5%	12.7	5.5%
Chehalis	Gas	52.1	5.2%	3.1	1.4%	3.1	1.4%
Currant Creek	Gas	49.3	4.9%	20.8	9.0%	20.8	9.0%
Gadsby 4	Gas	38.1	3.8%	0.2	0.1%	0.2	0.1%
Gadsby 5	Gas	36.4	3.6%	0.2	0.1%	0.2	0.1%
Gadsby 6	Gas	37.6	3.7%	0.3	0.1%	0.3	0.1%
Hermiston	Gas	30.1	3.0%	5.2	2.2%	5.2	2.2%
Lake Side 1	Gas	47.3	4.7%	19.3	8.4%	19.3	8.4%
Lake Side 2	Gas	62.1	6.2%	27.3	11.9%	27.3	11.9%
Magcorp	Interruptible Load	84.3	8.4%	0.0	0.0%	0.0	0.0%
Monsanto	Interruptible Load	94.4	9.4%	0.0	0.0%	0.0	0.0%
Nucor	Interruptible Load	52.5	5.2%	0.0	0.0%	0.0	0.0%
Coolkeeper (3)	Self-supply						
SCL Stateline (3)	Self-supply						
	Totals	**1006.5**	**100%**	**230.3**	**100%**	**230.3**	**100%**

(1) Naughton 3 ceased coal-fired operation in January 2019.
(2) Douglas Hydro contract expired August 2018.
(3) Self-supply - resource does not have a cost basis.

Table E
2018 Study Adjusted Results
Schedule 6, Supplemental Reserve

		Total 10-Minute Contingency Reserve		Supplemental Reserves Held for Supplemental Reserve Requirement		Spin Held for Supplemental Reserve Requirement		Total Reserve Held for Supplemental Reserve Requirement	
Plant	**Type**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**
Dave Johnston 1	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 1	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 1	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 1	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 1	Steam	1.3	0.1%	0.0	0.0%	0.0	1.7%	0.0	0.0%
Dave Johnston 1	Steam	1.9	0.2%	0.0	0.0%	0.0	2.1%	0.0	0.0%
Dave Johnston 1	Steam	2.6	0.3%	0.0	0.0%	0.0	0.4%	0.0	0.0%
Dave Johnston 1	Steam	21.6	2.1%	0.0	0.0%	0.0	6.6%	0.0	0.0%
Dave Johnston 1	Steam	19.5	1.9%	0.0	0.0%	0.0	6.4%	0.0	0.0%
Dave Johnston 1	Steam	26.0	2.6%	0.0	0.0%	0.0	5.2%	0.0	0.0%
Dave Johnston 1	Steam	26.3	2.6%	0.0	0.0%	0.0	3.1%	0.0	0.0%
Dave Johnston 1	Steam	23.1	2.3%	0.0	0.0%	0.0	4.5%	0.0	0.0%
Dave Johnston 1	Steam	19.3	1.9%	1.2	0.5%	0.0	0.0%	1.2	0.5%
Dave Johnston 1	Steam	5.8	0.6%	0.0	0.0%	0.0	0.7%	0.0	0.0%
Dave Johnston 1	Steam	6.2	0.6%	0.0	0.0%	0.0	1.2%	0.0	0.0%
Naughton 3 (1)	Steam								
Dave Johnston 1	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 1	Hydro	14.8	1.5%	0.0	0.0%	0.0	4.9%	0.0	0.0%
Dave Johnston 1	Hydro	13.6	1.4%	0.0	0.0%	0.0	5.0%	0.0	0.0%
Mid-C Hydro - Douglas	Hydro								
Dave Johnston 1	Hydro	3.0	0.3%	0.1	0.1%	0.0	0.0%	0.1	0.1%
Dave Johnston 1	Hydro	10.2	1.0%	0.0	0.0%	0.0	3.9%	0.0	0.0%
Dave Johnston 1	Hydro	6.1	0.6%	0.0	0.0%	0.0	2.2%	0.0	0.0%
Dave Johnston 1	Hydro	0.9	0.1%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 1	Hydro	129.0	12.8%	37.5	16.6%	0.0	0.0%	37.5	16.6%
Dave Johnston 1	Hydro	90.9	9.0%	10.7	4.8%	0.0	0.0%	10.7	4.7%
Dave Johnston 1	Gas	52.1	5.2%	3.0	1.3%	0.0	0.0%	3.0	1.3%
Dave Johnston 1	Gas	49.3	4.9%	0.0	0.0%	0.0	17.0%	0.0	0.0%
Dave Johnston 1	Gas	38.1	3.8%	18.9	8.4%	0.0	2.2%	18.9	8.4%
Dave Johnston 1	Gas	36.4	3.6%	16.8	7.4%	0.0	1.8%	16.8	7.4%
Dave Johnston 1	Gas	37.6	3.7%	16.5	7.3%	0.0	2.1%	16.5	7.3%
Dave Johnston 1	Gas	30.1	3.0%	4.0	1.8%	0.0	0.0%	4.0	1.8%
Dave Johnston 1	Gas	47.3	4.7%	0.0	0.0%	0.0	12.0%	0.0	0.0%
Dave Johnston 1	Gas	62.1	6.2%	0.0	0.0%	0.0	17.1%	0.0	0.0%
Dave Johnston 1	Interruptible Load	84.3	8.4%	38.9	17.2%	0.0	0.0%	38.9	17.2%
Dave Johnston 1	Interruptible Load	94.4	9.4%	50.7	22.4%	0.0	0.0%	50.7	22.4%
Dave Johnston 1	Interruptible Load	52.5	5.2%	27.8	12.3%	0.0	0.0%	27.8	12.3%
Coolkeeper (3)	Self-supply								
SCL Stateline (3)	Self-supply								
	Totals	**1006.5**	**100%**	**226.2**	**100%**	**0.1**	**100%**	**226.3**	**100%**

(1) Naughton 3 ceased coal-fired operation in January 2019.
(2) Douglas Hydro contract expired August 2018.
(3) Self-supply - resource does not have a cost basis.

Table F
2018 Study Adjusted Results
Schedule 3 and 3A, Regulation Reserve

		Total 10-Minute & 30-Minute Reserve		Excess Spin and Supplemental Available for Regulation Reserve		30-Minute Reserves Available for Regulation Reserve		Total Capability Available for Regulation Reserve	
Plant	**Type**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**	**(aMW)**	**% of Total**
Dave Johnston 1	Steam	5.0	0.4%	0.0	0.0%	5.0	2.0%	5.0	0.7%
Dave Johnston 1	Steam	5.5	0.5%	0.0	0.0%	5.5	2.1%	5.5	0.7%
Dave Johnston 1	Steam	16.2	1.3%	0.0	0.0%	16.2	6.3%	16.2	2.1%
Dave Johnston 1	Steam	15.6	1.3%	0.0	0.0%	15.6	6.0%	15.6	2.0%
Dave Johnston 1	Steam	1.3	0.1%	0.5	0.1%	0.0	0.0%	0.5	0.1%
Dave Johnston 1	Steam	2.1	0.2%	0.7	0.1%	0.2	0.1%	0.9	0.1%
Dave Johnston 1	Steam	4.6	0.4%	0.4	0.1%	2.0	0.8%	2.4	0.3%
Dave Johnston 1	Steam	37.5	3.1%	11.1	2.2%	15.9	6.2%	27.1	3.5%
Dave Johnston 1	Steam	25.9	2.1%	9.6	1.9%	6.4	2.5%	16.0	2.1%
Dave Johnston 1	Steam	59.3	4.9%	12.9	2.5%	33.2	12.9%	46.1	6.0%
Dave Johnston 1	Steam	59.8	4.9%	9.5	1.9%	33.5	13.0%	43.0	5.6%
Dave Johnston 1	Steam	53.3	4.4%	10.8	2.1%	30.3	11.8%	41.1	5.4%
Dave Johnston 1	Steam	39.2	3.2%	17.5	3.5%	19.9	7.7%	37.3	4.9%
Dave Johnston 1	Steam	6.2	0.5%	3.4	0.7%	0.4	0.2%	3.8	0.5%
Dave Johnston 1	Steam	7.4	0.6%	3.8	0.7%	1.2	0.5%	5.0	0.7%
Naughton 3 (1)	Steam								
Dave Johnston 1	Steam	16.2	1.3%	0.0	0.0%	16.2	6.3%	16.2	2.1%
Dave Johnston 1	Hydro	14.8	1.2%	7.2	1.4%	0.0	0.0%	7.2	0.9%
Dave Johnston 1	Hydro	13.6	1.1%	6.5	1.3%	0.0	0.0%	6.5	0.9%
Mid-C Hydro - Douglas (2)	Hydro								
Dave Johnston 1	Hydro	3.0	0.2%	2.9	0.6%	0.0	0.0%	2.9	0.4%
Dave Johnston 1	Hydro	10.2	0.8%	4.9	1.0%	0.0	0.0%	4.9	0.6%
Dave Johnston 1	Hydro	6.1	0.5%	2.9	0.6%	0.0	0.0%	2.9	0.4%
Dave Johnston 1	Hydro	0.9	0.1%	0.5	0.1%	0.0	0.0%	0.5	0.1%
Dave Johnston 1	Hydro	129.0	10.6%	46.6	9.2%	0.0	0.0%	46.6	6.1%
Dave Johnston 1	Hydro	90.9	7.4%	67.4	13.3%	0.0	0.0%	67.4	8.8%
Dave Johnston 1	Gas	52.1	4.3%	46.0	9.1%	0.0	0.0%	46.0	6.0%
Dave Johnston 1	Gas	59.2	4.8%	28.4	5.6%	9.9	3.8%	38.3	5.0%
Dave Johnston 1	Gas	48.0	3.9%	19.0	3.7%	9.9	3.8%	28.8	3.8%
Dave Johnston 1	Gas	43.9	3.6%	19.4	3.8%	7.5	2.9%	27.0	3.5%
Dave Johnston 1	Gas	44.8	3.7%	20.9	4.1%	7.2	2.8%	28.0	3.7%
Dave Johnston 1	Gas	30.1	2.5%	20.9	4.1%	0.0	0.0%	20.9	2.7%
Dave Johnston 1	Gas	54.9	4.5%	28.0	5.5%	7.6	3.0%	35.6	4.7%
Dave Johnston 1	Gas	76.1	6.2%	34.8	6.9%	14.0	5.4%	48.8	6.4%
Dave Johnston 1	Interruptible Load	84.3	6.9%	45.4	9.0%	0.0	0.0%	45.4	5.9%
Dave Johnston 1	Interruptible Load	50.7	4.2%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 1	Interruptible Load	52.5	4.3%	24.6	4.9%	0.0	0.0%	24.6	3.2%
Coolkeeper (3)	Self-supply								
SCL Stateline (3)	Self-supply								
	Totals	**1220.4**	**100%**	**506.2**	**100%**	**257.6**	**100%**	**763.9**	**100%**

(1) Naughton 3 ceased coal-fired operation in January 2019.
(2) Douglas Hydro contract expired August 2018.
(3) Self-supply - resource does not have a cost basis.

Table G

			Schedule 3/3A Regulation					Schedule 3/3A Regulation	
			(aMW)	% of Total				(aMW)	% of Total
	Cholla 4[1]	Steam	0.00	0.0%	1	Cholla 4[1]	Steam	0.00	0.0%
1	Currant Creek	Gas	27.07	5.0%	2	Currant Creek	Gas	38.3	5.0%
2	Dave Johnston	Steam	29.89	5.5%	3	Dave Johnston	Steam	42.3	5.5%
3	Gadsby Steam	Steam	2.63	0.5%	4	Gadsby Steam	Steam	3.7	0.5%
4	Gadsby Peakers	Gas	59.23	11.0%	5	Gadsby Peakers	Gas	83.9	11.0%
5	Hunter Unit No. 1	Steam	19.11	3.5%	6	Hunter Unit No. 1	Steam	27.1	3.5%
6	Hunter Unit No. 2	Steam	11.29	2.1%	7	Hunter Unit No. 2	Steam	16.0	2.1%
7	Hunter Unit No. 3	Steam	32.57	6.0%	8	Hunter Unit No. 3	Steam	46.1	6.0%
8	Huntington	Steam	59.39	11.0%	9	Huntington	Steam	84.1	11.0%
9	Lake Side 1	Gas	25.14	4.7%	10	Lake Side 1	Gas	35.6	4.7%
10	Lake Side 2	Gas	34.48	6.4%	11	Lake Side 2	Gas	48.8	6.4%
11	Naughton[2]	Steam	6.24	1.2%	12	Naughton[2]	Steam	8.8	1.2%
12	Wyodak	Steam	11.44	2.1%	13	Wyodak	Steam	16.2	2.1%
13	Oneida	Hydro	5.85	1.1%	14	Oneida	Hydro	8.3	1.1%
14	Cutler	Hydro	9.65	1.8%	15	Cutler	Hydro	13.7	1.8%
15	Monsanto	Contract	0.00	0.0%	16	Monsanto	Contract	0.0	0.0%
	Coolkeeper [4]	Contract	0.00	0.0%	17	Coolkeeper [4]	Contract	0.0	0.0%
16	Nucor	Contract	17.39	3.2%	18	Nucor	Contract	24.6	3.2%
17	Magcorp	Contract	32.04	5.9%	19	Magcorp	Contract	45.4	5.9%
18	Chehalis	Gas	32.47	6.0%	20	Chehalis	Gas	46.0	6.0%
19	Hermiston	Gas	14.76	2.7%	21	Hermiston	Gas	20.9	2.7%
20	Mid-Columbia Hydro-Grant	Contract	2.02	0.4%	22	Mid-Columbia Hydro-Gr	Contract	2.9	0.4%
	Mid-Columbia Hydro-Douglas [3]	Contract	0.00	0.0%		Mid-Columbia Hydro-Do	Contract	0.0	0.0%
21	Swift No. 1	Hydro	32.88	6.1%	23	Swift No. 1	Hydro	46.6	6.1%
22	Yale	Hydro	47.61	8.8%	24	Yale	Hydro	67.4	8.8%
23	Jim Bridger	Steam	26.51	4.9%	25	Jim Bridger	Steam	37.5	4.9%
	SCL Stateline [4]	Contract	0.00	0.0%	26	SCL Stateline [4]	Contract	0.0	0.0%
			540	**100%**				**764.0**	**100%**

Attachment E

Direct Testimony of Dr. Paul A. Dumais, Vice President of Dumais Consulting LLC

Exhibit Nos. PAC-0011 – PAC-0018

Exhibit No. PAC-0011

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp Docket No. ER21-___-000

DIRECT TESTIMONY OF DR. PAUL A. DUMAIS

On Behalf of PacifiCorp

February 1, 2021

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Exhibit No. PAC-0012 – Resume of Dr. Paul A. Dumais

Exhibit No. PAC-0013 – Statements BG and BH

Exhibit No. PAC-0014 - Waiver Request of Filing Requirements Under Code of Federal Regulations 35.13

Exhibit No. PAC-0015 – Ancillary Services 3/3A, 5 and 6 - Weighted Cost Per kW and Rate Design

Exhibit No. PAC-0016 – Ancillary Services 3/3A, 5 and 6 - Production Fixed Charge Rate

Exhibit No. PAC–0017 – Reactive Power Revenue Requirement and Rates

Exhibit No. PAC-0018 – Generator Information

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION AND BUSINESS ADDRESS.

A. My name is Dr. Paul A. Dumais. I am the CEO of Dumais Consulting LLC, with an address of 744 Crisfield Way, Annapolis, Maryland, 21401.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of PacifiCorp.

Q. DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A. I have over 40 years of experience in the electric and natural gas industry, primarily in the areas of regulatory strategy and policy, revenue requirements and ratemaking. Dumais Consulting LLC provides Federal Energy Regulatory Commission ("FERC" or "Commission")-related ratemaking services to the energy industry. Prior to forming Dumais Consulting in September 2018, I worked for Avangrid Networks and its predecessor companies in the northeast United States in senior level positions, with a focus on state and federal regulatory and ratemaking matters. Prior to my departure from Avangrid Networks, I was responsible for FERC regulatory policy, transmission formula rates, interconnections, and regional transmission organization stakeholder participation in New England and in New York, including Order No. 1000 implementation, transmission planning activities, interconnections, cost allocation, and competitive processes. I received a Bachelor of Science Degree

in Business Administration with an emphasis in Accounting from the University of Maine in Augusta in 1982. I received a Master of Science Degree in Business Administration from the University of Southern Maine in 1986. Lastly, I was awarded a Doctorate Degree in Strategic Leadership from Regent University in 2013. My resume is included as Exhibit No. PAC-0012.

Q. HAVE YOU SUBMITTED EXPERT TESTIMONY IN THE PAST TO FERC OR TO ANY OTHER REGULATORY BODIES?

A. Yes, I have. My testimony experience is included in my resume contained in Exhibit No. PAC-0012.

II. PURPOSE AND SCOPE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. PacifiCorp has reached a settlement agreement ("2020 Settlement Agreement') with its customers regarding the rates for certain ancillary services and now proposes to implement the settlement rates through this filing. The 2020 Settlement Agreement rates are "black box," negotiated rates. The purpose of my testimony is to present the cost of service and rate design analysis that were used to develop the revised ancillary service rates for Schedules 2, 3/3A, 5 and 6 in PacifiCorp's "base case," which was PacifiCorp's starting point for negotiations with customers and which would have been the case filed by PacifiCorp if settlement had not been reached. Since the 2020 Settlement Agreement rates are at or below the base case rates, this testimony is submitted

to support the justness and reasonableness of the 2020 Settlement Agreement rates.

My testimony focuses on the revenue requirement and rate development of the base case ancillary services (Schedules 3/3A, 5 and 6), while PacifiCorp witness Daniel J. MacNeil supports the development of the level of generating resources needed to satisfy reliability requirements for each of these ancillary service schedules and the generating units most likely to provide these ancillary services to PacifiCorp's customers . Together, my testimony and Mr. MacNeil's testimony demonstrate that the 2020 Settlement Agreement Schedule 3/3A, 5 and 6 rates are just and reasonable and not unduly discriminatory and should be approved by the Commission. In developing the base case rates, I adhered to approaches that are consistent both with those: (1) used by PacifiCorp in the previous proceeding (Docket No. ER17-219) that established the existing Schedule 3/3A, 5 and 6 rates, and (2) previously approved by the Commission for establishing rates for these ancillary services.

My testimony also provides the basis for PacifiCorp's base case rates for Reactive Supply and Voltage Control from Generation or Other Sources Service ("Reactive Service") in Schedule 2 of the PacifiCorp Open Access Transmission Tariff ("OATT").

Q. ARE YOU SPONSORING ANY EXHIBITS IN ADDITION TO THIS TESTIMONY?

A. Yes. I am sponsoring the following exhibits appended to this testimony:

- Exhibit No. PAC-0012 – Resume of Dr. Paul A. Dumais

- Exhibit No. PAC-0013 – Revenue Comparison – Statements BG and BH
- Exhibit No. PAC-0014 - Waiver Request of Filing Requirements Under Code of Federal Regulations 35.13
- Exhibit No. PAC-0015 - Ancillary Services 3/3A, 5 and 6 - Weighted Cost Per kW and Rate Design
- Exhibit No. PAC-0016 – Ancillary Services 3/3A, 5 and 6 - Production Fixed Charge Rate
- Exhibit No. PAC-0017 – Reactive Power Revenue Requirement and Rates
- Exhibit No. PAC-0018 – Reactive Power – Generator Information

III. REVENUE COMPARISON AND WAIVER OF STATEMENTS UNDER CODE OF FEDERAL REGULATIONS 35.13

Q. PLEASE DESCRIBE EXHIBIT NO. PAC-0013?

A. Exhibit No. PAC-0013 is the revenue comparison required under 18 CFR § 35.13, Statements BG and BH. It provides a comparison of wholesale revenues under the base case rates for Schedule 2, 3, 3A, 5 and 6 compared to the wholesale revenue under current rates. The first page is the Summary that shows the revenue comparison by ancillary service rate schedule and for Schedule 3 and 3A, by customer class. The base case and current rates for each Schedule are contained on Attachment 1. Attachments 2 and 3 contain the by customer MW volume and revenues for Schedule 2. Attachment 4 contains the by customer MW volumes and revenues for the Schedule 3 Load customer

class. Attachment 5 contains the by customer MW values and revenues for the Schedule 3 VERs-Wind, VERs-Solar and Non-VERs classes. Attachment 6 contains the by customer MWH values and revenues for Schedule 5, while Attachment 7 contains the by customer MWH values and revenues for Schedule 6.

Q. IS PACIFICORP REQUESTING A WAIVER FROM PROVIDING THE OTHER STATEMENTS REQUIRED BY CFR 35.13?

A. Yes. The reason for the request is the fixed cost rate methodology used for determining rates for Schedules 3/3A, 5 and 6 does not rely upon data from the 18 CFR § 35.13 cost of service statements, but rather it relies upon data predominately from FERC Form 1. Where data that is not available in FERC Form 1 is necessary, I have included applicable worksheets. Thus, to the extent the information is relevant to PacifiCorp's filing, the information is either already provided in the filing or is provided in the FERC Form 1. Additionally, the Commission regularly provides waivers from 35.13 for Schedule 2, Reactive Power, filings, which also relies heavily upon the data in FERC Form 1. Therefore, PacifiCorp believes a waiver is appropriate.

Q. PLEASE DESCRIBE WHERE DATA THAT IS CONTAINED IN THE 35.13 STATEMENTS AND UPON WHICH YOU RELY FOR THE SCHEDULES 3/3A, 5 AND 6 REVENUE REQUIREMENT AND RATE DESIGN CAN BE FOUND IN THE FERC FORM 1 OR IN YOUR EXHIBITS.

A. I have put together Exhibit No. PAC-0014 to show where the data contained in the various 18 CFR § 35.13 cost of service statements and on which I relied to determine the Schedules 3/3A, 5 and 6 rates can be found in FERC Form 1 or in my exhibits. Exhibit No. PAC-0014 demonstrates that all information relied upon in my revenue requirement analyses and rate design, and that is contained in the 18 CFR § 35.13 cost of service statements, is available in: (1) the FERC Form 1 or (2) worksheets that are part of Exhibit No. PAC-0015 or Exhibit No. PAC-0016.

IV. ANCILLARY SERVICE SCHEDULES 3/3A, 5 AND 6

Q. WHEN WERE PACIFICORP'S CURRENT SCHEDULES 3/3A, 5 AND 6 LAST UPDATED?

A. PacifiCorp's current Schedules 3/3A, 5 and 6 resulted from a settlement approved by the Commission on April 19, 2018 in Docket No. ER17-219.[1] The Docket No. ER17-219 Settlement established two sets of rates over two periods for these ancillary services. For Schedules 3 and 3A, the first set of rates was effective from July 13, 2017 through December 31, 2017, and the second set was effective beginning January 1, 2018. For Schedules 5 and 6, the first set of rates was effective February 13, 2017 through December 31, 2017, and the second set was effective beginning January 1, 2018. The reason for this two-tier rate approach with rates changing on January 1, 2018 was to incorporate

[1] *PacifiCorp,* Docket No. ER17-219-002 (Apr. 19, 2018), herein referred to as the "ER17-219 Settlement."

the impact on the revenue requirement from the Tax Reform and Jobs Act of 2017.

Q. WHAT OTHER PROVISIONS OF THE DOCKET NO. ER17-219 SETTLEMENT ARE RELEVANT TO THIS PROCEEDING?

A. The Docket No. ER17-219 Settlement contains a moratorium period which prohibits, among other things, changes to Schedule 3/3A, 5 and 6 rates until after June 30, 2020. The Docket No. ER17-219 Settlement also states that the settling parties will work together to develop a consensus regarding the methodology and associated data to calculate the applicable regulation (Schedule 3/3A) and operating reserve (Schedules 5 and 6) requirements to be used in future calculations, including those proposed by PacifiCorp in this proceeding. As part of the consensus effort, the Docket No. ER17-219 Settlement requires consideration of continuing to use the Production Fixed Charge Rate, which is modeled after PacifiCorp's transmission formula rate.

As discussed in further detail by PacifiCorp Witness Ms. Mary M. Wiencke, representatives of PacifiCorp met several times with stakeholders to review and discuss the resource requirements, explore self-supply options, and review the revenue requirement and rate development, including use of the Production Fixed Charge Rate. In addition, PacifiCorp provided responses to a series of information requests from customers regarding the development of the Production Fixed Charge Rate and related financial support and calculations.

Q. ARE YOU USING THE PRODUCTION FIXED CHARGE RATE IN YOUR CALCULATIONS OF THE SCHEDULE 3/3A, 5 AND 6 RATES?

A. Yes, I am.

Q. PLEASE SUMMARIZE THE APPROACH YOU TOOK TO DETERMINE THE BASE CASE RATES FOR SCHEDULE 3/3A, SCHEDULES 5 AND SCHEDULE 6.

A. I determined the revenue requirement of providing these ancillary services using the non-levelized, net plant methodology, as was done by PacifiCorp in Docket No. ER17-219. To determine the revenue requirement, I undertook the following steps:

1. I used 2019 data from FERC Form 1 to determine a Production Fixed Charge Rate, excluding generating facility specific operations and maintenance expenses ("O&M"), which are considered separately. The Production Fixed Charge Rate is like PacifiCorp's transmission formula rate, but with its focus on production costs.
2. I applied the Production Fixed Charge Rate to the net investment per kW for PacifiCorp generating resources most likely to provide Schedule 3/3A, Schedule 5 or Schedule 6 services to arrive at the annual fixed charge carrying cost per kW per resource providing the service.
3. I then added additional items for fixed O&M, applicable wheeling costs and a credit for reactive power revenue, using the base case Schedule 2 revenue requirements discussed later in my testimony, to arrive at an annual cost per kW for each resource most likely to provide the applicable ancillary service.

4. I then weighted these annual costs per kW by the expected participation of each resource in providing the ancillary service to arrive at a weighted annual fixed cost per kW for each ancillary service.
5. I then multiplied this weighted annual fixed cost per kW for each ancillary service by the regulation reserve requirement (Schedule 3/3A) and the operating reserve requirement (Schedules 5 and 6) to arrive at the revenue requirement of providing the applicable ancillary service.
6. Lastly, I divided the revenue requirement by the applicable billing determinants to arrive at the ancillary service rate.

Q. PLEASE PROVIDE THE BASE CASE RATES YOU DETERMINED FOR SCHEDULE 3/3A, 5 AND 6, AS WELL AS THE CURRENT RATES.

A. Table 1 below provides the base case, as well as current Schedule 3/3A, 5 and 6, rates.

Table 1
BASE CASE and Existing Rates for Schedules 3, 3A, 5, and 6

Ancillary Service	Base Case Rates	Current Rates
Schedule 3/3A		
Load	$1.579 per kW year	$2.124 per kW year
Non-VER	3.963	1.794
VER – Wind	8.106	6.593 (all VERS)
VER - Solar	6.622	N/A
Schedule 5	$0.182 per MWh	$0.151 per MWh
Schedule 6	$0.172 per MWh	$0.151 per MWh

Q. WHY IS PACIFICORP SEEKING A CHANGE TO ITS SCHEDULE 3/3A, 5 AND 6 RATES AT THIS TIME?

A. As previously mentioned, PacifiCorp was prohibited from seeking changes to its Schedule 3/3A, 5 and 6 rates to be effective prior to June 30, 2020. Notwithstanding, PacifiCorp's cost of service based upon 2019 data exceeds the revenue from current rates. Therefore, to recover the costs of providing Schedule 3/3A, 5 and 6 services, PacifiCorp needed to update its rates reflective of its 2019 cost of service.

A. Rate calculations for Schedules 3, 3A, 5, and 6

Q. PLEASE PROVIDE A SUMMARY OF THE RATE CALCULATION FOR SCHEDULES 3/3A.

A. Table 2 below contains the rate calculations from Exhibit No. PAC-0015, page 1 for PacifiCorp's base case rates for Schedules 3/3A.

Table 2

Rate Calculations for Schedule 3/3A

	Weighted Cost $/kW	Regulation Reserve Requirement (kW)	Revenue Requirement $	Billing Determinant (MW)	Description of Billing Determinant	Rates ($/MW-year)	Rates ($/kW-year)
	a	b	c = a*b	d	e	f = c/d	g = f/1000
Regulation and Frequency Response							
Schedule 3 (Load)	$ 93.92	171,521	$ 16,108,425	10,203	12 CP (CY 2019)	$ 1,578.81	$ 1.579
Schedule 3/3A (Non-VER)	$ 93.92	55,031	$ 5,168,213	1,304	Nameplate capacity	$ 3,962.59	$ 3.963
Schedule 3/3A -Wind (VER)	$ 93.92	236,932	$ 22,251,469	2,745	Nameplate capacity	$ 8,105.70	$ 8.106
Schedule 3/3A -Solar (VER)	$ 93.92	76,176	$ 7,154,065	1,080	Nameplate capacity	$ 6,622.16	$ 6.622
Total Schedule 3/3A Requirement		539,660					

I used the non-levelized, net plant revenue requirement methodology to determine the weighted cost per kW for Schedule 3/3A rates. To determine the revenue requirement of the four customer classes of Regulation and Frequency Response Service, I multiplied the weighted cost per kW by the Regulation and Frequency Response reserve requirement provided by Mr. MacNeil.

Then I determined the rate by dividing the revenue requirement for each customer class by either the average of the 12 monthly coincident peak demands during 2019 (Load class) or by the nameplate capacity of the generation (VER – wind and solar - and Non-VER classes). The rates are stated in Schedule 3/3A on a dollar per MW year and dollar per kW year basis. Use of these four customer classes (Load, Non-VER, VER – wind and VER – solar) permits PacifiCorp to allocate costs associated with providing Regulation and Frequency Response service to customers based upon obligations that the class of customer places on the PacifiCorp system. The rates for Schedule 3A service are the same as the rates for Schedule 3 service.

Q. WHAT IS THE RATE IMPACT UPON A TRANSMISSION CUSTOMER UNDER THE BASE CASE SCHEDULE 3 AND 3A RATES AS COMPARED TO THE EXISTING SCHEDULE 3 RATE?

A. As can be seen in Table 3 below, the change in the Schedule 3 rates will result in a rate increase for some classes and a rate decrease for others.

Table 3
Schedule 3 and 3A Base Case and Current Rates

Customer Class	Base Case Rates	Current Rates
Load	$1.579 per kW	$2.124 per kW
Non-VER	3.963 per kW	1.794 per kW
VER – Wind	8.106 per kW	6.593 per kW
VER - Solar	6.622 per kW	6.593 per kW

Using 2019 billing determinants for transmission customers, Schedule 3 revenues with the base case rates would be approximately $7.3 million, or an overall increase of approximately $0.2 million. See Exhibit PAC-0013, Summary.

Q PLEASE PROVIDE A SUMMARY OF THE RATE CALCULATION FOR SCHEDULES 5 AND 6.

A. Table 4 below contains the rate calculations from Exhibit No. PAC-0015, page 1 for the base case rates for Schedules 5 and 6.

Table 4

Rate Calculations for Schedule 5 and 6

	Weighted Cost $/kW	Avg Reserves Held (kW - 2018/2019)	Revenue Requirement $	Billing Determinant (MW)	Description of Billing Determinant	Rates ($/MWh)
	a	b	c = a*b	d	e	f = c/d
Contingency Reserves						
Schedule 5 (Spinning Reserves)	$ 106.18	230,269	$ 24,450,902	134,477,343	Hourly integrated load and generation (MW)	$ 0.182
		Spinning %	1.50%			
Schedule 6 (Supplemental Reserves)	$ 100.49	226,301	$ 22,741,734	132,159,864	Hourly integrated load and generation (MW)	$ 0.172
		Supplemental %	1.50%			
		Total reserve % for Schedules 5 & 6	3.00%			

As with Schedule 3/3A, I used the non-levelized, net plant revenue requirement methodology to determine the weighted cost per kW for these ancillary services. To determine the revenue requirement of Schedule 5 and Schedule 6, I multiplied the weighted cost per kW by the Spinning Reserves held or the Supplemental Reserves held, which were provided by Mr. MacNeil.

Then I determined the rates by dividing the revenue requirement by 1.5% of the average reserves held for every hour of the year. NERC Regional Reliability Standard BAL-002-WECC-2 requires operating reserves equal to 3% of load and 3% of generation.[2] PacifiCorp satisfies this requirement by

[2] Under the current NERC Regional Reliability Standard BAL-002-WECC-2, PacifiCorp is required to maintain a minimum amount of contingency reserve (spinning and supplemental) equal to the sum of three percent of hourly integrated load plus three percent of hourly integrated generation, with at least half comprised of spinning reserves. Therefore, consistent with PacifiCorp operating in accordance with NERC Regional Reliability Standard BAL-002-WECC-2: (1) the charges for Schedule 5 apply one and one-half percent to load and one and one-half percent to generation, with the remainder of the requirement being met with Schedule 6, Supplemental Reserve Service; and (2) the charges for Schedule 6 below apply one and one-half percent to load and one and one-half percent to generation.

providing operating reserves equal to 1.5% of load and 1.5% of generation from each Schedule 5 and Schedule 6. The rates in Schedule 5 and Schedule 6 are on a dollar per MWh basis.

Q. WHAT IS THE RATE IMPACT UPON A TRANSMISSION CUSTOMER UNDER THE BASE CASE SCHEDULES 5 AND 6 RATES AS COMPARED TO THE EXISTING SCHEDULES 5 AND 6 RATES?

A. Table 5 below shows the change in the Schedule 5 and 6 rates under the base case.

Table 5
Schedule 5 and 6 Base Case and Current Rates

Customer Class	Base Case Rates	Current Rates
Schedule 5	$0.182 per MWh	$0.151 per MWh
Schedule 6	0.172 per MWh	0.151 per MWh

Using 2019 billing determinants for transmission customers, Schedule 5 revenues with the base case rates would be approximately $1.9 million, or an overall increase of approximately $0.4 million. Using 2019 billing determinants for transmission customers, Schedule 6 revenues with the base case rates would be approximately $1.9 million, or an overall increase of approximately $0.3 million. See Exhibit PAC-0013, Summary.

B. <u>Weighted cost per kW and rate design</u>

Q. BEGINNING WITH EXHIBIT NO. PAC-0015, PAGE 2, PLEASE DESCRIBE HOW YOU DETERMINED THE WEIGHTED COST PER KW FOR EACH ANCILLARY SERVICE IN THIS PROCEEDING.

A. As shown on Exhibit No. PAC-0015 page 2, I began by developing a net plant investment per kW for each of the units most likely to provide these ancillary services. I determined the net plant investment (gross investment less accumulated depreciation and excluding asset retirement obligations, consistent with FERC practice) by resource, and then divided the net plant investments by the applicable nameplate kW to determine the net plant investment per kW.

Q. MOVING ON TO PAGE 3 OF EXHIBIT NO. PAC-0015, PLEASE DESCRIBE HOW YOU DETERMINED THE O&M EXPENSE PER KW THAT IS PART OF THE RESOURCE'S COST PER KW?

A. As shown on Exhibit No. PAC-0015, page 3, I next determined the fixed O&M expenses for each of the resources most likely to provide these ancillary services. These fixed O&M expenses include only those production O&M expenses that are considered fixed or non-variable under FERC's predominance method. I then divided each resource's fixed O&M expenses by the applicable nameplate kW to arrive at an O&M expense per kW, as shown in Column (m) of Page 3, for each unit most likely to provide these ancillary services.

Q. NEXT, DESCRIBE PAGES 4, 5 AND 6 OF EXHIBIT NO. PAC-0015.

A. The derivation of the weighted cost per kW for Schedule 3/3A services is shown on Exhibit No. PAC-0015, page 4, while the derivation of the weighted cost per

kW for Schedule 5 service is shown on Exhibit No. PAC-0015, page 5 and the derivation of the weighted cost per kW for Schedule 6 service is shown on Exhibit No. PAC-0015, page 6.

Q. DESCRIBE HOW YOU DETERMINED THE WEIGHTED COST PER KW FOR SCHEDULES 3 AND 3A.

A. Page 4 of Exhibit No. PAC-0015, Column (a) contains the PacifiCorp resources most likely to provide Schedule 3/3A, while Column (b) is each unit's nameplate MW. Column (c) is the capacity from each resource available to provide Regulation and Frequency Response Service, as per the reserve study presented by Mr. MacNeil. Column (d) is an accumulation of Column (c). Column (e) is the percent of Regulation and Frequency Response Service provided by each resource (sum of all resources is 100%). Column (f) is the net investment per kW for each resource from Page 2. Column (g) is the product of the net investment per kW times the Production Fixed Charge Rate, which I describe later in this testimony. Column (h) is the O&M per kW developed on Page 3. Since four resources require transmission wheeling to reach the PacifiCorp Balancing Authority Area ("BAA"), I added wheeling costs for these resources in Column (i). Column (j) reflects a credit for reactive power revenue under Schedule 2, which I developed on Exhibit No. PAC-0015, Page 7. Adding Columns g, h, i and j and multiplying the sum by the percent in Column (e) results in the weighted annual cost per kW for each resource. The sum of the weighted average cost per kW for each resource equals the total

weighted average cost per kW which I use to determine the Schedule 3/3A revenue requirement on Page 1.

Q. THERE ARE SOME RESOURCES LISTED AS CONTRACTS ON EXHIBIT NO. PAC-0015 PAGE 4. PLEASE EXPLAIN WHY THESE RESOURCES ARE INCLUDED IN THE WEIGHTED COST PER KW FOR SCHEDULE 3/3A SERVICES.

A. Three interruptible service contracts and one hydro purchase contract contribute to the provision of Regulation and Frequency Response Service. This is explained in the testimony of Mr. MacNeil. I include their costs on Page 4 under the O&M cost column (h) at their contract cost per kW, and their weighted cost per kW is included in the weighted cost per kW for providing Schedule 3/3A service.

Q. PLEASE DESCRIBE HOW YOU DETERMINED THE WEIGHTED COST PER KW FOR SCHEDULE 5 AND SCHEDULE 6.

A. I developed the weighted cost per kW for Schedule 5 on Exhibit No. PAC-0015, Page 5 using the same approach as used for Schedule 3/3A. Column (c) contains the available capacity from each resource providing Operating Reserves – Spinning Reserve, as per the reserve study presented by Mr. MacNeil. The remainder of the page follows the same approach as I used to develop the weighted cost per kW for Schedule 3/3A.

I developed the weighted cost per kW for Schedule 6 on Exhibit No. PAC-0015, Page 6 using the same approach as used to for Schedule 3/3A and 5. Column (c) contains the available capacity from each resource providing

Operating Reserves – Supplemental Reserve, as per the reserve study presented by Mr. MacNeil. The remainder of the page follows the same approach as I used to develop the weighted cost per kW for Schedule 3/3A and 5.

Q. THERE ARE SOME RESOURCES LISTED AS CONTRACTS ON EXHIBIT NO. PAC-0015, PAGE 6. PLEASE EXPLAIN WHY THESE RESOURCES ARE INCLUDED IN THE WEIGHTED COST PER KW FOR SCHEDULE 6 SERVICES.

A. Three interruptible service contracts and one hydro purchase contract contribute to the provision of Operating Reserves – Supplemental Reserve service. This is explained in the testimony of Mr. MacNeil. I included their costs on Page 6 under the O&M cost column (h) at their contract cost per kW, and their weighted cost per kW is included in the weighted cost per kW for providing Schedule 6 service.

Q. PLEASE DESCRIBE ANY METHODOLOGICAL DIFFERENCES IN DETERMINING THE WEIGHTED COST PER KW BETWEEN EXHIBIT NO. PAC-0015 AND THE COMPARABLE PACIFICORP EXHIBIT FROM DOCKET NO. ER17-219.

A. There is one change in the fixed O&M calculations. I am following the predominance method used by FERC in classifying O&M expenses into fixed and variable categories, and I am using only the fixed O&M amounts on Exhibit No. PAC-0015, Page 3.[3] The prior PacifiCorp calculations (in Docket No.

[3] For examples of FERC discussing the predominance method, see *Arizona Public Service Co*., 4 FERC ¶ 61,101 (1978); *Minnesota Power & Light Company*, 11 FERC ¶ 61,312 (1980); and *Old Dominion Electric Cooperative, Inc*., 158 FERC ¶ 61,223 (2017).

ER17-219) did not recognize differences in what FERC considers fixed O&M in the predominance method between steam production, hydro production, and other production resources. My analysis recognizes those differences, and I included fixed O&M from each of the different types of generating resources on Exhibit No. PAC-0015, Page 3.

Q. PLEASE REVIEW THE REMAINING PAGES OF EXHIBIT NO. PAC-0015.

A. Page 7 is where I determine the Schedule 2 credits. Pages 8 and 9 contain data from the reserve study that is used to develop the MW contribution from the units most likely to provide each ancillary service. Page 10 contains the wheeling costs added to four resources that provide ancillary services (see pages 4, 5 and 6). Page 11 contains the 2019 actual peak loads, excluding firm point-to-point contracts, used to design Schedule 3/3A rates for load. Page 12 contains the nameplate capacity amounts for wind, solar and non-variable resources. Exhibit No. PAC-0015, Workpapers contains the detail of the billing units contained on page 12 and used in the rate design of Schedule 3A on page 1.

C. Determination of the Production Fixed Charge Rate

Q. YOU PREVIOUSLY STATED THAT YOU INCLUDED THE PRODUCTION FIXED CHARGE RATE IN EACH OF THE ANCILLARY SERVICE REVENUE REQUIREMENT CALCULATIONS. PLEASE DESCRIBE THE PRODUCTION FIXED CHARGE RATE.

A. I present the Production Fixed Charge Rate in Exhibit No. PAC-0016, which consists of 45 pages of schedules that are the same as many of the schedules contained in PacifiCorp's transmission formula rate, which was implemented via a settlement agreement accepted by the Commission in Docket No. ER11-3643.[4] The Production Fixed Charge Rate is the percent that production fixed charges, excluding unit specific fixed O&M, are to the overall production net investment and is applied to the net investment of each generating unit most likely to provide the ancillary service. Consistent with the non-levelized, net plant revenue requirement methodology, the Production Fixed Charge Rate includes return on investment, income taxes, depreciation, real estate taxes, administrative and general expenses, and production O&M not applicable to a specific resource.

Q. DESCRIBE HOW YOU DETERMINED THE PRODUCTION FIXED CHARGE RATE.

A. To determine the Production Fixed Charge Rate, I used a production formula rate modeled after PacifiCorp's transmission formula rate. This is consistent with how PacifiCorp determined the Production Fixed Charge rate that was filed in Docket No. ER17-219. The Production Fixed Charge Rate, populated with 2019 information from FERC Form 1, is contained in Exhibit No. PAC-0016.

Q. PLEASE REVIEW EXHIBIT NO. PAC-0016.

[4] *PacifiCorp*, 143 FERC ¶ 61,162 at P 5 (2013).

A. Exhibit No. PAC-0016 includes attachments that are the same as that included in the PacifiCorp transmission formula rate. The pages in the exhibit are numbered sequentially and contain a reference to the attachment in the PacifiCorp transmission formula rate. For example, Exhibit No. PAC-0015, Attachment A, pages 1 through 6 are like Attachment A in the PacifiCorp transmission formula rate.

Q. PLEASE PROCEED.

A. Attachment A (pages 1-6) of Exhibit No. PAC-0016 contains the key worksheet where the Production Fixed Charge Rate is determined. It contains the following sections or categories:

(1) Allocators

(2) Plant Calculations

(3) Adjustments to Rate Base

(4) Operations and Maintenance Expense

(5) Depreciation & Amortization Expense

(6) Taxes Other Than Income

(7) Return\Capitalization Calculations

(8) Composite Income Taxes

(9) Revenue Requirement

Q. WHAT IS THE FIRST CATEGORY OF ITEMS, ALLOCATORS, ON PAGE 1 OF ATTACHMENT A OF EXHIBIT NO. PAC-0016?

A. The first category contains the allocators used to determine the production portion of certain revenue requirement items, including:

a. Wage and Salary Allocator – production wages as a percent of total operation and maintenance wages less administrative and general ("A&G") wages. This is used to allocate general and intangible plant to production rate base and most A&G expenses to production operating expenses; and

b. Gross and Net Plant Allocators – gross or net production plant investment as a percent of total gross or total net plant investment. These are used to allocate some ADIT items to production rate base and property insurance expense to production operating expenses.

Q. PLEASE DESCRIBE THE PLANT CALCULATIONS CATEGORY OF ITEMS ON EXHIBIT NO. PAC-0016, ATTACHMENT A, PAGE 1.

A. Production plant in service and production accumulated depreciation are from the specific FERC Accounts shown on Exhibit No. PAC-0016, Attachment 5, pages 1 and 2, and are directly assigned to production rate base. The worksheet determines the production portion of general and intangible plant and the related accumulated depreciation or amortization using the Wage and Salary Allocator. The plant in service and accumulated depreciation amounts are 13-month average values. This category of Exhibit No. PAC-0016, Attachment A determines the Net Production Plant in Service included in rate base, as shown on page 1.

Q. DID YOU MAKE ANY ADJUSTMENTS TO ANY OF THE FERC FORM 1 AMOUNTS IN THE NET PRODUCTION PLANT IN SERVICE CATEGORY?

A. Yes, I did. During 2018 and 2019, PacifiCorp, under an agreement with Utah and Oregon regulators, performed a buy-down of the net book value of certain generating assets using state-specific, non-protected Excess Accumulated Deferred Income Taxes ("EADIT") and other state-specific regulatory liabilities. To accomplish this buy-down, PacifiCorp increased production depreciation expense and increased production accumulated depreciation, while amortizing state-specific non-protected EADIT and other state-specific regulatory liabilities (and adjusting for income tax impacts) to offset the increase in depreciation expense so that the transaction had no impact on PacifiCorp's net income. Table 6 below shows the buy-down transactions.

Table 6
Plant Buy-Down Transactions

Jurisdiction	SAP Account	2018 Buy Down Debit/(Credit)	2019 Buy Down Debit/(Credit)	Total Debit/(Credit)
Utah	145244	(173,684,144)	(4,890,414)	(178,574,558)
Oregon	144243	-	(120,031,551)	(120,031,551)
Total Accumulated Depreciation		(173,684,144)	(124,921,965)	(298,606,109)
Jurisdiction	**SAP Account**	**2018 Buy Down Debit/(Credit)**	**2019 Buy Down Debit/(Credit)**	**Total Debit/(Credit)**
Utah	565244	173,684,144	4,890,414	178,574,558
Oregon	565243	-	120,031,551	120,031,551
Total Depreciation Expense		173,684,144	124,921,965	298,606,109

Since these transactions affect state retail customer revenue requirements, I reversed their impacts for ancillary service ratemaking. As can be seen on Exhibit No. PAC-0016, Attachment 5, page 2, Lines 85 through 98, I have reduced production accumulated depreciation to remove the buy-down transactions. I made related adjustments to depreciation expense and excess EADIT, which I discuss below in the respective sections of this testimony.

Q. PLEASE EXPLAIN PLANT HELD FOR FUTURE USE WHICH IS INCLUDED IN THE NET PRODUCTION PLANT IN SERVICE CATEGORY.

A. Plant Held for Future Use is included using a beginning and end of year average in Account 105. Included here is the original cost of production plant (excluding land and land rights) owned and held by PacifiCorp for future use under a definite plan for such use and production land and land rights held by PacifiCorp for future use under a plan for such use.

Q. PLEASE EXPLAIN THE NEXT CATEGORY, ADJUSTMENTS TO RATE BASE.

A. There are many adjustments to rate base shown on page 2 of Attachment A to Exhibit No. PAC-0016, both additions to and subtractions from, that are included in the Production Fixed Charge Rate. The first two items are ADIT-related. The first item is ADIT in FERC Accounts 190, 281, 282 and 283. Amounts in these accounts result from timing differences between when an item is recognized for income tax purposes versus when it is recognized for accounting and ratemaking purposes. The amount on Exhibit No. PAC-0016, Attachment A, Line 33 comes from Exhibit No. PAC-0016, Attachment 1A, page 22, where I determined the production portion of the items contained in these accounts, using a beginning and end of year average. The amount on the Exhibit No. PAC-0016, Attachment A, page 2, Line 33b is the average unamortized EADIT from Exhibit No. PAC-0016, Attachment 1B, page 33. As with accumulated depreciation, I have removed the impacts from the production asset buy-downs discussed above.

Q. PLEASE DESCRIBE THE ADIT ITEMS THAT ARE ASSIGNED OR ALLOCATED DIFFERENTLY BETWEEN THE TRANSMISSION FORMULA RATE AND THIS EXHIBIT NO. PAC-0016 PRODUCTION FIXED CHARGE RATE.

A. I provide in Table 7 below the items that received different treatment in the two formula rates.

Table 7
ADIT Differences

Item	Account	Transmission Formula Rate	Production Fixed Charge Rate	Amount $'s in Millions (12/31/19)
1. FAS 158 SERP Liability	190 – 287462	Other - Excluded	Labor Related	13.7
2. DTA NOL Carryforward - State	190 - 287437	Other - Excluded	Plant Related	65.1
3. DTA Federal Impact of State NOL	190 - 287449	Other - Excluded	Plant Related	(13.7)
4. Injuries and Damages	190 - 287341	Other - Excluded	Labor Related	2.9
5. Valuation Allowance for DTA	190 - 287270	Other - Excluded	Plant Related	(0.5) M
6. Intangible – Basis Difference	282 - 287704	Plant Related	Production	(1.1)
7. Remove Cholla	282 - 287605	Not Applicable	Production	40.8
8. Remove UT Buy-down of Production Facilities	282 - 287605	Not Applicable	Production	(43.9)
9. Remove OR Buy-down of Production Facilities	282 - 287605	Not Applicable	Production	(30.7)
10. Cholla SHL (amortization of gain)	282 - 287608	Plant Related	Other - Excluded	(1.2)
11. Cholla SHL NOPR (lease amortization)	282 - 287608	Plant Related	Other - Excluded	0.6
12. Hydro Relicensing	282 - 287928	Other - Excluded	Labor Related	(3.7)

13. Excess ADIT	282 - 287605	In 282 at 12/31/18	In separate tab	

- Items 1 - 5 are excluded from the transmission formula rate as per the settlement agreement accepted in Docket No. ER11-3643, but they are included via a Wage and Salary Allocator or Gross Plant Allocator in the Production Fixed Charge Rate. These items apply to all of PacifiCorp's business areas and therefore it is proper to include an allocation in the Production Fixed Charge Rate.
- Item 6 is allocated using gross plant in the transmission formula rate as it is an intangible plant item and is assigned to production in the Production Fixed Charge Rate as it relates to hydro relicensing costs.
- Items 7, 10 and 11 are removed from the Production Fixed Charge Rate as the Cholla 4 unit is being retired in December 2020.
- Items 8 and 9 remove the net book value production asset buy-down previously discussed.
- Item 12 is allocated in the Production Fixed Charge Rate with the Wage and Salary Allocator as hydro relicensing costs are an intangible asset, while this item was excluded from the transmission formula rates using the Wage Allocator.
- For Item 13, in the transmission formula rate, PacifiCorp included EADIT in Account 282 at December 31, 2018, while in the Production Fixed Charge Rate, the EADIT amount at December 31, 2018 is in a separate attachment.

Q. IN ADDITION TO THE ADIT ADJUSTMENTS, WHAT OTHER ADJUSTMENTS TO RATE BASE DO YOU INCLUDE IN THE PRODUCTION FIXED CHARGE RATE?

A. The following items are adjustments to rate base:

a. The CWIP for Incentive Projects applies to the transmission formula rate. Therefore, the value of this item is zero;

b. Production-related Investment Tax Credit under Internal Revenue Code 46(f);

c. Unfunded reserves, which generally represent reserves included in rates for a future contingency. These are detailed on Exhibit No. PAC-0016, Attachment 16, page 44;

d. Prepayments, which represent expenses for a service, or a supply paid in advance that will be consumed or used in future accounting periods. Prepayments are detailed on Exhibit No. PAC-0016, Attachment 11, page 41;

e. Abandoned Plant for which the value for production is zero;

f. Materials and Supplies, which are comprised of an undistributed component and construction component for which the worksheet allocates the beginning and end of year average to production using the Wage and Salary Allocator, and a production direct assigned amount, also based upon a beginning and end of year average;

g. Cash Working Capital is zero, consistent with how this item is determined in the transmission formula rate; and

h. Network Upgrade Balance, which is relevant to the transmission formula rate and has a value of zero.

Q. HOW IS TOTAL PRODUCTION RATE BASE DETERMINED?

A. As shown on Exhibit No. PAC-0016, Attachment A, page 2, total rate base equals the sum of Net Production Plant and Adjustments to Rate Base.

Q. GO ON TO THE NEXT CATEGORY IN EXHIBIT NO. PAC-0016, ATTACHMENT A, PAGE 3, OPERATIONS AND MAINTENANCE EXPENSE, AND DESCRIBE THE ITEMS IN THIS CATEGORY.

A. The first item in this category is production O&M expense. The only FERC Account included in the Production Fixed Charge Rate in production O&M is FERC Account 557, Other Expenses, which includes production expenses not specifically provided for in other production expense accounts (Accounts 500-554). It also includes expenses incurred directly in the connection with purchases of electricity. PacifiCorp costs recorded in Account 557 are related to the production function but not attributable to a specific generating resource. This includes costs associated with 1) generation engineering performance, 2) energy supply management finance, 3) back office operations, including software maintenance and support for settlement systems, 4) applications management for production system analysis and design, 5) long-term load forecasting and wholesale sales and purchases, 6) wholesale trading, and 7) integrated resource planning. As previously described, all other fixed production O&M is included with the associated generating facilities most likely to provide ancillary services and included in the weighted cost per kW

for each ancillary service (Exhibit No. PAC-0015, Pages 4, 5 and 6). Account 557 was not included in the Production Fixed Charge Rate submitted in Docket No. ER17-219.

Q. DESCRIBE HOW ADMINISTRATIVE AND GENERAL ("A&G") EXPENSES ARE REFLECTED IN THE PRODUCTION FIXED CHARGE RATE.

A. As shown on Exhibit No. PAC-0016, Attachment A, page 3, starting at line 57, this category begins with total A&G expenses, and then I removed the following items, in the same way these items are removed from the transmission formula rate: a Post-Retirement Benefits Other Than Pensions adjustment; property insurance; regulatory commission expenses; general advertising; and membership dues that are not applicable to PacifiCorp's production function. These items are contained in Exhibit No. PAC-0016, Attachment 5, page 38.

After applying the Wage and Salary Allocator to residual A&G expenses, I then added back the production function regulatory expenses and property insurance allocated to production using the Gross Plant Allocator. I then add together total production allocated A&G to production O&M to obtain total production O&M contained in the Production Fixed Charge Rate.

Q. PLEASE DESCRIBE THE NEXT CATEGORY OF EXHIBIT NO. PAC-0016, ATTACHMENT A, PAGE 3, DEPRECIATION AND AMORTIZATION EXPENSE.

A. In this category, I added together the production depreciation expense with a wage and salary allocated portion of the general and intangible depreciation and

amortization expense to arrive at total production depreciation and amortization expense. As with accumulated depreciation and EADIT, I removed the impacts of the production asset buy-downs previously described. As can be seen on Exhibit No. PAC-0016, Attachment 5, page 40, Line 174, I reduced production depreciation expense by $124.9 million.

Q. PLEASE DESCRIBE THE NEXT CATEGORY ON EXHIBIT NO. PAC-0016, ATTACHMENT A, PAGE 4, TAXES OTHER THAN INCOME.

A. I performed the calculation of taxes other than income in Exhibit No. PAC-0016, Attachment 2, page 34. The taxes included are real estate and possessory taxes, along with an annual report tax. I determined the production portion of these total amounts using the Net Plant Allocator.

Q. WHAT IS INCLUDED IN THE NEXT CATEGORY, RETURN\CAPITALIZATION, ON EXHIBIT NO. PAC-0016, ATTACHMENT A, PAGE 4?

A. This category includes information necessary to determine PacifiCorp's rate of return that is applied to rate base to calculate the return component of the Production Fixed Charge Rate. As can be seen on Exhibit No. PAC-0016, Attachment A, page 4, beginning at line 86, all the information needed to determine the cost of debt, preferred stock and common equity is included in this category, which data is from Exhibit No. PAC-0016, Attachment 14, page 43. This section is identical to that which is included in the transmission formula rate. I have used the transmission base ROE of 9.80% as the base ROE in this Production Fixed Charge Rate. The production rate of return is 7.5095%.

Q. PLEASE DESCRIBE THE NEXT CATEGORY OF EXHIBIT NO. PAC-0016, ATTACHMENT A, PAGE 5, INCOME TAXES.

A. This category includes income taxes applicable to the preferred stock and common equity portion of the investment return, using the federal tax rate of 21%[5] and a weighted average state tax rate of 4.54% (the same as used in the transmission formula rate). In addition, the following three items are included:

a. Investment Tax Credit – amortization of investment tax credits earned in prior periods. The production portion is determined in Exhibit No. PAC-0016, Attachment 5, page 38 using the Net Plant Allocator;

b. Though not part of the transmission formula rate, I have included the income taxes on the equity AFUDC component of production depreciation expense because equity AFUDC is not deductible for income taxes. Therefore, income taxes on the current year's equity AFUDC that is contained in production depreciation expense must be added to the production revenue requirement so PacifiCorp can recover its cost of service; and

c. Amortization of EADIT – PacifiCorp proposes to amortize the production portion of protected and unprotected excess ADIT resulting from the Tax Reform and Jobs Act of 2017 over the remaining life of the asset or group of assets using the Reverse South

[5] In Docket No. ER17-219, PacifiCorp used the higher 35% federal tax rate in determining its production fixed charge rate.

Georgia Method. The amortization by year is shown on Exhibit No. PAC-0016, Attachment 1B, page 33.

The worksheet then adds the individual income tax items together to arrive at total income taxes to include in the production revenue requirement.

Q. PLEASE DESCRIBE THE NEXT CATEGORY OF EXHIBIT NO. PAC-0016, ATTACHMENT A, PAGE 6, REVENUE REQUIREMENT.

A. Lines 137 to 145 of Exhibit No. PAC-0016, Attachment A, page 6, is a summary of the production revenue requirement components and the determination of the gross production revenue requirement. The formula then adjusts the gross production revenue requirement to remove the revenue requirement related to production facilities not includable, of which there are none for PacifiCorp. It then subtracts revenue credits, as contained in Exhibit No. PAC-0016, Attachment 3, page 35, to arrive at the Net Revenue Requirement.

Q. WHAT ARE THE REVENUE CREDITS THAT ARE SUBTRACTED FROM THE REVENUE REQUIREMENT?

A. These are production-related revenues, either allocated or direct assigned, received by PacifiCorp that offset the production revenue requirement. Refer to Exhibit No. PAC-0016, Attachment 3, page 35 for details.

Q. PLEASE DESCRIBE HOW YOU DETERMINED THE HOW THE PRODUCTION FIXED CHARGE RATE SHOWN ON EXHIBIT NO. PAC-0016, ATTACHMENT A, PAGE 6, LINE 156.

A. I determined the Production Fixed Charge Rate by dividing the net revenue requirement by the net production plant. The production fixed charge rate is 15.2044%. It is also referred to as the Net Plant Carrying Cost.

Q. PARAGRAPH 6.3.10 OF THE DOCKET NO. ER17-219 SETTLEMENT REQUIRES CONSIDERATION OF INCLUDING IN THE PRODUCTION PLANT REVENUE REQUIREMENT REVENUE CREDITS FOR ALL REVENUE GENERATED BY PACIFICORP'S EIM SALES OUT OF THE BAA FOR PURPOSE OF SERVING LOADS OTHER THAN FIRM NATIVE LOADS. DID YOU INCLUDE SUCH REVENUE CREDITS IN DETERMINING THE PRODUCTION FIXED CHARGE RATE AND OTHERWISE IN CALCULATING THE SCHEDULE 3/3A, 5 AND 6 RATES?

A. No, I did not, as revenue generated in excess of incremental costs by PacifiCorp's EIM sales out of the BAA for purpose of serving loads other than firm native loads have nothing to do with the provision of Schedule 3/3A, 5 and 6 services to customers in the PacifiCorp BAA. I am not aware of any precedent in support of revenue credits for EIM sales against ancillary service rates. Even under the Commission's older policies dealing with the crediting of off-system revenues to on-system customers, which is not strictly applicable here, energy-related revenues would be used to offset energy-related costs, and demand-related (fixed costs) revenue would offset demand-related costs. For there to be a basis to revenue credit, there must be a relationship between the revenues from the off-system sales and the costs included in customer rates. Through

EIM sales, PacifiCorp is compensated for its variable energy costs, which are not included in the revenue requirement for Schedules 3/3A, 5 and 6, which include fixed costs only.

Q. DOES THIS CONCLUDE YOUR PRESENTATION OF THE PACIFICORP PRODUCTION FIXED CHARGE RATE CONTAINED IN EXHIBIT NO. PAC-0016 AND THE RATES FOR SCHEDULES 3/3A, 5 AND 6?

A. Yes, it does.

V. ANCILLARY SERVICE SCHEDULES 2 – REACTIVE POWER

Q. WHEN WERE PACIFICORP'S CURRENTLY EFFECTIVE REACTIVE SERVICE RATES ESTABLISHED?

A. PacifiCorp's current rates for Reactive Service were established pursuant to a settlement agreement approved by the Commission in 2013 in Docket No. ER11-3643 and became effective on December 25, 2011.[6]

Q. DO PACIFICORP'S CURRENTLY EFFECTIVE REACTIVE SERVICE RATES ACCURATELY REFLECT THE GENERATION FACILITIES AND PURCHASED POWER AGREEMENTS THAT PROVIDE REACTIVE POWER TODAY AND THEIR RESPECTIVE CURRENT COSTS?

[6] *PacifiCorp*, 143 FERC ¶ 61,162 at P 5 (2013).

A. No. Since the Schedule 2 rates were set in Docket No. ER11-3643, PacifiCorp's generating fleet has changed due to the addition of several generating facilities, including a combined cycle unit and wind facilities, as well as the retirement of two thermal generating facilities.

The current Schedule 2 rates do not include reactive power revenue requirements related to PacifiCorp's wind facilities that existed at that time of the settlement agreement in Docket No. ER11-3643 because any reactive power capability of those wind facilities was not recognized in generator interconnection agreements and in Schedule 2 until 2016 and after. The Schedule 2 rates in existence today also do not include the reactive power costs of purchased power agreements ("PPAs").

Q. SUMMARIZE THE RESULTS OF YOUR REACTIVE POWER REVENUE REQUIREMENT ANALYSIS.

A. As shown on Exhibit No. PAC-0017, Schedule 2, page 1, I have determined that PacifiCorp's fleet-wide reactive power annual revenue requirement is approximately $22.6 million. Using the 2019 12-month average coincident system peak demand of 13,450,317 kWs and adjusted for customers that self-supply part of their Schedule 2 requirements, I determined that the Schedule 2 rate for PacifiCorp is $1.677 per kW-year, which is an increase from the current rate of $0.550 per kW-year.

A. FERC precedent for reactive power revenue requirements

Q. PLEASE EXPLAIN THE PURPOSE OF REACTIVE POWER AND HOW THE COST ASSOCIATED WITH REACTIVE POWER IS CALCULATED.

A. Reactive power (measured in vars) is required to maintain appropriate voltage on the transmission system to deliver real power (measured in watts) through transmission lines. Insufficient reactive power support could potentially result in a voltage collapse. In Order No. 888, the Commission found that reactive power from generators was an ancillary service, the costs of which should be separately assessed to customers. In *American Electric Power Service Corp.,* 88 FERC ¶ 61,141 (1999) (Opinion No. 440) ("*AEP*"), *order on reh'g*, 92 FERC ¶ 61,001 (2000), and *Dynegy Generation, Inc*., 121 FERC ¶ 61,025 (2007) (Opinion No. 498) ("*Dynegy*"), *order on reh'g,* 125 FERC ¶ 61,280 (2009), the Commission discussed the methodology for determining the cost of reactive power. I developed the base case reactive power revenue requirement here consistent with the methods described in *AEP* and *Dynegy* and with the additional guidance provided in *Wabash Valley Power Ass'n*, 154 FERC ¶ 61,246 (2016) ("*Wabash*").

Q. DESCRIBE THE AEP REACTIVE POWER METHODOLOGY.

A. The *AEP* reactive power methodology identifies the reactive power investment with respect to four types of equipment: (1) the generator and exciter; (2) the generator step-up ("GSU") transformers; (3) the accessory electrical equipment; and (4) the balance of plant investment. Because these groups of

investments are necessary to produce both real and reactive power, the *AEP* methodology includes allocation factors to separate the components between real and reactive power. These factors are based upon the capability of the generating unit, consistent with FERC precedent.

Once the investment in reactive power is determined using the allocation factors, both *AEP* and *Dynegy* applied a fixed charge factor to determine the annual revenue requirement. The fixed charge factor is determined using the levelized revenue requirement, which determines a fixed percentage to be applied to the gross investment. The fixed charge factor includes operations and maintenance expenses, administrative and general expenses, taxes other than income, general and intangible plant, cost of capital, income taxes, working capital and accumulated deferred income taxes. Applying the fixed charge factor to the reactive power investment results in the reactive power revenue requirement.

Q. WERE REAL POWER LOSSES THAT OCCUR DURING THE PRODUCTION OF REACTIVE POWER (COMMONLY REFERRED TO AS "HEATING LOSSES") INCLUDED IN THE *AEP* METHODOLOGY?

A. Yes, they were. When reactive power is produced, it results in incremental real power losses in the generator exciter. The value of these incremental losses was included as a cost of reactive power in both *AEP* and *Dynegy*[7] and in many

[7] *American Electric Power Service Corp.,* 88 FERC ¶ 61,141 (1999) (Opinion No. 440) ("*AEP*"), *order on reh'g*, 92 FERC ¶ 61,001 (2000), and *Dynegy Generation, Inc*., 121 FERC ¶ 61,025 (2007) (Opinion No. 498) ("*Dynegy*"), *order on r'hg,* 125 FERC ¶ 61,280 (2009).

other reactive power revenue requirement calculations approved by the Commission over the years. The Commission has determined that heating losses should be valued based upon actual reactive power production and associated real power losses and actual fuel costs.[8]

Q. DID *AEP* AND *DYNEGY* ADDRESS REACTIVE POWER RATE CALCULATIONS FOR WIND AND SOLAR GENERATING FACILITIES (NON-SYNCHRONOUS GENERATORS)?

A. No, they did not, as such generation options were not viable options at the time of those cases. *AEP* and *Dynegy* addressed the determination of reactive power rates for synchronous generators, such as combined cycle, steam, and hydro generating facilities. Due to the vintage of those cases, they did not address reactive power for non-synchronous generators, such as wind and solar generation. However, the principles underlying the *AEP* and *Dynegy* methodology apply equally to both synchronous and non-synchronous generators. As explained later in my testimony, I applied the reactive power approach in *AEP* and *Dynegy* to determine the appropriate reactive power revenue requirement for PacifiCorp's wind generating facilities. The *AEP* methodology has previously been used extensively to determine reactive power rates for wind facilities.[9]

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[8] *Dynegy Midwest Generation, Inc.*, *Order Denying in Part, and Granting in Part, Rehearing*, 125 FERC ¶ 61,280.

[9] *See, e.g.*, *See LWP Lessee, LLC*, 156 FERC ¶ 61,105 (2016); *LWP Lessee, LLC*, Docket No. ER16-1923-003, delegated letter order issued June 8, 2017 ("*LWP Lessee*"); *Kelly Creek Wind, LLC*, 158 FERC ¶ 61,059 (2017); *Kelly Creek Wind, LLC*, 160 FERC ¶ 62,127 (2017) ("*Kelly Creek*"); *Settlers Trail*

B. Overview of reactive power revenue requirement and rate calculations

Q. DID YOU USE THE *AEP* AND *DYNEGY* APPROACH IN DETERMINING REACTIVE SERVICE RATES FOR PACIFICORP?

A. Yes, I did. Below is an overview of the approach I used to determine PacifiCorp's fleet-wide reactive power revenue requirement and resulting Schedule 2 rates.

1. Investment:

a. I identified from PacifiCorp's accounting records the investment in the generator and exciter (from FERC Accounts 314 (steam), 333 (hydro) and 344 (other, including wind)) for all facilities except the new wind facilities. For the new wind facilities, I obtained estimates of the investment in the turbogenerators (prime movers and generators) and multiplied that investment by 8%, to determine the portion of the new wind turbogenerators that comprise the generators that produce both real and reactive power. The 8% is based upon information from the wind turbine manufacturer and reflects the percent that the generator

Wind Farm, LLC, 162 FERC ¶ 61,211 (2018) ("*Settlers Trail*"); *Red Pine Wind Project, LLC*, 162 FERC ¶ 61,177 (2018) ("*Red Pine*"); *Meadow Lake Wind Farm II, LLC*, 163 FERC ¶ 61,045 (2018) ("*Meadow Lake II*"); *Radford's Run Wind Farm, LLC,* 163 FERC ¶ 61,141 (2018) ("*Radford's Run*"); *Pioneer Trail Wind Farm, LLC*, 163 FERC ¶ 61,234 (2018) ("*Pioneer Trail*"); *Meadow Lake Wind Farm III LLC*, 164 FERC ¶ 61,047 (2018) ("*Meadow Lake III*"); *Blackstone Wind Farm II LLC*, 164 FERC ¶ 61,044 (2018) ("*Blackstone II*"); *Paulding Wind Farm III LLC*, 165 FERC ¶ 61,033 (2018) ("*Paulding III*"); *Meadow Lake Wind Farm V LLC*, 165 FERC ¶ 61,044 (2018) ("*Meadow Lake V*"); *Blackstone Wind Farm, LLC*, 165 FERC ¶ 61,043 (2018) ("*Blackstone*"); *Headwaters Wind Farm LLC*, 165 FERC ¶ 61,052 (2018) ("*Headwaters"*); *Rail Splitter Wind Farm LLC*, 165 FERC ¶ 61,157 (2018) ("*Rail Splitter*"); *Allegheny Ridge Wind Farm, LLC*, 165 FERC ¶ 61,271 (2018) ("*Allegheny*"); *Paulding Wind Farm II LLC*, 166 FERC ¶ 61,038 (2019).

investment is to the turbogenerator investment (i.e., nacelle, including generator, blades, and tower);

b. I identified from the PacifiCorp accounting records the investment in GSUs (FERC Account 353.1). The costs of these transformers are excluded from the calculation of PacifiCorp's transmission rates and are appropriately included in reactive power rate calculations, pursuant to the Commission's precedent under *AEP* and *Dynegy*;

c. I identified from the PacifiCorp accounting records the investment in accessory electrical equipment (FERC Accounts 315 (steam), 334 (hydro) and 345 (other)). For steam accessory electric equipment, I multiplied the investment by 10%, based on the percentage used in *AEP,* to determine the portion of accessory electrical equipment applicable to the production of real and reactive power, as I did not have detailed plant accounting records that would enable me to assign percentages by subcategories of thermal-accessory electric equipment. For hydro facilities, the PacifiCorp's accounting records provided sufficient detail so that I could apply a percentage to subcategories of accessory hydro-electric equipment to obtain the portion that is applicable to the production of real and reactive power. For the accessory electric equipment for wind facilities, which is recorded in FERC Account 345, I included

100% of such investment as it includes the investment in the transformers (that step-up the voltage from the wind turbine to the collector system) and the collector system to the low side of the GSUs, all of which are necessary to produce real and reactive power; and

d. I determined the balance of plant by determining the difference between the total investment in the generating facility and the sum of the investment in generators and exciters, GSUs and accessory electric equipment supporting the generator and exciter.

2. Allocation Factors:

a. I developed the reactive power allocation factor, which is based upon the characteristics of each generating facility and is used to determine the portion of the investments in generator and exciter, GSUs, and accessory electrical equipment supporting the generator and exciter that is used to produce reactive power; and

b. I developed the balance of plant allocator, which is calculated for the PacifiCorp generating fleet and is used to determine the share of the balance of plant to allocate to reactive power.

3. Fixed Charge Factor:

a. I determined a levelized fixed charge factor for each generating facility that includes the following items: operations and

maintenance expenses; administrative and general expenses; working capital; general and intangible plant; property and payroll taxes; depreciation; cost of capital including income taxes; and accumulated deferred income taxes.

4. Reactive Power Revenue Requirement and Rate Calculation:

a. I multiplied the investment in generators and exciters, GSUs, and accessory electrical equipment supporting the generators and exciters by the reactive power allocation factor to determine the portion of these items to include as reactive power investment;

b. I multiplied the balance of plant amount by the balance of plant allocator to determine the portion to include as reactive power investment;

c. I added the reactive power investments amounts in "a" and "b" to determine the investment in reactive power for each generating facility;

d. I multiplied the reactive power investment by the fixed charge factor to determine the reactive power revenue requirement for each generating facility;

e. After summing the reactive power revenue requirement for all PacifiCorp Generating Units and adding the reactive power costs associated with three PPAs, I divided the total reactive power

revenue requirement by the 12-month average coincident system peak demand to arrive at the Schedule 2 rate.

Q. PLEASE EXPLAIN WHY THE *AEP* AND *DYNEGY* APPROACH APPLIES TO WIND FACILITIES?

A. The underlying principle of the *AEP* methodology is to determine the cost of providing reactive power by identifying the investments in generators and exciters, GSUs, and accessory electric equipment supporting the generators and exciters and allocating these investments to the production of reactive power. This principle applies equally to wind generating facilities that can provide reactive power support, such as the PacifiCorp wind facilities I include in my study. Although a wind facility does not have the same equipment as a synchronous generator, it does have identifiable equipment that is needed to produce real and reactive power, and the reactive power portion of the relevant investments can be determined by applying reactive power allocation factors in the same manner as is done for synchronous generators.

Q. **DID YOU INCLUDE HEATING LOSSES IN THE PRODUCTION OF REAL POWER AS A COMPONENT IN PACIFICORP'S REACTIVE SERVICE RATE CALCULATION?**

A. Yes, I did. These heating losses are the actual real power losses in the exciters when producing reactive power.[10] I valued these losses at the average cost of fuel for generation for each of the steam, combined cycle, and gas turbine

[10] Though real power losses are greatest when a generator/exciter is absorbing vars, I have been conservative with the calculation of heating losses by using real power losses only when the generator/exciter is producing vars.

peaker units. There are no heating losses for hydro and wind facilities since the fuel costs for these facilities is zero.

Q. **WHAT DATA DID YOU USE IN YOUR REACTIVE POWER REVENUE REQUIREMENT CALCULATIONS?**

A. Except for wind facilities coming into service in 2020, I used investment data as of December 31, 2019 and expenses during 2019. The data I used comes from PacifiCorp's 2019 FERC Form 1 or internal accounting reports, which I have included in my exhibits to this testimony. For the wind generating facilities coming into service in 2020, I used PacifiCorp estimated investment data and O&M projected for 2021.

C. Reactive power revenue requirement

Q. PLEASE PROVIDE A SUMMARY OF THE PACIFICORP REACTIVE POWER REVENUE REQUIREMENT AND SCHEDULE 2 RATES COMPARED TO THE CURRENT SCHEDULE 2 RATES.

A. I present the PacifiCorp reactive power revenue requirement and Schedule 2 rates in Exhibit No. PAC-0017,[11] Attachment 2 and in Table 8 and Table 9 below:

[11] See Attachment 1 to Exhibit No. PAC-0017 for a table of contents to Exhibit No. PAC-0017.

Table 8 – Reactive Power Revenue Requirement

Thermal Generating Facilities	8,750		$ 10,363,603
Hydroelectric Generating Facilities	1,158		3,083,453
Wind Generating Facilities	2,537		6,956,246
Subtotal PAC Facilities	12,444		20,403,302
Purchased Power Agreements	447		2,149,672
Total	12,891		$ 22,552,974
Network Load Plus Firm Point-to-Point - kW			13,450,317

Table 9 below shows the base case Schedule 2 rates and the current Schedule 2 rates:

Table 9 – Base Case Reactive Power Rates

Proposed Reactive Power Rates:							
Annual	Charge:				$1.677	per	kW-Year
Monthly	Charge:				0.140	per	kW-Month
Weekly	Charge:				0.032	per	kW-Week
Daily	Charge:				0.005	per	kW-Day
Hourly	Charge:				0.191	per	MWh
Current Reactive Power Rates:							
Annual	Charge:				$0.550	per	kW-Year
Monthly	Charge:				0.046	per	kW-Month
Weekly	Charge:				0.011	per	kW-Week
Daily	Charge:				0.001	per	kW-Day
Hourly	Charge:				0.063	per	MWh

Using 2019 billing determinants for transmission customers, Schedule 2 revenues with the base case rates would be approximately $2.9 million, or an overall increase of approximately $2.0 million. See Exhibit PAC-0013, Summary.

Q. PLEASE SUMMARIZE THE REACTIVE POWER REVENUE REQUIREMENT FOR PACIFICORP'S THERMAL GENERATING FACILITIES.

A. I present the PacifiCorp reactive power revenue requirement for thermal generating facilities in Exhibit No. PAC-0017, Attachment 3 and in Table 10 below:

Table 10 - Reactive Power Base Case Revenue Requirement for Thermal Generating Facilities

Name of Facility	Type of Facility	In Service	Number of Units	MVA Rating - PacifiCorp Share	Annual Revenue Requirement
Blundell	Steam - Geothermal	1984-2007	2	44.8	$ 406,468
Chehalis	Combined Cycle	2003	3	698.0	In BPA BAA
Cholla	Steam - Coal	1981	1	460.0	In APS BAA
Colstrip	Steam - Coal	1984-1986	2	163.8	In Northwestern BAA
Currant Creek	Combined Cycle	2005-2006	3	649.0	1,107,512
Dave Johnston	Steam - Coal	1959-1972	4	922.4	800,553
Gadsby	Combustion Turbine and Steam-NG	1951-2002	6	514.8	1,136,123
Hermiston	Combined Cycle	1996	4	310.7	In BPA BAA
Hunter	Steam - Coal	1978-1983	3	1,336.0	1,283,818
Huntington	Steam - Coal	1974-1977	2	1,116.3	986,518
Jim Bridger	Steam - Coal	1974-1979	4	1,628.0	912,259
Lake Side	Combined Cycle	2007-2014	6	1,385.0	2,436,372
Naughton	Steam-Coal and Steam-NG	1963-1971	3	832.0	893,459
Craig	Steam - Coal	1979-1980	2	191.3	In WAPA BAA
Hayden	Steam - Coal	1965-1976	2	88.2	In PSCO BAA
Wyodak	Steam - Coal	1978	1	321.8	400,521
Total Thermal in PAC BA				8,750.2	$ 10,363,603

I present the reactive power revenue requirement for each thermal facility in Exhibit No. PAC-0017, Attachments 3a-3p. Though I computed the reactive power revenue requirement for all thermal facilities, I am not including the reactive power revenue requirement of thermal facilities that are not in the PacifiCorp BAA, even if such facilities are pseudo-tied to the PacifiCorp BAA. I have excluded the following PacifiCorp thermal generating facilities from the

reactive power revenue requirement for this reason: Chehalis, Cholla 4 (and retired in December 2020), Colstrip, Hermiston, Craig, and Hayden. See Exhibit No. PAC-0017, Attachments 3b, 3c, 3d, 3h, 3n, and 3o for additional details.

Q. PLEASE SUMMARIZE THE REACTIVE POWER REVENUE REQUIREMENT FOR PACIFICORP' HYDROELECTRIC GENERATING FACILITIES.

A. I present the PacifiCorp reactive power revenue requirement for hydro generating facilities in Exhibit No. PAC-0017, Attachment 4 and in Table 11 below:

Table 11 – Base Case Reactive Power Revenue Requirement for Hydro Generating Facilities

Name of Facility	In Service	Number of Units	MVA Rating	Annual Revenue Requirement
Merwin	1931-1958	4	170.0	$ 343,514
Yale	1953	2	137.4	74,184
Swift 1	1958	3	266.7	402,033
Lemolo	1955-1956	2	74.2	135,244
Toketee	1949-1950	3	50.0	172,148
Slide Creek	1951	1	21.2	153,375
Soda Springs	1952	1	12.9	23,355
Clearwater	1953	2	48.2	109,915
Fish Creek	1952	1	12.9	15,763
Prospect	1928	4	55.0	175,028
Copco	1918-1925	4	55.0	552,800
JC Boyle	1958	2	103.2	115,017
Irongate	1962	1	18.9	21,851
Ashton	1917	3	8.0	51,215
Soda	1924	2	16.4	99,430
Grace	1908-1923	3	36.7	110,875
Oneida	1915-1920	3	33.3	167,015
Cutler	1927	2	37.5	360,690
Total			1,158	$ 3,083,453

I present the reactive power revenue requirement for each hydro facility in Exhibit No. PAC-0017, Attachments 4a-4r.

Q. PLEASE SUMMARIZE THE REACTIVE POWER REVENUE REQUIREMENT FOR PACIFICORP'S WIND GENERATING FACILITIES.

A. I present the PacifiCorp reactive power revenue requirement for wind generating facilities in Exhibit No. PAC-0017, Attachment 5 and in Table 12 below:

Table 12 – Base Case Reactive Power Revenue Requirement for Wind Generating Facilities

Name of Facility	In Service Year	Number of Turbines	MVA Rating	Annual Revenue Requirement
Glenrock I and III	2008-2009	92	135.3	$ 748,573
Rolling Hills	2009	66	131.0	433,652
Seven Mile Hill 1 and 2	2008	79	155.1	567,520
High Plains/McFadden Ridge	2009	85	166.9	631,125
Goodnoe Hills	2008	47	104.5	In BPA BAA - pseudo-tied to PAC
Leaning Juniper	2006	67	120.7	In BPA BAA - pseudo-tied to PAC
Marengo I and II	2007-2008	117	245.3	430,396
Dunlap	2010	74	145.3	671,878
Foote Creek	1999	13	52.1	237,694
Cedar Springs II	2020	72	221.6	1,178,985
Ekola Flats	2020	63	274.2	1,171,858
TB Flats I	2020	79	331.1	884,567
TB Flatts II	2021	53	209.5	In service after rates effective
Pryor Mountain	2020	114	244.0	In service after base case rates determined
Total			2,537	$ 6,956,246

I present the reactive power revenue requirement for each wind facility in Exhibit No. PAC-0017, Attachments 5a-5m. PacifiCorp repowered the Dunlap and Foote Creek wind facilities during 2020.

PacifiCorp constructed four new wind facilities during 2020 – Cedar Springs II, Ekola Flats, TB Flats I, TB Flatts II (expected to be completed in 2021), and Pryor Mountain. Though I have computed the reactive power revenue requirement for all wind facilities, I am not including the reactive power revenue requirement of wind facilities that are not in the PacifiCorp BAA, even if such facilities are pseudo-tied to the PacifiCorp BAA. As a result, I have excluded the Goodnoe Hills and Leaning Juniper. I am also not including TB Flatts II that is expected to go into service after December 31, 2020 nor Pryor Mountain which, at the time the base case rates were developed, was not expected to be in service until after December 31, 2020. See Exhibit No. PAC-0017, Attachment 5.

Q. HAVE THERE BEEN CHANGES IN THE IN-SERVICE DATES OF THE PACIFICORP WIND RESOURCES SINCE YOU PERFORMED THIS REACTIVE POWER REVENUE REQUIREMENT ANALYSIS?

A. Yes, there have. However, the impact to the reactive power revenue requirement from the current expected in-service dates (including only those resources in service by December 31, 2020) is not significant (increase of $150,000).

Q. PLEASE SUMMARIZE THE REACTIVE POWER REVENUE REQUIREMENT FOR PACIFICORP'S PURCHASED POWER AGREEMENTS.

A. I present the PacifiCorp base case reactive power revenue requirement for PPAs in Exhibit No. PAC-0017, Attachment 6 and in Table 13 below:

Table 13 - Reactive Power Revenue Requirement for PPAs

Name of PPA	MW	LGIA Power Factor	MVA	Mvar	Comparable PAC Facility	Cost per MVAR	RP Revenue Requirement
Wind							
Cedar Springs I and III	322.4	0.90	358.2	156.1	Cedar Springs II	$ 11,764	$ 1,836,928
Pioneer Wind Park	80.0	0.90	88.9	38.7	Seven Mile Hill 1 and 2	8,072	312,744
Total	402.4		447.1	194.9			$ 2,149,672

D. Reactive power investment

Q. PLEASE EXPLAIN HOW YOU DETERMINED THE INVESTMENT IN GENERATORS AND EXCITERS FOR THE PACIFICORP GENERATING UNITS.

I identified from PacifiCorp's accounting records the investment in the generator and exciter (from FERC Accounts 314 (steam), 333 (hydro) and 344 (other, including wind)) for all facilities except the new wind facilities. For new wind facilities, I obtained an estimate of the investment in the turbogenerators (i.e., prime movers and generators) and then multiplied that investment by 8%, to determine the portion of the wind turbogenerators that

comprise the generators that produce both real and reactive power. The 8% is from the wind turbine manufacturer and reflects the percent that the generator is to the turbogenerator (nacelle, including generator, blades, and tower). The relevant investment information by generating facility is shown in Exhibit No. PAC-0017, Attachment 8 with the details provided in Exhibit No. PAC-0017, Attachments 8a-8c and 8h-8m. For the Dunlap and Foote Creek facilities that are being repowered in 2020, I added the repowering investments to the existing pre-repowering investment to obtain the total investment for these facilities.

Q. PLEASE EXPLAIN HOW YOU DETERMINED THE INVESTMENT IN GSU TRANSFORMERS?

A. I identified from the PacifiCorp accounting records the investment in GSUs (FERC Account 353.1). The costs of these transformers are excluded from the calculation of PacifiCorp's transmission rates and are appropriately included in reactive power rate calculations, pursuant to the Commission's precedent under *AEP* and *Dynegy*. I present the investments in GSUs by PacifiCorp generating unit in Exhibit No. PAC-0017, Attachment 8 with the details provided in Exhibit No. PAC-0017, Attachment 8a and 8d.

Q. PLEASE EXPLAIN HOW YOU DETERMINED THE INVESTMENT IN ACCESSORY ELECTRIC EQUIPMENT.

A. I identified from the PacifiCorp accounting records the investment in accessory electrical equipment (FERC Accounts 315 (steam), 334 (hydro) and 345 (other). For steam accessory electric equipment, I multiplied the investment by 10%, based on the percentage used in *AEP* to determine the portion of accessory

electrical equipment applicable to the production of real and reactive power as the accounting records did not provide granularity of equipment for a more detailed analysis. For hydro facilities, the accounting records were granular enough for me to apply a percentage to subcategories of accessory electric equipment to obtain the portion that is applicable to the production of real and reactive power. For the accessory electric equipment for wind facilities, which is recorded in FERC Account 345, I included 100% of such investment as it includes the investment necessary for the production of real and reactive power, such as the transformers that step-up the voltage from the wind turbine to the collector system and the collector system to the low-side of the GSUs.[12] I present the investment in accessory electric equipment and the related hydro calculations by generating facility in Exhibit No. PAC-0017, Attachment 8 with the details provided in Exhibit No. PAC-0017, Attachment 8a, 8e, 8f and 8h-8m.

Q. DID YOU INCLUDE THE INVESTMENT IN CAPACITOR BANKS IN SOME OF THE WIND FACILITY REACTIVE POWER REVENUE REQUIREMENT CALCULATIONS?

A. Yes, I included the capacitor bank investment for the following wind facilities - Marengo, Dunlap, High Plains and Pryor Mountain. These facilities have capacitor banks to meet power factor requirements under their respective interconnection agreements. The investments in these capacitor banks are not

[12] For the Dunlop and Foote Creek facilities that are being repowered in 2020, I added the repowering investments to the existing investment to obtain the total investment for these facilities.

included in PacifiCorp's transmission formula rate. I present the investment in capacitor banks in Exhibit No. PAC-0017, Attachment 8g.

Q. HOW DID YOU DETERMINE THE BALANCE OF PLANT?

A. Consistent with the *AEP* methodology, I determined the balance of plant investment by subtracting from the total investment in each generating facility the investment in generator and exciters, GSU transformers, and accessory electrical equipment supporting the generator or exciter. This is shown for each generating facility in Exhibit No. PAC-0017, Attachments 3a-3p (thermal facilities), 4a-4r (hydro facilities) and 5a-5m (wind facilities).

E. Reactive power and balance of plant allocation factors

Q. PLEASE EXPLAIN HOW YOU DETERMINED THE REACTIVE POWER ALLOCATION FACTORS.

A. The reactive power allocation factor is used to determine the portion of the investment in generator and exciters, GSU transformers, and accessory electrical equipment supporting the generator or exciter allocable to the production of reactive power and included in the reactive power revenue requirement. Consistent with the *AEP* methodology, I developed the reactive power allocation factors for each generating facility based upon the generating facility's reactive power capability at the generator, consistent with FERC precedent.[13]

[13] *See, e.g., Am. Mun. Power, Inc.*, 141 FERC ¶ 61,073 (2012); *Lively Grove Energy Partners, LLC*, 144 FERC ¶ 61,117 (2013).

The reactive power allocation factor is the ratio of the square of MVAr to the square of MVA. MVA, or Megavolt Ampere, a measure of total electric power, which includes both Watts (real) and vars (reactive). The size and cost of the generator and exciter, GSUs, and accessory electric equipment are proportional to the MVA rating of that equipment. The power factor used to determine the MVA is based upon the nameplate rating of the PacifiCorp Generating Units.

Furthermore, there is a fundamental relationship among MVA, MW, and MVAr as follows: MVA squared equals MW squared plus MVAr squared. The portion of the real and reactive power costs related to reactive power production would be equal to the MVAr squared divided by the MVA squared. The relationship between MVA and MW is expressed as the power factor (the MVA capability times the power factor equals the MW capability).[14] I provide the capability information for the PacifiCorp Generating Units and calculate the reactive power allocation factors in Exhibit No. PAC-0017, Attachment 7. Exhibit No. PAC-0017, Attachment 7a contains the wind facility power factors.

I applied the reactive power allocation factor by generating facility to the investment in the generator and exciter, GSUs and accessory electric equipment supporting the generators or exciters. The result is the portion of these investments applicable to reactive power production and included in the reactive power revenue requirement. I present these individual generating

[14] One minus the power factor squared equals the reactive power allocation factor.

facility calculations in Exhibit No. PAC-0017, Attachments 3a-3p (thermal facilities), 4a-4r (hydro facilities) and 5a-5m (wind facilities).

Q. PLEASE EXPLAIN HOW YOU DETERMINED THE BALANCE OF PLANT ALLOCATION FACTOR.

A. I developed a fleet-wide balance of plant allocator consistent with *AEP*. As shown in Exhibit No. PAC-0017, Attachment 7, the balance of plant allocator is the product of two ratios. The first ratio relates the total real power losses in the exciter when producing reactive power to the total MW rating of the PacifiCorp Generating Units. The second ratio adjusts for diversity among the reactive power outputs of the individual generators by relating the sum of the MVAr output at the time of the system peak to the total system MVAr capability. The two ratios are then multiplied together, yielding a balance of plant allocator for the PacifiCorp generating fleet of 0.0268%. For the wind facilities coming into service in 2020, the MVAr output at the time of the 2019 PacifiCorp system peak is zero, so their contribution to the fleet wide balance of plant allocator is zero.

Q. YOU USE THE NAMEPLATE CAPABILITY RATINGS FOR THE PACIFICORP GENERATING UNITS IN DEVELOPING THE REACTIVE POWER ALLOCATION FACTORS AND BALANCE OF PLANT ALLOCATION FACTOR. DO TECHNICAL CAPABILITY TESTS OF THE PACIFICORP GENERATING UNITS SUPPORT USING THE NAMEPLATE CAPABILITY RATINGS?

A. Yes, they do. I summarize the results of the MOD-25 and other tests in Exhibit No. PAC-0017, Attachment 7b. The MOD-25 Reports are provided in Confidential Exhibit No. PAC-0018. The test results show that the PacifiCorp Generating Units are capable of the nameplate MVAr production and support the use of the power factors I used in the reactive power revenue requirement calculations.

F. Fixed charge factors

Q. PLEASE DESCRIBE HOW YOU DETERMINED THE FIXED CHARGE FACTOR FOR EACH GENERATING FACILITY.

A. To determine the reactive power annual revenue requirement, I developed and applied a levelized fixed charged factor to the total reactive power investment for each generating facility, consistent with the *AEP* methodology. The fixed charge factor includes generating facility-specific operations and maintenance expenses, levelized depreciation, income taxes, levelized accumulated deferred income taxes and PacifiCorp-wide administrative and general expenses, working capital, general and intangible plant, payroll and property taxes and return. I present the calculations of the fixed charge factor for each generating facility in Exhibit No. PAC-0017, Attachments 3a-3p (thermal facilities), 4a-4r (hydro facilities) and 5a-5m (wind facilities) and for the PacifiCorp-wide items in Exhibit No. PAC-0017, Attachment 9.

Q. PLEASE DESCRIBE HOW YOU INCLUDED O&M IN THE FIXED CHARGE FACTOR.

A. I followed the predominance method used by FERC to determine which O&M expenses are considered variable and which are considered fixed and included only the fixed O&M accounts in my analysis. Therefore, I excluded the following O&M accounts from the determination of the operation and maintenance expense fixed charge factor:

Table 14 – Excluded O&M Expense Accounts

Generating Type	O&M FERC Accounts	O&M FERC Accounts Excluded
Steam	500-515	501, 509, 510, 512 and 513
Hydro	535-545	544
Other – combined cycle and wind	546-554	547

I present the O&M expenses by generating facility in Exhibit No. PAC-0017, Attachment 10. For each generating facility, I divided the fixed O&M by the total investment to arrive at the O&M fixed charge factor. See Exhibit No. PAC-0017, Attachments 3a-3p (thermal facilities), 4a-4r (hydro facilities) and 5a-5m (wind facilities). As previously stated, I used estimated 2021 O&M amounts for the four new wind facilities and the two repowered wind facilities.

Q. PLEASE DESCRIBE HOW YOU DETERMINED THE AMOUNT OF ADMINISTRATIVE AND GENERAL EXPENSES TO INCLUDE IN THE FIXED CHARGE FACTOR?

A. As shown in Exhibit No. PAC-0017, Attachment 9, as is done in transmission ratemaking, I determined the portion of administrative and general expenses

("A&G") applicable to the production function of PacifiCorp by using a wage allocator (production wages divided by total O&M wages less A&G wages). I then divided the production A&G expenses by the total production investment to determine the A&G fixed charge factor. I used the same A&G factor in each generating facilities' fixed charge factor.

Q. HOW DID YOU DETERMINE WORKING CAPITAL?

A. Working capital is comprised of two items: (i) cash working capital, and (ii) prepayments and materials and supplies inventory. To determine the cash working capital portion of the fixed charge factor for each generating facility, I took one-eighth of the sum of the O&M fixed charge factor and the A&G fixed charge factor and multiplied the result by the cost of capital and income tax factors, which I discuss below. I present these calculations in Exhibit No. PAC-0017, Attachments 3a-3p (thermal facilities), 4a-4r (hydro facilities) and 5a-5m (wind facilities).

For prepayments, I multiplied the total PacifiCorp prepayment amount by the wage allocator to determine the production prepayment amount. I then multiplied this amount by the return and income tax factors to arrive at the related revenue requirement. I then divided this amount by total production plant to arrive at the prepayment portion of the fixed charge factor. I present these calculations on Exhibit No. PAC-0017, Attachment 9.

For materials and supplies, I added together the production materials and supplies and an allocation of the construction materials and supplies to determine the total production materials and supplies. I then multiplied this

sum by the return and income tax factors to arrive at the related revenue requirement. I then divided this amount by total production plant to arrive at the materials and supplies portion of the fixed charge factor. I present these calculations on Exhibit No. PAC-0017, Attachment 9. I used the same prepayment and materials and supplies factor in each generating facility's fixed charge factor.

Q. PLEASE EXPLAIN THE MAINTENANCE PREPAYMENTS THAT ARE INCLUDED IN THE FIXED CHARGE RATE FOR SOME OF THE GENERATING FACILITIES.

A. PacifiCorp has long-term maintenance contracts for the Currant Creek, Lake Side and Chehalis[15] combined cycle generating facilities. Under the terms of these contracts, PacifiCorp pays a fee for each hour that the facilities operate. These fees are recorded as a prepayment and used to fund major maintenance overhauls. As such, they are funds paid in advance of expenses being incurred and thus are like other prepayments that are included in the reactive power revenue requirement. I present the related calculations on Exhibit No. PAC-0017, Attachment 3b, 3e and 3l.

Additionally, PacifiCorp has long-term full-service agreements related to its Seven Mile wind facility. A portion of the payments under these contracts are prepaid O&M expenses and are like other prepayments that are included in

[15] Chehalis is not located in the PacifiCorp BAA and therefore I do not include its reactive power revenue requirement in the PacifiCorp Schedule 2 calculations.

the reactive power revenue requirement. I present the related calculations on Exhibit No. PAC-0017, Attachment 5c.

Q. NEXT, DESCRIBE HOW YOU DETERMINED THE GENERAL AND INTANGIBLE PORTION OF THE FIXED CHARGE FACTOR.

A. General and intangible plant revenue requirement includes the investment and depreciation/amortization expense. As shown on Exhibit No. PAC-0017, Attachment 9, I first multiplied the general and intangible investment amounts by the return and income taxes. I then added that product to the related depreciation/amortization expense to arrive at the general and intangible property revenue requirement. I then multiplied this revenue requirement by the wage allocator to determine the production portion. I then divided the production portion by the total production plant investment to determine the general and intangible property portion of the fixed charge factor. I used the same general and intangible factor in each generating facilities' fixed charge factor.

Q. PLEASE DESCRIBE HOW YOU INCLUDED OTHER TAXES IN THE FIXED CHARGE FACTOR.

A. Other taxes are comprised of payroll taxes and property taxes. PacifiCorp allocates its payroll taxes with labor, so PacifiCorp has no additional payroll taxes to include here. For property taxes, I determined the production portion using the gross plant allocator. I then divided the allocated property taxes by total production plant to arrive at the other taxes portion of the fixed charge factor. I present these calculations on Exhibit No. PAC-0017, Attachment 9.

Q. DESCRIBE HOW YOU INCLUDED DEPRECIATION EXPENSE IN THE FIXED CHARGE FACTOR.

A. I include depreciation expense using the levelization approach adopted by the Commission for reactive power revenue requirement calculations. The formula to determine the depreciation expense portion of the fixed charge factor is the return divided by one minus the return raised to the depreciable life less one power.

[Return/(1-Return)]^(Life-1)

The resulting percentage for each generating facility is included in the fixed charge factor. The calculations for each generating facility are shown in Exhibit No. PAC-0017, Attachments 3a-3p (thermal facilities), 4a-4r (hydro facilities) and 5a-5m (wind facilities).

Q. PLEASE DESCRIBE HOW YOU DETERMINED THE RETURN COMPONENT OF THE FIXED CHARGE FACTOR.

A. As shown on Exhibit No. PAC-0017, Attachment 9, the return is based upon the PacifiCorp's capital structure at the end of 2019 and the cost of debt during 2019. Consistent with FERC precedent, the return on equity I used is the base return on equity included in the PacifiCorp transmission formula rate. I included the resulting rate of return of 7.55% in the fixed charge factor for each generating facility.

Q. PLEASE EXPLAIN HOW YOU REFLECT INCOME TAXES IN THE FIXED CHARGE FACTOR.

A. I include income taxes using the levelization approach adopted by the Commission for reactive power revenue requirement calculations. I use the weighted average state income tax rate (4.54%) for the states in which PacifiCorp operates and a federal income tax rate of 21%. The rather complex formula for including income taxes in the fixed charge factor for each respective generating facility is the composite tax rate divided by one less the composite tax rate times the return less the depreciation rate plus the depreciation factor (both based upon the respective book life of each generating facility) included in the fixed charge factor times one less the weighted cost of debt divided by the return.

(Tax Rate/(1-Tax Rate))*((Return-Depreciation Rate)+Depreciation Factor)*
((1-Debt Rate)/Return)

I present the income tax calculations for each generating facility in Exhibit No. PAC-0017, Attachments 3a-3p (thermal facilities), 4a-4r (hydro facilities) and 5a-5m (wind facilities).

Q. PLEASE DESCRIBE HOW YOU DETERMINED THE ACCUMULATED DEFERRED INCOME TAXES TO INCLUDE IN THE FIXED CHARGE FACTOR.

A. I reduced the fixed charge factor for accumulated deferred income taxes ("ADIT") to recognize the value of the non-investor supplied capital provided through accelerated depreciation and normalization accounting. I first determined the annual ADIT balances and the related revenue requirement impacts (based upon the return used herein and income taxes) over the life of

each generating facility. This is equivalent to ADIT reducing rate base in a traditional revenue requirement calculation.

I then computed the net present value and the levelized amount of the annual revenue requirement reductions. I divided the levelized amount for each generating facility by that facility's gross investment to determine the ADIT portion of the fixed charge factor. I present the ADIT calculations in Exhibit No. PAC-0017, Attachments 3a-3p (thermal facilities), 4a-4r (hydro facilities) and 5a-5m (wind facilities). I provide the tax depreciation rates in Exhibit No. PAC-0017, Attachment 13.

Q. HOW DID YOU ACCOUNT FOR THE CHANGE IN FEDERAL INCOME TAXES THAT OCCURRED EFFECTIVE JANUARY 1, 2018 IN THE ADIT CALCULATIONS?

A. For assets where accelerated tax depreciation had ended prior to 2018, there were no impacts. In this situation, I computed accelerated tax depreciation using the 35% federal tax rate in effect (plus the current state tax rate), and the ADIT ratably reverses in the calculations. Where a generating facility began service after 2017, I computed the accelerated depreciation using the current 21% federal tax rate and the current state tax rate. Again, the ADIT ratably reverses in the calculations.

Where accelerated depreciation began prior to 2018 and continued after 2017, I used the 35% federal income tax rate for periods prior to 2018 and the 21% federal income tax rate for periods after 2017. When accelerated depreciation ended, I divided the outstanding ADIT balance by the remaining

book life in years to determine the flowback of the ADIT. By doing so, I accounted for changing tax rates and ensured that the ADIT was returned ratably to customers in a manner consistent with the average rate assumption method.

Q. WHAT IS THE REACTIVE POWER FIXED CHARGE FACTOR THAT YOU CALCULATED?

A. I present the total reactive power fixed charge rate for each generating facility in Exhibit No. PAC-0017, Attachments 3a-3p (thermal facilities), 4a-4r (hydro facilities) and 5a-5m (wind facilities). I applied this fixed charge factor to the respective reactive power investment to arrive at the reactive power revenue requirement for each generating facility.

G. Reactive power – purchased power agreements

Q. YOU HAVE DESCRIBED HOW YOU DEVELOPED THE REACTIVE POWER REVENUE REQUIREMENT FOR THE PACIFICORP GENERATING UNITS. NOW DESCRIBE THE REACTIVE POWER COSTS ASSOCIATED WITH PURCHASED POWER AGREEMENTS.

A. PacifiCorp has several PPAs whereby the generator provides, among other things, reactive power support to the PacifiCorp BAA in exchange for the contractual payments under the PPAs. As can be seen on Exhibit No. PAC-0017, Attachment 6, these PPAs, which are wind generating facilities, provide 447 MVA and 195 MVAr to the PacifiCorp BAA. I have calculated their reactive power costs to be $2.1 million.

Q. PLEASE DESCRIBE HOW YOU DETERMINED THE REACTIVE POWER COSTS OF THESE PPAS.

A. I, with the assistance of PacifiCorp engineers, determined a comparable PacifiCorp wind generating facility for the two wind facility PPAs included in Exhibit No. PAC-0017, Attachment 6 and used the costs of the comparable PacifiCorp wind generating facility to determine the reactive power cost of the PPA. By comparable, I mean the PacifiCorp facility has the same wind turbine type and manufacturer as the facility providing power under the PPA. For example, as shown in Exhibit No. PAC-0017, Attachment 6, the PPA that PacifiCorp has with Cedar Springs I and III provides 322 MVA and 156 MVAr to the PacifiCorp BAA. PacifiCorp's Cedar Springs II wind facility is comparable to the Cedar Springs I and III facility. Therefore, I used the cost per MVAr of Cedar Springs II ($11,764) to determine the $1.8 million reactive power costs of Cedar Springs I and III PPA (252 MVAr times $11,764). I followed this same approach for the other PPA.

H. Heating Losses

Q. YOU INDICATED EARLIER THAT YOU HAVE INCLUDED HEATING LOSSES AS PART OF THE REACTIVE POWER REVENUE REQUIREMENT. PLEASE EXPLAIN.

A. Heating losses are the real power losses in the transformer and in the generator that result when producing reactive power. I determined the real power losses for each of the thermal generating units in Exhibit No. PAC-0017, Attachment

15a to 15e. I determined the incremental real power losses in both the transformer and in the generator by comparing performance at unity power factor and performance at the nameplate power factor, adjusted for actual operating experience by using an average power factor and actual operating hours during 2019. Since the units predominately produce real power, their average power factor is close to one. I then value the real power losses at the average cost of fuel during 2018 and 2019 for each generating unit to arrive at the cost of the real power losses or heating losses.

Q. WHY DID YOU COMPUTE HEATING LOSSES ONLY FOR THE THERMAL GENERATING UNITS?

A. The Commission allows the variable fuel cost associated with heating losses to be included in reactive power calculations. Since only thermal units have fuel costs (there are no fuel costs associated with hydro and wind generation), only the cost of heating losses for thermal units are included in the reactive power revenue requirement.

Q. WHY ARE THERE NO HEATING LOSSES FOR THE BLUNDELL GENERATING FACILITY AND GADSBY UNITS 4-6?

A. Though Blundell has two steam generating units, they operate on geothermal steam and have no fuel costs. Gadsby units 4-6 are peaker units that do not operate often and therefore their heating losses would be minimal.

Q. PLEASE SUMMARIZE YOUR HEATING LOSS CALCULATIONS.

A. I present a summary of the heating losses for each thermal generating facility on Exhibit No. PAC-0017, Attachment 15. The total amount of heating losses

that I have added to the reactive power revenue requirement for the respective generating facilities is $151,115. The heating losses are included in the respective reactive power revenue requirement for each thermal generating unit, as shown on Exhibit No. PAC-0017, Attachment 3a-3p.

I. Reactive power revenue requirement and rates

Q. PLEASE SUMMARIZE THE TOTAL REACTIVE POWER REVENUE REQUIREMENT FOR PACIFICORP.

A. As shown in Exhibit No. PAC-0017, Attachment 2, the total reactive power revenue requirement for PacifiCorp's Generating Units and PPAs is $22,552,974.

Q. HOW DID YOU DETERMINE THE RESULTING REACTIVE SERVICE RATES?

A. I divided the reactive power revenue requirement by the PacifiCorp's 12-month average coincident system peak load[16] of 13,450,317 kWs to derive an annual rate of $1.677 per kW-year. This is shown on Exhibit No. PAC-0017 Attachment 2, along with monthly, weekly, daily, and hourly Reactive Service rates.

Q. PLEASE EXPLAIN THE GENERATOR TECHNICAL INFORMATION YOU PROVIDE THAT IS REQUIRED BY THE COMMISSION IN REACTIVE POWER REVENUE REQUIREMENT CASES.

[16] The monthly coincident peak demands include coincident peak demand of PacifiCorp native load and network transmission customers, plus long-term firm point-to-point reservations. The amounts are adjusted for those customers that partially self-supply Schedule 2.

A. In Confidential Exhibit No. PAC-0018 (Thermal I, Thermal II, Hydro and Wind), I provide the following confidential, generator technical information as required by the Commission:

1. The latest test reports (MOD 25 Reports), which show the leading and lagging MVAr under test conditions. MOD-25 reports are not available for the four wind facilities entering commercial operation in 2020. MOD-25 testing will be conducted on those facilities in the first quarter of 2021;
2. D-curves – reactive capability curves – and Vee-curves – stator current versus field current; and
3. Nameplate pictures.

Q. ARE THERE ANY OTHER ITEMS THAT ARE RELEVANT TO REACTIVE POWER THAT YOU WISH TO DISCUSS?

A. Yes. On July 29, 2020, in Docket ER20-2528, Airport Solar filed with the Commission a rate schedule for Reactive Supply and Voltage Control from Generation Sources Service (reactive power) from Airport Solar's solar generating facility located in the PacifiCorp BAA. Airport Solar owns and operates a 47.25 MW solar generating facility located in Lake County, Oregon and is interconnected with the transmission system of PacifiCorp.

Q. WHAT IS THE IMPACT OF THIS FILING ON PACIFICORP

A. Airport Solar is requesting that it be compensated by PacifiCorp for providing reactive power to the PacifiCorp transmission system. It is requesting compensation of $1,203,288 annually. If approved, this amount represents an

additional cost to PacifiCorp of providing reactive power on its transmission system.

Q. IS PACIFICORP CONTESTING THE FILING BY AIRPORT SOLAR?

A. Yes. On August 19, 2020, PacifiCorp submitted a protest and comments to the petition. On September 25, 2020, FERC allowed the Airport Solar reactive power rate schedule to become effective, subject to refund, and set the proceeding for hearing and settlement judge procedures. The parties currently are in settlement negotiations.

Q. HAVE YOU INCLUDED ANY REACTIVE POWER COSTS FROM AIRPORT SOLAR IN YOUR DETERMINATION OF PACIFICORP REACTIVE POWER REVENUE REQUIREMENTS?

A. No, I have not, as the amount is not yet known.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission approve the Schedule 2, 3/3A, Schedule 5 and Schedule 6 rates of the 2020 Settlement Agreement and supported by my testimony regarding the base case rates.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Dr. Paul A. Dumais

Dr. Paul A. Dumais
Chief Executive Officer

Dr. Paul A. Dumais is a financial and economic consultant with more than 40 years of experience in the energy industry and provides strategic advice and tactical analysis to the benefit of clients. He has extensive senior level electric and natural gas utility and regulatory policy experience. Dr. Dumais' comprehensive expertise includes an extensive depth and breadth of the energy industry. Dr. Dumais has extensive experience with federal and state utility regulatory items, including revenue requirements, cost of service and rate design, formula and stated rates, reactive power and other ancillary service rates, electric transmission incentives, competitive electric transmission processes, Tax Reform impacts, transmission service agreements, open access transmission tariffs and regional transmission organization stakeholder participation. Dr. Dumais has provided expert testimony on ratemaking and financial matters before the Federal Energy Regulatory Commission (FERC) and the Maine Public Utilities Commission (MPUC). He has a doctorate degree in Strategic Leadership from Regent University and an MBA and BS degree in business administration and accounting, respectively, from the University of Maine. He joined Central Maine Power in 1979, where he worked in accounting, financial and regulatory groups until progressing to the parent company, Avangrid, where he led asset management and investment planning efforts before leading FERC regulatory policy efforts. He retired from Avangrid in late 2018 and began Dumais Consulting LLC where he is the Chief Executive Officer. The mission of Dumais Consulting is to be a trusted advisor to clients on regulatory policy and ratemaking matters so they successfully execute their business plans.

REPRESENTATIVE PROJECT EXPERIENCE

Expert Testimony

Provided expert testimony in many FERC and state regulatory proceedings on transmission formula rates, reactive power and other revenue requirements, cost of service, rate design, income tax issues, and regulatory policy issues. Effectively participated in numerous settlement efforts and was cross-examined in many litigated cases.

Electric Transmission and Ancillary Services, Including Reactive Power

Advisor to electric utilities on FERC-related regulator policy and ratemaking matters, including transmission formula rates and reactive power. Expert in FERC ratemaking, and accounting requirements as well as income tax implications. Leadership participation in several return on equity cases and complex formula rate litigation and settlement efforts. Led Transco development in New York through competing for new projects and negotiating a rate settlement at FERC. Led efforts to determine several, significant transmission development opportunities now being pursued by transmission owner.

Filed Testimony

Item No.	Jurisdiction	Docket No.	Organization Initiating Proceeding	Client	Date of Testimony	Subject Matter	Regulator Decision
1	FERC	ER20-2550	Entergy Mississippi	Entergy Mississippi	July 30, 2020	Reactive power for natural gas, combined cycle generating facility	Pending
2	FERC	ER20-2541	Entergy Louisiana	Entergy Louisiana	July 29, 2020	Reactive power for natural gas, combined cycle generating facility	Pending
1	FERC	ER20-1150	The Dayton Power and Light	The Dayton Power and Light	March 3, 2020	Electric transmission formula rate	Pending
2	FERC	ER19-2856	Birchwood Power Partners	Birchwood Power Partners	September 23, 2019	Reactive power revenue requirement for coal generating facility	Settlement approved
3	FERC	ER19-2683	EFS Parlin Holdings LLC	EFS Parlin Holdings LLC	August 26, 2019	Reactive power revenue requirement for combined cycle generating facility	Pending
4	FERC	ER19-2585	Florida Power & Light	Florida Power & Light	August 13, 2019	Fleetwide reactive power revenue requirement and rates	Pending
5	Maine	2019-132	Emera Maine	Emera Maine	August 1, 2019	Economics of renewing rights in HQ Phase I/II HVDC-transmission facility	Pending
6	FERC	ER19-2105	PJM Transmission Owners	Linden VFT	July 2, 2019	Critique of PJM TO proposal for a formula rate border rate	Pending
7	FERC	RM19-5 (Notice of Proposed Rulemaking)	FERC	Avangrid and NY Transco	May 22, 2018	Comments in Tax Reform NOI (RM18-12) and NOPR	Pending
8	FERC	ER18-2256 through ER18-2262	Central Maine Power	Central Maine Power	August 20, 2018	Demonstrating that rates in negotiated 20 and 40 year transmission service agreements are just and reasonable	Approved
9	FERC	EL18-103, EL18-110 and ER18-1588	New York State Electric and Gas and Rochester Gas and Electric	New York State Electric and Gas and Rochester Gas and Electric	May 14, 2018	Tax Cut and Jobs Act impact on stated transmission rates	Approved
10	FERC	AC18-175	United Illuminating	United Illuminating	June 15, 2018	Netting of regional network service transmission revenue and expenses to reduce gross receipts tax	Approved
11	Maine	Various	Central Maine Power Company or Maine Public Utilities Commission	Central Maine Power Company	1985 to 2010	Economics of $1.4 B transmission project, revenue requirements, rate design, standby rates, jurisdictional separation of transmission and distribution, purchased power agreements, AMI and customer service and reliability	Various

Other Regulatory Work

Item No.	Jurisdiction	Docket No.	Organization Initiating Proceeding	Client	Date of Testimony	Subject Matter	Regulator Decision
1	FERC	EL16-19	FERC	Avangrid	Part of New England Transmission Owner Team that negotiated settlement	Section 206 transmission formula rate investigation	FERC rejected settlement under Trailblazer precedent. Currently pending
2	FERC	EL11-66, EL13-33, EL14-86 and EL16-64	State regulators and municipal customers	Avangrid	Part of New England Transmission Owner Team that litigated cases	Section 206 base ROE complaints	Pending
3	FERC	AD16-18	FERC	Avangrid	In 2016, on panel at Order 1000 technical conference	Transmission incentives and cost caps considering competitive processes	No action since 2016
4	FERC	ER15-572	New York Transco	New York Transco	Lead negotiator in settlement efforts	Transmission formula rate, including incentives and cost caps	Settlement in August 2017 that was approved by FERC

Other Activities

Advisor on regulatory matters to entity pursing merger and acquisition activity. Advisor on FERC-related regulatory matters to several clients. Lead participant in the development of performance-based ratemaking in Maine. Active participant in restructuring electric industry, including recovery of stranded costs from over-market purchased power agreements and unbundling of transmission and distribution rates to recognize the federal/state jurisdictional split when a utility no longer provides bundled generation and delivery service.

PROFESSIONAL HISTORY

Dumais Consulting, LLC (2018 – Present)
Chief Executive Officer

Avangrid (2010 – 2018)
Director, FERC Regulation
Director, Asset Management and Investment Planning

Central Maine Power Company (1979 – 2010)
Director, Regulatory Services and Budgeting
Manger of Revenue Requirements and Rate Design
Other various positions

EDUCATION AND CERTIFICATION

Doctorate of Strategic Leadership, Regent University, Virginia Beach, 2013

Masters in Business Administration, University of Maine, May 1986

Bachelors of Business Administration, Accounting, May 1982

OTHER ORGANIZATIONS

WIRES, President-Elect – 2018. WIRES member 2014-2018.

EEI, Energy Delivery Advisory Committee – 2015-2018

Energy Bar Association – presented transmission ROE and incentives in context of Order 1000 at 2018 annual meeting.

American Bar Association - panel presenting webinar in December 2018 on FERC electric transmission ratemaking - formula rates, return on equity and incentives.

Energy Central - selected as a 2018 Top Poster for Energy Central's Grid community with the post, First Energy Receives Abandonment Incentive for Electric Transmission Project, considered one of the best in the community in 2018.

Exhibit No. PAC-0013

Statements BG and BH
(Excel Spreadsheet)

PacifiCorp
Waiver Request of Filing Requirements Under CFR 35.13
Schedules 3/3A, 5 and 6 Rate Change Request

Item/Statement	Comment	Data Source
Filing requires Period I and II data	PacifiCorp (PAC) using 2019 test period (most recent calendar year) with adjustments to remove Cholla 4 (retiring 12/20). PAC is not using Period II data for this ancillary services rate development.	NA
Statements – for Period I and Period II		
AA – balance sheet	PAC relying on FF1 information	FF1 pages 110-113
AB – income statement	PAC relying on FF1 information	FF1 pages 114-117
AC – retained earnings	Not used as needed information is on the balance sheet	FF1 pages 118-119
AD – cost of plant	PAC relying on extensive footnotes in FF1 for information	FF1 pages 204-207
AE – accumulated depreciation and amortization	PAC relying on extensive footnotes in FF1 for information	FF1 pages 219
AF – specified deferred credits (ADIT)	PAC relying upon extensive worksheets in Production Fixed Charge Rate (FCRF) that tie to FF1 (Attachments 1, 1a and 1b to Exhibit PAC No. 16)	FF1 pages 234, 272-273, 274-275 and 276-277
AG – specified plant accounts (other than plant in service) and deferred debits	PAC relying upon a worksheet in PFCR that ties FF1 for Account 190 (Attachments 1, 1a and 1b to Exhibit No. PAC-16). PAC relying upon FF1 for other relevant items (Account 105 and 182). Accounts 107 and 120.1 not relevant for this analysis.	FF1 pages 214, 233 and 234
AH – O&M	PAC relying upon FF1 information	FF1 pages 320-323 and by data by generating plant on pages 402-411
AI – wages and salaries	PAC relying upon FF1 information	FF1 pages 354-355
AJ – depreciation and amortization	PAC relying upon FF1 information and PAC information for adjusting state-asset buydowns	FF1 pages 336-337
AK – taxes other than income taxes	PAC relying upon FF1 information	FF1 pages 262-263
AL – working capital	PAC relying upon FF1 for all items except cash working capital, for which it includes none. Fuel supplies not relevant to this analysis	FF1 pages 110-113 and 227
AM - CWIP	Not relevant to this analysis	
AN – notes payable	Not relevant to this analysis	

PacifiCorp
Waiver Request of Filing Requirements Under CFR 35.13
Schedules 3/3A, 5 and 6 Rate Change Request

Item/Statement	Comment	Data Source
AO - AFUDC	Not relevant to this analysis	
AP, AQ and AR – federal income tax deductions/adjustments	Not relevant to this analysis as analysis uses statutory rate. Data available in FF1	FF1 pages 261
AS and AT – state income tax deductions/adjustments	Not relevant to this analysis as it uses statutory rate.	
AU – revenue credits	PAC relying upon worksheet in PFCR that ties to FF1 (Attachment 3 to Exhibit No. PAC-16)	FF1 pages 300-301
AV – rate of return	PAC relying upon worksheet that ties to FF1 (Attachment 14 of Exhibit No. PAC-16). All required data in FF1	FF1 pages 110-113 and 114-117
AW – cost of short-term debt	Not relevant to this analysis as short-term debt not included in capital structure. Data available in FF1	FF1 pages 110-113
AX – other recent and pending rate changes	No rate changes pending for Schedules 3/3A, 5 and 6	
AY – income and revenue tax rate data	Included in worksheet in PFCR (Attachment A, Lines 128-130, to Exhibit No. PAC-16)	
BA – wholesale customer rate groups	Data available in Exhibit No. PAC-13 (Statements BG/BH)	
BB – allocation of demand and capability data	Peak demand data provided in worksheet in PFCR (Pages 11 and 12 of Exhibit No. PAC-15). Other required information not relevant to Schedules 3/3A, 5 and 6	
BC – reliability data	Not relevant to this analysis	
BD – allocation of energy and supporting data	Not relevant to this analysis	
BE – specific assignment data	The allocation or direct assignment of revenues and expenses fully supported in analysis on worksheets with references to FF1, where applicable (Exhibit No. PAC-15 and 28)	
BF – exclusive commitments of major power supply facilities	Not relevant to this analysis	
BG – revenue data to reflect changed rates	Exhibit No. PAC-13	
BH – revenue data to reflect present rates	Exhibit No. PAC-13	

PacifiCorp
Waiver Request of Filing Requirements Under CFR 35.13
Schedules 3/3A, 5 and 6 Rate Change Request

Item/Statement	Comment	Data Source
BI – fuel cost adjustment factors	Not relevant to this analysis	
BJ – summary data tables	Provided in Exhibit No. PAC-27 and 28	
BK – electric utility cost of service total and as allocated	Provided in Exhibit No. PAC-27 and 28	
BL – rate design information	Provided in PAC testimony and in Exhibit No. PAC-27	
BM – construction program statement	Not relevant to this analysis	

Exhibit No. PAC-0015

Ancillary Services 3/3A, 5, and 6 –
Weighted Cost Per kW and Rate Design
(Excel Spreadsheet)

Exhibit No. PAC-0016

Ancillary Services 3/3A, 5, and 6 –
Production Fixed Charge Rate
(Excel Spreadsheet)

Exhibit No. PAC-0017

Reactive Power Revenue Requirement and Rates
(Excel Spreadsheet)

Exhibit No. PAC-0018

Generator Information
(CUI//PRIV Exhibit)

		Billing Units	Current Revenues	Proposed Revenues	Proposed Less Current
1	Schedule 2		$ 959,887	$ 2,926,803	$ 1,966,916
2	Schedule 3 - Load	13,821 (MW)	2,446,363	1,818,643	(627,720)
3	Schedule 3/3A				
4	VERS -Wind	469	3,091,460	3,800,903	709,444
5	VERS-Solar	123	808,962	812,519	3,557
6	Non-VERS - Nondispatchable	248	428,228	945,968	517,740
7	Non-VERS - Dispatchable	200	358,800	-	(358,800)
8	Subtotal - NonVERS	448	787,028	945,968	158,940
9	Subtotal	(MW)	4,687,449	5,559,390	871,941
10	Total Schedule 3/3A		7,133,812	7,378,034	244,221
11	Schedule 5	12,276,069 (MWh)	1,853,686	2,234,244	380,558
12	Schedule 6	12,764,293 (MWh)	1,927,408	2,195,458	268,050
13	Total		$ 11,874,794	$ 14,734,539	$ 2,859,746

(32) Statement BG - Revenue data to reflect changed rates. Statement BG is a statement of revenues for Period I and Period II, including those under the changed rate for the wholesale services at issue.

(i) For each month of Period I and Period II, and in total for each of the two periods, the utility shall show all billing determinants and metered quantities for each delivery point or set of delivery points that constitutes an individual wholesale customer billing unit, and the result of applying each specific rate component to the billing determinants for each billing unit stated with the total of the computed monthly bill for the customer. If the rates include a fuel clause, the utility shall compute and total the revenues under the fuel clause to reflect fuel costs incurred during each month of Period I and Period II. That is, the fuel clause revenues for the first month of Period I shall reflect fuel costs incurred for that month, and so on for each month of Period I and Period II. In computing fuel clause revenues, the utility shall determine fuel cost according to § 35.14 of this chapter.

(ii) If the form of the proposed fuel clause would produce revenues different from those computed in accordance with clause (i), the utility shall separately compute and state such fuel clause revenues for each customer for each month of Period I and Period II.

(iii) The utility shall summarize separately revenue data computed in accordance with clauses (i) and (ii) above for each month and in total for Period I and Period II, in accordance with wholesale rate groups specified in Statement BA under paragraph (h)(26) of this section. The utility shall show total electric department revenues for each period to include revenues under the changed rate for all such wholesale customer rate groups.

(iv) For Period I and as estimated for Period II, the utility shall summarize all billing determinants and revenues received from interruptible or curtailable services. Billing determinants and revenue data shall be consistent with interruptible demand and energy data in Statements BB and BD. The utility shall include an explanation of the extent to which interruptible or curtailable service revenues are or are not included in revenue credits in Statement AU under paragraph (h)(21) of this section.

(33) Statement BH - Revenue data to reflect present rates. Statement BH is a statement of revenues for Period I and Period II, including those under present rates for wholesale services at issue, and for total electric service to reflect such revenues for wholesale services. The utility shall prepare this statement to include data consistent with criteria specified for presentation of revenue under the changed rate in Statement BG under paragraph (h)(32) of this section.

			Current Rates		Proposed Rates	
	Schedule 2					
1	Annual	kW	$ 0.550		$ 1.677	
2	Monthly	MW	$ 45.833		$ 139.750	
	Schedule 3 - Load					
3	Annual	kW	$ 2.124		$ 1.579	
4	Monthly	MW	$ 177.000		$ 131.583	
	Schedule 3/3A - VERS					
5	Annual	kW	$ 6.593		$ 8.106	
6	Monthly	MW	$ 549.417	All	$ 675.500	Wind
6	Annual	kW			$ 6.622	
7	Monthly	MW			$ 551.833	Solar
	Schedule 3/3A - NonVERS - Nondisptachable					
8	Annual	kW	$ 1.794		$ 3.963	
9	Monthly	MW	$ 149.500		$ 330.250	
	Schedule 3/3A - NonVERS - Disptachable					
10	Annual	kW	$ 1.794		$ -	
11	Monthly	MW	$ 149.500		$ -	
10	Schedule 5	kWh	$ 0.151		$ 0.182	
11	Schedule 6	kWh	$ 0.151		$ 0.172	

	Network MW-2019	MW Volumes													
	Customer	January	February	March	April	May	June	July	August	September	October	November	December	Total	
1	Basin, SA 505	10.47	11.81	11.13	8.54	6.69	9.62	11.28	10.90	10.95	11.60	11.06	9.79	123.84	
2	Black Hills SA 347	45.55	55.25	54.20	37.79	32.18	44.89	53.47	50.13	51.58	48.47	43.68	43.64	560.83	
3	BPA Gazely SA 229	3.47	3.41	2.82	1.45	-	0.34	-	0.02	-	3.23	3.17	2.97	20.88	
4	BPA Yakima SA 328	6.64	7.36	6.38	2.59	-	0.44	-	0.03	-	6.06	4.20	4.50	38.20	
5	BPA Clark SA 735	27.75	34.14	30.59	8.70	-	1.17	-	0.09	-	24.49	23.89	22.87	173.69	
6	BPA Benton/Rimrock SA 539	1.29	1.30	1.32	0.50	-	0.04	-	-	-	1.17	1.10	0.84	7.56	
7	BPA OR Wind, SA 538	0.29	0.48	0.10	-	-	-	-	-	-	0.34	-	-	1.21	
8	BPA CEC FNO SA 827	-	0.02	0.02	-	-	-	-	-	-	0.12	0.17	0.17	0.50	
9	Tri State SA 628	19.78	18.86	21.94	16.23	11.21	14.36	12.68	13.95	16.11	18.17	17.03	17.09	197.41	
10	USBR SA 506	0.01	0.01	0.01	0.24	0.54	0.55	0.61	0.63	0.50	0.01	0.01	0.01	3.13	
11	WAPA SA 175	-	-	-	-	-	-	-	-	-	-	-	-	-	Not billed for Schedule 2
12	BPA Airport Solar SA 836	-	-	-	-	-	-	-	-	-	-	-	0.24	0.24	
13	BPA Southeast Idaho SA 748	280.50	229.98	212.72	80.40	-	13.02	-	0.66	-	238.73	203.97	236.82	1,496.80	
14	BPA Idaho Falls 747	97.00	96.00	94.35	68.05	95.29	96.09	122.05	106.80	83.61	92.90	78.49	65.63	1,096.26	
15	Exelon SA 943	0.75	0.79	0.77	0.70	0.79	0.87	0.72	0.34	0.71	0.78	0.55	0.72	8.49	
16	Avangrid SA 742	30.81	31.82	31.63	31.21	32.06	31.97	32.04	32.27	31.80	32.06	32.27	32.61	382.55	
17	NTUA SA 894	2.64	2.42	2.34	1.87	1.77	1.93	2.61	2.42	2.11	2.49	2.16	2.65	27.41	
18	3 Phases SA 876	0.01	0.06	0.05	0.07	0.08	0.11	0.14	0.18	0.14	0.07	0.07	0.08	1.06	
19	Calpine SA 299	15.45	16.14	14.33	13.71	15.44	15.40	17.43	17.57	17.35	14.16	13.84	13.91	184.73	
20	UAMPS RS 297	270.69	207.71	173.69	287.39	259.46	418.14	582.81	608.40	561.43	317.32	227.47	255.84	4,170.35	
21	UMPA RS 637	38.42	36.00	-	-	-	-	-	-	9.87	-	-	-	84.29	
22	Deseret RS 280	-	-	-	-	-	173.38	212.50	-	-	-	-	-	385.88	
23	WAPA RS 262/263	-	-	-	-	-	-	-	-	-	-	-	-	-	Not billed for Schedule 2
24	Total	851.52	753.56	658.39	559.44	455.51	822.32	1,048.34	844.39	786.16	812.17	663.13	710.38	8,965.31	

[ties with Exhibit No. PAC-0028, Attachment 14, line 13 (j6) excluding WAPA items not billed]

Monthly Revenue - Current Rate

		Current Rate	January	February	March	April	May	June	July	August	September	October	November	December	Total
25	Basin, SA 505	45.833	479.87	541.29	510.12	391.41	306.62	440.91	517.00	499.58	501.87	531.66	506.91	448.71	5,675.96
26	Black Hills SA 347	45.833	2,087.69	2,532.27	2,484.15	1,732.03	1,474.91	2,057.44	2,450.69	2,297.61	2,364.07	2,221.53	2,001.99	2,000.15	25,704.52
27	BPA Gazely SA 229	45.833	159.04	156.29	129.25	66.46	-	15.58	-	0.92	-	148.04	145.29	136.12	956.99
28	BPA Yakima SA 328	45.833	304.33	337.33	292.41	118.71	-	20.17	-	1.37	-	277.75	192.50	206.25	1,750.82
29	BPA Clark SA 370	45.833	1,271.87	1,564.74	1,402.03	398.75	-	53.62	-	4.12	-	1,122.45	1,094.95	1,048.20	7,960.73
30	BPA Benton/Rimrock SA 539	45.833	59.12	59.58	60.50	22.92	-	1.83	-	-	-	53.62	50.42	38.50	346.50
31	BPA OR Wind, SA 538	45.833	13.29	22.00	4.58	-	-	-	-	-	-	15.58	-	-	55.46
32	BPA Neff/Gala	45.833	-	0.92	0.92	-	-	-	-	-	-	5.50	7.79	7.79	22.92
33	Tri State SA 628	45.833	906.58	864.41	1,005.58	743.87	513.79	658.16	581.16	639.37	738.37	832.79	780.54	783.29	9,047.89
34	USBR SA 506	45.833	0.46	0.46	0.46	11.00	24.75	25.21	27.96	28.87	22.92	0.46	0.46	0.46	143.46
35	WAPA SA 175	45.833	-	-	-	-	-	-	-	-	-	-	-	-	-
36	Calpine	45.833	-	-	-	-	-	-	-	-	-	-	-	11.00	11.00
37	BPA Eastside	45.833	12,856.16	10,540.67	9,749.60	3,684.97	-	596.75	-	30.25	-	10,941.71	9,348.56	10,854.17	68,602.83
38	BPA Idaho Falls	45.833	4,445.80	4,399.97	4,324.34	3,118.94	4,367.43	4,404.09	5,593.92	4,894.96	3,832.10	4,257.89	3,597.43	3,008.02	50,244.88
39	Exelon	45.833	34.37	36.21	35.29	32.08	36.21	39.87	33.00	15.58	32.54	35.75	25.21	33.00	389.12
40	Avangrid	45.833	1,412.11	1,458.41	1,449.70	1,430.45	1,469.41	1,465.28	1,468.49	1,479.03	1,457.49	1,469.41	1,479.03	1,494.61	17,533.41
41	NTUA	45.833	121.00	110.92	107.25	85.71	81.12	88.46	119.62	110.92	96.71	114.12	99.00	121.46	1,256.28
42	3 Phases	45.833	0.46	2.75	2.29	3.21	3.67	5.04	6.42	8.25	6.42	3.21	3.21	3.67	48.58
43	UAMPS RS 297	45.833	708.12	739.74	656.79	628.37	707.66	705.83	798.87	805.29	795.20	649.00	634.33	637.54	8,466.73
44	UMPA RS 637	45.833	12,406.53	9,519.97	7,960.73	13,171.95	11,891.83	19,164.61	26,711.93	27,884.80	25,732.02	14,543.73	10,425.63	11,725.91	191,139.65
45	Deseret RS 280	45.833	1,760.90	1,649.99	-	-	-	-	-	-	452.37	-	-	-	3,863.26
46	WAPA RS 262/263	45.833	-	-	-	-	-	7,946.53	9,739.51	-	-	-	-	-	17,686.04
47	Total		39,027.72	34,537.92	30,175.99	25,640.81	20,877.39	37,689.39	48,048.57	38,700.93	36,032.07	37,224.19	30,393.24	32,558.85	410,907.05

Monthly Revenue - Proposed Rate

		Proposed Rate	January	February	March	April	May	June	July	August	September	October	November	December	Total
48	Basin, SA 505	139.75	1,463.18	1,650.45	1,555.42	1,193.47	934.93	1,344.40	1,576.38	1,523.28	1,530.26	1,621.10	1,545.64	1,368.15	17,306.64
49	Black Hills SA 347	139.75	6,365.61	7,721.19	7,574.45	5,281.15	4,497.16	6,273.38	7,472.43	7,005.67	7,208.31	6,773.68	6,104.28	6,098.69	78,375.99
50	BPA Gazely SA 229	139.75	484.93	476.55	394.10	202.64	-	47.52	-	2.80	-	451.39	443.01	415.06	2,917.98
51	BPA Yakima SA 328	139.75	927.94	1,028.56	891.61	361.95	-	61.49	-	4.19	-	846.89	586.95	628.88	5,338.45
52	BPA Clark SA 370	139.75	3,878.06	4,771.07	4,274.95	1,215.83	-	163.51	-	12.58	-	3,422.48	3,338.63	3,196.08	24,273.18
53	BPA Benton/Rimrock SA 539	139.75	180.28	181.68	184.47	69.88	-	5.59	-	-	-	163.51	153.73	117.39	1,056.51
54	BPA OR Wind, SA 538	139.75	40.53	67.08	13.98	-	-	-	-	-	-	47.52	-	-	169.10
55	BPA Neff/Gala	139.75	-	2.80	2.80	-	-	-	-	-	-	16.77	23.76	23.76	69.88
56	Tri State SA 628	139.75	2,764.26	2,635.69	3,066.12	2,268.14	1,566.60	2,006.81	1,772.03	1,949.51	2,251.37	2,539.26	2,379.94	2,388.33	27,588.05
57	USBR SA 506	139.75	1.40	1.40	1.40	33.54	75.47	76.86	85.25	88.04	69.88	1.40	1.40	1.40	437.42
58	WAPA SA 175	139.75	-	-	-	-	-	-	-	-	-	-	-	-	-
59	Calpine	139.75	-	-	-	-	-	-	-	-	-	-	-	33.54	33.54
60	BPA Eastside	139.75	39,199.88	32,139.71	29,727.62	11,235.90	-	1,819.55	-	92.24	-	33,362.52	28,504.81	33,095.60	209,177.80
61	BPA Idaho Falls	139.75	13,555.75	13,416.00	13,185.41	9,509.99	13,316.78	13,428.58	17,056.49	14,925.30	11,684.50	12,982.78	10,968.98	9,171.79	153,202.34
62	Exelon	139.75	104.81	110.40	107.61	97.83	110.40	121.58	100.62	47.52	99.22	109.01	76.86	100.62	1,186.48
63	Avangrid	139.75	4,305.70	4,446.85	4,420.29	4,361.60	4,480.39	4,467.81	4,477.59	4,509.73	4,444.05	4,480.39	4,509.73	4,557.25	53,461.36
64	NTUA	139.75	368.94	338.20	327.02	261.33	247.36	269.72	364.75	338.20	294.87	347.98	301.86	370.34	3,830.55
65	3 Phases	139.75	1.40	8.39	6.99	9.78	11.18	15.37	19.57	25.16	19.57	9.78	9.78	11.18	148.14
66	UAMPS RS 297	139.75	2,159.14	2,255.57	2,002.62	1,915.97	2,157.74	2,152.15	2,435.84	2,455.41	2,424.66	1,978.86	1,934.14	1,943.92	25,816.02
67	UMPA RS 637	139.75	37,828.93	29,027.47	24,273.18	40,162.75	36,259.54	58,435.07	81,447.70	85,023.90	78,459.84	44,345.47	31,788.93	35,753.64	582,806.41
68	Deseret RS 280	139.75	5,369.20	5,031.00	-	-	-	-	-	-	1,379.33	-	-	-	11,779.53
69	WAPA RS 262/263	139.75	-	-	-	-	-	24,229.86	29,696.88	-	-	-	-	-	53,926.73
70	Total	139.75	118,999.92	105,310.01	92,010.00	78,181.74	63,657.52	114,919.22	146,505.52	118,003.50	109,865.86	113,500.76	92,672.42	99,275.61	1,252,902.07

	Point to Point MW 2019														Monthly Revenue - Current Rate														Monthly Revenue - Proposed Rate												
	Customer	January	February	March	April	May	June	July	August	September	October	November	December	Total	Current Rate	January	February	March	April	May	June	July	August	September	October	November	December	Total	Proposed Rate	January	February	March	April	May	June	July	August	September	October	November	December	Total
1	Black Hills: SA 67	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	600.00	45.833	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	28,723.54	139.75	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	87,581.33
2	Avangrid SA 895	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	360.00	45.833	1,436.18	1,436.18	1,436.18	1,436.18	1,436.18	1,436.18	1,436.18	1,436.18	1,436.18	1,436.18	1,436.18	1,436.18	17,234.12	139.75	4,379.07	4,379.07	4,379.07	4,379.07	4,379.07	4,379.07	4,379.07	4,379.07	4,379.07	4,379.07	4,379.07	4,379.07	52,548.80
3	Thermo5A 568	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00	132.00	45.833	526.60	526.60	526.60	526.60	526.60	526.60	526.60	526.60	526.60	526.60	526.60	526.60	6,319.18	139.75	1,605.66	1,605.66	1,605.66	1,605.66	1,605.66	1,605.66	1,605.66	1,605.66	1,605.66	1,605.66	1,605.66	1,605.66	19,267.89
4	Powerex: SA 169	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	80.00	960.00	45.833	3,829.81	3,829.81	3,829.81	3,829.81	3,829.81	3,829.81	3,829.81	3,829.81	3,829.81	3,829.81	3,829.81	3,829.81	45,957.67	139.75	11,677.51	11,677.51	11,677.51	11,677.51	11,677.51	11,677.51	11,677.51	11,677.51	11,677.51	11,677.51	11,677.51	11,677.51	140,130.12
5	NextEra: SA 733	99.00	99.00	99.00	99.00	99.00	80.00	80.00	80.00	80.00	80.00	99.00	99.00	1,093.00	45.833	4,739.38	4,739.38	4,739.38	4,739.38	4,739.38	3,829.81	3,829.81	3,829.81	3,829.81	3,829.81	4,739.38	4,739.38	52,324.72	139.75	14,450.92	14,450.92	14,450.92	14,450.92	14,450.92	11,677.51	11,677.51	11,677.51	11,677.51	11,677.51	14,450.92	14,450.92	159,543.98
6	State of SD:SA 779	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	48.00	45.833	191.49	191.49	191.49	191.49	191.49	191.49	191.49	191.49	191.49	191.49	191.49	191.49	2,297.88	139.75	583.88	583.88	583.88	583.88	583.88	583.88	583.88	583.88	583.88	583.88	583.88	583.88	7,006.51
7	SMUD SA 863	19.00	19.00	19.00	19.00	19.00	19.00	19.00	19.00	19.00	19.00	19.00	19.00	228.00	45.833	909.58	909.58	909.58	909.58	909.58	909.58	909.58	909.58	909.58	909.58	909.58	909.58	10,914.95	139.75	2,773.41	2,773.41	2,773.41	2,773.41	2,773.41	2,773.41	2,773.41	2,773.41	2,773.41	2,773.41	2,773.41	2,773.41	33,280.90
8	Salt River Project SA 809	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	300.00	45.833	1,196.81	1,196.81	1,196.81	1,196.81	1,196.81	1,196.81	1,196.81	1,196.81	1,196.81	1,196.81	1,196.81	1,196.81	14,361.77	139.75	3,649.22	3,649.22	3,649.22	3,649.22	3,649.22	3,649.22	3,649.22	3,649.22	3,649.22	3,649.22	3,649.22	3,649.22	43,790.66
9	Clatskanie SA 899-901	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	18.00	15.00	15.00	15.00	207.00	45.833	861.71	861.71	861.71	861.71	861.71	861.71	861.71	861.71	861.71	718.09	718.09	718.09	9,909.62	139.75	2,627.44	2,627.44	2,627.44	2,627.44	2,627.44	2,627.44	2,627.44	2,627.44	2,189.53	2,189.53	2,189.53	2,189.53	30,215.56
10	Evergreen SA 874	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	10.00	120.00	45.833	478.73	478.73	478.73	478.73	478.73	478.73	478.73	478.73	478.73	478.73	478.73	478.73	5,744.71	139.75	1,459.69	1,459.69	1,459.69	1,459.69	1,459.69	1,459.69	1,459.69	1,459.69	1,459.69	1,459.69	1,459.69	1,459.69	17,516.27
11	Powerex: Malin -700-702	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	300.00	3,600.00	45.833	14,361.77	14,361.77	14,361.77	14,361.77	14,361.77	14,361.77	14,361.77	14,361.77	14,361.77	14,361.77	14,361.77	14,361.77	172,341.25	139.75	43,790.66	43,790.66	43,790.66	43,790.66	43,790.66	43,790.66	43,790.66	43,790.66	43,790.66	43,790.66	43,790.66	43,790.66	525,487.95
12	Powerex: Malin -748	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	600.00	45.833	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	28,723.54	139.75	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	87,581.33
13	Powerex: Malin -749	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	150.00	1,800.00	45.833	7,180.89	7,180.89	7,180.89	7,180.89	7,180.89	7,180.89	7,180.89	7,180.89	7,180.89	7,180.89	7,180.89	7,180.89	86,170.62	139.75	21,895.33	21,895.33	21,895.33	21,895.33	21,895.33	21,895.33	21,895.33	21,895.33	21,895.33	21,895.33	21,895.33	21,895.33	262,743.98
14	City of Roseville SA 881	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	600.00	45.833	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	28,723.54	139.75	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	87,581.33
15	BPA Lost Creek SA 656	40.49	40.49	5.49	6.49	25.49	-	10.49	26.49	25.49	37.49	53.48	38.49	310.38	45.833	1,938.36	1,938.36	262.82	310.69	1,220.27	-	502.18	1,268.14	1,220.27	1,794.74	2,560.22	1,842.62	14,858.69	139.75	5,910.28	5,910.28	801.37	947.34	3,720.75	-	1,531.21	3,866.72	3,720.75	5,472.37	7,806.42	5,618.34	45,305.82
16	BPA GS SA 179	13.11	12.62	5.81	5.79	10.97	8.37	10.31	10.68	13.88	18.80	-	18.80	129.14	45.833	627.61	604.15	278.14	277.18	525.16	400.69	493.57	511.28	664.47	900.00	-	900.00	6,182.26	139.75	1,913.65	1,842.13	848.08	845.16	1,601.28	1,221.76	1,504.94	1,558.95	2,026.05	2,744.21	-	-	18,850.42
17	Obsidian Renewables SA 880 and 836	-	-	-	-	-	-	-	-	-	10.00	60.00	50.00	120.00	45.833	-	-	-	-	-	-	-	-	-	478.73	2,872.35	2,393.63	5,744.71	139.75	-	-	-	-	-	-	-	-	-	-	1,459.69	8,758.13	7,298.44	17,516.27
18	Garrett SA 966	-	-	-	-	-	-	-	-	-	-	-	10.00	10.00	45.833	-	-	-	-	-	-	-	-	-	-	-	478.73	478.73	139.75	-	-	-	-	-	-	-	-	-	-	-	-	1,459.69	1,459.69
19	Idaho Power SA 212	-	-	-	-	-	50.00	50.00	50.00	50.00	50.00	-	-	250.00	45.833	-	-	-	-	-	2,393.63	2,393.63	2,393.63	2,393.63	2,393.63	-	-	11,968.14	139.75	-	-	-	-	-	7,298.44	7,298.44	7,298.44	7,298.44	7,298.44	-	-	36,492.22
20	EWEB SA 605	-	-	-	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	25.00	225.00																												
21	Total	949.60	949.11	907.30	933.28	957.46	960.37	972.80	989.17	991.37	1,015.29	1,031.48	1,035.29	11,692.52		45,459.79	45,436.33	43,434.78	43,481.70	44,639.26	44,778.56	45,373.62	46,157.29	46,262.61	47,407.73	48,182.78	48,365.18	548,979.64		138,612.04	138,540.52	132,437.56	132,580.61	136,110.14	136,534.91	138,349.30	140,738.81	141,059.94	144,551.52	146,914.75	147,470.89	1,673,900.99

Reconciliation to Exhibit No. PAC-0017, Attachment 14, line 26 (g26)

Total from Line 21	11,693
Losses from Exhibit No. PAC-0017, Attachment 14, line 42, g25	1,574
PAC LTP Various from Exhibit No. PAC-0021, Attachment 14, line 42 g1	29,827
Total - Ties with g26	43,094

	Load	BPA Yakama NFO	BPA Gazley NFO	BPA Clarke PUD NFO	BPA: Benton REA NFO	BPA Oregon Wind NFO	BPA CEC NFO	Tri-State NFO	Calpine Energy Solutions LLC NFO	Basin Electric NFO	Black Hills NFO	USBR NFO	WAPA NFO	Avangrid Renewables, LLC NFO	Exelon NFO	BPA South East Idaho NFO	BPA Idaho Falls NFO	3 Phases Renewables Inc. NFO	NTUA NFO	BPA SVEC		UAMPS OS	UMPA OS	Deseret OS	WAPA OS		
	Month	SA 328	SA 229	SA 735	SA 539	SA 538	SA 827	SA 628	SA 299	SA 505	SA 347	SA 506	SA 175	SA 742	SA 943	SA 746	SA 747	SA 876	SA 894	SA 865	Subtotal	RS 297	RS 637	RS 280	RS 262/263	Subtotal	Total
1	1/19	6.877	3.599	28.753	1.10	0.303	-	19.776	15.445	10.472	45.550	0.005	-	30.813	0.753	330.219	97.004	0.014	2.639	-		407.613	63.523	148.273	-		
2	2/19	7.675	3.556	35.605	1.57	0.503	0.025	18.859	16.139	11.805	55.250	0.005	-	31.822	0.794	280.106	96.004	0.061	2.423	-		382.961	63.998	81.327	-		
3	3/19	7.341	3.245	35.183	1.18	0.113	0.021	21.935	14.330	11.125	54.200	0.005	-	31.633	0.771	284.053	94.345	0.052	2.343	-		313.509	33.096	57.693	-		
4	4/19	5.693	3.184	19.137	1.13	-	-	16.229	13.705	8.541	37.790	0.239	-	31.207	0.695	176.913	68.051	0.065	1.872	-		338.385	17.893	60.144	-		
5	5/19	5.014	2.936	11.548	0.30	-	-	11.205	15.436	6.688	32.180	0.541	-	32.057	0.787	120.639	95.292	0.077	1.772	-		405.129	32.352	98.934	-		
6	6/19	4.277	3.306	11.268	0.33	-	-	14.356	15.396	9.619	44.890	0.545	-	31.974	0.873	168.546	96.091	0.105	1.930	-		616.856	95.206	120.695	-		
7	7/19	5.497	3.424	13.915	0.39	-	-	12.675	17.430	11.281	53.470	0.613	-	32.036	0.721	191.323	122.045	0.139	2.614	-		771.965	150.967	147.77	-		
8	8/19	5.823	3.626	16.110	0.36	-	-	13.948	17.571	10.900	50.130	0.626	-	32.271	0.337	166.870	106.803	0.183	2.422	-		805.291	152.486	86.76	-		
9	9/19	5.362	3.725	13.048	0.30	-	-	16.112	17.345	10.949	51.580	0.499	-	31.798	0.706	144.229	107.834	0.137	2.114	-		758.152	165.869	92.82	-		
10	10/19	6.574	3.503	26.583	0.37	0.373	0.125	18.170	14.160	11.595	48.470	0.006	-	32.055	0.775	298.056	92.898	0.072	2.494	-		384.322	43.626	69.167	-		
11	11/19	4.454	3.361	25.319	1.16	-	0.182	17.030	13.842	11.057	43.680	0.005	-	32.271	0.553	247.436	78.494	0.073	2.164	-		431.189	47.886	74.198	-		
12	12/19	4.806	3.168	24.416	1.27	-	0.182	17.090	13.906	9.793	43.640	0.005	-	32.605	0.716	290.964	65.626	0.083	2.648	0.235		464.398	32.605	85.158	-		
13	Total	69.393	40.633	260.885	9.448	1.292	0.535	197.385	184.705	123.825	560.830	3.094	- (not billed)	382.542	8.481	2,699.354	1,120.487	1.061	27.435	0.235	5,691.620	6,079.770	927.168	1,122.939	- (not billed)	8,129.877	13,821.50
	Monthly Revenue - Current Rate																					[Total ties to Exhibit No. PAC-0018, Page 11, line 13 f + line 27] excluding WAPA items not billed]					
14	1/19	1,217.23	637.02	5,089.28	194.17	53.63	-	3,500.35	2,733.77	1,853.54	8,062.35	0.89	-	5,453.90	133.28	58,448.76	17,169.71	2.48	467.10	-	105,017.46	72,147.50	11,243.57	26,244.32	-	109,635.39	214,652.86
15	2/19	1,358.48	629.41	6,302.09	278.24	89.03	4.43	3,338.04	2,856.60	2,089.49	9,779.25	0.89	-	5,632.49	140.54	49,578.76	16,992.71	10.80	428.87	-	99,510.11	67,784.10	11,327.65	14,394.88	-	93,506.62	193,016.73
16	3/19	1,299.36	574.37	6,227.39	208.51	20.00	3.72	3,882.50	2,536.41	1,969.13	9,593.40	0.89	-	5,599.04	136.47	50,277.38	16,699.07	9.20	414.71	-	99,451.52	55,491.09	5,857.99	10,211.66	-	71,560.75	171,012.27
17	4/19	1,007.66	563.57	3,387.25	199.30	-	-	2,872.53	2,425.79	1,511.76	6,688.83	42.30	-	5,523.64	123.02	31,313.60	12,045.03	11.51	331.34	-	68,047.12	59,894.15	3,167.06	10,645.49	-	73,706.69	141,753.81
18	5/19	887.48	519.67	2,044.00	53.63	-	-	1,983.29	2,732.17	1,183.78	5,695.86	95.76	-	5,674.09	139.30	21,353.10	16,866.68	13.63	313.64	-	59,556.08	71,707.83	5,726.30	17,511.32	-	94,945.46	154,501.53
19	6/19	757.03	585.16	1,994.44	57.53	-	-	2,541.01	2,725.09	1,702.56	7,945.53	96.47	-	5,659.40	154.52	29,832.64	17,008.11	18.59	341.61	-	71,419.68	109,183.51	16,851.46	21,363.02	-	147,397.99	218,817.67
20	7/19	972.97	606.05	2,462.96	69.21	-	-	2,243.48	3,085.11	1,996.74	9,464.19	108.50	-	5,670.37	127.62	33,864.17	21,601.97	24.60	462.68	-	82,760.60	136,637.81	26,721.16	26,155.29	-	189,514.25	272,274.85
21	8/19	1,030.67	641.80	2,851.47	63.54	-	-	2,468.80	3,110.07	1,929.30	8,873.01	110.80	-	5,711.97	59.65	29,535.99	18,904.13	32.39	428.69	-	75,752.28	142,536.51	26,990.02	15,356.52	-	184,883.05	260,635.33
22	9/19	949.07	659.33	2,309.50	53.10	-	-	2,851.82	3,070.07	1,937.97	9,129.66	88.32	-	5,628.25	124.96	25,528.53	19,086.62	24.25	374.18	-	71,815.63	134,192.90	29,358.81	16,429.14	-	179,980.86	251,796.48
23	10/19	1,163.60	620.03	4,705.19	65.31	66.02	22.13	3,216.09	2,506.32	2,052.32	8,579.19	1.06	-	5,673.74	137.18	52,755.91	16,442.95	12.74	441.44	-	98,461.21	68,024.99	7,721.80	12,242.56	-	87,989.36	186,450.56
24	11/19	788.36	594.90	4,481.46	205.32	-	32.21	3,014.31	2,450.03	1,957.09	7,731.36	0.89	-	5,711.97	97.88	43,796.17	13,893.44	12.92	383.03	-	85,151.34	76,320.45	8,475.82	13,133.05	-	97,929.32	183,080.66
25	12/19	850.66	560.74	4,321.63	224.44	-	32.21	3,024.93	2,461.36	1,733.36	7,724.28	0.89	-	5,771.09	126.73	51,500.63	11,615.80	14.69	468.70	41.60	90,432.13	82,198.45	10,667.08	15,072.97	-	107,938.49	198,370.63
26	Total	12,282.56	7,192.04	46,176.65	1,672.30	228.68	94.70	34,937.15	32,692.79	21,917.03	99,266.91	547.64	-	67,709.93	1,501.14	477,785.66	198,326.20	187.80	4,856.00	41.60	1,007,375.15	1,076,119.29	164,108.74	198,760.20	-	1,438,988.23	2,446,363.37
	Monthly Revenue - Proposed Rate																										
27	1/19	904.90	473.57	3,783.41	144.35	39.87	-	2,602.19	2,032.30	1,377.94	5,993.61	0.66	-	4,054.47	99.08	43,451.21	12,764.08	1.84	347.25	-	78,070.69	53,634.94	8,358.55	19,510.21	-	81,503.69	159,574.39
28	2/19	1,009.90	467.91	4,685.01	206.85	66.19	3.29	2,481.52	2,123.62	1,553.34	7,269.96	0.66	-	4,187.23	104.48	36,857.19	12,632.49	8.03	318.83	-	73,976.49	50,391.16	8,421.05	10,701.25	-	69,513.46	143,489.95
29	3/19	965.95	426.99	4,629.48	155.00	14.87	2.76	2,886.27	1,885.58	1,463.86	7,131.80	0.66	-	4,162.37	101.45	37,376.55	12,414.20	6.84	308.30	-	73,932.93	41,252.45	4,354.87	7,591.42	-	53,198.74	127,131.68
30	4/19	749.10	418.96	2,518.10	148.16	-	-	2,135.46	1,803.35	1,123.85	4,972.52	31.45	-	4,106.31	91.45	23,278.74	8,954.35	8.55	246.32	-	50,586.69	44,525.71	2,354.41	7,913.93	-	54,794.06	105,380.75
31	5/19	659.76	386.33	1,519.52	39.87	-	-	1,474.39	2,031.12	880.03	4,234.34	71.19	-	4,218.16	103.56	15,874.04	12,538.81	10.13	233.17	-	44,274.39	53,308.09	4,256.97	13,018.03	-	70,583.09	114,857.48
32	6/19	562.78	435.01	1,482.68	42.76	-	-	1,889.01	2,025.85	1,265.70	5,906.76	71.71	-	4,207.23	114.87	22,177.79	12,643.94	13.82	253.96	-	53,093.87	81,167.76	12,527.49	15,881.41	-	109,576.66	162,670.54
33	7/19	723.31	450.54	1,830.98	51.45	-	-	1,667.81	2,293.49	1,484.39	7,035.74	80.66	-	4,215.39	94.87	25,174.85	16,059.05	18.29	343.96	-	61,524.79	101,577.47	19,864.69	19,444.02	-	140,886.18	202,410.97
34	8/19	766.21	477.12	2,119.80	47.24	-	-	1,835.32	2,312.04	1,434.25	6,596.26	82.37	-	4,246.31	44.34	21,957.26	14,053.46	24.08	318.69	-	56,314.76	105,962.61	20,064.57	11,416.14	-	137,443.31	193,758.07
35	9/19	705.55	490.15	1,716.89	39.47	-	-	2,120.07	2,282.31	1,440.70	6,787.05	65.66	-	4,184.08	92.90	18,978.08	14,189.12	18.03	278.17	-	53,388.22	99,759.91	21,825.54	12,213.53	-	133,798.99	187,187.21
36	10/19	865.03	460.94	3,497.87	48.55	49.08	16.45	2,390.86	1,863.22	1,525.70	6,377.83	0.79	-	4,217.89	101.98	39,219.10	12,223.80	9.47	328.17	-	73,196.73	50,570.24	5,740.44	9,101.20	-	65,411.88	138,608.61
37	11/19	586.07	442.25	3,331.55	152.64	-	23.95	2,240.86	1,821.37	1,454.91	5,747.55	0.66	-	4,246.31	72.77	32,558.37	10,328.48	9.61	284.75	-	63,302.08	56,737.14	6,300.98	9,763.20	-	72,801.32	136,103.40
38	12/19	632.39	416.85	3,212.73	166.85	-	23.95	2,248.75	1,829.79	1,288.59	5,742.28	0.66	-	4,290.26	94.21	38,285.92	8,635.27	10.92	348.43	30.92	67,227.86	61,106.88	7,929.98	11,205.35	-	80,242.21	147,470.07
39	Total	9,130.94	5,346.61	34,328.03	1,243.20	170.01	70.40	25,972.51	24,304.04	16,293.26	73,795.69	407.12	-	50,336.02	1,115.96	355,189.10	147,437.04	139.61	3,609.98	30.92	748,889.51	799,994.38	121,999.55	147,759.68	-	1,069,753.61	1,818,643.12

	Customer:	Resources	Capacity		Monthly Revenue - Current Rate														Monthly Revenue - Proposed Rate												
			May - October	Nov-April	Current Rate	January	February	March	April	May	June	July	August	September	October	November	December	Total	Proposed Rate	January	February	March	April	May	June	July	August	September	October	November	December	Total
	Wind				549.417														675.5												
1	Avangrid	HINSHAW_7_UNITS	19.0	19.0		10,438.92	10,438.92	10,438.92	10,438.92	10,438.92	10,438.92	10,438.92	10,438.92	10,438.92	10,438.92	10,438.92	10,438.92	125,267.08		12,834.50	12,834.50	12,834.50	12,834.50	12,834.50	12,834.50	12,834.50	12,834.50	12,834.50	12,834.50	12,834.50	12,834.50	154,014.00
2	NextEra	CAMPCOL_6_UNIT	98.9	98.9		54,337.34	54,337.34	54,337.34	54,337.34	54,337.34	54,337.34	54,337.34	54,337.34	54,337.34	54,337.34	54,337.34	54,337.34	652,048.10		66,806.95	66,806.95	66,806.95	66,806.95	66,806.95	66,806.95	66,806.95	66,806.95	66,806.95	66,806.95	66,806.95	66,806.95	801,683.40
3	SCE	JOLLYHIL_1_GOSHEN	124.5	124.5		68,402.42	68,402.42	68,402.42	68,402.42	68,402.42	68,402.42	68,402.42	68,402.42	68,402.42	68,402.42	68,402.42	68,402.42	820,829.00		84,099.75	84,099.75	84,099.75	84,099.75	84,099.75	84,099.75	84,099.75	84,099.75	84,099.75	84,099.75	84,099.75	84,099.75	1,009,197.00
4	Exelon	NINEMIL_7_UNIT 1	210.0	210.0		115,377.57	115,377.57	115,377.57	115,377.57	115,377.57	115,377.57	115,377.57	115,377.57	115,377.57	115,377.57	115,377.57	115,377.57	1,384,530.84		141,855.00	141,855.00	141,855.00	141,855.00	141,855.00	141,855.00	141,855.00	141,855.00	141,855.00	141,855.00	141,855.00	141,855.00	1,702,260.00
5	Tenaska (ST Transmission)		16.5	16.5		9,065.38	9,065.38	9,065.38	9,065.38	9,065.38	9,065.38	9,065.38	9,065.38	9,065.38	9,065.38	9,065.38	9,065.38	108,784.57		11,145.75	11,145.75	11,145.75	11,145.75	11,145.75	11,145.75	11,145.75	11,145.75	11,145.75	11,145.75	11,145.75	11,145.75	133,749.00
6	Total		468.9	468.9		257,621.63	257,621.63	257,621.63	257,621.63	257,621.63	257,621.63	257,621.63	257,621.63	257,621.63	257,621.63	257,621.63	257,621.63	**3,091,459.58**		316,741.95	316,741.95	316,741.95	316,741.95	316,741.95	316,741.95	316,741.95	316,741.95	316,741.95	316,741.95	316,741.95	316,741.95	**3,800,903.40**
	Solar				549.417														551.833												
7	Avangrid	Gala	56.0	56.0		30,767.35	30,767.35	30,767.35	30,767.35	30,767.35	30,767.35	30,767.35	30,767.35	30,767.35	30,767.35	30,767.35	30,767.35	369,208.22		30,902.65	30,902.65	30,902.65	30,902.65	30,902.65	30,902.65	30,902.65	30,902.65	30,902.65	30,902.65	30,902.65	30,902.65	370,831.78
8	Airport Solar	Airport Solar	56.7	56.7		31,151.94	31,151.94	31,151.94	31,151.94	31,151.94	31,151.94	31,151.94	31,151.94	31,151.94	31,151.94	31,151.94	31,151.94	373,823.33		31,288.93	31,288.93	31,288.93	31,288.93	31,288.93	31,288.93	31,288.93	31,288.93	31,288.93	31,288.93	31,288.93	31,288.93	375,467.17
9	LH Garrett	Garrett Solar	10.0	10.0		5,494.17	5,494.17	5,494.17	5,494.17	5,494.17	5,494.17	5,494.17	5,494.17	5,494.17	5,494.17	5,494.17	5,494.17	65,930.04		5,518.33	5,518.33	5,518.33	5,518.33	5,518.33	5,518.33	5,518.33	5,518.33	5,518.33	5,518.33	5,518.33	5,518.33	66,219.96
10	Total		122.7	122.7		67,413.47	67,413.47	67,413.47	67,413.47	67,413.47	67,413.47	67,413.47	67,413.47	67,413.47	67,413.47	67,413.47	67,413.47	**808,961.59**		67,709.91	67,709.91	67,709.91	67,709.91	67,709.91	67,709.91	67,709.91	67,709.91	67,709.91	67,709.91	67,709.91	67,709.91	**812,518.91**
	Non-Ver				149.500														330.250												
11	BPA IDAHO FALLS IBDPCW	196 Upper Plant Out-nondispatchable	8.0	8.0		1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	14,352.00		2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	31,704.00
12	BPA IDAHO FALLS IBDPCW	197 Lower Plant Out-nondispatchable	8.0	8.0		1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	14,352.00		2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	31,704.00
13	BPA IDAHO FALLS IBDPCW	207 City Plant Out-nondispatchable	8.0	8.0		1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	1,196.00	14,352.00		2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	2,642.00	31,704.00
14	BPA IDAHO FALLS IBDPCW	296 Old Lower Plant Out-nondispatchable	3.7	3.7		559.13	559.13	559.13	559.13	559.13	559.13	559.13	559.13	559.13	559.13	559.13	559.13	6,709.56		1,235.14	1,235.14	1,235.14	1,235.14	1,235.14	1,235.14	1,235.14	1,235.14	1,235.14	1,235.14	1,235.14	1,235.14	14,821.62
15	BPA SOUTH IDAHO BPAPCE	PALISADI_7_UNIT 1-nondispatchable	44.0	44.0		6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	78,936.00		14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	174,372.00
16	BPA SOUTH IDAHO BPAPCE	PALISADI_7_UNIT 2-nondispatchable	44.0	44.0		6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	78,936.00		14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	174,372.00
17	BPA SOUTH IDAHO BPAPCE	PALISADI_7_UNIT 3-nondispatchable	44.0	44.0		6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	78,936.00		14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	174,372.00
18	BPA SOUTH IDAHO BPAPCE	PALISADI_7_UNIT 4-nondispatchable	44.0	44.0		6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	6,578.00	78,936.00		14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	14,531.00	174,372.00
19	Evergreen Bio Falls Creek H.P., LP SA 568	Nondispatchable	10.0	10.0		1,495.00	1,495.00	1,495.00	1,495.00	1,495.00	1,495.00	1,495.00	1,495.00	1,495.00	1,495.00	1,495.00	1,495.00	17,940.00		3,302.50	3,302.50	3,302.50	3,302.50	3,302.50	3,302.50	3,302.50	3,302.50	3,302.50	3,302.50	3,302.50	3,302.50	39,630.00
20	(818510)	Nondispatchable	5.0	5.0		741.52	741.52	741.52	741.52	741.52	741.52	741.52	741.52	741.52	741.52	741.52	741.52	8,898.24		1,638.04	1,638.04	1,638.04	1,638.04	1,638.04	1,638.04	1,638.04	1,638.04	1,638.04	1,638.04	1,638.04	1,638.04	19,656.48
21	Shell Energy Corporation, Inc.	WESTVALL7UNIT1 ch1-dispatchable	40.0	40.0		5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	71,760.00		-	-	-	-	-	-	-	-	-	-	-	-	-
22	Shell Energy Corporation, Inc.	WESTVALL7UNIT2 ch1-dispatchable	40.0	40.0		5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	71,760.00		-	-	-	-	-	-	-	-	-	-	-	-	-
23	Shell Energy Corporation, Inc.	WESTVALL7UNIT3 ch1-dispatchable	40.0	40.0		5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	71,760.00		-	-	-	-	-	-	-	-	-	-	-	-	-
24	Shell Energy Corporation, Inc.	WESTVALL7UNIT4 ch1-dispatchable	40.0	40.0		5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	71,760.00		-	-	-	-	-	-	-	-	-	-	-	-	-
25	Shell Energy Corporation, Inc.	WESTVALL7UNIT5 ch1-dispatchable	40.0	40.0		5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	5,980.00	71,760.00		-	-	-	-	-	-	-	-	-	-	-	-	-
26	SCPPA	TIETONHY_6_UNIT-nondispatchable	18.0	-		-	-	-	-	2,691.00	2,691.00	2,691.00	2,691.00	2,691.00	2,691.00	-	-	16,146.00		-	-	-	-	5,944.50	5,944.50	5,944.50	5,944.50	5,944.50	5,944.50	-	-	35,667.00
27	Thermo		11.0	11.0		1,644.50	1,644.50	1,644.50	1,644.50	1,644.50	1,644.50	1,644.50	1,644.50	1,644.50	1,644.50	1,644.50	1,644.50	19,734.00		3,632.75	3,632.75	3,632.75	3,632.75	3,632.75	3,632.75	3,632.75	3,632.75	3,632.75	3,632.75	3,632.75	3,632.75	43,593.00
28	Total		447.7	429.7		64,240.15	64,240.15	64,240.15	64,240.15	66,931.15	66,931.15	66,931.15	66,931.15	66,931.15	66,931.15	64,240.15	64,240.15	**787,027.80**		75,858.43	75,858.43	75,858.43	75,858.43	81,802.93	81,802.93	81,802.93	81,802.93	81,802.93	81,802.93	75,858.43	75,858.43	**945,968.10**

Rate 0.151

Billed in:

	Customer Nu	Customer Name	Contract	Amount	MWh
1	800400	Bonneville Power Administra	SA 229	(4,040.97)	(26,761)
2	800400	Bonneville Power Administra	SA 328	(6,188.04)	(40,980)
3	800400	Bonneville Power Administra	SA 538	(156.13)	(1,034)
4	800400	Bonneville Power Administra	SA 539	(948.17)	(6,279)
5	800400	Bonneville Power Administra	SA 735	(19,647.46)	(130,116)
6	800400	Bonneville Power Administra	SA 746	(328,868.71)	(2,177,938)
7	800400	Bonneville Power Administra	SA 747	(100,566.42)	(666,003)
8	800400	Bonneville Power Administra	SA 827	(120.34)	(797)
9	800400	Bonneville Power Administra	SA 865	(15.21)	(101)
10	800800	Exelon Generation Company	SA 759	(9,609.44)	(63,639)
11	800900	Shell Energy North America	SA 791	(29,018.63)	(192,176)
12	801500	Deseret Generation & Trans	RS 280	(483,694.53)	(3,203,275)
13	802400	Avangrid Renewables, LLC	RS 476	(51,875.64)	(343,547)
14	802400	Avangrid Renewables, LLC	SA 742	(60,643.05)	(401,610)
15	803400	Tri-State Generation & Trans	SA 628	(18,295.91)	(121,165)
16	803500	Utah Associated Municipal P	RS 297	(491,224.52)	(3,253,143)
17	803600	Utah Municipal Power Agency	RS 637	(145,299.50)	(962,248)
18	803800	Western Area Power Adm Ft	SA 175	0.70	5
19	804300	NextEra Energy Resources, L	SA 733	(30,055.19)	(199,041)
20	805000	Southern California Edison C	SA 642	(27,494.11)	(182,080)
21	805300	U.S. Bureau of Reclamation	SA 506	(332.26)	(2,200)
22	816200	Thermo No. 1 BE-01, LLC	SA 568	(9,908.68)	(65,620)
23	817990	Southern California Public Pc	SA 629	(4,401.33)	(29,148)
24	818140	Tenaska Power Services Co	SA 125	(1,081.09)	(7,160)
25	818334	Obsidian Renewables LLC	SA 836	(165.33)	(1,095)
26	818349	Exelon Generation Company	SA 943	(904.86)	(5,992)
27	818479	Calpine Energy Solutions	SA 299	(17,841.73)	(118,157)
28	818511	Evergreen Biopower	SA 874	(8,642.85)	(57,237)
29	818564	3 Phase Renewables	SA 876	(93.79)	(621)
30	818579	Navajo Tribal Utility Authorit	SA 894	(2,518.97)	(16,682)
31	818691	LH Garrett	SA 966	(34.32)	(227)
32		**Grand Total**		**(1,853,686.48)**	**(12,276,069)**

Monthly Revenue - Current Rate

	Current Rate	Jan-20	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
1	**0.151**	355.36	392.85	321.90	349.55	315.19	313.28	327.04	339.50	341.30	317.91	332.15	334.94	4,040.97
2		524.37	592.72	575.19	584.23	495.55	485.18	474.16	524.77	535.30	455.92	471.12	469.53	6,188.04
3		11.85	20.38	18.15	19.41	8.14	10.15	5.42	6.01	10.05	9.31	15.17	22.09	156.13
4		118.00	127.08	124.27	124.71	81.10	46.72	39.73	42.88	38.01	37.91	79.56	88.20	948.17
5		2,212.71	2,040.42	2,365.06	2,041.96	1,512.49	1,238.87	1,144.72	1,148.29	1,174.57	1,207.93	1,675.24	1,885.20	19,647.46
6		27,813.37	27,189.80	24,723.90	28,790.06	26,835.89	28,909.28	30,086.99	36,614.43	31,404.46	23,349.81	22,859.99	20,290.73	328,868.71
7		9,404.16	10,074.48	9,983.10	9,052.91	7,411.21	8,788.79	7,978.29	7,338.23	8,146.47	6,762.08	7,437.07	8,189.63	100,566.42
8		13.25	12.97	14.41	10.80	8.44	7.67	6.85	6.82	7.86	8.71	10.79	11.77	120.34
9		15.21	-	-	-	-	-	-	-	-	-	-	-	15.21
10		503.35	604.25	365.41	438.77	1,247.23	903.90	1,217.76	1,159.92	880.49	986.36	923.15	378.85	9,609.44
11		1,480.26	70.71	575.09	4,767.89	70.07	-	2,186.07	5,199.22	5,617.25	3,225.41	2,925.53	2,901.13	29,018.63
12		38,458.23	41,578.81	20,220.66	57,470.28	41,589.19	40,754.75	38,788.43	44,710.49	45,230.77	38,129.45	40,387.31	36,376.16	483,694.53
13		4,258.31	6,106.85	6,818.27	2,175.23	4,522.66	3,727.63	3,502.58	2,657.13	3,121.97	3,778.85	6,061.91	5,144.25	51,875.64
14		5,263.28	4,200.13	3,679.66	5,147.38	5,131.22	5,740.99	6,097.58	6,142.55	5,993.83	5,064.45	4,991.59	3,190.39	60,643.05
15		1,894.74	1,747.23	1,534.70	1,637.29	1,375.43	1,343.39	1,374.83	1,589.28	1,568.65	1,294.12	1,423.95	1,512.17	18,295.78
16		40,839.72	26,528.35	34,030.26	26,901.13	39,494.36	39,168.23	50,904.09	76,060.43	79,170.85	45,354.41	(842.02)	33,614.71	491,224.52
17		18,293.15	0.38	193.25	24.82	11,000.02	8,404.17	13,527.14	23,297.16	23,370.96	16,360.24	13,629.66	17,198.55	145,299.50
18		-	0.82	0.65	0.62	53.86	158.46	235.17	341.57	338.63	-	(1,130.48)	-	(0.70)
19		3,033.21	2,893.55	1,654.54	1,460.93	3,934.91	3,762.71	6,005.96	8,822.49	(9,753.72)	3,104.33	3,428.60	1,707.68	30,055.19
20		1,271.63	4,631.35	6,799.21	3,516.02	1,592.94	1,164.84	1,183.65	1,497.01	1,465.68	1,523.65	1,775.32	1,072.81	27,494.11
21		0.60	0.55	0.51	0.56	24.57	47.84	62.06	63.04	65.02	45.86	21.00	0.65	332.26
22		887.68	914.84	864.14	909.65	819.62	835.96	756.37	699.91	724.92	744.13	887.15	864.31	9,908.68
23		-	-	-	48.23	196.28	438.90	395.04	607.18	948.69	1,304.27	462.74	-	4,401.33
24		59.92	104.30	153.07	102.09	198.16	110.30	87.61	58.47	40.74	58.75	59.16	48.52	1,081.09
25		165.33	-	-	-	-	-	-	-	-	-	-	-	165.33
26		66.43	83.17	70.25	78.12	77.02	84.09	86.74	78.96	77.32	70.11	72.87	59.78	904.86
27		1,387.68	1,635.08	1,462.48	1,560.86	1,258.62	1,522.15	1,535.64	1,554.32	1,603.52	1,488.07	1,454.59	1,378.72	17,841.73
28		714.09	729.70	387.34	610.04	646.12	722.10	808.03	846.41	869.87	810.93	804.45	693.77	8,642.85
29		6.66	1.08	10.79	7.33	7.31	8.35	8.91	10.18	10.35	8.66	7.50	6.67	93.79
30		263.00	16.09	443.02	200.76	175.03	222.51	181.23	219.57	218.98	171.37	195.15	212.26	2,518.97
31		34.32	-	-	-	-	-	-	-	-	-	-	-	34.32
32		**159,349.87**	**132,297.94**	**117,389.28**	**148,031.63**	**150,082.63**	**148,921.21**	**169,008.09**	**221,636.22**	**203,222.79**	**155,673.00**	**110,420.22**	**137,653.47**	**1,853,686.35**

Monthly Revenue - Proposed Rate

	Proposed Rate	Jan-20	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
1	**0.182**	428.31	473.50	387.99	421.31	379.90	377.60	394.18	409.20	411.37	383.18	400.34	403.70	4,870.57
2		632.02	714.40	693.28	704.17	597.29	584.79	571.50	632.50	645.20	549.52	567.84	565.92	7,458.43
3		14.28	24.56	21.88	23.39	9.81	12.23	6.53	7.24	12.11	11.22	18.28	26.63	188.18
4		142.23	153.17	149.78	150.31	97.75	56.31	47.89	51.68	45.81	45.69	95.89	106.31	1,142.83
5		2,666.97	2,459.31	2,850.60	2,461.17	1,823.00	1,493.21	1,379.73	1,384.03	1,415.71	1,455.92	2,019.16	2,272.23	23,681.04
6		33,523.40	32,771.81	29,799.67	34,700.60	32,345.24	34,844.30	36,263.79	44,131.30	37,851.73	28,143.48	27,553.10	24,456.38	396,384.80
7		11,334.82	12,142.75	12,032.61	10,911.45	8,932.72	10,593.11	9,616.22	8,844.75	9,818.92	8,150.32	8,963.89	9,870.94	121,212.51
8		15.97	15.63	17.37	13.02	10.17	9.24	8.26	8.22	9.47	10.50	13.01	14.19	145.05
9		18.33	-	-	-	-	-	-	-	-	-	-	-	18.33
10		606.69	728.30	440.43	528.85	1,503.28	1,089.47	1,467.76	1,398.05	1,061.25	1,188.86	1,112.67	456.63	11,582.24
11		1,784.15	85.23	693.15	5,746.73	84.46	-	2,634.87	6,266.61	6,770.46	3,887.58	3,526.14	3,496.73	34,976.10
12		46,353.63	50,114.86	24,371.92	69,268.81	50,127.37	49,121.62	46,751.62	53,889.46	54,516.56	45,957.35	48,678.74	43,844.11	582,996.06
13		5,132.53	7,360.57	8,218.05	2,621.80	5,451.15	4,492.91	4,221.65	3,202.63	3,762.90	4,554.64	7,306.41	6,200.35	62,525.61
14		6,343.82	5,062.41	4,435.09	6,204.13	6,184.65	6,919.60	7,349.40	7,403.60	7,224.35	6,104.17	6,016.35	3,845.37	73,092.95
15		2,283.73	2,105.93	1,849.77	1,973.42	1,657.80	1,619.19	1,657.08	1,915.56	1,890.69	1,559.80	1,716.28	1,822.62	22,051.87
16		49,224.03	31,974.57	41,016.60	32,423.88	47,602.47	47,209.39	61,354.60	91,675.49	95,424.47	54,665.58	(1,014.89)	40,515.74	592,071.94
17		22,048.70	0.46	232.92	29.92	13,258.30	10,129.53	16,304.23	28,080.02	28,168.97	19,718.96	16,427.80	20,729.38	175,129.20
18		-	0.99	0.78	0.75	64.92	190.99	283.45	411.69	408.15	-	(1,362.57)	-	(0.84)
19		3,655.92	3,487.59	1,994.21	1,760.86	4,742.74	4,535.19	7,238.97	10,633.73	(11,756.14)	3,741.64	4,132.48	2,058.26	36,225.46
20		1,532.69	5,582.16	8,195.07	4,237.85	1,919.97	1,403.98	1,426.65	1,804.34	1,766.58	1,836.45	2,139.79	1,293.06	33,138.60
21		0.72	0.66	0.61	0.67	29.61	57.66	74.80	75.98	78.37	55.27	25.31	0.78	400.47
22		1,069.92	1,102.65	1,041.55	1,096.40	987.89	1,007.58	911.65	843.60	873.74	896.90	1,069.28	1,041.75	11,942.91
23		-	-	-	58.13	236.58	529.01	476.14	731.83	1,143.45	1,572.03	557.74	-	5,304.91
24		72.22	125.71	184.49	123.05	238.84	132.94	105.60	70.47	49.10	70.81	71.31	58.48	1,303.04
25		199.27	-	-	-	-	-	-	-	-	-	-	-	199.27
26		80.07	100.24	84.67	94.16	92.83	101.35	104.55	95.17	93.19	84.50	87.83	72.05	1,090.63
27		1,672.57	1,970.76	1,762.72	1,881.30	1,517.01	1,834.64	1,850.90	1,873.42	1,932.72	1,793.57	1,753.21	1,661.77	21,504.60
28		860.69	879.51	466.86	735.28	778.77	870.35	973.92	1,020.18	1,048.45	977.41	969.60	836.20	10,417.21
29		8.03	1.30	13.01	8.83	8.81	10.06	10.74	12.27	12.47	10.44	9.04	8.04	113.04
30		316.99	19.39	533.97	241.98	210.96	268.19	218.44	264.65	263.94	206.55	235.21	255.84	3,036.11
31		41.37	-	-	-	-	-	-	-	-	-	-	-	41.37
32		**192,064.08**	**159,458.44**	**141,489.07**	**178,422.23**	**180,894.30**	**179,494.44**	**203,705.12**	**267,137.70**	**244,944.03**	**187,632.36**	**133,089.27**	**165,913.45**	**2,234,244.47**

	Assignment	Document Number	Business Area	Document Type	Document Date	Posting Key	Amount in local currency	Text	Quantity	Reference	Reference Key 1	Reference Key 2	Reference Key 3	Contract
33	800400	135649461		ZS	2/26/2019	50	(362.02)	2019 01 BPA - EIM1 Cow Crk SS	0.000	59397	0	MW		SA 229
34	800400	135649462		ZS	2/26/2019	50	(30.83)	2019 01 BPA - EIM1A Cow Crk S	0.000	59360	0	MW		SA 229
35	800400	135722443		ZS	3/25/2019	50	(321.90)	2019 02 BPA - EIM1 Cow Crk SS	0.000	59800	0	MW		SA 229
36	800400	136076387		ZS	4/29/2019	50	(349.55)	2019 03 BPA - EIM1 Cow Crk SS	0.000	60131	0	MW		SA 229
37	800400	136159985		ZS	5/27/2019	50	(315.19)	2019 04 BPA - EIM1 Cow Crk SS	0.000	60444	0	MW		SA 229
38	800400	136253214		ZS	6/26/2019	50	(313.28)	2019 05 BPA - EIM1 Cow Crk SS	0.000	60971	0	MW		SA 229
39	800400	136596405		ZS	7/30/2019	50	(327.04)	2019 06 BPA - EIM1 Cow Crk SS	0.000	61366	0	MW		SA 229
40	800400	136687674		ZS	8/28/2019	50	(339.50)	2019 07 BPA - EIM1 Cow Crk SS	0.000	61796	0	MW		SA 229
41	800400	136774762		ZS	9/24/2019	50	(341.30)	2019 08 BPA - EIM1 Cow Crk SS	0.000	62127	0	MW		SA 229
42	800400	137132826		PS	10/29/2019	50	(317.91)	2019 09 BPAP FNO_S5	-2,105.371	100062	PACW	201909	BPAP_FNO_COW_S	SA 229
43	800400	137216494		PS	11/25/2019	50	(332.15)	2019 10 BPAP FNO_S5	-2,199.681	100110	PACW	201910	BPAP_FNO_COW_S	SA 229
44	800400	137307215		PS	12/23/2019	50	(334.94)	2019 11 BPAP FNO_S5	-2,218.146	100159	PACW	201911	BPAP_FNO_COW_S	SA 229
45	800400	137651513		PS	1/28/2020	50	(355.36)	2019 12 BPAP FNO_S5	-2353.374	100227	PACW	201912	BPAP_FNO_COW_S	SA 229
46	800400	135649466		ZS	2/26/2019	50	(595.97)	2019 01 BPA - EIM2 Yakama SSF	0.000	59432	0	MW		SA 328
47	800400	135654676		ZS	2/26/2019	40	7.01	2019 01 BPA - EIM2A Yakama S	0.000	59355	0	MW		SA 328
48	800400	135654676		ZS	2/26/2019	50	(1.88)	2019 01 BPA - EIM2A Yakama S	0.000	59355	0	MW		SA 328
49	800400	135654676		ZS	2/26/2019	50	(1.88)	2019 01 BPA - EIM2A Yakama S	0.000	59355	0	MW		SA 328
50	800400	135722783		ZS	3/25/2019	50	(575.19)	2019 02 BPA - EIM2 Yakama SSF	0.000	59806	0	MW		SA 328
51	800400	136076390		ZS	4/29/2019	50	(584.23)	2019 03 BPA - EIM2 Yakama SSF	0.000	60234	0	MW		SA 328
52	800400	136159987		ZS	5/27/2019	50	(495.55)	2019 04 BPA - EIM2 Yakama SSF	0.000	60548	0	MW		SA 328
53	800400	136253213		ZS	6/26/2019	50	(485.18)	2019 05 BPA - EIM2 Yakama SSF	0.000	60952	0	MW		SA 328
54	800400	136596401		ZS	7/30/2019	50	(452.08)	2019 06 BPA - EIM2 Yakama SSF	0.000	61416	0	MW		SA 328
55	800400	136597570		ZS	7/30/2019	50	(22.08)	2019 06 BPA - EIM2A Yakama S	0.000	61285	0	MW		SA 328
56	800400	136687670		ZS	8/28/2019	50	(524.77)	2019 07 BPA - EIM2 Yakama SSF	0.000	61808	0	MW		SA 328
57	800400	136773958		ZS	9/24/2019	50	(535.30)	2019 08 BPA - EIM2 Yakama SSF	0.000	62151	0	MW		SA 328
58	800400	137132826		PS	10/29/2019	50	(455.92)	2019 09 BPAP FNO_S5	-3,019.337	100062	PACW	201909	BPAP_FNO_YAK_SA	SA 328
59	800400	137216494		PS	11/25/2019	50	(471.12)	2019 10 BPAP FNO_S5	-3,120.027	100110	PACW	201910	BPAP_FNO_YAK_SA	SA 328
60	800400	137307215		PS	12/23/2019	50	(469.53)	2019 11 BPAP FNO_S5	-3,109.444	100159	PACW	201911	BPAP_FNO_YAK_SA	SA 328
61	800400	137651513		PS	1/28/2020	50	(524.37)	2019 12 BPAP FNO_S5	-3472.667	100227	PACW	201912	BPAP_FNO_YAK_SA	SA 328
62	800400	135649459		ZS	2/26/2019	50	(20.38)	2019 01 BPA - EIM5 Echo SSFNC	0.000	59420	0	MW		SA 538
63	800400	135722778		ZS	3/25/2019	50	(18.15)	2019 02 BPA - EIM5 Echo SSFNC	0.000	59801	0	MW		SA 538
64	800400	136076396		ZS	4/29/2019	50	(19.41)	2019 03 BPA - EIM5 Echo SSFNC	0.000	60165	0	MW		SA 538
65	800400	136159993		ZS	5/28/2019	50	(8.14)	2019 04 BPA - EIM5 Echo SSFNC	0.000	60465	0	MW		SA 538
66	800400	136252610		ZS	6/26/2019	50	(10.15)	2019 05 BPA - EIM5 Echo SSFNC	0.000	60981	0	MW		SA 538
67	800400	136596406		ZS	7/30/2019	50	(5.42)	2019 06 BPA - EIM5 Echo SSFNC	0.000	61417	0	MW		SA 538
68	800400	136687672		ZS	8/28/2019	50	(6.01)	2019 07 BPA - EIM5 Echo SSFNC	0.000	61805	0	MW		SA 538
69	800400	136773964		ZS	9/24/2019	50	(10.05)	2019 08 BPA - EIM5 Echo SSFNC	0.000	62129	0	MW		SA 538
70	800400	137132826		PS	10/29/2019	50	(9.31)	2019 09 BPAP FNO_S5	-61.642	100062	PACW	201909	BPAP_FNO_ECH_SA	SA 538
71	800400	137216494		PS	11/25/2019	50	(15.17)	2019 10 BPAP FNO_S5	-100.440	100110	PACW	201910	BPAP_FNO_ECH_SA	SA 538
72	800400	137307215		PS	12/23/2019	50	(22.09)	2019 11 BPAP FNO_S5	-146.264	100159	PACW	201911	BPAP_FNO_ECH_SA	SA 538
73	800400	137651513		PS	1/28/2020	50	(11.85)	2019 12 BPAP FNO_S5	-78.469	100227	PACW	201912	BPAP_FNO_ECH_SA	SA 538
74	800400	135649463		ZS	2/26/2019	50	(127.08)	2019 01 BPA - EIM3 Rimrock SSI	0.000	59421	0	MW		SA 539
75	800400	135722780		ZS	3/25/2019	50	(124.27)	2019 02 BPA - EIM3 Rimrock SSI	0.000	59802	0	MW		SA 539
76	800400	136076392		ZS	4/29/2019	50	(124.71)	2019 03 BPA - EIM3 Rimrock SSI	0.000	60235	0	MW		SA 539
77	800400	136159989		ZS	5/28/2019	50	(81.10)	2019 04 BPA - EIM3 Rimrock SSI	0.000	60546	0	MW		SA 539
78	800400	136253212		ZS	6/26/2019	50	(46.72)	2019 05 BPA - EIM3 Rimrock SSI	0.000	60974	0	MW		SA 539
79	800400	136596402		ZS	7/30/2019	50	(39.73)	2019 06 BPA - EIM3 Rimrock SSI	0.000	61365	0	MW		SA 539
80	800400	136687666		ZS	8/28/2019	50	(42.88)	2019 07 BPA - EIM3 Rimrock SSI	0.000	61814	0	MW		SA 539
81	800400	136773960		ZS	9/24/2019	50	(38.01)	2019 08 BPA - EIM3 Rimrock SSI	0.000	62132	0	MW		SA 539
82	800400	137132826		PS	10/29/2019	50	(37.91)	2019 09 BPAP FNO_S5	-251.040	100062	PACW	201909	BPAP_FNO_RIM_SA	SA 539
83	800400	137216494		PS	11/25/2019	50	(79.56)	2019 10 BPAP FNO_S5	-526.884	100110	PACW	201910	BPAP_FNO_RIM_SA	SA 539
84	800400	137307215		PS	12/23/2019	50	(88.20)	2019 11 BPAP FNO_S5	-584.082	100159	PACW	201911	BPAP_FNO_RIM_SA	SA 539
85	800400	137651513		PS	1/28/2020	50	(118.00)	2019 12 BPAP FNO_S5	-781.437	100227	PACW	201912	BPAP_FNO_RIM_SA	SA 539
86	800400	135651796		ZS	2/25/2019	50	(2,040.42)	2019 01 BPA - EIM4 Clark SSFNC	0.000	59336	0	MW		SA 735
87	800400	135722445		ZS	3/25/2019	50	(2,365.06)	2019 02 BPA - EIM4 Clark SSFNC	0.000	59784	0	MW		SA 735
88	800400	136076394		ZS	4/29/2019	50	(2,041.96)	2019 03 BPA - EIM4 Clark SSFNC	0.000	60124	0	MW		SA 735
89	800400	136159991		ZS	5/28/2019	50	(1,512.49)	2019 04 BPA - EIM4 Clark SSFNC	0.000	60445	0	MW		SA 735
90	800400	136252611		ZS	6/26/2019	50	(1,238.87)	2019 05 BPA - EIM4 Clark SSFNC	0.000	60969	0	MW		SA 735
91	800400	136596403		ZS	7/30/2019	50	(1,144.72)	2019 06 BPA - EIM4 Clark SSFNC	0.000	61326	0	MW		SA 735
92	800400	136687664		ZS	8/28/2019	50	(1,148.29)	2019 07 BPA - EIM4 Clark SSFNC	0.000	61801	0	MW		SA 735
93	800400	136773962		ZS	9/24/2019	50	(1,174.57)	2019 08 BPA - EIM4 Clark SSFNC	0.000	62128	0	MW		SA 735
94	800400	137132826		PS	10/29/2019	50	(1,207.93)	2019 09 BPAP FNO_S5	-7,999.550	100062	PACW	201909	BPAP_FNO_CLK_SA	SA 735
95	800400	137216494		PS	11/25/2019	50	(1,675.24)	2019 10 BPAP FNO_S5	-11,094.303	100110	PACW	201910	BPAP_FNO_CLK_SA	SA 735
96	800400	137307215		PS	12/23/2019	50	(1,885.20)	2019 11 BPAP FNO_S5	-12,484.739	100159	PACW	201911	BPAP_FNO_CLK_SA	SA 735
97	800400	137651513		PS	1/28/2020	50	(2,212.71)	2019 12 BPAP FNO_S5	-14653.722	100227	PACW	201912	BPAP_FNO_CLK_SA	SA 735
98	800400	135654571		ZS	2/27/2019	50	(27,189.80)	2019 01 BPA-L7 S Idaho G-PACE	0.000	59109	0	MW		SA 746
99	800400	135733905		ZS	3/27/2019	50	(24,270.49)	2019 02 BPA-L7 S Idaho G-PACE	0.000	59726	0	MW		SA 746
100	800400	135733905		ZS	3/27/2019	50	(453.41)	2019 02 BPA-L7 S Idaho G-PACE	0.000	59726	0	MW		SA 746
101	800400	136077897		ZS	4/30/2019	50	(28,790.06)	2019 03 BPA-L7 S Idaho G-PACE	0.000	60048	0	MW		SA 746
102	800400	136163201		ZS	5/28/2019	50	(26,835.89)	2019 04 BPA-L7 S Idaho G-PACE	0.000	60378	0	MW		SA 746
103	800400	136254966		ZS	6/28/2019	50	(28,909.28)	2019 05 BPA-L7 S Idaho G-PACE	0.000	60923	0	MW		SA 746
104	800400	136596399		ZS	7/30/2019	50	(30,086.99)	2019 06 BPA-L7 S Idaho G-PACE	0.000	61264	0	MW		SA 746
105	800400	136687650		ZS	8/28/2019	50	(36,614.43)	2019 07 BPA-L7 S Idaho G-PACE	0.000	61643	0	MW		SA 746
106	800400	136785282		ZS	9/27/2019	50	(31,404.46)	2019 08 BPA-L7 S Idaho G-PACE	0.000	62052	0	MW		SA 746
107	800400	137132826		PS	10/29/2019	50	(23,349.81)	2019 09 BPAP FNO_S5	-154,634.514	100062	PACW	201909	BPAP_FNO_GSH_SA	SA 746
108	800400	137216494		PS	11/25/2019	50	(22,859.99)	2019 10 BPAP FNO_S5	-151,390.632	100110	PACW	201910	BPAP_FNO_GSH_SA	SA 746
109	800400	137307215		PS	12/23/2019	50	(20,290.73)	2019 11 BPAP FNO_S5	-134,375.663	100159	PACW	201911	BPAP_FNO_GSH_SA	SA 746
110	800400	137635767		PS	1/22/2020	40	284.34	2019 12 BPAP FNO_S5	1883	100170	PACW	201910	BPAP_FNO_GSH_SA	SA 746
111	800400	137651513		PS	1/28/2020	50	(27,185.82)	2019 12 BPAP FNO_S5	-180038.56	100227	PACW	201912	BPAP_FNO_GSH_SA	SA 746
112	800400	137651604		PS	1/29/2020	50	(911.89)	2019 12 BPAP FNO_S5	-6039.028	100232	PACW	201911	BPAP_FNO_GSH_SA	SA 746
113	800400	135654570		ZS	2/27/2019	50	(10,074.48)	2019 01 BPA - L6 Idaho Falls Loa	0.000	59280	0	MW		SA 747
114	800400	135733904		ZS	3/28/2019	50	(8,766.71)	2019 02 BPA - L6 Idaho Falls Loa	0.000	59755	0	MW		SA 747
115	800400	135733904		ZS	3/28/2019	50	(1,216.39)	2019 02 BPA - L6 Idaho Falls Loa	0.000	59755	0	MW		SA 747
116	800400	136077896		ZS	4/30/2019	50	(8,137.38)	2019 03 BPA - L6 Idaho Falls Loa	0.000	60163	0	MW		SA 747
117	800400	136077896		ZS	4/30/2019	50	(2,131.66)	2019 03 BPA - L6 Idaho Falls Loa	0.000	60163	0	MW		SA 747
118	800400	136077896		ZS	4/30/2019	40	1,216.13	2019 03 BPA - L6 Idaho Falls Loa	0.000	60163	0	MW		SA 747
119	800400	136163202		ZS	5/27/2019	50	(5,043.56)	2019 04 BPA - L6 Idaho Falls Loa	0.000	60432	0	MW		SA 747
120	800400	136163202		ZS	5/27/2019	50

125	800400	136690308	ZS	8/28/2019	50	(6,933.11)	2019 07 BPA - L6 Idaho Falls Loa	0.000	61644	0	MW		SA 747
126	800400	136690308	ZS	8/28/2019	50	(2,328.21)	2019 07 BPA - L6 Idaho Falls Loa	0.000	61644	0	MW		SA 747
127	800400	136690308	ZS	8/28/2019	40	1,923.09	2019 07 BPA - L6 Idaho Falls Loa	0.000	61644	0	MW		SA 747
128	800400	136785280	ZS	9/27/2019	50	(6,078.43)	2019 08 BPA - L6 Idaho Falls Loa	0.000	62020	0	MW		SA 747
129	800400	136785280	ZS	9/27/2019	50	(2,068.04)	2019 08 BPA - L6 Idaho Falls Loa	0.000	62020	0	MW		SA 747
130	800400	137132826	PS	10/29/2019	50	(4,724.60)	2019 09 BPAP FNO_S5	-31,288	100062	PACE	201909	BPAP_FNO_IDF_SA	SA 747
131	800400	137132826	PS	10/29/2019	50	(2,037.48)	2019 09 BPAP FNO_S5NL	-13,493.240	100062	PACW	201909	BPAP_FNO_IDFBT_1SA	747
132	800400	137216494	PS	11/25/2019	50	(5,711.14)	2019 10 BPAP FNO_S5	-37,822	100110	PACE	201910	BPAP_FNO_IDF_SA	SA 747
133	800400	137216494	PS	11/25/2019	50	(1,725.93)	2019 10 BPAP FNO_S5NL	-11,429.970	100110	PACW	201910	BPAP_FNO_IDFBT_1SA	747
134	800400	137307215	PS	12/23/2019	50	(6,901.00)	2019 11 BPAP FNO_S5	-45,699	100159	PACE	201911	BPAP_FNO_IDF_SA	SA 747
135	800400	137307215	PS	12/23/2019	50	(1,288.63)	2019 11 BPAP FNO_S5NL	-8,533.980	100159	PACW	201911	BPAP_FNO_IDFBT_1SA	747
136	800400	137651513	PS	1/28/2020	50	(7,982.01)	2019 12 BPAP FNO_S5	-52858	100227	PACE	201912	BPAP_FNO_IDF_SA	SA 747
137	800400	137651513	PS	1/28/2020	50	(1,422.15)	2019 12 BPAP FNO_S5NL	-9418.23	100227	PACW	201912	BPAP_FNO_IDFBT_1SA	747
138	800400	135649467	ZS	2/26/2019	50	(12.97)	2019 01 BPA - EIM6 Neff S5FNO	0.000	59433	0	MW		SA 827
139	800400	135722785	ZS	3/25/2019	50	(14.41)	2019 02 BPA - EIM6 Neff S5FNO	0.000	59807	0	MW		SA 827
140	800400	136076398	ZS	4/29/2019	50	(10.80)	2019 03 BPA - EIM6 Neff S5FNO	0.000	60231	0	MW		SA 827
141	800400	136159995	ZS	5/28/2019	50	(8.44)	2019 04 BPA - EIM6 Neff S5FNO	0.000	60527	0	MW		SA 827
142	800400	136246868	ZS	6/26/2019	50	(7.67)	2019 05 BPA - EIM6 Neff S5FNO	0.000	60987	0	MW		SA 827
143	800400	136596404	ZS	7/30/2019	50	(6.85)	2019 06 BPA - EIM6 Neff S5FNO	0.000	61418	0	MW		SA 827
144	800400	136687667	ZS	8/28/2019	50	(6.82)	2019 07 BPA - EIM6 Neff S5FNO	0.000	61811	0	MW		SA 827
145	800400	136773966	ZS	9/24/2019	50	(7.86)	2019 08 BPA - EIM6 Neff S5FNO	0.000	62131	0	MW		SA 827
146	800400	137132826	PS	10/29/2019	50	(8.71)	2019 09 BPAP FNO_S5	-57.695	100062	PACW	201909	BPAP_FNO_NEF_SA	SA 827
147	800400	137216494	PS	11/25/2019	50	(10.79)	2019 10 BPAP FNO_S5	-71.459	100110	PACW	201910	BPAP_FNO_NEF_SA	SA 827
148	800400	137307215	PS	12/23/2019	50	(11.77)	2019 11 BPAP FNO_S5	-77.963	100159	PACW	201911	BPAP_FNO_NEF_SA	SA 827
149	800400	137651513	PS	1/28/2020	50	(13.25)	2019 12 BPAP FNO_S5	-87.737	100227	PACW	201912	BPAP_FNO_NEF_SA	SA 827
150	800400	137651513	PS	1/28/2020	50	(15.21)	2019 12 BPAP FNO_S5	-100.745	100227	PACW	201912	BPAP_FNO_AS_SA_	SA 865
151	800800	135652048	ZS	2/26/2019	50	(604.25)	2019 01 Constellation Generatic	0.000	59328	0	MW		SA 759
152	800800	135730140	ZS	3/26/2019	50	(365.41)	2019 02 Constellation Generatic	0.000	59803	0	MW		SA 759
153	800800	136068678	ZS	4/26/2019	50	(438.77)	2019 03 Constellation Generatic	0.000	60126	0	MW		SA 759
154	800800	136159923	ZS	5/23/2019	50	(1,247.23)	2019 04 Constellation Generatic	0.000	60528	0	MW		SA 759
155	800800	136246562	ZS	6/25/2019	50	(903.90)	2019 05 Constellation Generatic	0.000	60972	0	MW		SA 759
156	800800	136585139	ZS	7/24/2019	50	(1,217.76)	2019 06 Constellation Generatic	0.000	61323	0	MW		SA 759
157	800800	136687562	ZS	8/27/2019	50	(1,159.92)	2019 07 Constellation Generatic	0.000	61757	0	MW		SA 759
158	800800	136779624	ZS	9/25/2019	50	(880.49)	2019 08 Constellation Generatic	0.000	62095	0	MW		SA 759
159	800800	137125082	PS	10/28/2019	50	(986.36)	2019 09 EXGN GEN_S5	-6,532.157	100047	PACW	201909	EXGN_NF_SA_759	SA 759
160	800800	137213826	PS	11/22/2019	50	(923.15)	2019 10 EXGN GEN_S5	-6,113.592	100108	PACW	201910	EXGN_NF_SA_759	SA 759
161	800800	137300239	PS	12/20/2019	50	(378.85)	2019 11 EXGN GEN_S5	-2,508.924	100148	PACW	201911	EXGN_NF_SA_759	SA 759
162	800800	137648371	PS	1/27/2020	50	(503.35)	2019 12 EXGN GEN_S5	-3333.445	100221	PACW	201912	EXGN_NF_SA_759	SA 759
163	800900	135654144	ZS	2/27/2019	50	(70.71)	2019 01 Shell Energy EIM S5GE?	0.000	59140	0	MW		SA 791
164	800900	135733907	ZS	3/28/2019	50	(575.09)	2019 02 Shell Energy EIM S5GE?	0.000	59791	0	MW		SA 791
165	800900	136076523	ZS	4/29/2019	50	(4,767.89)	2019 03 Shell Energy EIM S5GE?	0.000	59938	0	MW		SA 791
166	800900	136159935	ZS	5/24/2019	50	(70.07)	2019 04 Shell Energy EIM S5GE?	0.000	60336	0	MW		SA 791
167	800900	136597566	ZS	7/30/2019	50	(2,186.07)	2019 06 Shell Energy EIM S5GE?	0.000	61414	0	MW		SA 791
168	800900	136687565	ZS	8/27/2019	50	(5,199.22)	2019 07 Shell Energy EIM S5GE?	0.000	61511	0	MW		SA 791
169	800900	136785286	ZS	9/27/2019	50	(5,617.25)	2019 08 Shell Energy EIM S5GE?	0.000	61997	0	MW		SA 791
170	800900	137124733	PS	10/25/2019	50	(3,225.41)	2019 09 CORP GEN_S5	-21,360.343	100042	PACE	201909	CORP_LFP_SA_791	SA 791
171	800900	137209960	PS	11/21/2019	50	(2,925.53)	2019 10 CORP GEN_S5	-19,374.397	100104	PACE	201910	CORP_LFP_SA_791	SA 791
172	800900	137303007	PS	12/23/2019	50	(2,901.13)	2019 11 CORP GEN_S5	-19,212.785	100157	PACE	201911	CORP_LFP_SA_791	SA 791
173	800900	137640264	PS	1/23/2020	50	(1,480.26)	2019 12 CORP GEN_S5	-9803.07	100172	PACE	201912	CORP_LFP_SA_791	SA 791
174	801000	135651798	ZS	2/26/2019	50	(41,578.81)	2019 01 Deseret - EIM S5FNO:Sc	0.000	59324	0	MW		RS 280
175	801000	135722790	ZS	3/25/2019	50	(20,220.66)	2019 02 Deseret - EIM S5FNO:Sc	0.000	59786	0	MW		RS 280
176	801000	136076382	ZS	4/24/2019	50	(57,470.28)	2019 03 Deseret - EIM S5FNO:Sc	0.000	60127	0	MW		RS 280
177	801000	136159926	ZS	5/23/2019	50	(41,589.19)	2019 04 Deseret - EIM S5FNO:Sc	0.000	60522	0	MW		RS 280
178	801000	136249240	ZS	6/25/2019	50	(40,754.75)	2019 05 Deseret - EIM S5FNO:Sc	0.000	60992	0	MW		RS 280
179	801000	136589476	ZS	7/25/2019	50	(38,788.43)	2019 06 Deseret - EIM S5FNO:Sc	0.000	61328	0	MW		RS 280
180	801000	136687651	ZS	8/28/2019	50	(44,710.49)	2019 07 Deseret - EIM S5FNO:Sc	0.000	61645	0	MW		RS 280
181	801000	136773951	ZS	9/24/2019	50	(45,230.77)	2019 08 Deseret - EIM S5FNO:Sc	0.000	62110	0	MW		RS 280
182	801000	137124093	SA	10/25/2019	40	8.74	VNL-BOZ DGTPCE 07-2019 Sch5	0.000	PP TR M141	0	MW		RS 280
183	801000	137124452	ZS	10/25/2019	50	(39,884.21)	2019 09 Deseret - EIM S5FNO:Sc	0.000	62474	0	MW		RS 280
184	801000	137132232	ZS	10/29/2019	40	177.25	2019 09 Deseret - S1 S5FNO:Sch	0.000	62425	0	MW		RS 280
185	801000	137132232	ZS	10/29/2019	40	639.09	2019 09 Deseret - S1 S5FNO:Sch	0.000	62425	0	MW		RS 280
186	801000	137132232	ZS	10/29/2019	40	357.07	2019 09 Deseret - S1 S5FNO:Sch	0.000	62425	0	MW		RS 280
187	801000	137132232	ZS	10/29/2019	40	199.94	2019 09 Deseret - S1 S5FNO:Sch	0.000	62425	0	MW		RS 280
188	801000	137132232	ZS	10/29/2019	40	171.45	2019 09 Deseret - S1 S5FNO:Sch	0.000	62425	0	MW		RS 280
189	801000	137132232	ZS	10/29/2019	40	135.17	2019 09 Deseret - S1 S5FNO:Sch	0.000	62425	0	MW		RS 280
190	801000	137132232	ZS	10/29/2019	40	66.05	2019 09 Deseret - S1 S5FNO:Sch	0.000	62425	0	MW		RS 280
191	801000	137213627	ZS	11/21/2019	50	(40,387.31)	2019 10 Deseret - EIM S5FNO:Sc	0.000	62866	0	MW		RS 280
192	801000	137301234	ZS	12/20/2019	50	(36,376.16)	2019 11 Deseret - EIM S5FNO:Sc	0.000	63189	0	MW		RS 280
193	801000	137648030	SA	1/27/2020	50	(63.68)	MonButte DGTPCE 11-2019 Sch	0	PP TR M141	0	MW		RS 280
194	801000	137648413	ZS	1/27/2020	50	(38,394.55)	2019 12 Deseret - EIM S5FNO:Sc	0	63406	0	MW		RS 280
195	802400	135651811	ZS	2/26/2019	50	(6,106.85)	2019 01 Avangrid - L3 Uinta EIM	0.000	59310	0	MW		RS 476
196	802400	135730155	ZS	3/26/2019	50	(6,818.27)	2019 02 Avangrid - L3 Uinta EIM	0.000	59787	0	MW		RS 476
197	802400	136068691	ZS	4/26/2019	50	(2,175.23)	2019 03 Avangrid - L3 Uinta EIM	0.000	60128	0	MW		RS 476
198	802400	136159932	ZS	5/23/2019	50	(4,522.66)	2019 04 Avangrid - L3 Uinta EIM	0.000	60524	0	MW		RS 476
199	802400	136246730	ZS	6/25/2019	50	(3,727.63)	2019 05 Avangrid - L3 Uinta EIM	0.000	60973	0	MW		RS 476
200	802400	136586651	ZS	7/25/2019	50	(3,502.58)	2019 06 Avangrid - L3 Uinta EIM	0.000	61320	0	MW		RS 476
201	802400	136683512	ZS	8/26/2019	50	(2,657.13)	2019 07 Avangrid - L3 Uinta EIM	0.000	61754	0	MW		RS 476
202	802400	136779353	ZS	9/25/2019	50	(3,121.97)	2019 08 Avangrid - L3 Uinta EIM	0.000	62097	0	MW		RS 476
203	802400	137132825	PS	10/29/2019	50	(3,778.85)	2019 09 PPMI GEN_S5	-25,025.500	100061	PACE	201909	PPMI_OS_SA_476	RS 476
204	802400	137213827	PS	11/22/2019	50	(3,061.91)	2019 10 PPMI GEN_S5	-40,145.100	100109	PACE	201910	PPMI_OS_SA_476	RS 476
205	802400	137300245	PS	12/20/2019	50	(5,144.25)	2019 11 PPMI GEN_S5	-34,067.900	100151	PACE	201911	PPMI_OS_SA_476	RS 476
206	802400	137648803	PS	1/28/2020	50	(4,258.31)	2019 12 PPMI GEN_S5	-28200.7	100225	PACE	201912	PPMI_OS_SA_476	RS 476
207	802400	135652050	ZS	2/26/2019	50	(718.14)	2019 01 Avangrid GALA EIM S5F	0.000	59334	0	MW		SA 742
208	802400	135652052	ZS	2/26/2019	50	(3,481.99)	2019 01 Avangrid - ESS EIME S5	0.000	59386	0	MW		SA 742
209	802400	135727943	ZS	3/25/2019	50	(3,213.30)	2019 02 Avangrid - ESS EIME S5	0.000	59788	0	MW		SA 742
210	802400	135730161	ZS	3/26/2019	50	(466.36)	2019 02 Avangrid GALA EIM S5F	0.000	59772	0	MW		SA 742
211	802400	136068687	ZS	4/26/2019	50	(3,526.05)	2019 03 Avangrid - ESS EIME S5	0.000	60129	0	MW		SA 742
212	802400	136068690	ZS	4/26/2019	50	(1,621.33)	2019 03 Avangrid GALA EIM S5F	0.000	60122	0	MW		SA 742
213	802400	136159918	ZS	5/24/2019	50	(3,394.24)	2019 04 Avangrid - ESS EIME S5	0.000	60525	0	MW		SA 742
214	802400	136159937	ZS	5/24/2019	50	(1,736.98)	2019 04 Avangrid GALA EIM S5F	0.000	60518	0	MW		SA 742
215	802400	136246733	ZS	6/25/2019	50	(2,194.76)	2019 05 Avangrid GALA EIM S5F	0.000	60967	0	MW		SA 742
216	802400	136246754	ZS	6/26/2019	50	(3,546.23)	2019 05 Avangrid - ESS EIME S5	0.000	60975	0	MW		SA 742
217	802400	136586660	ZS	7/25/2019	50	(2,763.50)	2019 06 Avangrid GALA EIM S5F	0.000	61324	0	MW		SA 742
218	802400	136589481	ZS	7/25/2019	50	(3,334.08)	2019 06 Avangrid - ESS EIME S5	0.000	61321	0	MW		SA 742
219	802400	136680507	ZS	8/26/2019	50	(3,551.40)	2019 07 Avangrid - ESS PACW S5	0.000	61762	0	MW		SA 742
220	802400	136680508	ZS	8/26/2019	50	(2,591.15)	2019 07 Avangrid GALA EIM S5F	0.000	61758	0	MW		SA 742
221	802400	136779354	ZS	9/24/2019	50	(2,495.90)	2019 08 Avangrid GALA EIM S5F	0.000	62096	0	MW		SA 742
222	802400	136779356	ZS	9/25/2019	50	(3,497.93)	2019 08 Avangrid - ESS PACW S5	0.000	62107	0	MW		SA 742
223	802400	137132825	PS	10/29/2019	50	(3,407.52)	2019 09 PPMI FNO_S5	-22,566.336	100061	PACW	201909	PPMI_FNO_SA_742	SA 742
224	802400	137132825	PS	10/29/2019	50	(1,656.93)	2019 09 PPMI GEN_S5	-10,973.023	100061	PACW	201909	PPMI_NF_SA_121	SA 742
225	802400	137213827	PS	11/22/2019	50	(3,560.04)	2019 10 PPMI FNO_S5	-23,576.446	100109	PACW	201910	PPMI_FNO_SA_742	SA 742
226	802400	137213827	PS	11/22/2019	50	(1,431.55)	2019 10 PPMI GEN_S5	-9,480.432	100109	PACW	201910	PPMI_FNOGS_SA_7	SA 742
227	802400	137300245	PS	12/20/2019	50	(2,370.03)	2019 11 PPMI FNO_S5	-15,695.551	100151	PACW	201911	PPMI_FNO_SA_742	SA 742
228	802400	137300245	PS	12/20/2019	50	(820.36)	2019 11 PPMI GEN_S5	-5,432.846	100151	PACW	201911	PPMI_FNOGS_SA_7	SA 742
229	802400	137640262	PS	1/23/2020	50	(1,099.19)	2019 12 PPMI FNO_S5	-7279.415	100171	PACW	201911	PPMI_FNO_SA_742	SA 742
230	802400	137648803	PS	1/28/2020	50	(3,616.31)	2019 12 PPMI FNO_S5	-23949.042	100225	PACW	201912	PPMI_FNO_SA_742	SA 742
231	802400	137648803	PS	1/28/2020	50	(547.78)	2019 12 PPMI GEN_S5	-3627.712	100225	PACW	201912	PPMI_FNOGS_SA_7	SA 742
232	802400	137651609	PS	1/29/2020	40	1,656.93	2019 12 PPMI GEN_S5	10973.023	100235	PACW	201909	PPMI_NF_SA_121	SA 742
233	802400	137651609	PS	1/29/2020	50	(1,656.93)	2019 12 PPMI GEN_S5	-10973.023	100235	PACW	201909	PPMI_FNOGS_SA_7	SA 742
234	803400	135651804	ZS	2/26/2019	50	(1,747.23)	2019 01 Tri-State EIM S5FNO:Sc	0.000	59298	0	MW		SA 628
235	803400	135727941	ZS	3/25/2019	50	(1,534.70)	2019 02 Tri-State EIM S5FNO:Sc	0.000	59796	0	MW		SA 628
236	803400	136068730	ZS	4/26/2019	50	(1,637.29)	2019 03 Tri-State EIM S5FNO:Sc	0.000	60139	0	MW		SA 628
237	803400	136160114	ZS	5/23/2019	50	(1,375.43)	2019 04 Tri-State EIM S5FNO:Sc	0.000	60594	0	MW		SA 628
238	803400	136249261	ZS	6/26/2019	50	(1,343.39)	2019 05 Tri-State EIM S5FNO:Sc	0.000	60976	0	MW		SA 628
239	803400	136589478	ZS	7/25/2019	50	(1,374.83)	2019 06 Tri-State EIM S5FNO:Sc	0.000	61353	0	MW		SA 628
240	803400	136683515	ZS	8/26/2019	50	(1,589.28)	2019 07 Tri-State EIM S5FNO:Sc	0.000	61753	0	MW		SA 628
241	803400	136785293	ZS	9/27/2019	50	(1,568.65)	2019 08 Tri-State EIM S5FNO:Sc	0.000	62104	0	MW		SA 628
242	803400	137125103	PS	10/28/2019	50	(1,294.12)	2019 09 TSPM FNO_S5	-8,570.345	100060	PACE	201909	TSPM_FNO_SA_628	SA 628
243	803400	137216487	SA	11/25/2019	50	(0.13)	08-2019 TRSPCE Schedule 5 627	0.000	PP TR M141	0	MW		SA 628
244	803400	137216496	PS	11/25/2019	50	(1,423.95)	2019 10 TSPM FNO_S5	-9,430.140	100113	PACE	201910	TSPM_FNO_SA_628	SA 628
245	803400	137300250	PS	12/20/2019	50	(1,512.17)	2019 11 TSPM FNO_S5	-10,014.383	100155	PACE	201911	TSPM_FNO_SA_628	SA 628
246	803400	137648795	PS	1/28/2020	50	(1,894.74)	2019 12 TSPM FNO_S5	-12547.923	100226	PACE	201912	TSPM_FNO_SA_628	SA 628
247	803500	135654148	ZS	2/27/2019	50	(26,528.35)	2019 01 UAMPS EIM S5GEN:Sch	0.000	59333	0	MW		RS 297
248	803500	135732684	ZS	3/28/2019	50	(34,030.26)	2019 02 UAMPS EIM S5GEN:Sch	0.000	59687	0	MW		RS 297
249	803500	136076385	ZS	4/29/2019	50	(26,901.13)	2019 03 UAMPS EIM S5GEN:Sch	0.000	60140	0	MW		RS 297
250	803500	136163203	ZS	5/29/2019	50	(39,494.36)	2019 04 UAMPS EIM S5GEN:Sch	0.000	60507	0	MW		RS 297
251	803500	136254959	ZS	6/27/2019	50	(39,168.23)	2019 05 UAMPS EIM S5GEN:Sch	0.000	60935	0	MW		RS 297
252	803500	136597270	ZS	7/30/2019	50	(50,904.09)	2019 06 UAMPS EIM S5GEN:Sch	0.000	61222	0	MW		RS 297
253	803500	136690914	ZS	8/28/2019	50	(76,060.43)	2019 07 UAMPS EIM S5GEN:Sch	0.000	61734	0	MW		RS 297
254	803500	136786052	ZS	9/27/2019	50	(79,170.85)	2019 08 UAMPS EIM S5GEN:Sch	0.000	62067	0	MW		RS 297
255	803500	137127304	ZS	10/29/2019	50	(45,354.41)	2019 09 UAMPS EIM S5GEN:Sch	0.000	62415	0	MW		RS 297
256	803500	137216837	ZS	11/25/2019	40	9,259.04	2019 10 UAMPS EIMA S5FNO:JL	0.000	62741	0	MW		RS 297
257	803500	137216837	ZS	11/25/2019	40	16,771.78	2019 10 UAMPS EIMA S5FNO:JL	0.000	62741	0	MW		RS 297
258	803500	137216837	ZS	11/25/2019	40	15,945.53	2019 10 UAMPS EIMA S5FNO:Al	0.000	62741	0	MW		RS 297
259	803500	137220976	ZS	11/25/2019	50	(41,134.33)	2019 10 UAMPS EIM S5GEN:Sch	0.000	62833	0	MW		RS 297
260	803500	137307037	ZS	12/23/2019	50	(33,614.71)	2019 11 UAMPS EIM S5GEN:Sch	0.000	63187	0	MW		RS 297
261	803500	137648089	ZS	1/28/2020	50	(40,300.29)	2019 12 UAMPS EIM S5GEN:Sch	0	63409	0	MW		RS 297
262	803500	137651367	ZS	1/28/2020	50	(284.37)	2019 12 UAMPS EIMA S5GEN:O	0	63412	0	MW		RS 297
263	803500	137651367	ZS	1/28/2020	50	(255.06)	2019 12 UAMPS EIMA S5GEN:N	0	63412	0	MW		RS 297
264	803600	135654572	ZS	2/27/2019	50	(5.56)	2019 01 UMPA S1 S5GEN:Sched	0.000	59295	0	MW		RS 637
265	803600	135654572	ZS	2/27/2019	40	0.91	2019 01 UMPA S1 S5FNO:Sched	0.000	59295	0	MW		RS 637
266	803600	135654572	ZS	2/27/2019	40	2.61	2019 01 UMPA S1 S5FNO:Sched	0.000	59295	0	MW		RS 637
267	803600	135654572	ZS	2/27/2019	40	1.66	2019 01 UMPA S1 S5FNO:Sched	0.000	59295	0	MW		RS 637
268	803600	135732686	ZS	3/28/2019	50	(193.25)	2019 02 UMPA S1 S5GEN:Sched	0.000	59760	0	MW		RS 637

269	803600	136076520	ZS	4/29/2019	50	(24.82)	2019	03	UMPA S1 SSGEN:Sched	0.000	60102	0	MW	RS 637
270	803600	136160690	ZS	5/28/2019	50	(11,000.02)	2019	04	UMPA S1 SSGEN:Sched	0.000	60414	0	MW	RS 637
271	803600	136254962	ZS	6/27/2019	50	(8,404.17)	2019	05	UMPA S1 SSGEN:Sched	0.000	60934	0	MW	RS 637
272	803600	136597269	ZS	7/30/2019	50	(13,527.14)	2019	06	UMPA S1 SSGEN:Sched	0.000	61313	0	MW	RS 637
273	803600	136687571	ZS	8/27/2019	50	(23,297.16)	2019	07	UMPA S1 SSGEN:Sched	0.000	61671	0	MW	RS 637
274	803600	136786056	ZS	9/27/2019	50	(23,370.96)	2019	08	UMPA S1 SSGEN:Sched	0.000	62094	0	MW	RS 637
275	803600	137132797	ZS	10/29/2019	50	(16,360.24)	2019	09	UMPA S1 SSGEN:Sched	0.000	62488	0	MW	RS 637
276	803600	137216736	ZS	11/25/2019	50	(13,629.66)	2019	10	UMPA S1 SSGEN:Sched	0.000	62778	0	MW	RS 637
277	803600	137307035	ZS	12/20/2019	50	(17,198.55)	2019	11	UMPA S1 SSGEN:Sched	0.000	63076	0	MW	RS 637
278	803600	137648068	ZS	1/28/2020	50	(18,293.15)	2019	12	UMPA S1 SSGEN:Sched	0	63410	0	MW	RS 637
279	803800	135648549	ZS	2/25/2019	50	(0.82)	2019	01	WAPA WY-F1 SSFNO:Sc	0.000	59257	0	MW	SA 175
280	803800	135709292	ZS	3/15/2019	50	(0.65)	2019	02	WAPA WY-F1 SSFNO:Sc	0.000	59650	0	MW	SA 175
281	803800	136069165	ZS	4/29/2019	50	(0.62)	2019	03	WAPA WY-F1 SSFNO:Sc	0.000	60179	0	MW	SA 175
282	803800	136160686	ZS	5/27/2019	50	(53.86)	2019	04	WAPA WY-F1 SSFNO:Sc	0.000	60574	0	MW	SA 175
283	803800	136249238	ZS	6/24/2019	50	(158.46)	2019	05	WAPA WY-F1 SSFNO:Sc	0.000	60891	0	MW	SA 175
284	803800	136582007	ZS	7/22/2019	50	(235.17)	2019	06	WAPA WY-F1 SSFNO:Sc	0.000	61210	0	MW	SA 175
285	803800	136667814	ZS	8/19/2019	50	(341.57)	2019	07	WAPA WY-F1 SSFNO:Sc	0.000	61598	0	MW	SA 175
286	803800	136786053	ZS	9/27/2019	50	(328.28)	2019	08	WAPA WY-F1 SSFNO:Sc	0.000	61979	0	MW	SA 175
287	803800	136786053	ZS	9/27/2019	50	(10.35)	2019	08	WAPA WY-F1 SSFNO:JL	0.000	61979	0	MW	SA 175
288	803800	137207388	ZS	11/20/2019	40	1,130.48	2019	10	WAPA WY-S1 SSFNO:Sc	0.000	62855	0	MW	SA 175
289	804300	135649456	ZS	2/26/2019	50	(2,893.55)	2019	01	NextEra EIM SSGEN:Scl	0.000	59143	0	MW	SA 733
290	804300	135735467	ZS	3/27/2019	50	(1,654.54)	2019	02	NextEra EIM SSGEN:Scl	0.000	59605	0	MW	SA 733
291	804300	136076516	ZS	4/26/2019	50	(1,487.30)	2019	03	NextEra EIM SSGEN:Scl	0.000	59942	0	MW	SA 733
292	804300	136135852	ZS	4/30/2019	40	26.37	2019	03	NextEra EIMS SSLFP:Ma	0.000	60268	0	MW	SA 733
293	804300	136160680	ZS	5/28/2019	50	(3,934.91)	2019	04	NextEra EIM SSGEN:Scl	0.000	60340	0	MW	SA 733
294	804300	136253069	ZS	6/27/2019	50	(3,762.71)	2019	05	NextEra EIM SSGEN:Scl	0.000	60805	0	MW	SA 733
295	804300	136586685	ZS	7/26/2019	50	(6,005.96)	2019	06	NextEra EIM SSGEN:Scl	0.000	61322	0	MW	SA 733
296	804300	136687573	ZS	8/27/2019	50	(8,822.49)	2019	07	NextEra EIM SSGEN:Scl	0.000	61515	0	MW	SA 733
297	804300	136785252	ZS	9/27/2019	50	(247.78)	2019	08	NextEra EIM SSGEN:Scl	0.000	61936	0	MW	SA 733
298	804300	136785259	ZS	9/27/2019	40	173.65	2019	08	NextEra EIMA SSGEN:A	0.000	61961	0	MW	SA 733
299	804300	136785259	ZS	9/27/2019	40	1,317.48	2019	08	NextEra EIMA SSGEN:M	0.000	61961	0	MW	SA 733
300	804300	136785259	ZS	9/27/2019	40	2,194.79	2019	08	NextEra EIMA SSGEN:JI	0.000	61961	0	MW	SA 733
301	804300	136785259	ZS	9/27/2019	40	6,315.58	2019	08	NextEra EIMA SSGEN:JI	0.000	61961	0	MW	SA 733
302	804300	137125083	PS	10/28/2019	50	(3,104.33)	2019	09	FPLP GEN_SS	-20,558.500	100048	PACW	201909	FPLP_LFP_SA_733 SA 733
303	804300	137216493	PS	11/25/2019	50	(3,428.60)	2019	10	FPLP GEN_SS	-22,705.975	100112	PACW	201910	FPLP_LFP_SA_733 SA 733
304	804300	137300247	PS	12/20/2019	50	(1,707.68)	2019	11	FPLP GEN_SS	-11,309.150	100152	PACW	201911	FPLP_LFP_SA_733 SA 733
305	804300	137640282	PS	1/23/2020	50	(3,033.21)	2019	12	FPLP GEN_SS	-20087.5	100181	PACW	201912	FPLP_LFP_SA_733 SA 733
306	805000	135649457	ZS	2/26/2019	50	(4,631.35)	2019	01	Southern Cal Edison Ell	0.000	59153	0	MW	SA 642
307	805000	135733619	ZS	3/27/2019	50	(6,799.21)	2019	02	Southern Cal Edison Ell	0.000	59559	0	MW	SA 642
308	805000	136076402	ZS	4/29/2019	50	(3,516.02)	2019	03	Southern Cal Edison Ell	0.000	59953	0	MW	SA 642
309	805000	136159965	ZS	5/28/2019	50	(1,592.94)	2019	04	Southern Cal Edison Ell	0.000	60367	0	MW	SA 642
310	805000	136253071	ZS	6/27/2019	50	(1,164.84)	2019	05	Southern Cal Edison Ell	0.000	60737	0	MW	SA 642
311	805000	136593872	ZS	7/28/2019	50	(1,183.65)	2019	06	Southern Cal Edison Ell	0.000	61143	0	MW	SA 642
312	805000	136678769	ZS	8/26/2019	50	(1,497.01)	2019	07	Southern Cal Edison Ell	0.000	61524	0	MW	SA 642
313	805000	136785283	ZS	9/27/2019	50	(1,465.68)	2019	08	Southern Cal Edison Ell	0.000	61945	0	MW	SA 642
314	805000	137125088	PS	10/28/2019	50	(1,523.65)	2019	09	SCET GEN_SS	-10,090.393	100052	PACE	201909	SCET_NF_SA_642 SA 642
315	805000	137216491	PS	11/25/2019	50	(1,775.32)	2019	10	SCET GEN_SS	-11,757.087	100111	PACE	201910	SCET_NF_SA_642 SA 642
316	805000	137300249	PS	12/20/2019	50	(1,072.81)	2019	11	SCET GEN_SS	-7,104.699	100153	PACE	201911	SCET_NF_SA_642 SA 642
317	805000	137640268	PS	1/23/2020	50	(1,271.63)	2019	12	SCET GEN_SS	-8421.421	100177	PACE	201912	SCET_NF_SA_642 SA 642
318	805300	135646626	ZS	2/24/2019	50	(0.55)	2019	01	U.S.B.R.-L4 Burbank Pu	0.000	59390	0	MW	SA 506
319	805300	135709291	ZS	3/15/2019	50	(0.51)	2019	02	U.S.B.R.-L4 Burbank Pu	0.000	59651	0	MW	SA 506
320	805300	136069166	ZS	4/29/2019	50	(0.56)	2019	03	U.S.B.R.-L4 Burbank Pu	0.000	60187	0	MW	SA 506
321	805300	136163200	ZS	5/29/2019	50	(24.57)	2019	04	U.S.B.R.-L4 Burbank Pu	0.000	60547	0	MW	SA 506
322	805300	136249239	ZS	6/24/2019	50	(47.84)	2019	05	U.S.B.R.-L4 Burbank Pu	0.000	60838	0	MW	SA 506
323	805300	136579657	ZS	7/22/2019	50	(62.06)	2019	06	U.S.B.R.-L4 Burbank Pu	0.000	61211	0	MW	SA 506
324	805300	136667815	ZS	8/19/2019	50	(63.04)	2019	07	U.S.B.R.-L4 Burbank Pu	0.000	61669	0	MW	SA 506
325	805300	136785285	ZS	9/27/2019	50	(65.02)	2019	08	U.S.B.R.-L4 Burbank Pu	0.000	62193	0	MW	SA 506
326	805300	137124726	PS	10/25/2019	50	(45.86)	2019	09	USBR FNO_SS	-303.686	100026	PACW	201909	USBR_FNO_SA_506 SA 506
327	805300	137202792	PS	11/20/2019	50	(21.00)	2019	10	USBR FNO_SS	-139.061	100071	PACW	201910	USBR_FNO_SA_506 SA 506
328	805300	137295506	PS	12/18/2019	50	(0.65)	2019	11	USBR FNO_SS	-4.279	100123	PACW	201911	USBR_FNO_SA_506 SA 506
329	805300	137613280	PS	1/14/2020	50	(0.60)	2019	12	USBR FNO_SS	-4	100167	PACW	201912	USBR_FNO_SA_506 SA 506
330	816200	135649468	ZS	2/26/2019	50	(914.84)	2019	01	Cyrq Energy Imb F2 SSC	0.000	59176	0	MW	SA 568
331	816200	135722786	ZS	3/25/2019	50	(864.14)	2019	02	Cyrq Energy Imb F2 SSC	0.000	59603	0	MW	SA 568
332	816200	136075844	ZS	4/27/2019	50	(909.65)	2019	03	Cyrq Energy Imb F2 SSC	0.000	59971	0	MW	SA 568
333	816200	136160113	ZS	5/23/2019	50	(819.62)	2019	04	Cyrq Energy Imb F2 SSC	0.000	60379	0	MW	SA 568
334	816200	136249262	ZS	6/26/2019	50	(835.96)	2019	05	Cyrq Energy Imb F2 SSC	0.000	60802	0	MW	SA 568
335	816200	136594555	ZS	7/26/2019	50	(756.37)	2019	06	Cyrq Energy Imb F2 SSC	0.000	61149	0	MW	SA 568
336	816200	136687537	ZS	8/26/2019	50	(699.91)	2019	07	Cyrq Energy Imb F2 SSC	0.000	61496	0	MW	SA 568
337	816200	136785258	ZS	9/27/2019	50	(724.92)	2019	08	Cyrq Energy Imb F2 SSC	0.000	61926	0	MW	SA 568
338	816200	137125092	PS	10/28/2019	50	(744.13)	2019	09	BE01 GEN_SS	-4,927.984	100056	PACE	201909	BE01_LFP_SA_568 SA 568
339	816200	137209949	PS	11/21/2019	50	(3,277.09)	2019	10	BE01 GEN_SS	-21,702.560	100095	PACE	201910	BE01_LFP_SA_568 SA 568
340	816200	137216499	PS	11/25/2019	40	2,389.94	2019	10	BE01 GEN_SS	15,827.422	100114	PACE	201910	BE01_LFP_SA_568 SA 568
341	816200	137300236	PS	12/20/2019	50	(864.31)	2019	11	BE01 GEN_SS	-5,723.897	100147	PACE	201911	BE01_LFP_SA_568 SA 568
342	816200	137640266	PS	1/23/2020	50	(887.68)	2019	12	BE01 GEN_SS	-5878.694	100173	PACE	201912	BE01_LFP_SA_568 SA 568
343	817990	136069167	ZS	4/29/2019	50	(48.23)	2019	03	Southern Cal PPA Tieto	0.000	60207	0	MW	SA 629
344	817990	136160001	ZS	5/27/2019	50	(196.28)	2019	04	Southern Cal PPA Tieto	0.000	60529	0	MW	SA 629
345	817990	136246560	ZS	6/25/2019	50	(438.90)	2019	05	Southern Cal PPA Tieto	0.000	60977	0	MW	SA 629
346	817990	136593873	ZS	7/28/2019	50	(395.04)	2019	06	Southern Cal PPA Tieto	0.000	61209	0	MW	SA 629
347	817990	136687726	ZS	8/27/2019	50	(607.18)	2019	07	Southern Cal PPA Tieto	0.000	61599	0	MW	SA 629
348	817990	136777012	ZS	9/24/2019	50	(948.69)	2019	08	Southern Cal PPA Tieto	0.000	61981	0	MW	SA 629
349	817990	137125089	PS	10/28/2019	50	(1,304.27)	2019	09	SCPA GEN_SS	-8,637.525	100053	PACW	201909	SCPA_NF_SA_629 SA 629
350	817990	137209947	PS	11/21/2019	50	(462.74)	2019	10	SCPA GEN_SS	-3,064.525	100092	PACW	201910	SCPA_NF_SA_629 SA 629
351	818140	135654557	ZS	2/25/2019	50	(104.30)	2019	01	Tenaska EIM SSGEN:Scl	0.000	59174	0	MW	SA 125
352	818140	135732695	ZS	3/27/2019	50	(153.07)	2019	02	Tenaska EIM SSGEN:Scl	0.000	59562	0	MW	SA 125
353	818140	136075929	ZS	4/29/2019	50	(102.09)	2019	03	Tenaska EIM SSGEN:Scl	0.000	59957	0	MW	SA 125
354	818140	136163415	ZS	5/29/2019	50	(198.16)	2019	04	Tenaska EIM SSGEN:Scl	0.000	60371	0	MW	SA 125
355	818140	136254967	ZS	6/28/2019	50	(110.30)	2019	05	Tenaska EIM SSGEN:Scl	0.000	60740	0	MW	SA 125
356	818140	136594422	ZS	7/29/2019	50	(87.61)	2019	06	Tenaska EIM SSGEN:Scl	0.000	61146	0	MW	SA 125
357	818140	136687728	ZS	8/27/2019	50	(58.47)	2019	07	Tenaska EIM SSGEN:Scl	0.000	61527	0	MW	SA 125
358	818140	136773945	ZS	9/24/2019	50	(40.74)	2019	08	Tenaska EIM SSGEN:Scl	0.000	61948	0	MW	SA 125
359	818140	137125090	PS	10/28/2019	50	(58.75)	2019	09	TNSK GEN_SS	-389.067	100054	PACE	201909	TNSK_NF_SA_125 SA 125
360	818140	137213823	PS	11/22/2019	50	(59.16)	2019	10	TNSK GEN_SS	-391.803	100106	PACE	201910	TNSK_NF_SA_125 SA 125
361	818140	137300248	PS	12/20/2019	50	(48.52)	2019	11	TNSK GEN_SS	-321.297	100154	PACE	201911	TNSK_NF_SA_125 SA 125
362	818140	137640270	PS	1/23/2020	50	(59.92)	2019	12	TNSK GEN_SS	-396.847	100176	PACE	201912	TNSK_NF_SA_125 SA 125
363	818334	137653119	PS	1/29/2020	50	(165.33)	2019	12	OBRE GEN_SS	-1094.931	100237	PACW	201912	OBRE_LFP_SA_836 SA 836
364	818349	135651806	ZS	2/26/2019	50	(83.17)	2019	01	Exelon Generation ESS	0.000	59436	0	MW	SA 943
365	818349	135722787	ZS	3/25/2019	50	(70.25)	2019	02	Exelon Generation ESS	0.000	59810	0	MW	SA 943
366	818349	136068683	ZS	4/26/2019	50	(78.12)	2019	03	Exelon Generation ESS	0.000	60209	0	MW	SA 943
367	818349	136159921	ZS	5/23/2019	50	(77.02)	2019	04	Exelon Generation ESS	0.000	60595	0	MW	SA 943
368	818349	136246557	ZS	6/25/2019	50	(84.09)	2019	05	Exelon Generation ESS	0.000	61015	0	MW	SA 943
369	818349	136589483	ZS	7/24/2019	50	(86.74)	2019	06	Exelon Generation ESS	0.000	61369	0	MW	SA 943
370	818349	136687559	ZS	8/27/2019	50	(78.96)	2019	07	Exelon Generation ESS	0.000	61763	0	MW	SA 943
371	818349	136779333	ZS	9/25/2019	50	(77.32)	2019	08	Exelon Generation ESS	0.000	62099	0	MW	SA 943
372	818349	137125097	PS	10/28/2019	50	(70.11)	2019	09	EXGN FNO_SS	-464.326	100059	PACW	201909	EXGN_FNO_SA_943 SA 943
373	818349	137209934	PS	11/21/2019	50	(72.87)	2019	10	EXGN FNO_SS	-482.600	100081	PACW	201910	EXGN_FNO_SA_943 SA 943
374	818349	137300231	PS	12/20/2019	50	(59.78)	2019	11	EXGN FNO_SS	-395.921	100142	PACW	201911	EXGN_FNO_SA_943 SA 943
375	818349	137648364	PS	1/27/2020	50	(66.43)	2019	12	EXGN FNO_SS	-439.932	100218	PACW	201912	EXGN_FNO_SA_943 SA 943
376	818479	135651800	ZS	2/26/2019	50	(1,635.08)	2019	01	Calpine Energy Solutior	0.000	59419	0	MW	SA 299
377	818479	135727378	ZS	3/25/2019	50	(1,462.48)	2019	02	Calpine Energy Solutior	0.000	59763	0	MW	SA 299
378	818479	136065738	ZS	4/25/2019	50	(1,560.86)	2019	03	Calpine Energy Solutior	0.000	60130	0	MW	SA 299
379	818479	136159928	ZS	5/23/2019	50	(1,258.62)	2019	04	Calpine Energy Solutior	0.000	60592	0	MW	SA 299
380	818479	136246725	ZS	6/25/2019	50	(1,522.15)	2019	05	Calpine Energy Solutior	0.000	60979	0	MW	SA 299
381	818479	136589482	ZS	7/24/2019	50	(1,535.64)	2019	06	Calpine Energy Solutior	0.000	61344	0	MW	SA 299
382	818479	136678764	ZS	8/26/2019	50	(1,554.32)	2019	07	Calpine Energy Solutior	0.000	61723	0	MW	SA 299
383	818479	136773955	ZS	9/24/2019	50	(1,603.52)	2019	08	Calpine Energy Solutior	0.000	62098	0	MW	SA 299
384	818479	137125081	PS	10/28/2019	50	(1,488.07)	2019	09	SES FNO_SS	-9,854.768	100046	PACW	201909	SES_FNO_SA_299 SA 299
385	818479	137209930	PS	11/21/2019	50	(1,454.59)	2019	10	SES FNO_SS	-9,633.039	100079	PACW	201910	SES_FNO_SA_299 SA 299
386	818479	137300228	PS	12/20/2019	50	(1,378.72)	2019	11	SES FNO_SS	-9,130.571	100138	PACW	201911	SES_FNO_SA_299 SA 299
387	818479	137642318	PS	1/24/2020	50	(1,387.68)	2019	12	SES FNO_SS	-9189.954	100204	PACW	201912	SES_FNO_SA_299 SA 299
388	818511	135654671	ZS	2/27/2019	50	(729.70)	2019	01	Evergreen Biopower SS	0.000	59395	0	MW	SA 874
389	818511	135722789	ZS	3/25/2019	40	107.72	2019	02	Evergreen Biopower SS	0.000	59722	0	MW	SA 874
390	818511	135722792	ZS	3/25/2019	50	(495.06)	2019	02	Evergreen Biopower SS	0.000	59549	0	MW	SA 874
391	818511	136075846	ZS	4/27/2019	50	(610.04)	2019	03	Evergreen Biopower SS	0.000	60009	0	MW	SA 874
392	818511	136160682	ZS	5/25/2019	50	(646.12)	2019	04	Evergreen Biopower SS	0.000	60385	0	MW	SA 874
393	818511	136249252	ZS	6/26/2019	50	(722.10)	2019	05	Evergreen Biopower SS	0.000	60804	0	MW	SA 874
394	818511	136594376	ZS	7/29/2019	50	(808.03)	2019	06	Evergreen Biopower SS	0.000	61410	0	MW	SA 874
395	818511	136678756	ZS	8/26/2019	50	(846.41)	2019	07	Evergreen Biopower SS	0.000	61577	0	MW	SA 874
396	818511	136785278	ZS	9/27/2019	50	(869.87)	2019	08	Evergreen Biopower SS	0.000	61998	0	MW	SA 874
397	818511	137124649	PS	10/25/2019	50	(810.93)	2019	09	EVGB GEN_SS	-5,370.380	100005	PACW	201909	EVGB_LFP_SA_874 SA 874
398	818511	137209933	PS	11/21/2019	50	(804.45)	2019	10	EVGB GEN_SS	-5,327.472	100075	PACW	201910	EVGB_LFP_SA_874 SA 874
399	818511	137300232	PS	12/20/2019	50	(693.77)	2019	11	EVGB GEN_SS	-4,594.511	100141	PACW	201911	EVGB_LFP_SA_874 SA 874
400	818511	137640281	PS	1/23/2020	50	(714.09)	2019	12	EVGB GEN_SS	-4729.056	100180	PACW	201912	EVGB_LFP_SA_874 SA 874
401	818564	135649212	ZS	2/25/2019	50	(1.08)	2019	01	3 Phases Renewables E	0.000	59299	0	MW	SA 876
402	818564	135727938	ZS	3/25/2019	50	(4.74)	2019	02	3 Phases Renewables E	0.000	59735	0	MW	SA 876
403	818564	135727939	ZS	3/25/2019	50	(6.05)	2019	02	3 Phases Renewables E	0.000	59748	0	MW	SA 876
404	818564	136075840	ZS	4/27/2019	50	(7.33)	2019	03	3 Phases Renewables E	0.000	60166	0	MW	SA 876
405	818564	136160112	ZS	5/23/2019	50	(7.31)	2019	04	3 Phases Renewables E	0.000	60580	0	MW	SA 876
406	818564	136254960	ZS	6/27/2019	50	(8.35)	2019	05	3 Phases Renewables E	0.000	60980	0	MW	SA 876
407	818564	136593949	ZS	7/29/2019	50	(8.91)	2019	06	3 Phases Renewables E	0.000	61291	0	MW	SA 876
408	818564	136680511	ZS	8/26/2019	50	(10.18)	2019	07	3 Phases Renewables E	0.000	61602	0	MW	SA 876
409	818564	136786055	ZS	9/27/2019	50	(10.35)	2019	08	3 Phases Renewables E	0.000	61982	0	MW	SA 876
410	818564	137124647	PS	10/25/2019	50	(8.66)	2019	09	TPES FNO_SS	-57.367	100004	PACW	201909	TPES_FNO_SA_876 SA 876
411	818564	137209928	PS	11/21/2019	50	(7.50)	2019	10	TPES FNO_SS	-49.691	100076	PACW	201910	TPES_FNO_SA_876 SA 876
412	818564	137297993	PS	12/19/2019	50	(6.67)	2019	11	TPES FNO_SS	-44.154	100136	PACW	201911	TPES_FNO_SA_876 SA 876

413	818564	137640267	PS	1/23/2020	50	(6.66)	2019	12	TPES FNO_S5	-44.091	100175	PACW	201912	TPES_FNO_SA_876	SA 876
414	818579	135651801	ZS	2/26/2019	50	(16.09)	2019	01	Navajo Tribal Utility Au	0.000	59323	0	MW		SA 894
415	818579	135730151	SA	3/26/2019	50	(230.50)	2019	01	2019 MetersSched 5 NAVPCI	0.000	PP TR M141	0	MW		SA 894
416	818579	135730166	ZS	3/26/2019	50	(212.52)	2019	02	Navajo Tribal Utility Au	0.000	59769	0	MW		SA 894
417	818579	136068727	ZS	4/26/2019	50	(200.76)	2019	03	Navajo Tribal Utility Au	0.000	60208	0	MW		SA 894
418	818579	136159930	ZS	5/23/2019	50	(175.03)	2019	04	Navajo Tribal Utility Au	0.000	60593	0	MW		SA 894
419	818579	136236810	SA	6/21/2019	50	(10.48)	02-2019	T5Sched 5 NAVPCE 60		0.000	PP TR M141	69.384	MW		SA 894
420	818579	136236810	SA	6/21/2019	50	(12.19)	01-2019	Sched5&6CalcSched 5 I		0.000	PP TR M141	80.729	MW		SA 894
421	818579	136236810	SA	6/21/2019	50	(9.86)	03-2019	Sched5&6CalcSched 5 I		0.000	PP TR M141	65.308	MW		SA 894
422	818579	136236810	SA	6/21/2019	50	(8.52)	04-2019	Sched5&6CalcSched 5 I		0.000	PP TR M141	56.428	MW		SA 894
423	818579	136249237	ZS	6/21/2019	50	(181.46)	2019	05	Navajo Tribal Utility Au	0.000	60988	0	MW		SA 894
424	818579	136586573	ZS	7/25/2019	50	(181.23)	2019	06	Navajo Tribal Utility Au	0.000	61345	0	MW		SA 894
425	818579	136678759	ZS	8/26/2019	50	(219.57)	2019	07	Navajo Tribal Utility Au	0.000	61739	0	MW		SA 894
426	818579	136779629	ZS	9/25/2019	50	(218.98)	2019	08	Navajo Tribal Utility Au	0.000	62106	0	MW		SA 894
427	818579	137124745	PS	10/25/2019	50	(171.37)	2019	09	NTUA FNO_S5	-1,134.927	100032	PACE	201909	NTUA_FNO_SA_894	SA 894
428	818579	137209957	PS	11/21/2019	50	(195.15)	2019	10	NTUA FNO_S5	-1,292.365	100103	PACE	201910	NTUA_FNO_SA_894	SA 894
429	818579	137300233	PS	12/20/2019	50	(212.26)	2019	11	NTUA FNO_S5	-1,405.675	100144	PACE	201911	NTUA_FNO_SA_894	SA 894
430	818579	137640296	PS	1/24/2020	50	(245.73)	2019	12	NTUA FNO_S5	-1627.353	100186	PACE	201912	NTUA_FNO_SA_894	SA 894
431	818579	137640306	PS	1/24/2020	50	(17.27)	2019	12	NTUA FNO_S5	-114.343	100195	PACE	201909	NTUA_FNO_SA_894	SA 894
432	818691	137651605	PS	1/29/2020	50	(34.32)	2019	12	1888 GEN_S5	-227.304	100233	PACW	201912	1888_LFP_SA_966	SA 966

Rate 0.151

	Customer	Customer Name	Contract	Billed In Amount	MWh	Current Rate	Monthly Revenue - Current Rate Jan-20	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total	Proposed Rate	Monthly Revenue - Proposed Rate Jan-20	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
						0.151														0.172												
1	800400	Bonneville Power Administration	SA 229	(4,040.97)	(26,761.391)		355.36	392.85	321.90	349.55	315.19	313.28	327.04	339.50	341.30	317.91	332.15	334.94	4,040.97		404.78	447.48	366.67	398.16	359.02	356.85	372.52	386.72	388.77	362.12	378.34	381.52	4,602.96
2	800400	Bonneville Power Administration	SA 328	(6,184.28)	(40,955.497)		524.37	588.96	575.19	584.23	495.55	485.18	474.16	524.77	535.30	455.92	471.12	469.53	6,184.28		597.30	670.87	655.18	665.48	564.47	552.66	540.10	597.75	609.75	519.33	536.64	534.83	7,044.35
3	800400	Bonneville Power Administration	SA 538	(156.13)	(1,033.974)		11.85	20.38	18.15	19.41	8.14	10.15	5.42	6.01	10.05	9.31	15.17	22.09	156.13		13.50	23.21	20.67	22.11	9.27	11.56	6.17	6.85	11.45	10.60	17.28	25.16	177.84
4	800400	Bonneville Power Administration	SA 539	(948.17)	(6,279.272)		118.00	127.08	124.27	124.71	81.10	46.72	39.73	42.88	38.01	37.91	79.56	88.20	948.17		134.41	144.75	141.55	142.05	92.38	53.22	45.26	48.84	43.30	43.18	90.62	100.47	1,080.03
5	800400	Bonneville Power Administration	SA 735	(19,647.46)	(130,115.629)		2,212.71	2,040.42	2,365.06	2,041.96	1,512.49	1,238.87	1,144.72	1,148.29	1,174.57	1,207.93	1,675.24	1,885.20	19,647.46		2,520.44	2,324.19	2,693.98	2,325.94	1,722.84	1,411.16	1,303.92	1,307.99	1,337.92	1,375.92	1,908.22	2,147.38	22,379.89
6	800400	Bonneville Power Administration	SA 746	(328,868.71)	(2,177,938.477)		27,813.37	27,189.80	24,723.90	28,790.06	26,835.89	28,909.28	30,086.99	36,614.43	31,404.46	23,349.81	22,859.99	20,290.73	328,868.71		31,681.45	30,971.16	28,162.32	32,793.98	30,568.03	32,929.78	34,271.27	41,706.50	35,771.97	26,597.13	26,039.19	23,112.62	374,605.42
7	800400	Bonneville Power Administration	SA 747	(100,566.42)	(666,002.781)		9,404.16	10,074.48	9,983.10	9,052.91	7,411.21	8,788.79	7,978.29	7,338.23	8,146.47	6,762.08	7,437.07	8,189.63	100,566.42		10,712.02	11,475.57	11,371.48	10,311.92	8,441.91	10,011.07	9,087.85	8,358.78	9,279.42	7,702.50	8,471.36	9,328.59	114,552.48
8	800400	Bonneville Power Administration	SA 827	(120.34)	(796.954)		13.25	12.97	14.41	10.80	8.44	7.67	6.85	6.82	7.86	8.71	10.79	11.77	120.34		15.09	14.77	16.41	12.30	9.61	8.74	7.80	7.77	8.95	9.92	12.29	13.41	137.08
9	800400	Bonneville Power Administration	SA 865	(15.21)	(100.728)		15.21	-	-	-	-	-	-	-	-	-	-	-	15.21		17.33	-	-	-	-	-	-	-	-	-	-	-	17.33
10	800800	Exelon Generation Company, LLC (Sta	SA 759	(9,609.44)	(63,638.675)		503.35	604.25	365.41	438.77	1,247.23	903.90	1,217.76	1,159.92	880.49	986.36	923.15	378.85	9,609.44		573.35	688.28	416.23	499.79	1,420.69	1,029.61	1,387.12	1,321.23	1,002.94	1,123.54	1,051.54	431.54	10,945.85
11	800900	Shell Energy North America	SA 791	(29,018.63)	(192,176.358)		1,480.26	70.71	575.09	4,767.89	70.07	-	2,186.07	5,199.22	5,617.25	3,225.41	2,925.53	2,901.13	29,018.63		1,686.12	80.54	655.07	5,430.97	79.81	-	2,490.09	5,922.29	6,398.46	3,673.98	3,332.39	3,304.60	33,054.33
12	801000	Deseret Generation & Trans.	RS 280	(577,514.38)	(3,824,598.543)		44,716.87	42,396.71	30,920.28	57,470.28	49,575.36	49,048.42	40,366.24	61,971.43	63,424.68	43,730.37	49,512.77	44,380.97	577,514.38		50,935.77	48,292.94	35,220.45	65,462.84	56,469.95	55,869.72	45,980.09	70,589.97	72,245.33	49,812.08	56,398.65	50,553.16	657,830.95
13	802400	Avangrid Renewables, LLC	RS 476	(32,632.32)	(216,108.079)		-	6,106.85	6,818.27	2,175.23	4,522.66	3,727.63	3,502.58	2,657.13	3,121.97	-	-	-	32,632.32		-	6,956.15	7,766.51	2,477.75	5,151.64	4,246.04	3,989.69	3,026.66	3,556.15	-	-	-	37,170.59
14	802400	Avangrid Renewables, LLC	SA 121	-	-		(1,656.93)	-	-	-	-	-	-	-	-	1,656.93	-	-	-		(1,887.36)	-	-	-	-	-	-	-	-	1,887.36	-	-	-
15	802400	Avangrid Renewables, LLC	SA 476	(19,243.32)	(127,439.205)		4,258.31	-	-	-	-	-	-	-	-	3,778.85	6,061.91	5,144.25	19,243.32		4,850.53	-	-	-	-	-	-	-	-	4,304.39	6,904.96	5,859.68	21,919.54
16	802400	Avangrid Renewables, LLC	SA 742	(60,643.05)	(401,609.603)		6,920.21	4,200.13	3,679.66	5,147.38	5,131.22	5,740.99	6,097.58	6,142.55	5,993.83	3,407.52	4,991.59	3,190.39	60,643.05		7,882.62	4,784.25	4,191.40	5,863.24	5,844.83	6,539.41	6,945.59	6,996.81	6,827.41	3,881.41	5,685.78	3,634.09	69,076.85
17	803400	Tri-State Generation & Trans.	SA 628	(18,295.91)	(121,164.967)		1,894.74	1,747.23	1,534.70	1,637.29	1,375.43	1,343.39	1,374.83	1,589.28	1,568.65	1,294.12	1,424.08	1,512.17	18,295.91		2,158.25	1,990.22	1,748.14	1,864.99	1,566.71	1,530.22	1,566.03	1,810.31	1,786.81	1,474.10	1,622.13	1,722.47	20,840.37
18	803500	Utah Associated Municipal Power Sys	RS 297	(567,088.07)	(3,755,550.132)		55,494.53	27,162.30	34,175.96	27,022.87	39,494.32	39,168.32	50,904.08	76,060.49	79,170.89	57,998.30	41,272.47	39,163.54	567,088.07		63,212.31	30,939.84	38,928.91	30,781.02	44,986.91	44,615.57	57,983.46	86,638.44	90,181.41	66,064.29	47,012.35	44,610.13	645,954.62
19	803600	Utah Municipal Power Agency	RS 637	(49,341.55)	(326,765.232)		163.16	211.97	75.97	6.29	73.45	116.51	54.73	23,146.65	23,344.94	735.98	855.38	556.52	49,341.55		185.85	241.45	86.54	7.16	83.66	132.71	62.34	26,365.72	26,591.59	838.33	974.34	633.92	56,203.62
20	803800	Western Area Power Adm FNO	SA 175	0.70	4.636		-	0.82	0.65	0.62	53.86	158.46	235.17	341.57	338.63	-	(1,130.48)		(0.70)		-	0.93	0.74	0.71	61.35	180.50	267.88	389.07	385.72	-	(1,287.70)	-	(0.80)
21	804300	NextEra Energy Resources, LLC	SA 733	(30,055.19)	(199,040.993)		3,033.21	2,893.55	1,654.54	1,460.93	3,934.91	3,762.71	6,005.96	8,822.49	(9,753.72)	3,104.33	3,428.60	1,707.68	30,055.19		3,455.05	3,295.96	1,884.64	1,664.11	4,482.15	4,286.00	6,841.23	10,049.46	(11,110.20)	3,536.06	3,905.43	1,945.17	34,235.05
22	805000	Southern California Edison Company	SA 642	(27,494.11)	(182,080.199)		1,271.63	4,631.35	6,799.21	3,516.02	1,592.94	1,164.84	1,183.65	1,497.01	1,465.68	1,523.65	1,775.32	1,072.81	27,494.11		1,448.48	5,275.45	7,744.80	4,005.00	1,814.47	1,326.84	1,348.26	1,705.20	1,669.52	1,735.55	2,022.22	1,222.01	31,317.79
23	805300	U.S. Bureau of Reclamation	SA 506	(332.26)	(2,200.397)		0.60	0.55	0.51	0.56	24.57	47.84	62.06	63.04	65.02	45.86	21.00	0.65	332.26		0.68	0.63	0.58	0.64	27.99	54.49	70.69	71.81	74.06	52.24	23.92	0.74	378.47
24	816200	Thermo No. 1 BE-01, LLC	SA 568	(9,908.68)	(65,620.397)		887.68	914.84	864.14	909.65	819.62	835.96	756.37	699.91	724.92	744.13	887.15	864.31	9,908.68		1,011.13	1,042.07	984.32	1,036.16	933.61	952.22	861.56	797.25	825.74	847.62	1,010.53	984.51	11,286.71
25	817990	Southern California Public Power Autl	SA 629	(4,401.33)	(29,147.881)		-	-	-	48.23	196.28	438.90	395.04	607.18	948.69	1,304.27	462.74	-	4,401.33		-	-	-	54.94	223.58	499.94	449.98	691.62	1,080.63	1,485.66	527.09	-	5,013.44
26	818140	Tenaska Power Services Co	SA 125	(1,081.09)	(7,159.536)		59.92	104.30	153.07	102.09	198.16	110.30	87.61	58.47	40.74	58.75	59.16	48.52	1,081.09		68.25	118.81	174.36	116.29	225.72	125.64	99.79	66.60	46.41	66.92	67.39	55.27	1,231.44
27	818334	Obsidian Renewables LLC	SA 836	(165.33)	(1,094.901)		165.33	-	-	-	-	-	-	-	-	-	-	-	165.33		188.32	-	-	-	-	-	-	-	-	-	-	-	188.32
28	818349	Exelon Generation Company	SA 943	(904.86)	(5,992.450)		66.43	83.17	70.25	78.12	77.02	84.09	86.74	78.96	77.32	70.11	72.87	59.78	904.86		75.67	94.74	80.02	88.98	87.73	95.78	98.80	89.94	88.07	79.86	83.00	68.09	1,030.70
29	818479	Calpine Energy Solutions	SA 299	(17,841.73)	(118,157.152)		1,387.68	1,635.08	1,462.48	1,560.86	1,258.62	1,522.15	1,535.64	1,554.32	1,603.52	1,488.07	1,454.59	1,378.72	17,841.73		1,580.67	1,862.48	1,665.87	1,777.93	1,433.66	1,733.84	1,749.21	1,770.48	1,826.53	1,695.02	1,656.88	1,570.46	20,323.03
30	818513	Evergreen Biopower	SA 874	(8,642.85)	(57,237.417)		714.09	729.70	387.34	610.04	646.12	722.10	808.03	846.41	869.87	810.93	804.45	693.77	8,642.85		813.40	831.18	441.21	694.88	735.98	822.52	920.41	964.12	990.85	923.71	916.33	790.25	9,844.84
31	818564	3 Phase Renewables	SA 876	(93.79)	(621.126)		6.66	1.08	10.79	7.33	7.31	8.35	8.91	10.18	10.35	8.66	7.50	6.67	93.79		7.59	1.23	12.29	8.35	8.33	9.51	10.15	11.60	11.79	9.86	8.54	7.60	106.83
32	818579	Navajo Tribal Utility Authority	SA 894	(2,518.97)	(16,681.921)		263.00	16.09	443.02	200.76	175.03	222.51	181.23	219.57	218.98	171.37	195.15	212.26	2,518.97		299.58	18.33	504.63	228.68	199.37	253.46	206.43	250.11	249.43	195.20	222.29	241.78	2,869.29
33	818691	LH Garrett	SA 966	(34.32)	(227.285)		34.32	-	-	-	-	-	-	-	-	-	-	-	34.32		39.09	-	-	-	-	-	-	-	-	-	-	-	39.09
34		**Grand Total**		**(1,927,408.17)**	**(12,764,292.52)**		**162,133.33**	**133,957.62**	**128,117.32**	**148,134.84**	**147,142.19**	**148,927.31**	**157,113.48**	**238,746.71**	**221,390.72**	**158,293.55**	**148,886.02**	**134,565.08**	**1,927,408.17**		**184,681.67**	**152,587.49**	**145,934.96**	**168,736.37**	**167,605.67**	**169,639.06**	**178,963.70**	**271,949.89**	**252,180.16**	**180,307.88**	**169,592.02**	**153,279.43**	**2,195,458.31**

	Assignment	Document Number	Business A	Document Type	Document Date	Posting	Amount in local currency	Local Currency	Tax code	Clearing Docur	Text	Quantity	Reference	Reference Key	Reference Key	Reference Key	Contract
35	800400	135649461		ZS	2/26/2019	50	-362.02	USD	S0		2019 01 BPA - I	0.000	59397	0	MW		SA 229
36	800400	135649462		ZS	2/26/2019	50	-30.83	USD	S0		2019 01 BPA - I	0.000	59360	0	MW		SA 229
37	800400	135722443		ZS	3/25/2019	50	-321.90	USD	S0		2019 02 BPA - I	0.000	59800	0	MW		SA 229
38	800400	136076387		ZS	4/29/2019	50	-349.55	USD	S0		2019 03 BPA - I	0.000	60131	0	MW		SA 229
39	800400	136159985		ZS	5/27/2019	50	-315.19	USD	S0		2019 04 BPA - I	0.000	60444	0	MW		SA 229
40	800400	136253214		ZS	6/26/2019	50	-313.28	USD	S0		2019 05 BPA - I	0.000	60971	0	MW		SA 229
41	800400	136596405		ZS	7/30/2019	50	-327.04	USD	S0		2019 06 BPA - I	0.000	61366	0	MW		SA 229
42	800400	136687674		ZS	8/28/2019	50	-339.50	USD	S0		2019 07 BPA - I	0.000	61796	0	MW		SA 229
43	800400	136774762		ZS	9/24/2019	50	-341.30	USD	S0		2019 08 BPA - I	0.000	62127	0	MW		SA 229
44	800400	137132826		PS	10/29/2019	50	-317.91	USD	S0		2019 09 BPAP I	-2,105.371	100062	PACW	201909	BPAP_FNO_CC	SA 229
45	800400	137216494		PS	11/25/2019	50	-332.15	USD	S0		2019 10 BPAP I	-2,199.681	100110	PACW	201910	BPAP_FNO_CC	SA 229
46	800400	137307215		PS	12/23/2019	50	-334.94	USD	S0		2019 11 BPAP I	-2,218.146	100159	PACW	201911	BPAP_FNO_CC	SA 229
47	800400	137651513		PS	1/28/2020	50	-355.36	USD	S0		2019 12 BPAP I	-2,353.374	100227	PACW	201912	BPAP_FNO_CC	SA 229
48	800400	135649466		ZS	2/26/2019	50	-595.97	USD	S0		2019 01 BPA - I	0.000	59432	0	MW		SA 328
49	800400	135654676		ZS	2/26/2019	40	7.01	USD	S0		2019 01 BPA - I	0.000	59355	0	MW		SA 328
50	800400	135722783		ZS	3/25/2019	50	-575.19	USD	S0		2019 02 BPA - I	0.000	59806	0	MW		SA 328
51	800400	136076390		ZS	4/29/2019	50	-584.23	USD	S0		2019 03 BPA - I	0.000	60234	0	MW		SA 328
52	800400	136159987		ZS	5/27/2019	50	-495.55	USD	S0		2019 04 BPA - I	0.000	60548	0	MW		SA 328
53	800400	136253213		ZS	6/26/2019	50	-485.18	USD	S0		2019 05 BPA - I	0.000	60952	0	MW		SA 328
54	800400	136596401		ZS	7/30/2019	50	-452.08	USD	S0		2019 06 BPA - I	0.000	61416	0	MW		SA 328
55	800400	136597570		ZS	7/30/2019	50	-22.08	USD	S0		2019 06 BPA - I	0.000	61285	0	MW		SA 328
56	800400	136687670		ZS	8/28/2019	50	-524.77	USD	S0		2019 07 BPA - I	0.000	61808	0	MW		SA 328
57	800400	136773958		ZS	9/24/2019	50	-535.30	USD	S0		2019 08 BPA - I	0.000	62151	0	MW		SA 328
58	800400	137132826		PS	10/29/2019	50	-455.92	USD	S0		2019 09 BPAP I	-3,019.337	100062	PACW	201909	BPAP_FNO_YA	SA 328
59	800400	137216494		PS	11/25/2019	50	-471.12	USD	S0		2019 10 BPAP I	-3,120.027	100110	PACW	201910	BPAP_FNO_YA	SA 328
60	800400	137307215		PS	12/23/2019	50	-469.53	USD	S0		2019 11 BPAP I	-3,109.444	100159	PACW	201911	BPAP_FNO_YA	SA 328
61	800400	137651513		PS	1/28/2020	50	-524.37	USD	S0		2019 12 BPAP I	-3,472.667	100227	PACW	201912	BPAP_FNO_YA	SA 328
62	800400	135649459		ZS	2/26/2019	50	-20.38	USD	S0		2019 01 BPA - I	0.000	59420	0	MW		SA 538
63	800400	135722778		ZS	3/25/2019	50	-18.15	USD	S0		2019 02 BPA - I	0.000	59801	0	MW		SA 538
64	800400	136076396		ZS	4/29/2019	50	-19.41	USD	S0		2019 03 BPA - I	0.000	60165	0	MW		SA 538
65	800400	136159993		ZS	5/28/2019	50	-8.14	USD	S0		2019 04 BPA - I	0.000	60465	0	MW		SA 538
66	800400	136252610		ZS	6/26/2019	50	-10.15	USD	S0		2019 05 BPA - I	0.000	60981	0	MW		SA 538
67	800400	136596406		ZS	7/30/2019	50	-5.42	USD	S0		2019 06 BPA - I	0.000	61417	0	MW		SA 538
68	800400	136687672		ZS	8/28/2019	50	-6.01	USD	S0		2019 07 BPA - I	0.000	61805	0	MW		SA 538
69	800400	136773964		ZS	9/24/2019	50	-10.05	USD	S0		2019 08 BPA - I	0.000	62129	0	MW		SA 538
70	800400	137132826		PS	10/29/2019	50	-9.31	USD	S0		2019 09 BPAP I	-61.642	100062	PACW	201909	BPAP_FNO_EC	SA 538
71	800400	137216494		PS	11/25/2019	50	-15.17	USD	S0		2019 10 BPAP I	-100.440	100110	PACW	201910	BPAP_FNO_EC	SA 538
72	800400	137307215		PS	12/23/2019	50	-22.09	USD	S0		2019 11 BPAP I	-146.264	100159	PACW	201911	BPAP_FNO_EC	SA 538
73	800400	137651513		PS	1/28/2020	50	-11.85	USD	S0		2019 12 BPAP I	-78.469	100227	PACW	201912	BPAP_FNO_EC	SA 538
74	800400	135649463		ZS	2/26/2019	50	-127.08	USD	S0		2019 01 BPA - I	0.000	59421	0	MW		SA 539
75	800400	135722780		ZS	3/25/2019	50	-124.27	USD	S0		2019 02 BPA - I	0.000	59802	0	MW		SA 539
76	800400	136076392		ZS	4/29/2019	50	-124.71	USD	S0		2019 03 BPA - I	0.000	60235	0	MW		SA 539
77	800400	136159989		ZS	5/28/2019	50	-81.10	USD	S0		2019 04 BPA - I	0.000	60546	0	MW		SA 539
78	800400	136253212		ZS	6/26/2019	50	-46.72	USD	S0		2019 05 BPA - I	0.000	60974	0	MW		SA 539
79	800400	136596402		ZS	7/30/2019	50	-39.73	USD	S0		2019 06 BPA - I	0.000	61365	0	MW		SA 539
80	800400	136687666		ZS	8/28/2019	50	-42.88	USD	S0		2019 07 BPA - I	0.000	61814	0	MW		SA 539
81	800400	136773960		ZS	9/24/2019	50	-38.01	USD	S0		2019 08 BPA - I	0.000	62132	0	MW		SA 539
82	800400	137132826		PS	10/29/2019	50	-37.91	USD	S0		2019 09 BPAP I	-251.040	100062	PACW	201909	BPAP_FNO_RII	SA 539
83	800400	137216494		PS	11/25/2019	50	-79.56	USD	S0		2019 10 BPAP I	-526.884	100110	PACW	201910	BPAP_FNO_RII	SA 539
84	800400	137307215		PS	12/23/2019	50	-88.20	USD	S0		2019 11 BPAP I	-584.082	100159	PACW	201911	BPAP_FNO_RII	SA 539
85	800400	137651513		PS	1/28/2020	50	-118.00	USD	S0		2019 12 BPAP I	-781.437	100227	PACW	201912	BPAP_FNO_RII	SA 539
86	800400	135651796		ZS	2/25/2019	50	-2,040.42	USD	S0		2019 01 BPA - I	0.000	59336	0	MW		SA 735
87	800400	135722445		ZS	3/25/2019	50	-2,365.06	USD	S0		2019 02 BPA - I	0.000	59784	0	MW		SA 735
88	800400	136076394		ZS	4/29/2019	50	-2,041.96	USD	S0		2019 03 BPA - I	0.000	60124	0	MW		SA 735
89	800400	136159991		ZS	5/28/2019	50	-1,512.49	USD	S0		2019 04 BPA - I	0.000	60445	0	MW		SA 735
90	800400	136252611		ZS	6/26/2019	50	-1,238.87	USD	S0		2019 05 BPA - I	0.000	60969	0	MW		SA 735
91	800400	136596403		ZS	7/30/2019	50	-1,144.72	USD	S0		2019 06 BPA - I	0.000	61326	0	MW		SA 735
92	800400	136687664		ZS	8/28/2019	50	-1,148.29	USD	S0		2019 07 BPA - I	0.000	61801	0	MW		SA 735
93	800400	136773962		ZS	9/24/2019	50	-1,174.57	USD	S0		2019 08 BPA - I	0.000	62128	0	MW		SA 735
94	800400	137132826		PS	10/29/2019	50	-1,207.93	USD	S0		2019 09 BPAP I	-7,999.550	100062	PACW	201909	BPAP_FNO_CL	SA 735
95	800400	137216494		PS	11/25/2019	50	-1,675.24	USD	S0		2019 10 BPAP I	-11,094.303	100110	PACW	201910	BPAP_FNO_CL	SA 735
96	800400	137307215		PS	12/23/2019	50	-1,885.20	USD	S0		2019 11 BPAP I	-12,484.739	100159	PACW	201911	BPAP_FNO_CL	SA 735
97	800400	137651513		PS	1/28/2020	50	-2,212.71	USD	S0		2019 12 BPAP I	-14,653.722	100227	PACW	201912	BPAP_FNO_CL	SA 735
98	800400	135654571		ZS	2/27/2019	50	-27,189.80	USD	S0		2019 01 BPA-L'	0.000	59109	0	MW		SA 746
99	800400	135733905		ZS	3/27/2019	50	-24,270.49	USD	S0		2019 02 BPA-L'	0.000	59726	0	MW		SA 746
100	800400	135733905		ZS	3/27/2019	50	-453.41	USD	S0		2019 02 BPA-L'	0.000	59726	0	MW		SA 746
101	800400	136077897		ZS	4/30/2019	50	-28,790.06	USD	S0		2019 03 BPA-L'	0.000	60048	0	MW		SA 746
102	800400	136163201		ZS	5/28/2019	50	-26,835.89	USD	S0		2019 04 BPA-L'	0.000	60378	0	MW		SA 746
103	800400	136254966		ZS	6/28/2019	50	-28,909.28	USD	S0		2019 05 BPA-L'	0.000	60923	0	MW		SA 746
104	800400	136596399		ZS	7/30/2019	50	-30,086.99	USD	S0		2019 06 BPA-L'	0.000	61264	0	MW		SA 746
105	800400	136687650		ZS	8/28/2019	50	-36,614.43	USD	S0		2019 07 BPA-L'	0.000	61643	0	MW		SA 746
106	800400	136785282		ZS	9/27/2019	50	-31,404.46	USD	S0		2019 08 BPA-L'	0.000	62052	0	MW		SA 746
107	800400	137132826		PS	10/29/2019	50	-23,349.81	USD	S0		2019 09 BPAP I	-154,634.514	100062	PACW	201909	BPAP_FNO_GS	SA 746
108	800400	137216494		PS	11/25/2019	50	-22,859.99	USD	S0		2019 10 BPAP I	-151,390.632	100110	PACW	201910	BPAP_FNO_GS	SA 746
109	800400	137307215		PS	12/23/2019	50	-20,290.73	USD	S0		2019 11 BPAP I	-134,375.663	100159	PACW	201911	BPAP_FNO_GS	SA 746
110	800400	137635767		PS	1/22/2020	40	284.34	USD	S0		2019 12 BPAP I	1,883	100170	PACW	201910	BPAP_FNO_GS	SA 746
111	800400	137651513		PS	1/28/2020	50	-27,185.82	USD	S0		2019 12 BPAP I	-180,038.560	100227	PACW	201912	BPAP_FNO_GS	SA 746
112	800400	137651604		PS	1/29/2020	50	-911.89	USD	S0		2019 12 BPAP I	-6,039.028	100232	PACW	201911	BPAP_FNO_GS	SA 746
113	800400	135654570		ZS	2/27/2019	50	-10,074.48	USD	S0		2019 01 BPA - I	0.000	59280	0	MW		SA 747
114	800400	135733904		ZS	3/28/2019	50	-8,766.71	USD	S0		2019 02 BPA - I	0.000	59755	0	MW		SA 747
115	800400	135733904		ZS	3/28/2019	50	-1,216.39	USD	S0		2019 02 BPA - I	0.000	59755	0	MW		SA 747
116	800400	136077896		ZS	4/30/2019	50	-8,137.38	USD	S0		2019 03 BPA - I	0.000	60163	0	MW		SA 747

117	800400	136077896	ZS	4/30/2019	50	-2,131.66	USD	S0	2019 03 BPA - I	0.000	60163	0	MW	SA 747
118	800400	136077896	ZS	4/30/2019	40	1,216.13	USD	S0	2019 03 BPA - I	0.000	60163	0	MW	SA 747
119	800400	136163202	ZS	5/27/2019	50	-5,043.56	USD	S0	2019 04 BPA - I	0.000	60432	0	MW	SA 747
120	800400	136163202	ZS	5/27/2019	50	-2,367.65	USD	S0	2019 04 BPA - I	0.000	60432	0	MW	SA 747
121	800400	136254965	ZS	6/28/2019	50	-6,475.64	USD	S0	2019 05 BPA - I	0.000	60922	0	MW	SA 747
122	800400	136254965	ZS	6/28/2019	50	-2,313.15	USD	S0	2019 05 BPA - I	0.000	60922	0	MW	SA 747
123	800400	136596400	ZS	7/30/2019	50	-5,582.42	USD	S0	2019 06 BPA - I	0.000	61305	0	MW	SA 747
124	800400	136596400	ZS	7/30/2019	50	-2,395.87	USD	S0	2019 06 BPA - I	0.000	61305	0	MW	SA 747
125	800400	136690308	ZS	8/28/2019	50	-6,933.11	USD	S0	2019 07 BPA - I	0.000	61644	0	MW	SA 747
126	800400	136690308	ZS	8/28/2019	50	-2,328.21	USD	S0	2019 07 BPA - I	0.000	61644	0	MW	SA 747
127	800400	136690308	ZS	8/28/2019	40	1,923.09	USD	S0	2019 07 BPA - I	0.000	61644	0	MW	SA 747
128	800400	136785280	ZS	9/27/2019	50	-6,078.43	USD	S0	2019 08 BPA - I	0.000	62020	0	MW	SA 747
129	800400	136785280	ZS	9/27/2019	50	-2,068.04	USD	S0	2019 08 BPA - I	0.000	62020	0	MW	SA 747
130	800400	137132826	PS	10/29/2019	50	-4,724.60	USD	S0	2019 09 BPAP I	-31,288	100062	PACE	201909	BPAP_FNO_IDSA 747
131	800400	137132826	PS	10/29/2019	50	-2,037.48	USD	S0	2019 09 BPAP I	-13,493.240	100062	PACW	201909	BPAP_FNO_IDSA 747
132	800400	137216494	PS	11/25/2019	50	-5,711.14	USD	S0	2019 10 BPAP I	-37,822	100110	PACE	201910	BPAP_FNO_IDSA 747
133	800400	137216494	PS	11/25/2019	50	-1,725.93	USD	S0	2019 10 BPAP I	-11,429.970	100110	PACW	201910	BPAP_FNO_IDSA 747
134	800400	137307215	PS	12/23/2019	50	-6,901.00	USD	S0	2019 11 BPAP I	-45,699	100159	PACE	201911	BPAP_FNO_IDSA 747
135	800400	137307215	PS	12/23/2019	50	-1,288.63	USD	S0	2019 11 BPAP I	-8,533.980	100159	PACW	201911	BPAP_FNO_IDSA 747
136	800400	137651513	PS	1/28/2020	50	-7,982.01	USD	S0	2019 12 BPAP I	-52,858	100227	PACE	201912	BPAP_FNO_IDSA 747
137	800400	137651513	PS	1/28/2020	50	-1,422.15	USD	S0	2019 12 BPAP I	-9,418.230	100227	PACW	201912	BPAP_FNO_IDSA 747
138	800400	135649467	ZS	2/26/2019	50	-12.97	USD	S0	2019 01 BPA - I	0.000	59433	0	MW	SA 827
139	800400	135722785	ZS	3/25/2019	50	-14.41	USD	S0	2019 02 BPA - I	0.000	59807	0	MW	SA 827
140	800400	136076398	ZS	4/29/2019	50	-10.80	USD	S0	2019 03 BPA - I	0.000	60231	0	MW	SA 827
141	800400	136159995	ZS	5/28/2019	50	-8.44	USD	S0	2019 04 BPA - I	0.000	60527	0	MW	SA 827
142	800400	136246868	ZS	6/26/2019	50	-7.67	USD	S0	2019 05 BPA - I	0.000	60987	0	MW	SA 827
143	800400	136596404	ZS	7/30/2019	50	-6.85	USD	S0	2019 06 BPA - I	0.000	61418	0	MW	SA 827
144	800400	136687667	ZS	8/28/2019	50	-6.82	USD	S0	2019 07 BPA - I	0.000	61811	0	MW	SA 827
145	800400	136773966	ZS	9/24/2019	50	-7.86	USD	S0	2019 08 BPA - I	0.000	62131	0	MW	SA 827
146	800400	137132826	PS	10/29/2019	50	-8.71	USD	S0	2019 09 BPAP I	-57.695	100062	PACW	201909	BPAP_FNO_NESA 827
147	800400	137216494	PS	11/25/2019	50	-10.79	USD	S0	2019 10 BPAP I	-71.459	100110	PACW	201910	BPAP_FNO_NESA 827
148	800400	137307215	PS	12/23/2019	50	-11.77	USD	S0	2019 11 BPAP I	-77.963	100159	PACW	201911	BPAP_FNO_NESA 827
149	800400	137651513	PS	1/28/2020	50	-13.25	USD	S0	2019 12 BPAP I	-87.737	100227	PACW	201912	BPAP_FNO_NESA 827
150	800400	137651513	PS	1/28/2020	50	-15.21	USD	S0	2019 12 BPAP I	-100.745	100227	PACW	201912	BPAP_FNO_ASSA 865
151	800800	135652048	ZS	2/26/2019	50	-604.25	USD	S0	2019 01 Constr	0.000	59328	0	MW	SA 759
152	800800	135730140	ZS	3/26/2019	50	-365.41	USD	S0	2019 02 Constr	0.000	59803	0	MW	SA 759
153	800800	136068678	ZS	4/26/2019	50	-438.77	USD	S0	2019 03 Constr	0.000	60126	0	MW	SA 759
154	800800	136159923	ZS	5/23/2019	50	-1,247.23	USD	S0	2019 04 Constr	0.000	60528	0	MW	SA 759
155	800800	136246562	ZS	6/25/2019	50	-903.90	USD	S0	2019 05 Constr	0.000	60972	0	MW	SA 759
156	800800	136585139	ZS	7/24/2019	50	-1,217.76	USD	S0	2019 06 Constr	0.000	61323	0	MW	SA 759
157	800800	136687562	ZS	8/27/2019	50	-1,159.92	USD	S0	2019 07 Constr	0.000	61757	0	MW	SA 759
158	800800	136779624	ZS	9/25/2019	50	-880.49	USD	S0	2019 08 Constr	0.000	62095	0	MW	SA 759
159	800800	137125082	PS	10/28/2019	50	-986.36	USD	S0	2019 09 EXGN	-6,532.157	100047	PACW	201909	EXGN_NF_SA_SA 759
160	800800	137213826	PS	11/22/2019	50	-923.15	USD	S0	2019 10 EXGN	-6,113.592	100108	PACW	201910	EXGN_NF_SA_SA 759
161	800800	137300239	PS	12/20/2019	50	-378.85	USD	S0	2019 11 EXGN	-2,508.924	100148	PACW	201911	EXGN_NF_SA_SA 759
162	800800	137648371	PS	1/27/2020	50	-503.35	USD	S0	2019 12 EXGN	-3,333.445	100221	PACW	201912	EXGN_NF_SA_SA 759
163	800900	135654144	ZS	2/27/2019	50	-70.71	USD	S0	2019 01 Shell E	0.000	59140	0	MW	SA 791
164	800900	135733907	ZS	3/28/2019	50	-575.09	USD	S0	2019 02 Shell E	0.000	59791	0	MW	SA 791
165	800900	136076523	ZS	4/29/2019	50	-4,767.89	USD	S0	2019 03 Shell E	0.000	59938	0	MW	SA 791
166	800900	136159935	ZS	5/24/2019	50	-70.07	USD	S0	2019 04 Shell E	0.000	60336	0	MW	SA 791
167	800900	136597566	ZS	7/30/2019	50	-2,186.07	USD	S0	2019 06 Shell E	0.000	61414	0	MW	SA 791
168	800900	136687565	ZS	8/27/2019	50	-5,199.22	USD	S0	2019 07 Shell E	0.000	61511	0	MW	SA 791
169	800900	136785286	ZS	9/27/2019	50	-5,617.25	USD	S0	2019 08 Shell E	0.000	61997	0	MW	SA 791
170	800900	137124733	PS	10/25/2019	50	-3,225.41	USD	S0	2019 09 CORP	-21,360.343	100042	PACE	201909	CORP_LFP_SA_SA 791
171	800900	137209960	PS	11/21/2019	50	-2,925.53	USD	S0	2019 10 CORP	-19,374.397	100104	PACE	201910	CORP_LFP_SA_SA 791
172	800900	137303007	PS	12/23/2019	50	-2,901.13	USD	S0	2019 11 CORP	-19,212.785	100157	PACE	201911	CORP_LFP_SA_SA 791
173	800900	137640264	PS	1/23/2020	50	-1,480.26	USD	S0	2019 12 CORP	-9,803.070	100172	PACE	201912	CORP_LFP_SA_SA 791
174	801000	135651798	ZS	2/26/2019	50	-42,396.71	USD	S0	2019 01 Deser	0.000	59324	0	MW	RS 280
175	801000	135722790	ZS	3/25/2019	50	-30,920.28	USD	S0	2019 02 Deser	0.000	59786	0	MW	RS 280
176	801000	136076382	ZS	4/24/2019	50	-57,470.28	USD	S0	2019 03 Deser	0.000	60127	0	MW	RS 280
177	801000	136159926	ZS	5/23/2019	50	-49,575.36	USD	S0	2019 04 Deser	0.000	60522	0	MW	RS 280
178	801000	136249240	ZS	6/25/2019	50	-49,048.42	USD	S0	2019 05 Deser	0.000	60992	0	MW	RS 280
179	801000	136589476	ZS	7/25/2019	50	-40,366.24	USD	S0	2019 06 Deser	0.000	61328	0	MW	RS 280
180	801000	136687651	ZS	8/28/2019	50	-61,971.43	USD	S0	2019 07 Deser	0.000	61645	0	MW	RS 280
181	801000	136773951	ZS	9/24/2019	50	-63,424.68	USD	S0	2019 08 Deser	0.000	62110	0	MW	RS 280
182	801000	137124093	SA	10/25/2019	40	8.74	USD		VNL-BOZ DGTF	0.000	PP TR M141	0	MW	RS 280
183	801000	137124452	ZS	10/25/2019	50	-44,992.27	USD	S0	2019 09 Deser	0.000	62474	0	MW	RS 280
184	801000	137132232	ZS	10/29/2019	40	142.38	USD	S0	2019 09 Deser	0.000	62425	0	MW	RS 280
185	801000	137132232	ZS	10/29/2019	40	408.14	USD	S0	2019 09 Deser	0.000	62425	0	MW	RS 280
186	801000	137132232	ZS	10/29/2019	40	5.19	USD	S0	2019 09 Deser	0.000	62425	0	MW	RS 280
187	801000	137132232	ZS	10/29/2019	40	14.65	USD	S0	2019 09 Deser	0.000	62425	0	MW	RS 280
188	801000	137132232	ZS	10/29/2019	40	290.98	USD	S0	2019 09 Deser	0.000	62425	0	MW	RS 280
189	801000	137132232	ZS	10/29/2019	40	269.45	USD	S0	2019 09 Deser	0.000	62425	0	MW	RS 280
190	801000	137132232	ZS	10/29/2019	40	122.37	USD	S0	2019 09 Deser	0.000	62425	0	MW	RS 280
191	801000	137213627	ZS	11/21/2019	50	-49,512.77	USD	S0	2019 10 Deser	0.000	62866	0	MW	RS 280
192	801000	137301234	ZS	12/20/2019	50	-44,380.97	USD	S0	2019 11 Deser	0.000	63189	0	MW	RS 280
193	801000	137648030	SA	1/27/2020	50	-153.83	USD		MonButte DGT	0.000	PP TR M141	0	MW	RS 280
194	801000	137648413	ZS	1/27/2020	50	-44,563.04	USD	S0	2019 12 Deser	0.000	63406	0	MW	RS 280
195	802400	135651811	ZS	2/26/2019	50	-6,106.85	USD	S0	2019 01 Avang	0.000	59310	0	MW	RS 476
196	802400	135730155	ZS	3/26/2019	50	-6,818.27	USD	S0	2019 02 Avang	0.000	59787	0	MW	RS 476
197	802400	136068691	ZS	4/26/2019	50	-2,175.23	USD	S0	2019 03 Avang	0.000	60128	0	MW	RS 476
198	802400	136159932	ZS	5/23/2019	50	-4,522.66	USD	S0	2019 04 Avang	0.000	60524	0	MW	RS 476
199	802400	136246730	ZS	6/25/2019	50	-3,727.63	USD	S0	2019 05 Avang	0.000	60973	0	MW	RS 476
200	802400	136586651	ZS	7/25/2019	50	-3,502.58	USD	S0	2019 06 Avang	0.000	61320	0	MW	RS 476
201	802400	136683512	ZS	8/26/2019	50	-2,657.13	USD	S0	2019 07 Avang	0.000	61754	0	MW	RS 476
202	802400	136779353	ZS	9/25/2019	50	-3,121.97	USD	S0	2019 08 Avang	0.000	62097	0	MW	RS 476
203	802400	137132825	PS	10/29/2019	50	-1,656.93	USD	S0	2019 09 PPMI I	-10,973.023	100061	PACW	201909	PPMI_NF_SA_SA 121
204	802400	137651609	PS	1/29/2020	40	1,656.93	USD	S0	2019 12 PPMI I	10,973.023	100235	PACW	201909	PPMI_NF_SA_SA 121
205	802400	137132825	PS	10/29/2019	50	-3,778.85	USD	S0	2019 09 PPMI I	-25,025.500	100061	PACE	201909	PPMI_OS_SA_SA 476
206	802400	137213827	PS	11/22/2019	50	-6,061.91	USD	S0	2019 10 PPMI I	-40,145.100	100109	PACE	201910	PPMI_OS_SA_SA 476
207	802400	137300245	PS	12/20/2019	50	-5,144.25	USD	S0	2019 11 PPMI I	-34,067.900	100151	PACE	201911	PPMI_OS_SA_SA 476
208	802400	137648803	PS	1/28/2020	50	-4,258.31	USD	S0	2019 12 PPMI I	-28,200.700	100225	PACE	201912	PPMI_OS_SA_SA 476
209	802400	135652050	ZS	2/26/2019	50	-718.14	USD	S0	2019 01 Avang	0.000	59334	0	MW	SA 742
210	802400	135652052	ZS	2/26/2019	50	-3,481.99	USD	S0	2019 01 Avang	0.000	59386	0	MW	SA 742
211	802400	135727943	ZS	3/25/2019	50	-3,213.30	USD	S0	2019 02 Avang	0.000	59788	0	MW	SA 742
212	802400	135730161	ZS	3/26/2019	50	-466.36	USD	S0	2019 02 Avang	0.000	59772	0	MW	SA 742
213	802400	136068687	ZS	4/26/2019	50	-3,526.05	USD	S0	2019 03 Avang	0.000	60129	0	MW	SA 742
214	802400	136068690	ZS	4/26/2019	50	-1,621.33	USD	S0	2019 03 Avang	0.000	60122	0	MW	SA 742
215	802400	136159918	ZS	5/24/2019	50	-3,394.24	USD	S0	2019 04 Avang	0.000	60525	0	MW	SA 742
216	802400	136159937	ZS	5/24/2019	50	-1,736.98	USD	S0	2019 04 Avang	0.000	60518	0	MW	SA 742
217	802400	136246733	ZS	6/25/2019	50	-2,194.76	USD	S0	2019 05 Avang	0.000	60967	0	MW	SA 742
218	802400	136246754	ZS	6/26/2019	50	-3,546.23	USD	S0	2019 05 Avang	0.000	60975	0	MW	SA 742
219	802400	136586660	ZS	7/25/2019	50	-2,763.50	USD	S0	2019 06 Avang	0.000	61324	0	MW	SA 742
220	802400	136589481	ZS	7/25/2019	50	-3,334.08	USD	S0	2019 06 Avang	0.000	61321	0	MW	SA 742
221	802400	136680507	ZS	8/26/2019	50	-3,551.40	USD	S0	2019 07 Avang	0.000	61762	0	MW	SA 742
222	802400	136680508	ZS	8/26/2019	50	-2,591.15	USD	S0	2019 07 Avang	0.000	61758	0	MW	SA 742
223	802400	136779354	ZS	9/24/2019	50	-2,495.90	USD	S0	2019 08 Avang	0.000	62096	0	MW	SA 742
224	802400	136779356	ZS	9/25/2019	50	-3,497.93	USD	S0	2019 08 Avang	0.000	62107	0	MW	SA 742
225	802400	137132825	PS	10/29/2019	50	-3,407.52	USD	S0	2019 09 PPMI I	-22,566.336	100061	PACW	201909	PPMI_FNO_SASA 742
226	802400	137213827	PS	11/22/2019	50	-3,560.04	USD	S0	2019 10 PPMI I	-23,576.446	100109	PACW	201910	PPMI_FNO_SASA 742
227	802400	137213827	PS	11/22/2019	50	-1,431.55	USD	S0	2019 10 PPMI I	-9,480.432	100109	PACW	201910	PPMI_FNOGS_SA 742
228	802400	137300245	PS	12/20/2019	50	-2,370.03	USD	S0	2019 11 PPMI I	-15,695.551	100151	PACW	201911	PPMI_FNO_SASA 742
229	802400	137300245	PS	12/20/2019	50	-820.36	USD	S0	2019 11 PPMI I	-5,432.846	100151	PACW	201911	PPMI_FNOGS_SA 742
230	802400	137640262	PS	1/23/2020	50	-1,099.19	USD	S0	2019 12 PPMI I	-7,279.415	100171	PACW	201911	PPMI_FNO_SASA 742
231	802400	137648803	PS	1/28/2020	50	-3,616.31	USD	S0	2019 12 PPMI I	-23,949.042	100225	PACW	201912	PPMI_FNO_SASA 742
232	802400	137648803	PS	1/28/2020	50	-547.78	USD	S0	2019 12 PPMI I	-3,627.712	100225	PACW	201912	PPMI_FNOGS_SA 742
233	802400	137651609	PS	1/29/2020	50	-1,656.93	USD	S0	2019 12 PPMI I	-10,973.023	100235	PACW	201909	PPMI_FNOGS_SA 742
234	803400	135651804	ZS	2/26/2019	50	-1,747.23	USD	S0	2019 01 Tri-Sta	0.000	59298	0	MW	SA 628
235	803400	135727941	ZS	3/25/2019	50	-1,534.70	USD	S0	2019 02 Tri-Sta	0.000	59796	0	MW	SA 628
236	803400	136068730	ZS	4/26/2019	50	-1,637.29	USD	S0	2019 03 Tri-Sta	0.000	60139	0	MW	SA 628
237	803400	136160114	ZS	5/23/2019	50	-1,375.43	USD	S0	2019 04 Tri-Sta	0.000	60594	0	MW	SA 628
238	803400	136249261	ZS	6/26/2019	50	-1,343.39	USD	S0	2019 05 Tri-Sta	0.000	60976	0	MW	SA 628
239	803400	136589478	ZS	7/25/2019	50	-1,374.83	USD	S0	2019 06 Tri-Sta	0.000	61353	0	MW	SA 628
240	803400	136683515	ZS	8/26/2019	50	-1,589.28	USD	S0	2019 07 Tri-Sta	0.000	61753	0	MW	SA 628
241	803400	136785293	ZS	9/27/2019	50	-1,568.65	USD	S0	2019 08 Tri-Sta	0.000	62104	0	MW	SA 628
242	803400	137125103	PS	10/28/2019	50	-1,294.12	USD	S0	2019 09 TSPM	-8,570.345	100060	PACE	201909	TSPM_FNO_SFSA 628
243	803400	137216487	SA	11/25/2019	50	-0.13	USD		08-2019 TRSPC	0.000	PP TR M141	0	MW	SA 628
244	803400	137216496	PS	11/25/2019	50	-1,423.95	USD	S0	2019 10 TSPM	-9,430.140	100113	PACE	201910	TSPM_FNO_SFSA 628
245	803400	137300250	PS	12/20/2019	50	-1,512.17	USD	S0	2019 11 TSPM	-10,014.383	100155	PACE	201911	TSPM_FNO_SFSA 628
246	803400	137648795	PS	1/28/2020	50	-1,894.74	USD	S0	2019 12 TSPM	-12,547.923	100226	PACE	201912	TSPM_FNO_SFSA 628
247	803500	135654148	ZS	2/27/2019	50	-27,162.30	USD	S0	2019 01 UAMP	0.000	59333	0	MW	RS 297
248	803500	135732684	ZS	3/28/2019	50	-34,175.96	USD	S0	2019 02 UAMP	0.000	59687	0	MW	RS 297
249	803500	136076385	ZS	4/29/2019	50	-27,022.87	USD	S0	2019 03 UAMP	0.000	60140	0	MW	RS 297
250	803500	136163203	ZS	5/29/2019	50	-39,494.32	USD	S0	2019 04 UAMP	0.000	60507	0	MW	RS 297
251	803500	136254959	ZS	6/27/2019	50	-39,168.32	USD	S0	2019 05 UAMP	0.000	60935	0	MW	RS 297

252	803500	136597270	ZS	7/30/2019	50	-50,904.08	USD	S0	2019 06 UAMP	0.000	61222	0	MW	RS 297
253	803500	136690914	ZS	8/28/2019	50	-76,060.49	USD	S0	2019 07 UAMP	0.000	61734	0	MW	RS 297
254	803500	136786052	ZS	9/27/2019	50	-79,170.89	USD	S0	2019 08 UAMP	0.000	62067	0	MW	RS 297
255	803500	137127304	ZS	10/29/2019	50	-57,998.30	USD	S0	2019 09 UAMP	0.000	62415	0	MW	RS 297
256	803500	137216837	ZS	11/25/2019	40	2.26	USD	S0	2019 10 UAMP	0.000	62741	0	MW	RS 297
257	803500	137216837	ZS	11/25/2019	50	-59.57	USD	S0	2019 10 UAMP	0.000	62741	0	MW	RS 297
258	803500	137216837	ZS	11/25/2019	50	-80.77	USD	S0	2019 10 UAMP	0.000	62741	0	MW	RS 297
259	803500	137220976	ZS	11/25/2019	50	-41,134.39	USD	S0	2019 10 UAMP	0.000	62833	0	MW	RS 297
260	803500	137307037	ZS	12/23/2019	50	-39,163.54	USD	S0	2019 11 UAMP	0.000	63187	0	MW	RS 297
261	803500	137648089	ZS	1/28/2020	50	-54,874.38	USD	S0	2019 12 UAMP	0.000	63409	0	MW	RS 297
262	803500	137651367	ZS	1/28/2020	50	-284.33	USD	S0	2019 12 UAMP	0.000	63412	0	MW	RS 297
263	803500	137651367	ZS	1/28/2020	50	-335.82	USD	S0	2019 12 UAMP	0.000	63412	0	MW	RS 297
264	803600	135654572	ZS	2/27/2019	50	-217.55	USD	S0	2019 01 UMPA	0.000	59295	0	MW	RS 637
265	803600	135654572	ZS	2/27/2019	40	0.90	USD	S0	2019 01 UMPA	0.000	59295	0	MW	RS 637
266	803600	135654572	ZS	2/27/2019	40	3.06	USD	S0	2019 01 UMPA	0.000	59295	0	MW	RS 637
267	803600	135654572	ZS	2/27/2019	40	1.62	USD	S0	2019 01 UMPA	0.000	59295	0	MW	RS 637
268	803600	135732686	ZS	3/28/2019	50	-75.97	USD	S0	2019 02 UMPA	0.000	59760	0	MW	RS 637
269	803600	136076520	ZS	4/29/2019	50	-6.29	USD	S0	2019 03 UMPA	0.000	60102	0	MW	RS 637
270	803600	136160690	ZS	5/28/2019	50	-73.45	USD	S0	2019 04 UMPA	0.000	60414	0	MW	RS 637
271	803600	136254962	ZS	6/27/2019	50	-116.51	USD	S0	2019 05 UMPA	0.000	60934	0	MW	RS 637
272	803600	136597269	ZS	7/30/2019	50	-54.73	USD	S0	2019 06 UMPA	0.000	61313	0	MW	RS 637
273	803600	136687571	ZS	8/27/2019	50	-23,146.65	USD	S0	2019 07 UMPA	0.000	61671	0	MW	RS 637
274	803600	136786056	ZS	9/27/2019	50	-23,344.94	USD	S0	2019 08 UMPA	0.000	62094	0	MW	RS 637
275	803600	137132797	ZS	10/29/2019	50	-735.98	USD	S0	2019 09 UMPA	0.000	62488	0	MW	RS 637
276	803600	137216736	ZS	11/25/2019	50	-855.38	USD	S0	2019 10 UMPA	0.000	62778	0	MW	RS 637
277	803600	137307035	ZS	12/20/2019	50	-556.52	USD	S0	2019 11 UMPA	0.000	63076	0	MW	RS 637
278	803600	137648068	ZS	1/28/2020	50	-163.16	USD	S0	2019 12 UMPA	0.000	63410	0	MW	RS 637
279	803800	135648549	ZS	2/25/2019	50	-0.82	USD	S0	2019 01 WAPA	0.000	59257	0	MW	SA 175
280	803800	135709292	ZS	3/15/2019	50	-0.65	USD	S0	2019 02 WAPA	0.000	59650	0	MW	SA 175
281	803800	136069165	ZS	4/29/2019	50	-0.62	USD	S0	2019 03 WAPA	0.000	60179	0	MW	SA 175
282	803800	136160686	ZS	5/27/2019	50	-53.86	USD	S0	2019 04 WAPA	0.000	60574	0	MW	SA 175
283	803800	136249238	ZS	6/24/2019	50	-158.46	USD	S0	2019 05 WAPA	0.000	60891	0	MW	SA 175
284	803800	136582007	ZS	7/22/2019	50	-235.17	USD	S0	2019 06 WAPA	0.000	61210	0	MW	SA 175
285	803800	136667814	ZS	8/19/2019	50	-341.57	USD	S0	2019 07 WAPA	0.000	61598	0	MW	SA 175
286	803800	136786053	ZS	9/27/2019	50	-328.28	USD	S0	2019 08 WAPA	0.000	61979	0	MW	SA 175
287	803800	136786053	ZS	9/27/2019	50	-10.35	USD	S0	2019 08 WAPA	0.000	61979	0	MW	SA 175
288	803800	137122242	SA	10/25/2019	41	1,130.48	USD		Accrue WAPA '	0.000	PP TR NRE			SA 175
289	803800	137137614	SA	10/31/2019	50	-1,130.48	USD		Accrue WAPA '	0.000	PP TR NRE			SA 175
290	803800	137207388	ZS	11/20/2019	40	1,130.48	USD	S0	2019 10 WAPA	0.000	62855	0	MW	SA 175
291	803800	137224068	SR	10/25/2019	51	-1,130.48	USD		Accrue WAPA '	0.000	PP TR NRE			SA 175
292	803800	137224117	SR	10/31/2019	40	1,130.48	USD		Accrue WAPA '	0.000	PP TR NRE			SA 175
293	804300	135649456	ZS	2/26/2019	50	-2,893.55	USD	S0	2019 01 NextE	0.000	59143	0	MW	SA 733
294	804300	135735467	ZS	3/27/2019	50	-1,654.54	USD	S0	2019 02 NextE	0.000	59605	0	MW	SA 733
295	804300	136076516	ZS	4/26/2019	50	-1,487.30	USD	S0	2019 03 NextE	0.000	59942	0	MW	SA 733
296	804300	136135852	ZS	4/30/2019	40	26.37	USD	S0	2019 03 NextE	0.000	60268	0	MW	SA 733
297	804300	136160680	ZS	5/28/2019	50	-3,934.91	USD	S0	2019 04 NextE	0.000	60340	0	MW	SA 733
298	804300	136253069	ZS	6/27/2019	50	-3,762.71	USD	S0	2019 05 NextE	0.000	60805	0	MW	SA 733
299	804300	136586685	ZS	7/26/2019	50	-6,005.96	USD	S0	2019 06 NextE	0.000	61322	0	MW	SA 733
300	804300	136687573	ZS	8/27/2019	50	-8,822.49	USD	S0	2019 07 NextE	0.000	61515	0	MW	SA 733
301	804300	136785252	ZS	9/27/2019	50	-247.78	USD	S0	2019 08 NextE	0.000	61936	0	MW	SA 733
302	804300	136785259	ZS	9/27/2019	40	173.65	USD	S0	2019 08 NextE	0.000	61961	0	MW	SA 733
303	804300	136785259	ZS	9/27/2019	40	1,317.48	USD	S0	2019 08 NextE	0.000	61961	0	MW	SA 733
304	804300	136785259	ZS	9/27/2019	40	2,194.79	USD	S0	2019 08 NextE	0.000	61961	0	MW	SA 733
305	804300	136785259	ZS	9/27/2019	40	6,315.58	USD	S0	2019 08 NextE	0.000	61961	0	MW	SA 733
306	804300	137125083	PS	10/28/2019	50	-3,104.33	USD	S0	2019 09 FPLP (	-20,558.500	100048	PACW	201909	FPLP_LFP_SA_ SA 733
307	804300	137216493	PS	11/25/2019	50	-3,428.60	USD	S0	2019 10 FPLP (	-22,705.975	100112	PACW	201910	FPLP_LFP_SA_ SA 733
308	804300	137300247	PS	12/20/2019	50	-1,707.68	USD	S0	2019 11 FPLP (	-11,309.150	100152	PACW	201911	FPLP_LFP_SA_ SA 733
309	804300	137640282	PS	1/23/2020	50	-3,033.21	USD	S0	2019 12 FPLP (	-20,087.500	100181	PACW	201912	FPLP_LFP_SA_ SA 733
310	805000	135649457	ZS	2/26/2019	50	-4,631.35	USD	S0	2019 01 South	0.000	59153	0	MW	SA 642
311	805000	135733619	ZS	3/27/2019	50	-6,799.21	USD	S0	2019 02 South	0.000	59559	0	MW	SA 642
312	805000	136076402	ZS	4/29/2019	50	-3,516.02	USD	S0	2019 03 South	0.000	59953	0	MW	SA 642
313	805000	136159965	ZS	5/28/2019	50	-1,592.94	USD	S0	2019 04 South	0.000	60367	0	MW	SA 642
314	805000	136253071	ZS	6/27/2019	50	-1,164.84	USD	S0	2019 05 South	0.000	60737	0	MW	SA 642
315	805000	136593872	ZS	7/28/2019	50	-1,183.65	USD	S0	2019 06 South	0.000	61143	0	MW	SA 642
316	805000	136678769	ZS	8/26/2019	50	-1,497.01	USD	S0	2019 07 South	0.000	61524	0	MW	SA 642
317	805000	136785283	ZS	9/27/2019	50	-1,465.68	USD	S0	2019 08 South	0.000	61945	0	MW	SA 642
318	805000	137125088	PS	10/28/2019	50	-1,523.65	USD	S0	2019 09 SCET (	-10,090.393	100052	PACE	201909	SCET_NF_SA_(SA 642
319	805000	137216491	PS	11/25/2019	50	-1,775.32	USD	S0	2019 10 SCET (	-11,757.087	100111	PACE	201910	SCET_NF_SA_(SA 642
320	805000	137300249	PS	12/20/2019	50	-1,072.81	USD	S0	2019 11 SCET (	-7,104.699	100153	PACE	201911	SCET_NF_SA_(SA 642
321	805000	137640268	PS	1/23/2020	50	-1,271.63	USD	S0	2019 12 SCET (	-8,421.421	100177	PACE	201912	SCET_NF_SA_(SA 642
322	805300	135646626	ZS	2/24/2019	50	-0.55	USD	S0	2019 01 U.S.B.	0.000	59390	0	MW	SA 506
323	805300	135709291	ZS	3/15/2019	50	-0.51	USD	S0	2019 02 U.S.B.	0.000	59651	0	MW	SA 506
324	805300	136069166	ZS	4/29/2019	50	-0.56	USD	S0	2019 03 U.S.B.	0.000	60187	0	MW	SA 506
325	805300	136163200	ZS	5/29/2019	50	-24.57	USD	S0	2019 04 U.S.B.	0.000	60547	0	MW	SA 506
326	805300	136249239	ZS	6/24/2019	50	-47.84	USD	S0	2019 05 U.S.B.	0.000	60838	0	MW	SA 506
327	805300	136579657	ZS	7/22/2019	50	-62.06	USD	S0	2019 06 U.S.B.	0.000	61211	0	MW	SA 506
328	805300	136667815	ZS	8/19/2019	50	-63.04	USD	S0	2019 07 U.S.B.	0.000	61669	0	MW	SA 506
329	805300	136785285	ZS	9/27/2019	50	-65.02	USD	S0	2019 08 U.S.B.	0.000	62193	0	MW	SA 506
330	805300	137124726	PS	10/25/2019	50	-45.86	USD	S0	2019 09 USBR	-303.686	100026	PACW	201909	USBR_FNO_SA SA 506
331	805300	137202792	PS	11/20/2019	50	-21.00	USD	S0	2019 10 USBR	-139.061	100071	PACW	201910	USBR_FNO_SA SA 506
332	805300	137295506	PS	12/18/2019	50	-0.65	USD	S0	2019 11 USBR	-4.279	100123	PACW	201911	USBR_FNO_SA SA 506
333	805300	137613280	PS	1/14/2020	50	-0.60	USD	S0	2019 12 USBR	-4	100167	PACW	201912	USBR_FNO_SA SA 506
334	816200	135649468	ZS	2/26/2019	50	-914.84	USD	S0	2019 01 Cyrq E	0.000	59176	0	MW	SA 568
335	816200	135722786	ZS	3/25/2019	50	-864.14	USD	S0	2019 02 Cyrq E	0.000	59603	0	MW	SA 568
336	816200	136075844	ZS	4/27/2019	50	-909.65	USD	S0	2019 03 Cyrq E	0.000	59971	0	MW	SA 568
337	816200	136160113	ZS	5/23/2019	50	-819.62	USD	S0	2019 04 Cyrq E	0.000	60379	0	MW	SA 568
338	816200	136249262	ZS	6/26/2019	50	-835.96	USD	S0	2019 05 Cyrq E	0.000	60802	0	MW	SA 568
339	816200	136594555	ZS	7/26/2019	50	-756.37	USD	S0	2019 06 Cyrq E	0.000	61149	0	MW	SA 568
340	816200	136687537	ZS	8/26/2019	50	-699.91	USD	S0	2019 07 Cyrq E	0.000	61496	0	MW	SA 568
341	816200	136785258	ZS	9/27/2019	50	-724.92	USD	S0	2019 08 Cyrq E	0.000	61926	0	MW	SA 568
342	816200	137125092	PS	10/28/2019	50	-744.13	USD	S0	2019 09 BE01 (	-4,927.984	100056	PACE	201909	BE01_LFP_SA_ SA 568
343	816200	137209949	PS	11/21/2019	50	-3,277.09	USD	S0	2019 10 BE01 (	-21,702.560	100095	PACE	201910	BE01_LFP_SA_ SA 568
344	816200	137216499	PS	11/25/2019	40	2,389.94	USD	S0	2019 10 BE01 (	15,827.422	100114	PACE	201910	BE01_LFP_SA_ SA 568
345	816200	137300236	PS	12/20/2019	50	-864.31	USD	S0	2019 11 BE01 (	-5,723.897	100147	PACE	201911	BE01_LFP_SA_ SA 568
346	816200	137640266	PS	1/23/2020	50	-887.68	USD	S0	2019 12 BE01 (	-5,878.694	100173	PACE	201912	BE01_LFP_SA_ SA 568
347	817990	136060167	ZS	4/29/2019	50	-48.23	USD	S0	2019 03 South	0.000	60207	0	MW	SA 629
348	817990	136160001	ZS	5/27/2019	50	-196.28	USD	S0	2019 04 South	0.000	60529	0	MW	SA 629
349	817990	136246560	ZS	6/25/2019	50	-438.90	USD	S0	2019 05 South	0.000	60977	0	MW	SA 629
350	817990	136593873	ZS	7/28/2019	50	-395.04	USD	S0	2019 06 South	0.000	61209	0	MW	SA 629
351	817990	136687726	ZS	8/27/2019	50	-607.18	USD	S0	2019 07 South	0.000	61599	0	MW	SA 629
352	817990	136777012	ZS	9/24/2019	50	-948.69	USD	S0	2019 08 South	0.000	61981	0	MW	SA 629
353	817990	137125089	PS	10/28/2019	50	-1,304.27	USD	S0	2019 09 SCPA (	-8,637.525	100053	PACW	201909	SCPA_NF_SA_(SA 629
354	817990	137209947	PS	11/21/2019	50	-462.74	USD	S0	2019 10 SCPA (	-3,064.525	100092	PACW	201910	SCPA_NF_SA_(SA 629
355	818140	135654557	ZS	2/25/2019	50	-104.30	USD	S0	2019 01 Tenas	0.000	59174	0	MW	SA 125
356	818140	135732695	ZS	3/27/2019	50	-153.07	USD	S0	2019 02 Tenas	0.000	59562	0	MW	SA 125
357	818140	136075929	ZS	4/29/2019	50	-102.09	USD	S0	2019 03 Tenas	0.000	59957	0	MW	SA 125
358	818140	136163415	ZS	5/29/2019	50	-198.16	USD	S0	2019 04 Tenas	0.000	60371	0	MW	SA 125
359	818140	136254967	ZS	6/28/2019	50	-110.30	USD	S0	2019 05 Tenas	0.000	60740	0	MW	SA 125
360	818140	136594422	ZS	7/29/2019	50	-87.61	USD	S0	2019 06 Tenas	0.000	61146	0	MW	SA 125
361	818140	136687728	ZS	8/27/2019	50	-58.47	USD	S0	2019 07 Tenas	0.000	61527	0	MW	SA 125
362	818140	136773945	ZS	9/24/2019	50	-40.74	USD	S0	2019 08 Tenas	0.000	61948	0	MW	SA 125
363	818140	137125090	PS	10/28/2019	50	-58.75	USD	S0	2019 09 TNSK (	-389.067	100054	PACE	201909	TNSK_NF_SA_: SA 125
364	818140	137213823	PS	11/22/2019	50	-59.16	USD	S0	2019 10 TNSK (	-391.803	100106	PACE	201910	TNSK_NF_SA_: SA 125
365	818140	137300248	PS	12/20/2019	50	-48.52	USD	S0	2019 11 TNSK (	-321.297	100154	PACE	201911	TNSK_NF_SA_: SA 125
366	818140	137640270	PS	1/23/2020	50	-59.92	USD	S0	2019 12 TNSK (	-396.847	100176	PACE	201912	TNSK_NF_SA_: SA 125
367	818334	137653119	PS	1/29/2020	50	-165.33	USD	S0	2019 12 OBRE	-1,094.931	100237	PACW	201912	OBRE_LFP_SA_ SA 836
368	818349	135651806	ZS	2/26/2019	50	-83.17	USD	S0	2019 01 Exelor	0.000	59436	0	MW	SA 943
369	818349	135722787	ZS	3/25/2019	50	-70.25	USD	S0	2019 02 Exelor	0.000	59810	0	MW	SA 943
370	818349	136068683	ZS	4/26/2019	50	-78.12	USD	S0	2019 03 Exelor	0.000	60209	0	MW	SA 943
371	818349	136159921	ZS	5/23/2019	50	-77.02	USD	S0	2019 04 Exelor	0.000	60595	0	MW	SA 943
372	818349	136246557	ZS	6/25/2019	50	-84.09	USD	S0	2019 05 Exelor	0.000	61015	0	MW	SA 943
373	818349	136589483	ZS	7/24/2019	50	-86.74	USD	S0	2019 06 Exelor	0.000	61369	0	MW	SA 943
374	818349	136687559	ZS	8/27/2019	50	-78.96	USD	S0	2019 07 Exelor	0.000	61763	0	MW	SA 943
375	818349	136779333	ZS	9/25/2019	50	-77.32	USD	S0	2019 08 Exelor	0.000	62099	0	MW	SA 943
376	818349	137125097	PS	10/28/2019	50	-70.11	USD	S0	2019 09 EXGN	-464.326	100059	PACW	201909	EXGN_FNO_SA SA 943
377	818349	137209934	PS	11/21/2019	50	-72.87	USD	S0	2019 10 EXGN	-482.600	100081	PACW	201910	EXGN_FNO_SA SA 943
378	818349	137300231	PS	12/20/2019	50	-59.78	USD	S0	2019 11 EXGN	-395.921	100142	PACW	201911	EXGN_FNO_SA SA 943
379	818349	137648364	PS	1/27/2020	50	-66.43	USD	S0	2019 12 EXGN	-439.932	100218	PACW	201912	EXGN_FNO_SA SA 943
380	818479	135651800	ZS	2/26/2019	50	-1,635.08	USD	S0	2019 01 Calpin	0.000	59419	0	MW	SA 299
381	818479	135727378	ZS	3/25/2019	50	-1,462.48	USD	S0	2019 02 Calpin	0.000	59763	0	MW	SA 299
382	818479	136065738	ZS	4/25/2019	50	-1,560.86	USD	S0	2019 03 Calpin	0.000	60130	0	MW	SA 299
383	818479	136159928	ZS	5/23/2019	50	-1,258.62	USD	S0	2019 04 Calpin	0.000	60592	0	MW	SA 299
384	818479	136246725	ZS	6/25/2019	50	-1,522.15	USD	S0	2019 05 Calpin	0.000	60979	0	MW	SA 299
385	818479	136589482	ZS	7/24/2019	50	-1,535.64	USD	S0	2019 06 Calpin	0.000	61344	0	MW	SA 299
386	818479	136678764	ZS	8/26/2019	50	-1,554.32	USD	S0	2019 07 Calpin	0.000	61723	0	MW	SA 299

387	818479	136773955	ZS	9/24/2019	50	-1,603.52	USD	S0	2019 08 Calpin	0.000	62098	0	MW	SA 299
388	818479	137125081	PS	10/28/2019	50	-1,488.07	USD	S0	2019 09 SES FN	-9,854.768	100046	PACW	201909	SES_FNO_SA_; SA 299
389	818479	137209930	PS	11/21/2019	50	-1,454.59	USD	S0	2019 10 SES FN	-9,633.039	100079	PACW	201910	SES_FNO_SA_; SA 299
390	818479	137300228	PS	12/20/2019	50	-1,378.72	USD	S0	2019 11 SES FN	-9,130.571	100138	PACW	201911	SES_FNO_SA_; SA 299
391	818479	137642318	PS	1/24/2020	50	-1,387.68	USD	S0	2019 12 SES FN	-9,189.954	100204	PACW	201912	SES_FNO_SA_; SA 299
392	818511	135654671	ZS	2/27/2019	50	-729.70	USD	S0	2019 01 Evergr	0.000	59395	0	MW	SA 874
393	818511	135722789	ZS	3/25/2019	40	107.72	USD	S0	2019 02 Evergr	0.000	59722	0	MW	SA 874
394	818511	135722792	ZS	3/25/2019	50	-495.06	USD	S0	2019 02 Evergr	0.000	59549	0	MW	SA 874
395	818511	136075846	ZS	4/27/2019	50	-610.04	USD	S0	2019 03 Evergr	0.000	60009	0	MW	SA 874
396	818511	136160682	ZS	5/25/2019	50	-646.12	USD	S0	2019 04 Evergr	0.000	60385	0	MW	SA 874
397	818511	136249252	ZS	6/26/2019	50	-722.10	USD	S0	2019 05 Evergr	0.000	60804	0	MW	SA 874
398	818511	136594376	ZS	7/29/2019	50	-808.03	USD	S0	2019 06 Evergr	0.000	61410	0	MW	SA 874
399	818511	136678756	ZS	8/26/2019	50	-846.41	USD	S0	2019 07 Evergr	0.000	61577	0	MW	SA 874
400	818511	136785278	ZS	9/27/2019	50	-869.87	USD	S0	2019 08 Evergr	0.000	61998	0	MW	SA 874
401	818511	137124649	PS	10/25/2019	50	-810.93	USD	S0	2019 09 EVGB	-5,370.380	100005	PACW	201909	EVGB_LFP_SA_ SA 874
402	818511	137209933	PS	11/21/2019	50	-804.45	USD	S0	2019 10 EVGB	-5,327.472	100075	PACW	201910	EVGB_LFP_SA_ SA 874
403	818511	137300232	PS	12/20/2019	50	-693.77	USD	S0	2019 11 EVGB	-4,594.511	100141	PACW	201911	EVGB_LFP_SA_ SA 874
404	818511	137640281	PS	1/23/2020	50	-714.09	USD	S0	2019 12 EVGB	-4,729.056	100180	PACW	201912	EVGB_LFP_SA_ SA 874
405	818564	135649212	ZS	2/25/2019	50	-1.08	USD	S0	2019 01 3 Phas	0.000	59299	0	MW	SA 876
406	818564	135727938	ZS	3/25/2019	50	-4.74	USD	S0	2019 02 3 Phas	0.000	59735	0	MW	SA 876
407	818564	135727939	ZS	3/25/2019	50	-6.05	USD	S0	2019 02 3 Phas	0.000	59748	0	MW	SA 876
408	818564	136075840	ZS	4/27/2019	50	-7.33	USD	S0	2019 03 3 Phas	0.000	60166	0	MW	SA 876
409	818564	136160112	ZS	5/23/2019	50	-7.31	USD	S0	2019 04 3 Phas	0.000	60580	0	MW	SA 876
410	818564	136254960	ZS	6/27/2019	50	-8.35	USD	S0	2019 05 3 Phas	0.000	60980	0	MW	SA 876
411	818564	136593949	ZS	7/29/2019	50	-8.91	USD	S0	2019 06 3 Phas	0.000	61291	0	MW	SA 876
412	818564	136680511	ZS	8/26/2019	50	-10.18	USD	S0	2019 07 3 Phas	0.000	61602	0	MW	SA 876
413	818564	136786055	ZS	9/27/2019	50	-10.35	USD	S0	2019 08 3 Phas	0.000	61982	0	MW	SA 876
414	818564	137124647	PS	10/25/2019	50	-8.66	USD	S0	2019 09 TPES F	-57.367	100004	PACW	201909	TPES_FNO_SA_ SA 876
415	818564	137209928	PS	11/21/2019	50	-7.50	USD	S0	2019 10 TPES F	-49.691	100076	PACW	201910	TPES_FNO_SA_ SA 876
416	818564	137297993	PS	12/19/2019	50	-6.67	USD	S0	2019 11 TPES F	-44.154	100136	PACW	201911	TPES_FNO_SA_ SA 876
417	818564	137640267	PS	1/23/2020	50	-6.66	USD	S0	2019 12 TPES F	-44.091	100175	PACW	201912	TPES_FNO_SA_ SA 876
418	818579	135651801	ZS	2/26/2019	50	-16.09	USD	S0	2019 01 Navaj	0.000	59323	0	MW	SA 894
419	818579	135730151	SA	3/26/2019	50	-230.50	USD		01-2019 Meter	0.000	PP TR M141	0	MW	SA 894
420	818579	135730166	ZS	3/26/2019	50	-212.52	USD	S0	2019 02 Navaj	0.000	59769	0	MW	SA 894
421	818579	136068727	ZS	4/26/2019	50	-200.76	USD	S0	2019 03 Navaj	0.000	60208	0	MW	SA 894
422	818579	136159930	ZS	5/23/2019	50	-175.03	USD	S0	2019 04 Navaj	0.000	60593	0	MW	SA 894
423	818579	136236810	SA	6/21/2019	50	-10.48	USD		02-2019 T55 S	0.000	PP TR M141	69.384	MW	SA 894
424	818579	136236810	SA	6/21/2019	50	-12.19	USD		01-2019 Sched	0.000	PP TR M141	80.729	MW	SA 894
425	818579	136236810	SA	6/21/2019	50	-9.86	USD		03-2019 Sched	0.000	PP TR M141	65.308	MW	SA 894
426	818579	136236810	SA	6/21/2019	50	-8.52	USD		04-2019 Sched	0.000	PP TR M141	56.428	MW	SA 894
427	818579	136249237	ZS	6/21/2019	50	-181.46	USD	S0	2019 05 Navaj	0.000	60988	0	MW	SA 894
428	818579	136586573	ZS	7/25/2019	50	-181.23	USD	S0	2019 06 Navaj	0.000	61345	0	MW	SA 894
429	818579	136678759	ZS	8/26/2019	50	-219.57	USD	S0	2019 07 Navaj	0.000	61739	0	MW	SA 894
430	818579	136779629	ZS	9/25/2019	50	-218.98	USD	S0	2019 08 Navaj	0.000	62106	0	MW	SA 894
431	818579	137124745	PS	10/25/2019	50	-171.37	USD	S0	2019 09 NTUA	-1,134.927	100032	PACE	201909	NTUA_FNO_SA SA 894
432	818579	137209957	PS	11/21/2019	50	-195.15	USD	S0	2019 10 NTUA	-1,292.365	100103	PACE	201910	NTUA_FNO_SA SA 894
433	818579	137300233	PS	12/20/2019	50	-212.26	USD	S0	2019 11 NTUA	-1,405.675	100144	PACE	201911	NTUA_FNO_SA SA 894
434	818579	137640296	PS	1/24/2020	50	-245.73	USD	S0	2019 12 NTUA	-1,627.353	100186	PACE	201912	NTUA_FNO_SA SA 894
435	818579	137640306	PS	1/24/2020	50	-17.27	USD	S0	2019 12 NTUA	-114.343	100195	PACE	201909	NTUA_FNO_SA SA 894
436	818691	137651605	PS	1/29/2020	50	-34.32	USD	S0	2019 12 1888 (	-227.304	100233	PACW	201912	1888_LFP_SA_ SA 966

InvoiceGroup	PPA_NAME	SAP_ACCOUNT_NUMBER	INVOICE_ENITTY_NAME
Transmission	1888_LFP_SA_966	818691	LH Garrett
Transmission	AIR1_LFP_SA_965	818614	Airport Solar LLC
Transmission	ANHM_NF_SA_798	818386	City of Anaheim
Transmission	ANHM_SFP_SA_797	818386	City of Anaheim
Transmission	APS_NF_SA_042	818529	Arizona Public Service Company
Transmission	APS_SFP_SA_721	818529	Arizona Public Service Company
Transmission	AVWP_NF_SA_887	808700	Avista
Transmission	AVWP_SFP_SA_886	808700	Avista
Transmission	BE01_LFP_SA_568	816200	Thermo No. 1 BE-01, LLC
Transmission	BEPM_FNO_SA_505	800100	Basin Electric Power Cooperative
Transmission	BEPM_NF_SA_607	800100	Basin Electric Power Cooperative
Transmission	BEPM_O&M_RS_136	800100	Basin Electric Power Cooperative
Transmission	BEPM_SFP_SA_606	800100	Basin Electric Power Cooperative
Transmission	BHCE_NF_SA_562	817590	Black Hills/Colorado Electric Utility Company
Transmission	BHCE_SFP_SA_563	817590	Black Hills/Colorado Electric Utility Company
Transmission	BHG_NF_SA_112	800200	BHG
Transmission	BHG_SFP_SA_111	800200	BHG
Transmission	BHP_FNO_SA_347	800200	Black Hills Corporation
Transmission	BHP_LFP_SA_67	800200	Black Hills Corporation
Transmission	BHP_NF_SA_768	800200	Black Hills Corporation
Transmission	BHP_O&M_RS_226	800200	Black Hills Corporation
Transmission	BHP_SFP_SA_767	800200	Black Hills Corporation
Transmission	BHPM_NF_SA_043	800200	Black Hills Power Marketing
Transmission	BHPM_SFP_SA_714	800200	Black Hills Power Marketing
Transmission	BMLP_NF_SA_756	818296	Brookfield Renewable Trading & Marketing LP
Transmission	BMLP_SFP_SA_757	818296	Brookfield Renewable Trading & Marketing LP
Transmission	BPAP_FNO_AS_SA_865	800400	Bonneville Power Administration
Transmission	BPAP_FNO_CLK_SA_735	800400	Bonneville Power Administration
Transmission	BPAP_FNO_COW_SA_229	800400	Bonneville Power Administration
Transmission	BPAP_FNO_ECH_SA_538	800400	Bonneville Power Administration
Transmission	BPAP_FNO_GSH_SA_746	800400	Bonneville Power Administration
Transmission	BPAP_FNO_IDF_SA_747	800400	Bonneville Power Administration
Transmission	BPAP_FNO_IDFBT_SA_747	800400	Bonneville Power Administration
Transmission	BPAP_FNO_NEF_SA_827	800400	Bonneville Power Administration
Transmission	BPAP_FNO_RIM_SA_539	800400	Bonneville Power Administration
Transmission	BPAP_FNO_YAK_SA_328	800400	Bonneville Power Administration
Transmission	BPAP_LFP_COW_SA_179	800400	Bonneville Power Administration
Transmission	BPAP_LFP_LC_SA_656	800400	Bonneville Power Administration
Transmission	BPAP_NF_SA_044	800400	Bonneville Power Administration
Transmission	BPAP_OS_RS_237	800400	Bonneville Power Administration
Transmission	BPAP_OS_RS_368	800400	Bonneville Power Administration
Transmission	BPAP_OS_RS_369	800400	Bonneville Power Administration
Transmission	BPAP_SFP_SA_720	800400	Bonneville Power Administration
Transmission	BRTM_NF_SA_941	818296	Brookfield Renewable Trading & Marketing LP
Transmission	BRTM_SFP_SA_940	818296	Brookfield Renewable Trading & Marketing LP
Transmission	CARG_NF_SA_262	800500	Cargill Power Markets, LLC
Transmission	CARG_SFP_SA_263	800500	Cargill Power Markets, LLC
Transmission	CLSK / CPUD_LFP_SA_800	818357	Clatskanie Peoples Utility District
Transmission	CORP_LFP_SA_791	800900	Shell Energy North America
Transmission	CORP_NF_SA_023	800900	Shell Energy North America
Transmission	CORP_SFP_SA_162	800900	Shell Energy North America
Transmission	CRSP_NF_SA_132	803850	Western Area Power Adm CO River
Transmission	CRSP_SFP_SA_724	803850	Western Area Power Adm CO River
Transmission	DGTM_NF_SA_156	801000	Deseret Generation & Trans.
Transmission	DGTM_O&M_RS_213	801000	Deseret Generation & Trans.
Transmission	DGTM_O&M_RS_342	801000	Deseret Generation & Trans.

Transmission	DGTM_OS_RS_280	801000	Deseret Generation & Trans.
Transmission	DGTM_SFP_SA_159	801000	Deseret Generation & Trans.
Transmission	EAGL_NF_SA_569	817600	EDF Trading North America, LLC
Transmission	EAGL_SFP_SA_570	817600	EDF Trading North America, LLC
Transmission	EEMU_LFP_SA_969	818692	CP Energy Marketing (US) Inc.
Transmission	EEMU_NF_SA_968	818692	CP Energy Marketing (US) Inc.
Transmission	EEMU_SFP_SA_967	818692	CP Energy Marketing (US) Inc.
Transmission	ENKP_NF_SA_814	818418	Energy Keepers, Inc
Transmission	ENKP_SFP_SA_815	818418	Energy Keepers, Inc
Transmission	ETNA_LFP_SA_963	818690	Enel Trading North America
Transmission	ETNA_NF_SA_962	818690	Enel Trading North America
Transmission	ETNA_SFP_SA_961	818690	Enel Trading North America
Transmission	EVGB_LFP_SA_874	818511	Evergreen Biopower
Transmission	EWEB_LFP_SA_780	805700	Eugene Water & Electric Board
Transmission	EWEB_NF_SA_013	805700	Eugene Water & Electric Board
Transmission	EWEB_SFP_SA_719	805700	Eugene Water & Electric Board
Transmission	EXGN_FNO_SA_847	818349	Exelon Generation Company
Transmission	EXGN_FNO_SA_943	818349	Exelon Generation Company
Transmission	EXGN_NF_SA_759	800800	Exelon Generation Company, LLC (Stateline)
Transmission	EXGN_SFP_SA_760	800800	Exelon Generation Company, LLC (Stateline)
Transmission	FCP_LFP_SA_868	818510	Falls Creek H.P. LP
Transmission	FCR3_OS_RS_761	801300	Foote Creek III, LLC
Transmission	FCR4_OS_RS_763	818411	Foote Creek IV, LLC
Transmission	FPLP_LFP_SA_733	804300	NextEra Energy Resources, LLC
Transmission	FPLP_NF_SA_236	804300	NextEra Energy Resources, LLC
Transmission	FPLP_SFP_SA_237	804300	NextEra Energy Resources, LLC
Transmission	FRRE_OS_RS_322	801100	Fall River Rural Electric Cooperative
Transmission	IPA_O&M_RS_342	801500	Intermountain Power Agency
Transmission	IPCL_LFP_SA_212	801400	Idaho Power Company
Transmission	IPCL_NF_SA_725	801400	Idaho Power Company
Transmission	IPCL_SFP_SA_726	801400	Idaho Power Company
Transmission	Klamath_O&M_ANNUAL_RS_508	800600	Klamath Energy LLC
Transmission	LAP_NF_SA_137	803850	Western Area Power Adm LAP
Transmission	LAP_SFP_SA_723	803850	Western Area Power Adm LAP
Transmission	LAWM_NF_SA_142	818204	Los Angeles Department of Water & Power
Transmission	LAWM_SFP_SA_143	818204	Los Angeles Department of Water & Power
Transmission	MAG_NF_SA_903	818611	MAG Energy Solutions, Inc.
Transmission	MAG_SFP_SA_902	818611	MAG Energy Solutions, Inc.
Transmission	MCPI_NF_SA_755	817500	Macquarie Energy, LLC
Transmission	MCPI_SFP_SA_754	817500	Macquarie Energy, LLC
Transmission	MEAN_NF_SA_307	816000	Municipal Energy Nebraska, Inc.
Transmission	MEAN_SFP_SA_308	816000	Municipal Energy Nebraska, Inc.
Transmission	MLEA_OS_RS_302	805400	Moon Lake Electric Association
Transmission	MRSV_OS_RS_322	809900	Marysville Hydro Partners
Transmission	MSCG_NF_SA_157	801800	Morgan Stanley
Transmission	MSCG_SFP_SA_160	801800	Morgan Stanley
Transmission	NTUA_FNO_SA_894	818579	Navajo Tribal Utility Authority
Transmission	NVPM_NF_SA_455	817260	Nevada Power Company
Transmission	NVPM_SFP_SA_454	817260	Nevada Power Company
Transmission	OBRE_LFP_SA_836	818334	Obsidian Renewables LLC
Transmission	OBRE_LFP_SA_880	818334	Obsidian Renewables LLC
Transmission	PAC_FNO_SA_066	802000	PACIFICORP
Transmission	PAC_LFP_SA_VAR	802000	PACIFICORP
Transmission	PAC_NF_SA_060	802000	PACIFICORP
Transmission	PAC_SFP_SA_079	802000	PACIFICORP
Transmission	PCG2_NF_SA_338	802100	Pacific Gas & Electric Company
Transmission	PCG2_O&M_RS_439	802100	Pacific Gas & Electric Company
Transmission	PCG2_SFP_SA_337	802100	Pacific Gas & Electric Company
Transmission	PGEM_NF_SA_008	802200	Portland General Electric Company
Transmission	PGEM_OS_RS_137	802200	Portland General Electric Company
Transmission	PGEM_SFP_SA_248	802200	Portland General Electric Company
Transmission	PPMI_FNO_SA_742	802400	Avangrid Renewables, LLC
Transmission	PPMI_FNOGS_SA_742	802400	Avangrid Renewables, LLC

		Customer Numbers	
Transmission	PPMI_LFP_SA_279	802400	Avangrid Renewables, LLC
Transmission	PPMI_NF_SA_121	802400	Avangrid Renewables, LLC
Transmission	PPMI_OS_SA_476	802400	Avangrid Renewables, LLC
Transmission	PPMI_SFP_SA_122	802400	Avangrid Renewables, LLC
Transmission	PREC_OS_SA_707	818231	Powder River Energy Corporation
Transmission	PSCM_NF_SA_664	802500	Public Services Company of Colorado
Transmission	PSCM_SFP_SA_665	802500	Public Services Company of Colorado
Transmission	PUD1_OS_RS_234	818288	PUD No. 1 of Cowlitz County
Transmission	PWX_LFP_SA_169	802300	Powerex Corporation
Transmission	PWX_LFP_SA_700	802300	Powerex Corporation
Transmission	PWX_LFP_SA_701	802300	Powerex Corporation
Transmission	PWX_LFP_SA_702	802300	Powerex Corporation
Transmission	PWX_LFP_SA_748	802300	Powerex Corporation
Transmission	PWX_LFP_SA_749	802300	Powerex Corporation
Transmission	PWX_NF_SA_047	802300	Powerex Corporation
Transmission	PWX_SFP_SA_151	802300	Powerex Corporation
Transmission	REMC_NF_SA_316	802700	Rainbow Energy Marketing
Transmission	REMC_SFP_SA_261	802700	Rainbow Energy Marketing
Transmission	ROSE_LFP_SA_881	818563	City of Roseville
Transmission	ROSE_NF_SA_851	818563	City of Roseville
Transmission	ROSE_SFP_SA_881	818563	City of Roseville
Transmission	SCET_NF_SA_642	805000	Southern California Edison Company
Transmission	SCET_O&M_RS_439	805000	Southern California Edison Company
Transmission	SCET_SFP_SA_643	805000	Southern California Edison Company
Transmission	SCPA_NF_SA_629	817990	Southern California Public Power Authority
Transmission	SD_LFP_SA_779	803000	State of South Dakota
Transmission	SD_NF_SA_771	803000	State of South Dakota
Transmission	SES_FNO_SA_299	818479	Calpine Energy Solutions
Transmission	SMUD_LFP_SA_751	817330	Sacramento Municipal Utility District
Transmission	SMUD_NF_SA_176	817330	Sacramento Municipal Utility District
Transmission	SMUD_SFP_SA_177	817330	Sacramento Municipal Utility District
Transmission	SPPM_O&M_RS_627	802900	Sierra Pacific Power Company
Transmission	SPPM_OS_RS_674	802900	Sierra Pacific Power Company
Transmission	SRPM_LFP_SA_809	817530	Salt River Project
Transmission	SRPM_NF_SA_557	817530	Salt River Project
Transmission	SRPM_SFP_SA_556	817530	Salt River Project
Transmission	TEA_NF_SA_310	817920	The Energy Authority, Inc.
Transmission	TEA_SFP_SA_311	817920	The Energy Authority, Inc.
Transmission	TEMU_NF_SA_127	803300	TransAlta Energy Marketing (U.S.) Inc.
Transmission	TEMU_SFP_SA_128	803300	TransAlta Energy Marketing (U.S.) Inc.
Transmission	TEPM_NF_SA_595	818419	Tucson Electric Power Co
Transmission	TEPM_SFP_SA_596	818419	Tucson Electric Power Co
Transmission	TICA/2019/C/001	818600	Slate Creek Hydro Associates LP
Transmission	TIOR/2015/C/022	818288	Cowlitz Public Utility District
Transmission	TIOR/2015/C/023	818353	Prineville Solar Energy LLC
Transmission	TIOR/2016/C/004	818354	Ochoco Solar LLC
Transmission	TIOR/2018/C/007	818334	Garrett Solar LLC
Transmission	TIUT/2016/C/010	818382	Cove Mountain Solar LLC
Transmission	TIUT/2018/C/005	818382	Cove Mountain Solar 2 LLC
Transmission	TIUT/2018/C/006	818335	Sigurd Solar LLC
Transmission	TIUT/2018/C/007	818443	Hunter Solar
Transmission	TIUT/2018/C/008	818442	Graphite Solar I LLC
Transmission	TIUT/2018/C/009	818448	Elektron Solar LLC
Transmission	TIUT/2019/C/004	818441	Appaloosa Solar I LLC
Transmission	TIUT/2019/C/005	818376	Milford Solar I LLC
Transmission	TIUT/2019/C/006	818656	Clover Creek Solar LLC
Transmission	TIWY/2017/C/003	818457	Sage Solar I LLC
Transmission	TIWY/2017/C/004	818458	Sage Solar II LLC
Transmission	TIWY/2018/C/002	804300	Cedar Springs Resources LLC
Transmission	TIWY/2019/C/001	818451	Echo Divide Wind LLC
Transmission	TNSK_NF_SA_125	818140	Tenaska Power Services Co
Transmission	TNSK_SFP_SA_126	818140	Tenaska Power Services Co
Transmission	TPES_FNO_SA_876	818564	3 Phase Renewables

Customer Numbers

Transmission	TSPM_FNO_SA_628	803400	Tri-State Generation & Trans.
Transmission	TSPM_FNOMON_SA_628	803400	Tri-State Generation & Trans.
Transmission	TSPM_NF_SA_033	803400	Tri-State Generation & Trans.
Transmission	TSPM_SFP_SA_722	803400	Tri-State Generation & Trans.
Transmission	UAMP_NF_SA_009	803500	Utah Associated Municipal Power Systems
Transmission	UAMP_O&M_MTH_RS_641	803500	Utah Associated Municipal Power Systems
Transmission	UAMP_OS_RS_297	803500	Utah Associated Municipal Power Systems
Transmission	UAMP_OSH2_RS_297	803500	Utah Associated Municipal Power Systems
Transmission	UAMP_SFP_SA_718	803500	Utah Associated Municipal Power Systems
Transmission	UMPA_NF_SA_020	803600	Utah Municipal Power Agency
Transmission	UMPA_OS_RS_637	803600	Utah Municipal Power Agency
Transmission	UMPA_SFP_SA_135	803600	Utah Municipal Power Agency
Transmission	USBR_FNO_SA_506	805300	U.S. Bureau of Reclamation
Transmission	USBR_OS_RS_286	805300	U.S. Bureau of Reclamation WB
Transmission	USBR_OS_RS_67	805300	U.S. Bureau of Reclamation CR
Transmission	WAPA_FNO_SA_175	803800	Western Area Power Adm FNO
Transmission	WAPA_OS_RS_2436-262L	803850	Western Area Power Administration
Transmission	WAPA_OS_RS_2436-263L	803850	Western Area Power Administration
Transmission	WAPA_OS_RS_684	803850	Western Area Power Administration
Transmission	WRGS_NF_SA_813	818426	Westar Energy, Inc.
Transmission	WRGS_SFP_SA_812	818426	Westar Energy, Inc.
Transmission	WSPE_OS_RS_591	803700	Warm Springs Power Enterprises

PacifiCorp
Rate Summary

		Weighted Cost $/kW	Avg Reserves Held (kW - 2018/2019)	Revenue Requirement $	Billing Determinant (MW)	Description of Billing Determinant	Rates ($/MWh)
		a	b	c = a*b	d	e	f = c/d
	Contingency Reserves						
1	**Schedule 5 (Spinning Reserves)**	$ 106.18	230,269	$ 24,450,960	134,477,343	Hourly integrated load and generation (MW)	**$ 0.182**
2			Spinning %	1.50%			
3	**Schedule 6 (Supplemental Reserves)**	$ 100.49	226,301	$ 22,741,752	132,159,864	Hourly integrated load and generation (MW)	**$ 0.172**
4			Supplemental %	1.50%			
5			**Total reserve % for Schedules 5 & 6**	3.00%			

* Schedule 5 & 6 rates are energy-based charges billed in dollars per Megawatt-hour ($/MWh) only.

		Weighted Cost $/kW	Regulation Reserve Requirement (kW)	Revenue Requirement $	Billing Determinant (MW)	Description of Billing Determinant	Rates ($/MW-year)	Rates ($/kW-year)
		a	b	c = a*b	d	e	f = c/d	g = f/1000
	Regulation and Frequency Response							
6	**Schedule 3 (Load)**	$ 93.92	171,521	$ 16,108,425	10,203	12 CP (CY 2019)	**$ 1,578.81**	**$ 1.579**
7	**Schedule 3/3A (Non-VER)**	$ 93.92	55,031	$ 5,168,213	1,304	Nameplate capacity	**$ 3,962.59**	**$ 3.963**
8	**Schedule 3/3A -Wind (VER)**	$ 93.92	236,932	$ 22,251,469	2,745	Nameplate capacity	**$ 8,105.70**	**$ 8.106**
9	**Schedule 3/3A -Solar (VER)**	$ 93.92	76,176	$ 7,154,065	1,080	Nameplate capacity	**$ 6,622.16**	**$ 6.622**
10	**Total Schedule 3/3A Requirement**		**539,660**					

	Service Increment	Period	Unit	Schedule 3 - Load	Schedule 3/3A - Non-VER	Schedule 3/3A - Wind (VER)	Schedule 3/3A - Solar (VER)
11	Yearly		$/MW-year	**1,578.809**	**3,962.594**	**8,105.700**	**6,622.157**
12	Monthly		$/MW-month	131.567	330.216	675.475	551.846
13	Weekly		$/MW-week	30.362	76.204	155.879	127.349
14	Daily	On peak	$/MW-day	6.072	15.241	31.176	25.47
15	Daily	Off peak	$/MW-day	4.337	10.886	22.268	18.193
16	Hourly	On peak	$/MWh	0.38	0.953	1.948	1.592
17	Hourly	Off peak	$/MWh	0.181	0.454	0.928	0.758

PacifiCorp
Net Production Plant Investments

2019 data

	Plant	Type	Installed Cost (gross plant) FN1 page 402.17	Accumulated Depreciation Reserves	Net Plant (a-b)	ARO Electric Plant FN1 page 402.16	ARO Depreciation Reserves	ARO Net book value (d-e)	Net Plant Investments w/o ARO (c-f)	Total Installed capacity (kW) FN1 page 402.5 (PAC Share)	Net Plant Investments per (kW) (g/h) Attach.B, p.3-5
			(a)	(b)	**(c)**	(d)	(e)	(f)	(g)	(h)	(i)
1	Cholla 4 (retiring end of 2020)	Steam									
2	Currant Creek	Gas	$ 355,617,439	84,416,101	**$ 271,201,338**	$ 134,848	$ (54,491)	**$ 80,357**	**$ 271,120,981**	566,900kW	**$478.25/kW**
3	Dave Johnston	Steam	$ 1,102,701,532	771,265,729	**$ 331,435,803**	$ 29,368,123	$ (14,184,073)	**$ 15,184,049**	**$ 316,251,754**	816,770kW	**$387.20/kW**
4	Gadsby Steam	Steam	$ 87,226,385	76,125,323	**$ 11,101,062**	$ 1,132,809	$ (730,471)	**$ 402,338**	**$ 10,698,724**	251,640kW	**$42.52/kW**
5	Gadsby Peakers	Gas	$ 85,974,361	38,462,251	**$ 47,512,110**	$ -	$ -	**$ -**	**$ 47,512,110**	181,050kW	**$262.43/kW**
6	Hunter Unit No. 1	Steam	$ 394,703,993	145,148,063	**$ 249,555,930**	$ 4,278,309	$ (988,535)	**$ 3,289,774**	**$ 246,266,156**	457,730kW	**$538.02/kW**
7	Hunter Unit No. 2	Steam	$ 247,278,690	90,334,354	**$ 156,944,336**	$ 4,278,309	$ (619,309)	**$ 3,659,000**	**$ 153,285,336**	294,460kW	**$520.56/kW**
8	Hunter Unit No. 3	Steam	$ 495,454,951	247,229,753	**$ 248,225,198**	$ 4,278,309	$ (1,240,865)	**$ 3,037,443**	**$ 245,187,755**	495,590kW	**$494.74/kW**
9	Huntington	Steam	$ 912,636,823	401,933,053	**$ 510,703,769**	$ 10,022,886	$ (2,841,472)	**$ 7,181,414**	**$ 503,522,356**	1,015,500kW	**$495.84/kW**
10	Lake Side 1	Gas	$ 337,674,928	61,788,889	**$ 275,886,039**	$ -	$ -	**$ -**	**$ 275,886,039**	591,300kW	**$466.58/kW**
11	Lake Side 2	Gas	$ 692,667,027	86,479,580	**$ 606,187,447**	$ -	$ -	**$ -**	**$ 606,187,447**	655,200kW	**$925.19/kW**
12	Naughton	Steam	$ 802,662,872	354,759,144	**$ 447,903,728**	$ 50,914,765	$ (26,858,542)	**$ 24,056,223**	**$ 423,847,505**	707,200kW	**$599.33/kW**
13	Wyodak	Steam	$ 467,373,180	237,167,695	**$ 230,205,485**	$ 279,518	$ (279,518)	**$ -**	**$ 230,205,485**	289,660kW	**$794.74/kW**
14	Oneida	Hydro	$ 27,475,861	7,708,731	**$ 19,767,130**	$ -	$ -	**$ -**	**$ 19,767,130**	30,000kW	**$658.90/kW**
15	Cutler	Hydro	$ 34,071,125	18,024,147	**$ 16,046,978**	$ -	$ -	**$ -**	**$ 16,046,978**	30,000kW	**$534.90/kW**
16	Monsanto	Contract									
17	Nucor	Contract									
18	Magcorp	Contract									
19	Chehalis	Gas	$ 358,946,697	117,725,749	**$ 241,220,948**	$ 1,030,777	$ (362,548)	**$ 668,229**	**$ 240,552,719**	593,300kW	**$405.45/kW**
20	Hermiston	Gas	$ 180,203,293	92,598,553	**$ 87,604,740**	$ 407,646	$ (251,187)	**$ 156,459**	**$ 87,448,281**	279,560kW	**$312.81/kW**
21	Mid-Columbia Hydro-Grant	Contract									
22	Swift No. 1	Hydro	$ 165,499,345	49,599,638	**$ 115,899,708**	$ -	$ -	**$ -**	**$ 115,899,708**	240,000kW	**$482.92/kW**
23	Yale	Hydro	$ 82,226,548	33,222,989	**$ 49,003,558**	$ -	$ -	**$ -**	**$ 49,003,558**	134,000kW	**$365.70/kW**
24	Jim Bridger	Steam	$ 1,454,899,786	683,511,971	**$ 771,387,815**	$ 19,566,856	$ (13,856,180)	**$ 5,710,676**	**$ 765,677,139**	1,550,650kW	**$493.78/kW**

*Gross plant, accumulated depreciation and ARO reserves represent account balances at December 31, 2019.

Cholla 4 will be retiring in December 2020

Naughton 3 ceased coal-fired operation in January 2019.

Douglas Hydro contract expired August 2018.

Huntington Unit 2 upgraded to 517,500

PacifiCorp
Fixed Expenses for Units Most Likely to Provide

2019 data

	Plant	Type	Operation Supervision and Engineering FERC 500, 535 & 546 (FN1, page 402, 406, 410)	Steam/Hydraulic Expenses FERC 502 (FN1, page 402, 406, 410)	Electric/Hydraulic Expenses FERC 505, 537 & 538 (FN1, page 402, 406, 410)	Misc Steam (Hydraulic) Power Expenses FERC 506 & 549 (FN1, page 402, 406, 410)	Rents FERC 507, 540 & 550 (FN1, page 402, 406, 410)	Maintenance of Structures FERC 511, 542 & 552 (FN1, page 402, 406, 410)	Maintenance of Misc Steam/Hydraulic Plant FERC 514, 554 & 545 (FN1, page 402, 406, 410)	Maintenance of generating and electric plant FERC 553	Maintenance of Reservoirs, Dams and Waterways FERC 543	Adjustments to FERC 506 [4]	**Total Demand Related Expenses** (sum((a):(h)) or contract costs	Total Installed capacity (kW) (FF1, page 402, 406, 410)	**Total O&M per KW (Attach.B, p. 3-5)**
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	**(k)=sum((a):(j)**	(l)	**m = (k)/(l)**
1	Cholla 4	Steam													
2	Currant Creek	Gas	$ 60,872	$ -	$ 1,747,075	$ 1,021,373	$ -	$ 420,484	$ 68,252	$ 920,033			**$ 4,238,089**	566,900kW	**$7.48/kW**
3	Dave Johnston	Steam	$ 15,843	$ 2,024,824	$ -	$ 16,810,355	$ 86,157	$ 4,307,318	$ 1,386,180				**$ 24,630,677**	816,770kW	**$30.16/kW**
4	Gadsby Steam	Steam	$ 34,410	$ 144,257	$ -	$ 3,691,399	$ -	$ 128,946	$ 445,065				**$ 4,444,077**	251,640kW	**$17.66/kW**
5	Gadsby Peakers	Gas	$ -	$ -	$ 734,954	$ -	$ -	$ 58,078	$ 123,631	$ 307,244			**$ 1,223,907**	181,050kW	**$6.76/kW**
6	Hunter Unit No. 1	Steam		$ 8,268,308	$ (60,931)	$ 2,914,656	$ -	$ 889,773	$ 332,077				**$ 12,343,883**	457,730kW	**$26.97/kW**
7	Hunter Unit No. 2	Steam		$ 6,256,877	$ 85,963	$ (6,351,823)	$ -	$ 1,413,135	$ 385,252				**$ 1,789,404**	294,460kW	**$6.08/kW**
8	Hunter Unit No. 3	Steam	$ (1,376)	$ 8,989,022	$ (57,347)	$ 3,807,812	$ -	$ 1,109,881	$ 532,779				**$ 14,380,771**	495,590kW	**$29.02/kW**
9	Huntington	Steam	$ 15,087	$ 13,205,769	$ -	$ 9,848,321	$ 25,964	$ 2,477,961	$ 822,980				**$ 26,396,082**	1,015,500kW	**$25.99/kW**
10	Lake Side 1	Gas	$ 47,328	$ -	$ 2,341,763	$ 496,509	$ -	$ 909,310	$ 14,715	$ 1,256,397			**$ 5,066,022**	591,300kW	**$8.57/kW**
11	Lake Side 2	Gas	$ 54,696	$ -	$ 3,127,779	$ 574,681	$ -	$ 957,626	$ 15,451	$ 378,560			**$ 5,108,793**	655,200kW	**$7.80/kW**
12	Naughton	Steam	$ 299,356	$ 7,913,360	$ 1,865	$ 6,252,984	$ 14,350	$ 1,031,530	$ 826,583				**$ 16,340,028**	707,200kW	**$23.11/kW**
13	Wyodak	Steam	$ 9,495	$ 3,295,495	$ -	$ 3,800,445	$ 15,043	$ 240,210	$ 134,621				**$ 7,495,309**	289,660kW	**$25.88/kW**
14	Oneida	Hydro	$ 90,472	$ -	$ 34,232	$ 849,267	$ 10,751	$ -	$ 57,958		$ 7,436		**$ 1,050,116**	30,000kW	**$35.00/kW**
15	Cutler	Hydro	$ 129,376	$ -	$ 114,728	$ 1,428,546	$ 18,011	$ -	$ 334,104		$ 5,682		**$ 2,030,447**	30,000kW	**$67.68/kW**
16	Monsanto	Contract											**$ 14,826,317**	94,440kW	**$156.99/kW**
17	Nucor	Contract											**$ 7,201,200**	52,460kW	**$137.27/kW**
18	Magcorp	Contract											**$ 5,477,029**	84,310kW	**$64.96/kW**
19	Chehalis	Gas	$ 192,912	$ -	$ 1,934,664	$ 878,661		$ 28,915	$ -	$ 1,693,967			**$ 4,729,119**	593,300kW	**$7.97/kW**
20	Hermiston	Gas	$ -	$ -	$ 7,137,888	$ -	$ -	$ -	$ -				**$ 7,137,888**	279,560kW	**$25.53/kW**
21	Mid-Columbia Hydro-Grant	Contract											**$ 2,038,742**	14,257kW	**$143.00/kW**
22	Swift No. 1	Hydro	$ 2,948,946	$ -	$ 1,636,070	$ 404,476	$ 170,475	$ 32,253	$ 854,965		$ 114,965		**$ 6,162,150**	240,000kW	**$25.68/kW**
23	Yale	Hydro	$ 1,576,354	$ -	$ 776,553	$ 486,488	$ 95,182	$ 24,888	$ 478,730		$ 75,687		**$ 3,513,882**	134,000kW	**$26.22/kW**
24	Jim Bridger	Steam	$ 14,234,340	$ 19,568,003	$ -	$ (21,036,522)	$ 331,946	$ 10,304,164	$ 2,295,209				**$ 25,697,140**	1,550,650kW	**$16.57/kW**

Cholla 4 will be retiring in December 2020

Naughton 3 ceased coal-fired operation in January 2019.

Douglas Hydro contract expired August 2018.

PacifiCorp
Schedule 3/3A - Regulation and Frequency Response Service

Line No	Plant	Type	Total installed capacity (MW)	Reserve Study Available Capacity (MW) - Attach. D, p.1	Reserve Study Cumulative Avail. Cap. (MW) Attach. D, p.1	Reserve Study Expected Participation Attach. D, p.1	Net Investment Cost/kW Attach. B, p. 1	Annual Carrying Cost per kW (f) x 15.20% Attach. A (FCR)	Operation and Maintenance Cost per kW Attach. B, p.2	Wheeling Cost per kW (FERC 565) Attach. E	Credit for Contributions to Reactive Power Service per kW Attach. C	Weighted Annual Cost per kW ((g)+(h)+(i)-(j))*(e)
	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Blank	Blank										
2	Currant Creek	Gas	566.90	27.07	27.07	5.0%	$478.25/kW	$72.72/kW	$7.48/kW	-	$1.95/kW	**$3.92/kW**
3	Dave Johnston	Steam	816.77	29.89	56.95	5.5%	$387.20/kW	$58.87/kW	$30.16/kW	-	$0.98/kW	**$4.88/kW**
4	Gadsby Steam	Steam	251.64	2.63	59.58	0.5%	$42.52/kW	$6.46/kW	$17.66/kW	-	$2.63/kW	**$0.10/kW**
5	Gadsby Peakers	Gas	181.05	59.23	118.81	11.0%	$262.43/kW	$39.90/kW	$6.76/kW	-	$2.63/kW	**$4.83/kW**
6	Hunter Unit No. 1	Steam	457.73	19.11	137.92	3.5%	$538.02/kW	$81.80/kW	$26.97/kW	-	$1.09/kW	**$3.82/kW**
7	Hunter Unit No. 2	Steam	294.46	11.29	149.21	2.1%	$520.56/kW	$79.15/kW	$6.08/kW	-	$1.03/kW	**$1.76/kW**
8	Hunter Unit No. 3	Steam	495.59	32.57	181.77	6.0%	$494.74/kW	$75.22/kW	$29.02/kW	-	$1.03/kW	**$6.23/kW**
9	Huntington	Steam	1,015.50	59.39	241.17	11.0%	$495.84/kW	$75.39/kW	$25.99/kW	-	$0.97/kW	**$11.05/kW**
10	Lake Side 1	Gas	591.30	25.14	266.31	4.7%	$466.58/kW	$70.94/kW	$8.57/kW	-	$1.95/kW	**$3.61/kW**
11	Lake Side 2	Gas	655.20	34.48	300.79	6.4%	$925.19/kW	$140.67/kW	$7.80/kW	-	$1.95/kW	**$9.36/kW**
12	Naughton	Steam	707.20	6.24	307.03	1.2%	$599.33/kW	$91.12/kW	$23.11/kW	-	$1.26/kW	**$1.31/kW**
13	Wyodak	Steam	289.66	11.44	318.47	2.1%	$794.74/kW	$120.84/kW	$25.88/kW	-	$1.38/kW	**$3.08/kW**
14	Oneida	Hydro	30.00	5.85	324.32	1.1%	$658.90/kW	$100.18/kW	$35.00/kW	-	$5.57/kW	**$1.40/kW**
15	Cutler	Hydro	30.00	9.65	333.97	1.8%	$534.90/kW	$81.33/kW	$67.68/kW	-	$12.02/kW	**$2.45/kW**
16	Monsanto	Contract	94.44	0.00	333.97			$0.00/kW	$156.99/kW	-		**$0.00/kW**
17	Nucor	Contract	52.46	17.39	351.36	3.2%		$0.00/kW	$137.27/kW	-	-	**$4.42/kW**
18	Magcorp	Contract	84.31	32.04	383.40	5.9%		$0.00/kW	$64.96/kW	-	-	**$3.86/kW**
19	Chehalis	Gas	593.30	32.47	415.87	6.0%	$405.45/kW	$61.65/kW	$7.97/kW	$21.69/kW	-	**$5.49/kW**
20	Hermiston	Gas	279.56	14.76	430.63	2.7%	$312.81/kW	$47.56/kW	$25.53/kW	$21.69/kW	-	**$2.59/kW**
21	Mid-Columbia Hydro-Grant	Contract	14.26	2.02	432.65	0.4%		$0.00/kW	$143.00/kW	-	-	**$0.54/kW**
22	Swift No. 1	Hydro	240.00	32.88	465.54	6.1%	$482.92/kW	$73.42/kW	$25.68/kW	$21.69/kW	$1.68/kW	**$7.26/kW**
23	Yale	Hydro	134.00	47.61	513.15	8.8%	$365.70/kW	$55.60/kW	$26.22/kW		$0.55/kW	**$7.17/kW**
24	Jim Bridger	Steam	1,550.65	26.51	539.66	4.9%	$493.78/kW	$75.08/kW	$16.57/kW	$6.15/kW	$0.59/kW	**$4.78/kW**
						100.0%						
											Total Weighted Annual Cost	**$93.92/kW**
25	Production Fixed Charge Rate		15.2044%									

Cholla 4 will be retiring in December 2020
Naughton 3 ceased coal-fired operation in January 2019.
Douglas Hydro contract expired August 2018.

PacifiCorp

Schedule 5 - Operating Reserves - Spinning Reserve

Line No	Plant	Type	Total Installed capacity (MW)	Reserve Study Available Capacity (MW) - Attach. D, p.1	Reserve Study Cumulative Avail. Cap. (MW) Attach. D, p.1	Reserve Study Expected Participation Attach. D, p.1	Net Investment Cost/kW Attach. B, p. 1	Annual Carrying Cost per kW (TI x 15.20% Attach. A (FCR)	Operation and Maintenance Cost per kW Attach. B, p.2	Wheeling Cost per kW (FERC 565) Attach. E	Credit for Contributions to Reactive Power Service per kW Attach. C	Weighted Annual Cost per kW (g)=(h+i)-(j)*(w)
	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Blank	Blank										
2	Currant Creek	Gas	566.90	20.84	20.84	9.0%	$478.25/kW	$72.72/kW	$7.48/kW	-	$1.95/kW	**$7.08/kW**
3	Dave Johnston	Steam	816.77	0.00	20.84	-	$387.20/kW	$58.87/kW	$30.16/kW	-	$0.98/kW	**$0.00/kW**
4	Gadsby Steam	Steam	251.64	4.30	25.13	1.9%	$42.52/kW	$6.46/kW	$17.66/kW	-	$2.63/kW	**$0.40/kW**
5	Gadsby Peakers	Gas	181.05	0.71	25.84	0.3%	$262.43/kW	$39.90/kW	$6.76/kW	-	$2.63/kW	**$0.14/kW**
6	Hunter Unit No. 1	Steam	457.73	10.45	36.29	4.5%	$538.02/kW	$81.80/kW	$26.97/kW	-	$1.03/kW	**$4.85/kW**
7	Hunter Unit No. 2	Steam	294.46	9.93	46.22	4.3%	$520.56/kW	$79.15/kW	$6.08/kW	-	$1.03/kW	**$3.63/kW**
8	Hunter Unit No. 3	Steam	495.59	13.16	59.38	5.7%	$494.74/kW	$75.22/kW	$29.02/kW	-	$1.03/kW	**$5.90/kW**
9	Huntington	Steam	1,015.50	29.06	88.44	12.6%	$495.84/kW	$75.39/kW	$25.99/kW	-	$0.97/kW	**$12.67/kW**
10	Lake Side 1	Gas	591.30	19.30	107.74	8.4%	$466.58/kW	$70.94/kW	$8.57/kW	-	$1.95/kW	**$6.50/kW**
11	Lake Side 2	Gas	655.20	27.31	135.05	11.9%	$925.19/kW	$140.67/kW	$7.80/kW	-	$1.95/kW	**$17.38/kW**
12	Naughton	Steam	707.20	4.81	139.86	2.1%	$599.33/kW	$91.12/kW	$23.11/kW	-	$1.26/kW	**$2.36/kW**
13	Wyodak	Steam	289.66	0.00	139.86	-	$794.74/kW	$120.84/kW	$25.88/kW	-	$1.38/kW	**$0.00/kW**
14	Oneida	Hydro	30.00	8.93	148.80	3.9%	$658.90/kW	$100.18/kW	$35.00/kW	-	$5.57/kW	**$5.03/kW**
15	Cutler	Hydro	30.00	14.77	163.57	6.4%	$534.90/kW	$81.33/kW	$67.68/kW	-	$12.02/kW	**$8.79/kW**
16	Monsanto	Contract	94.44	0.00	163.57	-		$0.00/kW	$156.99/kW	-	-	**$0.00/kW**
17	Nucor	Contract	52.46	0.00	163.57	-		$0.00/kW	$137.27/kW	-	-	**$0.00/kW**
18	Magcorp	Contract	84.31	0.00	163.57	-		$0.00/kW	$64.96/kW	-	-	**$0.00/kW**
19	Chehalis	Gas	593.30	3.11	166.68	1.4%	$405.45/kW	$61.65/kW	$7.97/kW	$21.69/kW	-	**$1.24/kW**
20	Hermiston	Gas	279.56	5.17	171.85	2.2%	$312.81/kW	$47.56/kW	$25.53/kW	$21.69/kW	-	**$2.13/kW**
21	Mid-Columbia Hydro-Grant	Contract	14.26	0.02	171.87	0.0%		$0.00/kW	$143.00/kW	-	-	**$0.01/kW**
22	Swift No. 1	Hydro	240.00	44.98	216.85	19.5%	$482.92/kW	$73.42/kW	$25.68/kW	$21.69/kW	$1.48/kW	**$23.27/kW**
23	Yale	Hydro	134.00	12.74	229.59	5.5%	$365.70/kW	$55.60/kW	$26.22/kW	-	$0.55/kW	**$4.50/kW**
24	Jim Bridger	Steam	1,550.65	0.68	230.27	0.3%	$493.78/kW	$75.08/kW	$16.57/kW	$6.15/kW	$0.59/kW	**$0.29/kW**
						100.0%						
											Total Weighted Annual Cost	**$106.18/kW**
25	Production Fixed Charge Rate		15.2044%									

Cholla 4 will be retiring in December 2020
Naughton 3 ceased coal-fired operation in January 2019.
Douglas Hydro contract expired August 2018.

PacifiCorp

Schedule 6 - Operating Reserve - Supplemental Reserve

Line No	Plant	Type	Total Installed capacity (MW)	Reserve Study Available Capacity (MW) - Attach. D, p.1	Reserve Study Cumulative Avail. Cap. (MW) Attach. D, p.1	Reserve Study Expected Participation Attach. D, p.1	Net Investment Cost/kW Attach. B, p. 1	Annual Carrying Cost per kW (TI x 15.20% Attach. A (FCR)	Operation and Maintenance Cost per kW Attach. B, p.2	Wheeling Cost per kW (FERC 565) Attach. E	Credit for Contributions to Reactive Power Service per kW Attach. C	Weighted Annual Cost per kW (g)=(h+i)-(j)*(w)
	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Blank	Blank										
2	Currant Creek	Gas	566.90	0.02	0.02	0.0%	$478.25/kW	$72.72/kW	$7.48/kW	-	$1.95/kW	**$0.01/kW**
3	Dave Johnston	Steam	816.77	0.00	0.02	-	$387.20/kW	$58.87/kW	$30.16/kW	-	$0.98/kW	**$0.00/kW**
4	Gadsby Steam	Steam	251.64	0.00	0.02	0.0%	$42.52/kW	$6.46/kW	$17.66/kW	-	$2.63/kW	**$0.00/kW**
5	Gadsby Peakers	Gas	181.05	52.18	52.20	23.1%	$262.43/kW	$39.90/kW	$6.76/kW	-	$2.63/kW	**$10.15/kW**
6	Hunter Unit No. 1	Steam	457.73	0.01	52.21	0.0%	$538.02/kW	$81.80/kW	$26.97/kW	-	$1.03/kW	**$0.00/kW**
7	Hunter Unit No. 2	Steam	294.46	0.01	52.21	0.0%	$520.56/kW	$79.15/kW	$6.08/kW	-	$1.03/kW	**$0.00/kW**
8	Hunter Unit No. 3	Steam	495.59	0.01	52.22	0.0%	$494.74/kW	$75.22/kW	$29.02/kW	-	$1.03/kW	**$0.00/kW**
9	Huntington	Steam	1,015.50	0.01	52.23	0.0%	$495.84/kW	$75.39/kW	$25.99/kW	-	$0.97/kW	**$0.00/kW**
10	Lake Side 1	Gas	591.30	0.01	52.24	0.0%	$466.58/kW	$70.94/kW	$8.57/kW	-	$1.95/kW	**$0.00/kW**
11	Lake Side 2	Gas	655.20	0.02	52.26	0.0%	$925.19/kW	$140.67/kW	$7.80/kW	-	$1.95/kW	**$0.01/kW**
12	Naughton	Steam	707.20	0.00	52.26	0.0%	$599.33/kW	$91.12/kW	$23.11/kW	-	$1.26/kW	**$0.00/kW**
13	Wyodak	Steam	289.66	0.00	52.26	-	$794.74/kW	$120.84/kW	$25.88/kW	-	$1.38/kW	**$0.00/kW**
14	Oneida	Hydro	30.00	0.01	52.27	0.0%	$658.90/kW	$100.18/kW	$35.00/kW	-	$5.57/kW	**$0.00/kW**
15	Cutler	Hydro	30.00	0.01	52.28	0.0%	$534.90/kW	$81.33/kW	$67.68/kW	-	$12.02/kW	**$0.01/kW**
16	Monsanto	Contract	94.44	50.69	102.97	22.4%		$0.00/kW	$156.99/kW	-	-	**$35.16/kW**
17	Nucor	Contract	52.46	27.83	130.80	12.3%		$0.00/kW	$137.27/kW	-	-	**$16.88/kW**
18	Magcorp	Contract	84.31	38.95	169.75	17.2%		$0.00/kW	$64.96/kW	-	-	**$11.18/kW**
19	Chehalis	Gas	593.30	2.98	172.73	1.3%	$405.45/kW	$61.65/kW	$7.97/kW	$21.69/kW	-	**$1.20/kW**
20	Hermiston	Gas	279.56	4.05	176.78	1.8%	$312.81/kW	$47.56/kW	$25.53/kW	$21.69/kW	-	**$1.70/kW**
21	Mid-Columbia Hydro-Grant	Contract	14.26	0.13	176.90	0.1%		$0.00/kW	$143.00/kW	-	-	**$0.08/kW**
22	Swift No. 1	Hydro	240.00	37.46	214.37	16.6%	$482.92/kW	$73.42/kW	$25.68/kW	$21.69/kW	$1.48/kW	**$19.72/kW**
23	Yale	Hydro	134.00	10.75	225.11	4.7%	$365.70/kW	$55.60/kW	$26.22/kW	-	$0.55/kW	**$3.86/kW**
24	Jim Bridger	Steam	1,550.65	1.19	226.30	0.5%	$493.78/kW	$75.08/kW	$16.57/kW	$6.15/kW	$0.59/kW	**$0.51/kW**
						100.0%						
											Total Weighted Annual Cost	**$100.49/kW**
25	Production Fixed Charge Rate		15.2044%									

Cholla 4 will be retiring in December 2020
Naughton 3 ceased coal-fired operation in January 2019.
Douglas Hydro contract expired August 2018.

PacifiCorp
Schedule 2 - Reactive Power - Credit

	Plant	Schedule 2 (Reactive Supply and Voltage Control) Summary 2019 Study1 Reactive Rev Req (2019 Study)	2019 Name Plate (MW) FN1, p.402-407	Reactive Revenue Req. ($/kW) 2019 Credit
		(a)	(b)	((c)=(a)/(b)/1000)
	WEST			
1	Clearwater	109,915	41.00	$2.68
2	Copco	552,800	47.00	$11.76
3	Fish Creek	15,763	11.00	$1.43
4	Iron Gate	21,851	18.00	$1.21
5	JC Boyle	115,017	97.98	$1.17
6	Jim Bridger	912,260	1,550.65	$0.59
7	Lemolo	135,244	70.49	$1.92
8	Merwin	343,514	136.00	$2.53
9	Prospect	175,028	44.00	$3.98
10	Slide Creek	153,375	18.00	$8.52
11	Soda	99,430	14.45	$6.88
12	Soda Springs	23,355	11.00	$2.12
13	Swift No. 1	402,033	240.00	$1.68
14	Toketee	172,148	42.50	$4.05
15	Yale	74,184	134.00	$0.55
	EAST			
1	Ashton	51,215	6.70	$7.64
2	Blundell	406,468	38.10	$10.67
3	Currant Creek	1,107,512	566.90	$1.95
4	Cutler	360,690	30.00	$12.02
5	Dave Johnston	800,553	816.77	$0.98
6	Gadsby (Combustion Turbine and Steam)	1,136,124	432.69	$2.63
7	Grace	110,875	33.00	$3.36
8	Hunter (1,2&3)	1,283,819	1,247.78	$1.03
9	Huntington	986,518	1,015.50	$0.97
10	Lake Side (1&2)	2,436,373	1,246.50	$1.95
11	Naughton	893,460	707.20	$1.26
12	Oneida	167,015	30.00	$5.57
13	Wyodak	400,521	289.66	$1.38
	Total Reactive Rev Req	**$ 13,447,060**		

Note 1: The Total Reactive Revenue Requirement is based on a 2020 reactive power filing, based on 2019 data.

From Exhibit No. PAC-29, Attachment 2

Thermal	$	10,363,607

PacifiCorp
Results from the Reserve Study

Table A
Summary of Results
2018/2019 Regulation Reserve Study Results

	Scenario	Portfolio Regulation Forecast with EIM benefit (aMW)	Portfolio Rate with EIM (%)	2019 Capacity (MW)	Rate Determinant
1	**Non-VER**	**55**	**4.2%**	**1,304**	Nameplate
2	**Load**	**172**	**1.7%**	**10,203**	12 CP
3	**VER - Wind**	**237**	**8.6%**	**2,745**	Nameplate
4	**VER - Solar**	**76**	**7.1%**	**1,080**	Nameplate
5	**Total**	**540**			

Source: See file "5. Class Allocation.xlsx"

Table B
Schedule 3 and 3A, Regulating Reserves 2018/2019 Regulation Reserve Study Results

			Schedule 3/3A Regulation	
			(MW)	% of Total
6	Cholla 4	Steam	0.00	0.0%
7	Currant Creek	Gas	27.07	5.0%
8	Dave Johnston	Steam	29.89	5.5%
9				
10				
11				
12	Gadsby Steam	Steam	2.63	0.5%
13				
14				
15	Gadsby Peakers	Gas	59.23	11.0%
16				
17				
18	Hunter Unit No. 1	Steam	19.11	3.5%
19	Hunter Unit No. 2	Steam	11.29	2.1%
20	Hunter Unit No. 3	Steam	32.57	6.0%
21	Huntington	Steam	59.39	11.0%
22				
23	Lake Side 1	Gas	25.14	4.7%
24	Lake Side 2	Gas	34.48	6.4%
25	Naughton	Steam	6.24	1.2%
26				
27				
28	Wyodak	Steam	11.44	2.1%
29	Oneida	Hydro	5.85	1.1%
30				
31				
32	Cutler	Hydro	9.65	1.8%
33				
34	Monsanto	Contract	0.00	0.0%
35	Coolkeeper	Contract	0.00	0.0%
36	Nucor	Contract	17.39	3.2%
37	Magcorp	Contract	32.04	5.9%
38	Chehalis	Gas	32.47	6.0%
39	Hermiston	Gas	14.76	2.7%
40	Mid-Columbia Hydro-Grant	Contract	2.02	0.4%
41	Mid-Columbia Hydro-Douglas	Contract	0.00	0.0%
42	Swift No. 1	Hydro	32.88	6.1%
43	Yale	Hydro	47.61	8.8%
44	Jim Bridger	Steam	26.51	4.9%
45	SCL Stateline	Contract	0.00	0.0%
46	Total		**540**	**100%**

Table C
2018-2019 Results - Summary

			Schedule 3/3A Regulation		Schedule 5 Spinning		Schedule 6 Non-Spinning	
			(MW)	% of Total	(MW)	% of Total	(MW)	% of Total
	Cholla 4	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
	Currant Creek	Gas	38.3	5.0%	20.8	9.0%	0.0	0.0%
	Dave Johnston	Steam	42.3	5.5%	0.0	0.0%	0.0	0.0%
	Gadsby Steam	Steam	3.7	0.5%	4.3	1.9%	0.0	0.0%
	Gadsby Peakers	Gas	83.9	11.0%	0.7	0.3%	52.2	23.1%
	Hunter Unit No. 1	Steam	27.1	3.5%	10.5	4.5%	0.0	0.0%
	Hunter Unit No. 2	Steam	16.0	2.1%	9.9	4.3%	0.0	0.0%
	Hunter Unit No. 3	Steam	46.1	6.0%	13.2	5.7%	0.0	0.0%
	Huntington	Steam	84.1	11.0%	29.1	12.6%	0.0	0.0%
	Lake Side 1	Gas	35.6	4.7%	19.3	8.4%	0.0	0.0%
	Lake Side 2	Gas	48.8	6.4%	27.3	11.9%	0.0	0.0%
	Naughton	Steam	8.8	1.2%	4.8	2.1%	0.0	0.0%
	Wyodak	Steam	16.2	2.1%	0.0	0.0%	0.0	0.0%
	Oneida	Hydro	8.3	1.1%	8.9	3.9%	0.0	0.0%
	Cutler	Hydro	13.7	1.8%	14.8	6.4%	0.0	0.0%
	Monsanto	Contract	0.0	0.0%	0.0	0.0%	50.7	22.4%
	Coolkeeper	Contract	0.0	0.0%	0.0	0.0%	0.0	0.0%
	Nucor	Contract	24.6	3.2%	0.0	0.0%	27.8	12.3%
	Magcorp	Contract	45.4	5.9%	0.0	0.0%	38.9	17.2%
	Chehalis	Gas	46.0	6.0%	3.1	1.4%	3.0	1.3%
	Hermiston	Gas	20.9	2.7%	5.2	2.2%	4.0	1.8%
	Mid-Columbia Hydro-Grant	Contract	2.9	0.4%	0.0	0.0%	0.1	0.1%
	Mid-Columbia Hydro-Douglas	Contract	0.0	0.0%	0.0	0.0%	0.0	0.0%
	Swift No. 1	Hydro	46.6	6.1%	45.0	19.5%	37.5	16.6%
	Yale	Hydro	67.4	8.8%	12.7	5.5%	10.7	4.7%
	Jim Bridger	Steam	37.5	4.9%	0.7	0.3%	1.2	0.5%
	SCL Stateline	Contract	0.0	0.0%	0.0	0.0%	0.0	0.0%
			764.0	**100%**	**230.3**	**100%**	**226.3**	**100%**

Notes:
Note 1: Tables D, E, and F contain the historical reserve availability from the 2018/2019 Reserve Analysis adjusted for the following changes:
- removed spinning, supplemental, and regulation reserve associated with Cholla -will retire December 2020,
- removed spinning, supplemental, and regulation reserve associated with Naughton 3 which ceased coal-fired operation in January 2019,
- removed spinning, supplemental, and regulation reserve associated with Douglas Hydro contract which expired in August 2018,
- removed reserves attributable to CoolKeeper from regulation and supplemental pool of reserves, and
- removed the supplemental reserve by Seattle City Light (SCL) Stateline contract that self-supplies operating reserves and thus has no embedded cost basis.

Note 2: Table F (Schedule 3 and 3A, Regulation Reserves) contains the resources holding regulation reserves in 2018/2019 adjusted for the changes described in Note 1. The calculated percentage are applied to the total reserves required to determine the contribution from each resource in Table C

Note 3: Table C summarizes the reserve values from Tables D, E, and F by plant.

Note 4: Table B summarizes the contribution of units toward the final 540 MW regulation reserve requirement in the 2018/2019 Reserve Study.

PacifiCorp
Results from the Reserve Study

Table D
2018/2019 Results
Schedule 5, Spinning Reserves

	Plant	Type	Total 10-Minute Contingency Reserves (MW)	Total 10-Minute Contingency Reserves % of Total	Spin Held for Contingency Spin Requirement (MW)	Spin Held for Contingency Spin Requirement % of Total	Total Reserves Held for Spinning Reserve Requirements (MW)	Total Reserves Held for Spinning Reserve Requirements % of Total
1	Cholla 4	Steam						
2	Currant Creek	Gas	49.3	4.9%	20.8	9.0%	20.8	9.0%
3	Dave Johnston 1	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
4	Dave Johnston 2	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
5	Dave Johnston 3	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
6	Dave Johnston 4	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
7	Gadsby 1	Steam	1.3	0.1%	0.8	0.4%	0.8	0.4%
8	Gadsby 2	Steam	1.9	0.2%	1.2	0.5%	1.2	0.5%
9	Gadsby 3	Steam	2.6	0.3%	2.3	1.0%	2.3	1.0%
10	Gadsby 4	Gas	38.1	3.8%	0.2	0.1%	0.2	0.1%
11	Gadsby 5	Gas	36.4	3.6%	0.2	0.1%	0.2	0.1%
12	Gadsby 6	Gas	37.6	3.7%	0.3	0.1%	0.3	0.1%
13	Hunter 1	Steam	21.6	2.1%	10.5	4.5%	10.5	4.5%
14	Hunter 2	Steam	19.5	1.9%	9.9	4.3%	9.9	4.3%
15	Hunter 3	Steam	26.0	2.6%	13.2	5.7%	13.2	5.7%
16	Huntington 1	Steam	26.3	2.6%	16.8	7.3%	16.8	7.3%
17	Huntington 2	Steam	23.1	2.3%	12.3	5.3%	12.3	5.3%
18	Lake Side 1	Gas	47.3	4.7%	19.3	8.4%	19.3	8.4%
19	Lake Side 2	Gas	62.1	6.2%	27.3	11.9%	27.3	11.9%
20	Naughton 1	Steam	5.8	0.6%	2.4	1.0%	2.4	1.0%
21	Naughton 2	Steam	6.2	0.6%	2.4	1.0%	2.4	1.0%
22	Naughton 3	Steam						
23	Wyodak	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%
24	Oneida 1	Hydro	10.2	1.0%	5.3	2.3%	5.3	2.3%
25	Oneida 2	Hydro	6.1	0.6%	3.2	1.4%	3.2	1.4%
26	Oneida 3	Hydro	0.9	0.1%	0.4	0.2%	0.4	0.2%
27	Cutler 1	Hydro	14.8	1.5%	7.6	3.3%	7.6	3.3%
28	Cutler 2	Hydro	13.6	1.4%	7.1	3.1%	7.1	3.1%
29	Monsanto	Contract	94.4	9.4%	0.0	0.0%	0.0	0.0%
30	Coolkeeper	Contract						
31	Nucor	Contract	52.5	5.2%	0.0	0.0%	0.0	0.0%
32	Magcorp	Contract	84.3	8.4%	0.0	0.0%	0.0	0.0%
33	Chehalis	Gas	52.1	5.2%	3.1	1.4%	3.1	1.4%
34	Hermiston Owned	Gas	30.1	3.0%	5.2	2.2%	5.2	2.2%
35	Mid-Columbia Hydro-Grant	Hydro	3.0	0.3%	0.0	0.0%	0.0	0.0%
36	Mid-Columbia Hydro-Douglas	Hydro						
37	Swift	Hydro	129.0	12.8%	45.0	19.5%	45.0	19.5%
38	Yale	Hydro	90.9	9.0%	12.7	5.5%	12.7	5.5%
39	Jim Bridger	Steam	19.3	1.9%	0.7	0.3%	0.7	0.3%
40	SCL Stateline	Contract						
41		**Totals**	**1006.5**	**100%**	**230.3**	**100%**	**230.3**	**100%**

Table E
2018/2019 Results
Schedule 6, Supplemental Reserves

Plant	Type	Total 10-Minute Contingency Reserves (MW)	Total 10-Minute Contingency Reserves % of Total	Supplemental Reserves Held for Supplemental Reserve Requirement (MW)	Supplemental Reserves Held for Supplemental Reserve Requirement % of Total	Spin Held for Supplemental Reserve Requirement (MW)	Spin Held for Supplemental Reserve Requirement % of Total	Total 10-Minute & Supplemental Reserves Held for Supplemental Reserve Requirement (MW)	Total 10-Minute & Supplemental Reserves Held for Supplemental Reserve Requirement % of Total
Cholla 4	Steam								
Currant Creek	Gas	49.3	4.9%	0.0	0.0%	0.0	17.0%	0.0	0.0%
Dave Johnston 1	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 2	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 3	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Dave Johnston 4	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Gadsby 1	Steam	1.3	0.1%	0.0	0.0%	0.0	1.7%	0.0	0.0%
Gadsby 2	Steam	1.9	0.2%	0.0	0.0%	0.0	2.1%	0.0	0.0%
Gadsby 3	Steam	2.6	0.3%	0.0	0.0%	0.0	0.4%	0.0	0.0%
Gadsby 4	Gas	38.1	3.8%	18.9	8.4%	0.0	2.2%	18.9	8.4%
Gadsby 5	Gas	36.4	3.6%	16.8	7.4%	0.0	1.8%	16.8	7.4%
Gadsby 6	Gas	37.6	3.7%	16.5	7.3%	0.0	2.1%	16.5	7.3%
Hunter 1	Steam	21.6	2.1%	0.0	0.0%	0.0	6.6%	0.0	0.0%
Hunter 2	Steam	19.5	1.9%	0.0	0.0%	0.0	6.4%	0.0	0.0%
Hunter 3	Steam	26.0	2.6%	0.0	0.0%	0.0	5.2%	0.0	0.0%
Huntington 1	Steam	26.3	2.6%	0.0	0.0%	0.0	3.1%	0.0	0.0%
Huntington 2	Steam	23.1	2.3%	0.0	0.0%	0.0	4.5%	0.0	0.0%
Lake Side 1	Gas	47.3	4.7%	0.0	0.0%	0.0	12.0%	0.0	0.0%
Lake Side 2	Gas	62.1	6.2%	0.0	0.0%	0.0	17.1%	0.0	0.0%
Naughton 1	Steam	5.8	0.6%	0.0	0.0%	0.0	0.7%	0.0	0.0%
Naughton 2	Steam	6.2	0.6%	0.0	0.0%	0.0	1.2%	0.0	0.0%
Naughton 3	Steam								
Wyodak	Steam	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Oneida 1	Hydro	10.2	1.0%	0.0	0.0%	0.0	3.9%	0.0	0.0%
Oneida 2	Hydro	6.1	0.6%	0.0	0.0%	0.0	2.2%	0.0	0.0%
Oneida 3	Hydro	0.9	0.1%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Cutler 1	Hydro	14.8	1.5%	0.0	0.0%	0.0	4.9%	0.0	0.0%
Cutler 2	Hydro	13.6	1.4%	0.0	0.0%	0.0	5.0%	0.0	0.0%
Monsanto	Contract	94.4	9.4%	50.7	22.4%	0.0	0.0%	50.7	22.4%
Coolkeeper	Contract								
Nucor	Contract	52.5	5.2%	27.8	12.3%	0.0	0.0%	27.8	12.3%
Magcorp	Contract	84.3	8.4%	38.9	17.2%	0.0	0.0%	38.9	17.2%
Chehalis	Gas	52.1	5.2%	3.0	1.3%	0.0	0.0%	3.0	1.3%
Hermiston Owned	Gas	30.1	3.0%	4.0	1.8%	0.0	0.0%	4.0	1.8%
Mid-Columbia Hydro-Grant	Hydro	3.0	0.3%	0.1	0.1%	0.0	0.0%	0.1	0.1%
Mid-Columbia Hydro-Douglas	Hydro								
Swift	Hydro	129.0	12.8%	37.5	16.6%	0.0	0.0%	37.5	16.6%
Yale	Hydro	90.9	9.0%	10.7	4.8%	0.0	0.0%	10.7	4.7%
Jim Bridger	Steam	19.3	1.9%	1.2	0.5%	0.0	0.0%	1.2	0.5%
SCL Stateline	Contract								
Totals		**1006.5**	**100%**	**226.2**	**100%**	**0.1**	**100%**	**226.3**	**100%**

Table F
2018/2019 Results
Schedule 3 and 3A, Regulating Reserves

Plant	Type	Total 10-Minute & 30-Minute Reserve (MW)	Total 10-Minute & 30-Minute Reserve % of Total	Excess Spin and Supplemental Available for Regulation Reserve (MW)	Excess Spin and Supplemental Available for Regulation Reserve % of Total	30-Minute Reserves Available for Regulation Reserve (MW)	30-Minute Reserves Available for Regulation Reserve % of Total	Total Capability Available for Regulation Reserve (MW)	Total Capability Available for Regulation Reserve % of Total
Cholla 4 [1]	Steam								
Currant Creek	Gas	59.2	4.8%	28.4	5.6%	9.9	3.8%	38.3	5.0%
Dave Johnston 1	Steam	5.0	0.4%	0.0	0.0%	5.0	2.0%	5.0	0.7%
Dave Johnston 2	Steam	5.5	0.5%	0.0	0.0%	5.5	2.1%	5.5	0.7%
Dave Johnston 3	Steam	16.2	1.3%	0.0	0.0%	16.2	6.3%	16.2	2.1%
Dave Johnston 4	Steam	15.6	1.3%	0.0	0.0%	15.6	6.0%	15.6	2.0%
Gadsby 1	Steam	1.3	0.1%	0.5	0.1%	0.0	0.0%	0.5	0.1%
Gadsby 2	Steam	2.1	0.2%	0.7	0.1%	0.2	0.1%	0.9	0.1%
Gadsby 3	Steam	4.6	0.4%	0.4	0.1%	2.0	0.8%	2.4	0.3%
Gadsby 4	Gas	48.0	3.9%	19.0	3.7%	9.9	3.8%	28.8	3.8%
Gadsby 5	Gas	43.9	3.6%	19.4	3.8%	7.5	2.9%	27.0	3.5%
Gadsby 6	Gas	44.8	3.7%	20.9	4.1%	7.2	2.8%	28.0	3.7%
Hunter 1	Steam	37.5	3.1%	11.1	2.2%	15.9	6.2%	27.1	3.5%
Hunter 2	Steam	25.9	2.1%	9.6	1.9%	6.4	2.5%	16.0	2.1%
Hunter 3	Steam	59.3	4.9%	12.9	2.5%	33.2	12.9%	46.1	6.0%
Huntington 1	Steam	59.8	4.9%	9.5	1.9%	33.5	13.0%	43.0	5.6%
Huntington 2	Steam	53.3	4.4%	10.8	2.1%	30.3	11.7%	41.1	5.4%
Lake Side 1	Gas	54.9	4.5%	28.0	5.5%	7.6	3.0%	35.6	4.7%
Lake Side 2	Gas	76.1	6.2%	34.8	6.9%	14.0	5.4%	48.8	6.4%
Naughton 1	Steam	6.2	0.5%	3.4	0.7%	0.4	0.2%	3.8	0.5%
Naughton 2	Steam	7.4	0.6%	3.8	0.7%	1.2	0.5%	5.0	0.7%
Naughton 3 [2]	Steam								
Wyodak	Steam	16.2	1.3%	0.0	0.0%	16.2	6.3%	16.2	2.1%
Oneida 1	Hydro	10.2	0.8%	4.9	1.0%	0.0	0.0%	4.9	0.6%
Oneida 2	Hydro	6.1	0.5%	2.9	0.6%	0.0	0.0%	2.9	0.4%
Oneida 3	Hydro	0.9	0.1%	0.5	0.1%	0.0	0.0%	0.5	0.1%
Cutler 1	Hydro	14.8	1.2%	7.2	1.4%	0.0	0.0%	7.2	0.9%
Cutler 2	Hydro	13.6	1.1%	6.5	1.3%	0.0	0.0%	6.5	0.9%
Monsanto	Contract	50.7	4.2%	0.0	0.0%	0.0	0.0%	0.0	0.0%
Coolkeeper [4]	Contract								
Nucor	Contract	52.5	4.3%	24.6	4.9%	0.0	0.0%	24.6	3.2%
Magcorp	Contract	84.3	6.9%	45.4	9.0%	0.0	0.0%	45.4	5.9%
Chehalis	Gas	52.1	4.3%	46.0	9.1%	0.0	0.0%	46.0	6.0%
Hermiston Owned	Gas	30.1	2.5%	20.9	4.1%	0.0	0.0%	20.9	2.7%
Mid-Columbia Hydro	Hydro	3.0	0.2%	2.9	0.6%	0.0	0.0%	2.9	0.4%
Mid-Columbia Hydro	Hydro								
Swift	Hydro	129.0	10.6%	46.6	9.2%	0.0	0.0%	46.6	6.1%
Yale	Hydro	90.9	7.4%	67.4	13.3%	0.0	0.0%	67.4	8.8%
Jim Bridger	Steam	39.4	3.2%	17.5	3.5%	20.1	7.8%	37.5	4.9%
SCL Stateline [4]	Contract								
Totals		**1,220.6**	**100%**	**506.2**	**100%**	**257.8**	**100%**	**764.0**	**100%**

PacifiCorp
Wheeling Costs

Wheeling Costs included in Attachment B, pages 3-5, column (i)

Unit	Third party Transmission Cost ($/kW-year)	Source
Chehalis	21.69	BPA: PTP + Scheduling
Hermiston	21.69	BPA: PTP + Scheduling
Jim Bridger	6.15	IPC: PTP
Swift No. 1	21.69	BPA: PTP + Scheduling

	$/kW-year	Period	
Chehalis, Hermiston, Swift			
	$21.52/kW	(Jan '19 - Sep '19)	
	$22.20/kW	(Oct '19 - Dec '19)	
Jim Bridger			
	$6.35/kW	(Jan '19 - Sep '19)	PAC (NT)/IPC (PTP)
	$5.55/kW	(Oct '19 - Dec '19)	PAC (NT)/IPC (PTP)

PacifiCorp
2019 Actual Load - Monthly Peaks
(Attachment 9b from the 2020 Annual Update of PacifiCorp's transmission Formula)

			OATT (Part III - Network Service)																	
	Column		e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f13	f14	f15	f16	f17	f18	f
	Customer Class RS / SA		PacifiCorp NFS (see note)	BPA Yakama FNO SA 328	BPA Gazley FNO SA 229	BPA Clarke PUD FNO SA 735	BPA: Benton REA FNO SA 539	BPA Oregon Wind FNO SA 538	BPA CEC FNO SA 827	Tri-State FNO SA 628	Calpine Energy Solutions LLC FNO SA 299	Basin Electric FNO SA 505	Black Hills FNO SA 347	USBR FNO SA 506	WAPA FNO SA 175	Avangrid Renewables, LLC FNO SA 742	Exelon FNO SA 943	BPA South East Idaho FNO SA 746	BPA Idaho Falls FNO SA 747	3 Phases Renewables Inc. FNO SA 876	NTUA FNO SA 894	Total NFO
1	Jan	2 9:00	8,233	6.88	3.60	28.75	1.10	0.30	-	19.78	15.45	10.47	45.55	0.01	0.01	30.81	0.75	330.22	97.00	0.01	2.64	593
2	Feb	7 8:00	8,604	7.68	3.56	35.61	1.57	0.50	0.03	18.86	16.14	11.81	55.25	0.01	0.01	31.82	0.79	280.11	96.00	0.06	2.42	562
3	March	4 8:00	8,218	7.34	3.25	35.18	1.18	0.11	0.02	21.94	14.33	11.13	54.20	0.01	0.01	31.63	0.77	284.05	94.35	0.05	2.34	562
4	April	10 8:00	7,167	5.69	3.18	19.14	1.13	-	-	16.23	13.71	8.54	37.79	0.24	0.01	31.21	0.70	176.91	68.05	0.07	1.87	384
5	May	13 18:00	7,311	5.01	2.94	11.55	0.30	-	-	11.21	15.44	6.69	32.18	0.54	1.99	32.06	0.79	120.64	95.29	0.08	1.77	338
6	Jun	28 18:00	8,681	4.28	3.31	11.27	0.33	-	-	14.36	15.40	9.62	44.89	0.55	3.20	31.97	0.87	168.55	96.09	0.11	1.93	407
7	Jul	22 17:00	10,334	5.50	3.42	13.92	0.39	-	-	12.68	17.43	11.28	53.47	0.61	3.09	32.04	0.72	191.32	122.05	0.14	2.61	471
8	Aug	5 17:00	10,220	5.82	3.63	16.11	0.36	-	-	13.95	17.57	10.90	50.13	0.63	2.93	32.27	0.34	166.87	106.80	0.18	2.42	431
9	Sept	5 17:00	9,722	5.36	3.73	13.05	0.30	-	-	16.11	17.35	10.95	51.58	0.50	3.17	31.80	0.71	144.23	107.83	0.14	2.11	409
10	Oct	30 8:00	8,274	6.57	3.50	26.58	0.37	0.37	0.13	18.17	14.16	11.60	48.47	0.01	0.01	32.06	0.78	298.06	92.90	0.07	2.49	556
11	Nov	26 18:00	8,081	4.45	3.36	25.32	1.16	-	0.18	17.03	13.84	11.06	43.68	0.01	0.01	32.27	0.55	247.44	78.49	0.07	2.16	481
12	Dec	17 18:00	8,498	4.81	3.17	24.42	1.27	-	0.18	17.09	13.91	9.79	43.64	0.01	0.01	32.61	0.72	290.96	65.63	0.08	2.65	511
13	Total		103,344	69.39	40.63	260.89	9.45	1.29	0.54	197.39	184.71	123.83	560.83	3.09	14.44	382.54	8.48	2,699.35	1,120.49	1.06	27.44	5,706
14	**Ave 12CP**		**8,611.99**	**5.78**	**3.39**	**21.74**	**0.79**	**0.11**	**0.04**	**16.45**	**15.39**	**10.32**	**46.74**	**0.26**	**1.20**	**31.88**	**0.71**	**224.95**	**93.37**	**0.09**	**2.29**	475.49
													(not included (telemetered))		(not included (telemetered))							

	Column	Other Service j1	j2	j3	j4		j
	Customer Class RS / SA	UAMPS OS RS 297	UMPA OS RS 637	Deseret OS RS 280	WAPA OS RS 262/RS 263	APS OS RS 436	Total OS
15	Jan	408	64	148	324		943
16	Feb	383	64	81	340		868
17	March	314	33	58	320		724
18	April	338	18	60	290		706
19	May	405	32	99	295		831
20	Jun	617	95	121	317		1,150
21	Jul	772	151	148	318		1,389
22	Aug	805	152	87	318		1,363
23	Sept	758	166	93	288		1,305
24	Oct	384	44	69	334		831
25	Nov	431	48	74	299		852
26	Dec	464	60	85	314		924
27	Total	6,080	927	1,123	3,757	-	11,887
28	**Ave 12CP**	**506.65**	**77.26**	**93.58**	**313.08**	**-**	**990.57**

Total load excluding telemetered exports (Sch 3 divisor) **10,030.11**

		Total billed (MW)	Total previously included		Adjustment to account for Deseret Area Load (MW)	
29	2019 Jan	275.40	148.27		127.12	
30	2019 Feb	254.73	81.33		173.41	
31	2019 March	223.34	57.69		165.64	
32	2019 April	214.75	60.14		154.61	
33	2019 May	246.57	98.93		147.64	
34	2019 Jun	274.05	120.70		153.35	
35	2019 Jul	328.21	147.77		180.44	
36	2019 Aug	318.02	86.76		231.26	
37	2019 Sept	312.78	92.82		219.96	
38	2019 Oct	241.02	69.17		171.85	
39	2019 Nov	245.18	74.20		170.98	
40	2019 Dec	262.29	85.16		177.13	
41	Total	3196.34	1122.94		2073.40	
42	**Ave 12CP**	**266.36**	**93.58**	**-**	**172.78**	**172.78**

10,202.90

"The adjusted load for Deseret is due to PacifiCorp recognizing the need to include the full billing demands of Deseret that is allowed to be charged under the ARTSOA in the development of schedule 3 rates. We need to include the "Deseret Area Load" in schedule 3 rate denominator (what was billed) ."

PacifiCorp
Summary for Nameplate Capacity
(Schedule 3/3A Billing Determinants)

		NamePlate Capcity (MW) / Billing		
	Year	**Wind (VER)**	**Solar (VER)**	**Non-VER**
1	2018	2,741	993	1,304
2	2019	2,750	1,168	1,304
3	Average	2,745	1,080	1,304

BA	RSRC_ID	Resource_Name	FUEL_SOURCE	EFFECTIVE_DATE	TERMINATION_DATE	Capacity	BAA	DISPATCHABLE	Class
1006	3PEAKS_1_UNIT1	Iron Springs Solar	SOLR	5/01/2014		80	PACE	NO	Solar
8030	AGATEBAY_7_SOLAR1	Agate Bay Solar	SOLR	11/20/2016		10	PACW	NO	Solar
8030	AIRPORT_7_UNIT1	Airport Solar	SOLR	10/01/2019		47.25	PACW	NO	Solar
8029	ARROWHE_7_UNIT1	Simplot	OTHR	11/19/2016		13	PACE	NO	Exclude - load and resource
8029	ASHTON_6_UNIT1	Ashton	WATR	5/19/2017		7	PACE	NO	Non-VER
1006	BASELINE_7_UNIT1	Pavant II	SOLR	2/28/2017		50	PACE	NO	Solar
8030	BIOMAS_7_PACW	QF - Biomass One	BIOM	5/01/2014		32.5	PACW	NO	Non-VER
8029	BLUNDELL_7_UNIT1	Blundell1	GEOT	12/22/2017		23	PACE	NO	Non-VER
8029	BLUNDELL_7_UNIT2	Blundell2	GEOT	12/22/2017		10	PACE	NO	Non-VER
8029	BONANZA_7_UNIT	Bonanza	COAL	5/01/2014		458	PACE	YES	Non-VER
8030	CAMASMI_7_UNIT	Camas Mill Cogen	WAST	5/01/2014	12/31/2017	61.5	PACW	NO	Non-VER
8030	CAMPCOL_6_UNIT	Campbell Wind	WIND	5/01/2014		98.9	PACW	NO	Wind
8029	CARBON_7_UNIT 1	Carbon 1	COAL	5/01/2014	3/23/2016	67	PACE	YES	Non-VER
8029	CARBON_7_UNIT 2	Carbon 2	COAL	5/01/2014	3/23/2016	105	PACE	YES	Non-VER
1006	CEDARVAS_7_SOLAR1	Cedar Valley Solar	SOLR	5/01/2014		3	PACE	NO	Solar
1006	CHAUTAUQ_7_UNIT1	Pavant III	SOLR	2/28/2017		20	PACE	NO	Solar
1006	CHEHALIS_7_UNITS	Chehalis	GAS	5/01/2014		510	PACW	YES	Non-VER
1006	CHERRYLA_7_UNIT1	Adams Solar	SOLR	11/01/2018		10	PACW	NO	Solar
1006	CHILOQUI_7_UNIT1	Saturn Power - Chiloquin	SOLR	5/08/2018		9.9	PACW	NO	Solar
8029	CHOLLA_7_UNIT	Cholla 4	COAL	5/01/2014		387	PACE	YES	Non-VER
1006	CHOPINWF_6_UNIT1	Chopin Wind Farm	WIND	12/08/2016		18	PACW	NO	Wind
8030	CLEARWA1_7_UNIT	Clearwater 1 Hydro	WATR	5/01/2014		15	PACW	NO	Non-VER
8030	CLEARWA2_7_UNIT	Clearwater 2 Hydro	WATR	5/01/2014		26	PACW	NO	Non-VER
8030	COID_7_UNITS	QF - COID - Siphon	WATR	5/01/2014		6	PACW	NO	Non-VER
1006	COLRSLR_7_UNIT1	Collier Solar	SOLR	2/28/2017		9.9	PACW	NO	Solar
8030	COMBINEH_6_UNIT	Combine Hills Wind	WIND	5/01/2014		41	PACW	NO	Wind
1006	COMMERCE_7_UNIT 1	Fiddler's Canyon 1-3	SOLR	5/01/2014		9	PACE	NO	Solar
1006	CONCHO_7_ UNIT 1	Latigo Wind	WIND	5/01/2014		60	PACE	NO	Wind
8030	COPCO1_7_UNIT 1	Copco 1 Hydro Unit 1	WATR	5/01/2014		13	PACW	NO	Non-VER
8030	COPCO1_7_UNIT 2	Copco 1 Hydro Unit 2	WATR	5/01/2014		13	PACW	NO	Non-VER
8030	COPCO2_7_UNIT 1	Copco 2 Hydro Unit 1	WATR	5/01/2014		18	PACW	NO	Non-VER
8030	COPCO2_7_UNIT 2	Copco 2 Hydro Unit 2	WATR	5/01/2014		18	PACW	NO	Non-VER
1006	CURRCRK_7_UNITS	Currant Creek	GAS	5/01/2014		530	PACE	YES	Non-VER
8029	CUTLER_7_UNIT 1	Cutler Hydro Unit 1	WATR	5/01/2014		15	PACE	YES	Non-VER
8029	CUTLER_7_UNIT 2	Cutler Hydro Unit 2	WATR	5/01/2014		15	PACE	YES	Non-VER
8030	DALREED_7_BIO	QF - Three Mile Farm Biofuel	BGAS	5/01/2014		4.8	PACW	NO	Non-VER
8030	DALREED_7_WIND	Three Mile Canyon Wind	WIND	5/01/2014		9.9	PACW	NO	Wind
8029	DALTONU_7_UNIT	Granger	BGAS	5/01/2014		4.6	PACE	NO	Non-VER
8029	DAVEJOHN_7_UNIT 1	Dave Johnston 1	COAL	5/01/2014		106	PACE	YES	Non-VER
8029	DAVEJOHN_7_UNIT 2	Dave Johnston 2	COAL	5/01/2014		106	PACE	YES	Non-VER
1006	DAVEJOHN_7_UNIT 3	Dave Johnston 3	COAL	5/01/2014		223	PACE	YES	Non-VER
1006	DAVEJOHN_7_UNIT 4	Dave Johnston 4	COAL	5/01/2014		325	PACE	YES	Non-VER
1006	DEADMAN_7_SOLAR1	Black Cap II Solar	SOLR	11/01/2018		8	PACW	NO	Solar
1006	DOBBISLR_7_UNIT1	Bear Creek Solar	SOLR	11/01/2018		10	PACW	NO	Solar
8030	DORENALK_7_UNIT1	Dorena	WATR	5/19/2017		6.1	PACW	NO	Non-VER
1006	DRAZIL_7_SOLAR1	Drazil Solar	SOLR	5/08/2018		10	PACW	NO	Solar
1006	DUNLAP_6_UNIT	Dunlap Wind	WIND	5/01/2014		111	PACE	NO	Wind
1006	DYNAMO_7_UNITS	Lake Side 1	GAS	5/01/2014		525	PACE	YES	Non-VER
1006	ELBESLR_7_UNIT1	Elbe Solar	SOLR	11/01/2018		10	PACW	NO	Solar
1006	ENTERPRU_1_SOLAR1	Beryl Solar	SOLR	5/01/2014		3	PACE	NO	Solar
8030	EVERGBIO_6_BIO	QF - Evergreen Biomass	BIOM	5/01/2014		10	PACW	NO	Non-VER
8029	EXXON_7_UNITS	QF - ExxonMobile Production Company	GAS	5/01/2014		118	PACE	NO	Exclude - load and resource
8030	FALLCREE_7_UNIT	QF - Falls Creek Hydro	WATR	5/01/2014		4.1	PACW	NO	Non-VER
8030	FARMERS_6_UNIT	QF - Farmers Irrigation District Hydro	WATR	5/01/2014		4.15	PACW	NO	Non-VER
8030	FISHCREO_7_UNIT	Fish Creek Hydro	WATR	5/01/2014		13	PACW	NO	Non-VER
8029	FOOTECRE_7_UNITS	Foote Creek I-V Wind	WIND	5/01/2014		133.15	PACE	NO	Wind
1006	FREEZOUT_6_UNIT	Seven Mile Hill I & II Wind	WIND	5/01/2014		118.5	PACE	NO	Wind

8029	GADSBY_7_UNIT 1	Gadsby 1	GAS	12/01/2014		64	PACE	YES	Non-VER
8029	GADSBY_7_UNIT 2	Gadsby 2	GAS	12/01/2014		69	PACE	YES	Non-VER
1006	GADSBY_7_UNIT 3	Gadsby 3	GAS	5/01/2014		104.5	PACE	YES	Non-VER
1006	GADSBY_7_UNIT 4	Gadsby 4	GAS	5/01/2014		40	PACE	YES	Non-VER
1006	GADSBY_7_UNIT 5	Gadsby 5	GAS	5/01/2014		40	PACE	YES	Non-VER
1006	GADSBY_7_UNIT 6	Gadsby 6	GAS	5/01/2014		40	PACE	YES	Non-VER
8030	GALASLR_1_UNIT1	Gala Solar	SOLR	7/28/2017		56	PACW	NO	Solar
8030	GARRETT_1_SOLAR1	Garrett Solar	SOLR	11/01/2019		10	PACW	NO	Solar
8029	GEMSTATE_1_UNIT	Gem State Hydro	WATR	5/01/2014		23.4	PACE	NO	Non-VER
1006	GLENR_ROLLH_2_UNITS	GlenR_RollH	WIND	10/01/2019		237	PACE	NO	Wind
1006	GLENROCW_6_UNIT	Glenrock I & III Wind	WIND	5/01/2014	9/30/2019	118.5	PACE	NO	Wind
1006	GOODNOEH_7_UNIT	Goodnoe Hill Wind	WIND	5/01/2014		94	PACW	NO	Wind
8029	GRACE_7_UNIT 3	Grace Hydro Unit 3	WATR	5/01/2014		11	PACE	NO	Non-VER
8029	GRACE_7_UNIT 4	Grace Hydro Unit 4	WATR	5/01/2014		11	PACE	NO	Non-VER
8029	GRACE_7_UNIT 5	Grace Hydro Unit 5	WATR	5/01/2014		11	PACE	NO	Non-VER
1006	HERMISTO_7_UNIT 3	Hermiston 3	GAS	5/01/2014		252	PACW	YES	Non-VER
1006	HICKORY_3_SOLAR1	Escalante Solar	SOLR	5/01/2014		240	PACE	NO	Solar
8030	HINKLE_6_UNIT	Oregon 9 Windfarms (Hinkle)	WIND	5/01/2014		64.55	PACW	NO	Wind
8029	HINSHAW_7_UNITS	Hinshaw (WY Wind)	WIND	5/01/2014		144	PACE	NO	Wind
1006	HIPLAINS_7_UNITS	High Plains & McFadden Ridge Wind	WIND	5/01/2014		127.5	PACE	NO	Wind
1006	HOLT_1_SOLAR1	Enterprise Solar	SOLR	5/01/2014		80	PACE	NO	Solar
8029	HORSEBU_7_UNIT	Horse Butte	WIND	5/01/2014		57.6	PACE	NO	Wind
1006	HORSEFLY_6_UNIT1	Bly Solar	SOLR	4/02/2019		8.5	PACW	NO	Solar
8029	HUNTERP_7_UNIT 1	Hunter 1	COAL	5/01/2014		446	PACE	YES	Non-VER
8029	HUNTERP_7_UNIT 2	Hunter 2	COAL	5/01/2014		446	PACE	YES	Non-VER
1006	HUNTERP_7_UNIT 3	Hunter 3	COAL	5/01/2014		471	PACE	YES	Non-VER
1006	HUNTINGT_7_UNIT 1	Huntington 1	COAL	5/01/2014		459	PACE	YES	Non-VER
1006	HUNTINGT_7_UNIT 2	Huntington 2	COAL	5/01/2014		450	PACE	YES	Non-VER
8030	IRONGATE_7_UNIT	Iron Gate Hydro	WATR	5/01/2014		20	PACW	NO	Non-VER
8030	JCBOYLE_7_UNIT 1	JC Boyle Hydro Unit 1	WATR	5/01/2014		50.35	PACW	NO	Non-VER
8030	JCBOYLE_7_UNIT 2	JC Boyle Hydro Unit 2	WATR	5/01/2014		48	PACW	NO	Non-VER
1006	JIMBRIDG_7_UNIT 1	Jim Bridger Unit 1	COAL	3/15/2018		354	PACW	YES	Non-VER
1006	JIMBRIDG_7_UNIT 2	Jim Bridger Unit 2	COAL	3/15/2018		359	PACW	YES	Non-VER
1006	JIMBRIDG_7_UNIT 3	Jim Bridger Unit 3	COAL	3/15/2018		349	PACW	YES	Non-VER
1006	JIMBRIDG_7_UNIT 4	Jim Bridger Unit 4	COAL	3/15/2018		353	PACW	YES	Non-VER
1006	JIMBRIDG_7_UNITS	Jim Bridger Plant	COAL	5/01/2014		1415	PACW	YES	Non-VER
8029	JOLLYHIL_1_GOSHEN	Jollyhill Wind	WIND	5/01/2014		124.5	PACE	NO	Wind
8029	KENNECOT_1_NCL	QF - Kennecott Refinery & Smelter Net	WAST	5/01/2014	12/31/2017	39.34	PACE	NO	Non-VER
1006	LAKESID2_7_UNITS	Lake Side 2	GAS	5/01/2014		620	PACE	YES	Non-VER
8029	LATIGO_6_UNIT	Three Buttes Wind	WIND	5/01/2014		99	PACE	NO	Wind
1006	LEANJNPR_7_UNIT	Leaning Juniper Wind	WIND	5/01/2014		100.5	PACW	NO	Wind
8030	LEMOLO1_7_UNIT	Lemolo 1 Hydro	WATR	5/01/2014		32	PACW	NO	Non-VER
8030	LEMOLO2_7_UNIT	Lemolo 2 Hydro	WATR	5/01/2014		38.5	PACW	NO	Non-VER
1006	LIMESTNE_7_UNIT1	Tumbleweed Solar	SOLR	5/08/2018		9.9	PACW	NO	Solar
1006	LOSTRVR_7_SOLAR1	Lost River Solar	SOLR	5/08/2018		8	PACW	NO	Solar
1006	MARENGO_6_UNITS	Marengo I & II Wind	WIND	5/01/2014		210.6	PACW	NO	Wind
1006	MCCARTIE_7_UNIT1	Bonanza Solar	SOLR	4/02/2019		4.8	PACW	NO	Solar
8029	MEADOWCR_6_UNIT	Meadow Creek Wind	WIND	5/01/2014		119.7	PACE	NO	Wind
8030	MERWIN_7_UNITS	Merwin Hydro	WATR	5/01/2014		151	PACW	NO	Non-VER
1006	MIDC_7_DOUGPACSHARE	MIDC Douglas PAC Share	WATR	6/21/2017		46	PACW	YES	Non-VER
1006	MIDC_7_MCCCPACSHARE	MIDC Grant PAC Share	WATR	6/21/2017		22	PACW	YES	Non-VER
1006	MIDC_7_PACWSHARE	MIDC Share	WATR	2/23/2017		64	PACW	YES	Non-VER
8029	MIDDLETO_1_UNIT1	Veyo	OTHR	5/01/2014		9.5	PACE	NO	Non-VER
1006	MILFORD_7_SOLAR1	Granite Peak Solar	SOLR	5/01/2014		3	PACE	NO	Solar
8029	MILLCRK_7_UNIT 1	Millcreek 1	GAS	5/01/2014		40	PACE	NO	Non-VER
8029	MILLCRK_7_UNIT 2	Millcreek 2	GAS	5/01/2014		40	PACE	NO	Non-VER
1006	MONSANTO_NCL1	Interruptible - Monsanto Load 1	DDR	5/01/2014		0	PACE	YES	Non-VER
1006	MONSANTO_NCL2	Interruptible - Monsanto Load 2	DDR	5/01/2014		0	PACE	YES	Non-VER
8029	MOONSHIN_7_UNITS	Moonshine Power County N/S Wind	WIND	5/01/2014		45	PACE	NO	Wind
8029	MTWNDCOL_7_UNITS	Mountain Power I & II Wind	WIND	5/01/2014		140.7	PACE	NO	Wind
1006	MTZKRSL1_7_SOLAR1	Metzker Solar	SOLR	5/08/2018		10	PACW	NO	Solar
1006	NAUGHTON_7_UNIT 1	Naughton 1	COAL	5/01/2014		158	PACE	YES	Non-VER

1006	NAUGHTON_7_UNIT 2	Naughton 2	COAL	5/01/2014		206	PACE	YES	Non-VER
1006	NAUGHTON_7_UNIT 3	Naughton 3	GAS	5/01/2014		27	PACE	YES	Non-VER
8029	NEBOPS_7_UNIT 1	Nebo 1	GAS	5/01/2014	1/20/2015	75	PACE	NO	Non-VER
8029	NEBOPS_7_UNIT 2	Nebo 2	GAS	5/01/2014	1/20/2015	135	PACE	NO	Non-VER
8029	NEBOPS_7_UNITS	Nebo	GAS	5/01/2014		140	PACE	NO	Non-VER
1006	NEFFSLR_7_SOLAR1	Neff Solar	SOLR	2/28/2017		9.9	PACW	NO	Solar
8030	NINEMIL_7_UNIT 1	Stateline wind	WIND	5/01/2014		210	PACW	NO	Wind
1006	NUCOR_NCL	Interruptible - Nucor Load	DDR	5/01/2014		0	PACE	YES	Non-VER
1006	OLDMLSLR_7_SOLAR1	Old Mill Solar	SOLR	5/01/2014		5	PACW	NO	Solar
8029	ONEIDA_7_UNIT 1	Oneida Hydro Unit 1	WATR	5/01/2014		10	PACE	YES	Non-VER
8029	ONEIDA_7_UNIT 2	Oneida Hydro Unit 2	WATR	5/01/2014		10	PACE	YES	Non-VER
8029	ONEIDA_7_UNIT 3	Oneida Hydro Unit 3	WATR	5/01/2014		10	PACE	YES	Non-VER
8030	OPALSPRI_7_UNIT	QF - Deschutes Valley Waters	WATR	5/01/2014		4.3	PACW	NO	Non-VER
8029	PALISADI_7_UNIT 1	Palisades 1	WATR	5/01/2014	8/24/2016	44	PACE	NO	Non-VER
8029	PALISADI_7_UNIT 2	Palisades 2	WATR	5/01/2014	8/24/2016	44	PACE	NO	Non-VER
8029	PALISADI_7_UNIT 3	Palisades 3	WATR	5/01/2014	8/24/2016	44	PACE	NO	Non-VER
8029	PALISADI_7_UNIT 4	Palisades 4	WATR	5/01/2014	8/24/2016	44	PACE	NO	Non-VER
8029	PALISADI_7_UNITS	Palisades	WATR	5/01/2014		176.6	PACE	NO	Non-VER
1006	PAROWANC_1_SOLAR1	Utah Red Hills Solar	SOLR	5/01/2014		80	PACE	NO	Solar
1006	PAROWANC_1_SOLAR2	Buckhorn Solar	SOLR	5/01/2014		3	PACE	NO	Solar
1006	PAVANT_7_SOLAR1	Pavant Solar	SOLR	5/01/2014		50	PACE	NO	Solar
8030	PELTONRE_7_UNIT	Pelton Re-Reg	WATR	5/01/2014		19.6	PACW	NO	Non-VER
1006	PENDAIR_7_UNIT1	Pendleton Solar	SOLR	4/02/2019		6	PACW	NO	Solar
8030	PENSTOCK_6_UNIT	QF - COID - Juniper Ridge	WATR	5/01/2014		5	PACW	NO	Non-VER
1006	PINEFSLR_7_UNIT1	Dairy Solar	SOLR	5/08/2018		10	PACW	NO	Solar
1006	PINTURA_1_UNIT1	Granite Mountain Solar	SOLR	5/01/2014		130	PACE	NO	Solar
8030	PROSPEC1_7_UNIT	Prospect 1 Hydro	WATR	5/01/2014		6	PACW	NO	Non-VER
8030	PROSPEC2_7_UNIT 1	Prospect 2 Hydro Unit 1	WATR	5/01/2014		22	PACW	NO	Non-VER
8030	PROSPEC2_7_UNIT 2	Prospect 2 Hydro Unit 2	WATR	5/01/2014		20	PACW	NO	Non-VER
8030	PROSPEC3_7_UNIT	Prospect 3 Hydro	WATR	5/01/2014		8	PACW	NO	Non-VER
8029	RAWHIDE_6_UNIT	Chevron Wind	WIND	5/01/2014		16.5	PACE	NO	Wind
8030	RFP_6_UNIT	QF - Roseburg Forest Products -Weed	BIOM	5/01/2014		10	PACW	NO	Exclude - load and resource
1006	ROLLHILL_6_UNIT	Rollings Hills Wind	WIND	5/01/2014	9/30/2019	118.5	PACE	NO	Wind
1006	ROOTCREE_2_UNIT1	Pioneer Wind	WIND	12/08/2016		80	PACE	NO	Wind
8030	ROSEBURL_7_LUMB	QF - Roseburg Forest Products - Dillard	BIOM	5/01/2014		20	PACW	NO	Exclude - load and resource
1006	ROWLEY_NCL1	Interruptible - US Magnesium Corp Load 1	DDR	5/01/2014	6/27/2018	0	PACE	YES	Non-VER
1006	ROWLEY_NCL2	Interruptible - US Magnesium Corp Load 2	DDR	5/01/2014	6/27/2018	0	PACE	YES	Non-VER
1006	ROWLEY_NCL3	Interruptible - US Magnesium Corp Load 3	DDR	5/01/2014	6/27/2018	0	PACE	YES	Non-VER
8029	SAGESOL_7_UNIT1	Sage Solar	SOLR	6/28/2019		57.6	PACE	NO	Solar
8029	SETTLEME_7_UNIT1	Tooele Army Depot	WIND	5/01/2014		4.95	PACE	NO	Wind
8029	SLENERGY_7_UNIT	Salt Lake Landfill	BGAS	5/01/2014		3.2	PACE	NO	Non-VER
8030	SLIDECRE_7_UNIT	Slide Creek Hydro	WATR	5/01/2014		18	PACW	NO	Non-VER
1006	SMILFORD_7_SOLAR1	Laho Solar	SOLR	5/01/2014		3	PACE	NO	Solar
1006	SMILFORD_7_SOLAR2	Milford Flat Solar	SOLR	5/01/2014		3	PACE	NO	Solar
8029	SMILFORD_7_UNIT1	Blue Mountain (Blue Knoll)	BGAS	12/01/2016		3.2	PACE	NO	Non-VER
8029	SMILFORD_7_UNIT2	Intermountain Geo	GEOT	5/01/2014		11	PACE	NO	Non-VER
8029	SODA_7_UNIT 1	Soda Hydro Unit 1	WATR	5/01/2014		7	PACE	NO	Non-VER
8029	SODA_7_UNIT 2	Soda Hydro Unit 2	WATR	5/01/2014		7	PACE	NO	Non-VER
8030	SODASPRI_7_UNIT	Soda Springs Hydro	WATR	5/01/2014		13	PACW	NO	Non-VER
8029	SPNFKWND_7_UNIT	Spanish Fork Wind	WIND	5/01/2014		18.9	PACE	NO	Wind
1006	STEVENSV_1_UNIT1	Three Peaks Solar	SOLR	2/28/2017		80	PACE	NO	Solar
8029	SUNNYSIU_6_UNIT	QF - Sunnyside Cogeneration	COAL	5/01/2014		53	PACE	NO	Non-VER
1006	SWANSON_7_UNIT1	Eagle Point Solar	SOLR	5/08/2018		9.9	PACW	NO	Solar
1006	SWEETWAT_7_UNIT1	Sweetwater Solar	SOLR	4/02/2019		80	PACE	NO	Solar
1006	SWIFT1_7_UNITS	Swift Hydro	WATR	5/01/2014		330	PACW	YES	Non-VER
8029	TESORO_7_UNITS	QF - Tesoro Refining and Marketing	GAS	5/01/2014		25	PACE	NO	Exclude - load and resource
8030	TIETONHY_6_UNIT	Tieton	WATR	5/01/2014		20	PACW	NO	Non-VER
8030	TOKETEE_7_UNIT 1	Toketee Hydro Unit 1	WATR	5/01/2014		15	PACW	NO	Non-VER
8030	TOKETEE_7_UNIT 2	Toketee Hydro Unit 2	WATR	5/01/2014		15	PACW	NO	Non-VER
8030	TOKETEE_7_UNIT 3	Toketee Hydro Unit 3	WATR	5/01/2014		15	PACW	NO	Non-VER
1006	TOPWORLD_7_UNITS	Top of the World Wind	WIND	1/18/2018		200.2	PACE	NO	Wind
8029	USBRGATE_7_UNIT	Gateway	WATR	5/01/2014		4.5	PACE	NO	Non-VER

1006	USMAG1_NCL	Interruptible - US Magnesium Corp Tot Ld	DDR	6/27/2018	0	PACE	YES	Non-VER	
8029	WCEDAR_7_UNIT1	Quichapa 1	SOLR	5/01/2014	3	PACE	NO	Solar	
8029	WCEDAR_7_UNIT2	Quichapa 2	SOLR	5/01/2014	3	PACE	NO	Solar	
8029	WCEDAR_7_UNIT3	Quichapa 3	SOLR	5/01/2014	3	PACE	NO	Solar	
8029	WEBER_7_UNIT	Weber Hydro	WATR	5/01/2014	3.85	PACE	NO	Non-VER	
1006	WESTVALL_7_UNIT 1	West Valley Unit 1	GAS	7/01/2017	38	PACE	YES	Non-VER	
1006	WESTVALL_7_UNIT 2	West Valley Unit 2	GAS	7/01/2017	38	PACE	YES	Non-VER	
1006	WESTVALL_7_UNIT 3	West Valley Unit 3	GAS	7/01/2017	38	PACE	YES	Non-VER	
1006	WESTVALL_7_UNIT 4	West Valley Unit 4	GAS	7/01/2017	38	PACE	YES	Non-VER	
1006	WESTVALL_7_UNIT 5	West Valley Unit 5	GAS	7/01/2017	38	PACE	YES	Non-VER	
8029	WOLVERIN_7_UNITS	Wolverine Creek Wind	WIND	5/01/2014	64.5	PACE	NO	Wind	
1006	WOODLINE_7_UNIT1	Woodline Solar	SOLR	5/08/2018	8	PACW	NO	Solar	
1006	WYODAK73_7_UNIT	Wyodak	COAL	11/21/2017	272	PACE	YES	Non-VER	
1006	YALE_7_UNITS	Yale Hydro	WATR	5/01/2014	167	PACW	YES	Non-VER	
8029	COLSTR_5_PACE	Colstrip 3 & 4 - East	COAL	5/01/2014	148	PACE	YES	Non-VER	
8030	COLSTR_5_PACW	Colstrip 3 & 4 - West	COAL	5/01/2014	148	PACW	YES	Non-VER	

	2018	**2,741**	**993**	**1,304**		**846**	**600**	**847**	**147**	**704**
	2019	**2,750**	**1,168**	**1,304**		**936**	**600**	**847**	**233**	**704**

Year	Date	Wind	Solar	Non-VER	PACE Solar	PACE Non-VER	PACW Wind	PACW Solar	PACW Non-VER
2018	1/1/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/2/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/3/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/4/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/5/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/6/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/7/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/8/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/9/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/10/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/11/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/12/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/13/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/14/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/15/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/16/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/17/2018	2549.95	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/18/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/19/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/20/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/21/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/22/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/23/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/24/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/25/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/26/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/27/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/28/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/29/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/30/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	1/31/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/1/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/2/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/3/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/4/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/5/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/6/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/7/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/8/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/9/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/10/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4

2018	2/11/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/12/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/13/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/14/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/15/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/16/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/17/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/18/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/19/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/20/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/21/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/22/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/23/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/24/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/25/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/26/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/27/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	2/28/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/1/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/2/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/3/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/4/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/5/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/6/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/7/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/8/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/9/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/10/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/11/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/12/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/13/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/14/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/15/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/16/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/17/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/18/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/19/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/20/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/21/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/22/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/23/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/24/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/25/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/26/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/27/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/28/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/29/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/30/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	3/31/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/1/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/2/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/3/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/4/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/5/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/6/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/7/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/8/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/9/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/10/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/11/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/12/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/13/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4

2018	4/14/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/15/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/16/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/17/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/18/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/19/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/20/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/21/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/22/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/23/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/24/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/25/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/26/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/27/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/28/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/29/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	4/30/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	5/1/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	5/2/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	5/3/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	5/4/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	5/5/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	5/6/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	5/7/2018	2750.15	936.8	1304.25	846	599.85	847.45	90.8	704.4
2018	5/8/2018	2750.15	1012.5	1304.25	846	599.85	847.45	166.5	704.4
2018	5/9/2018	2750.15	1012.5	1304.25	846	599.85	847.45	166.5	704.4
2018	5/10/2018	2750.15	1012.5	1304.25	846	599.85	847.45	166.5	704.4
2018	5/11/2018	2750.15	1012.5	1304.25	846	599.85	847.45	166.5	704.4
2018	5/12/2018	2750.15	1012.5	1304.25	846	599.85	847.45	166.5	704.4
2018	5/13/2018	2750.15	1012.5	1304.25	846	599.85	847.45	166.5	704.4
2018	5/14/2018	2750.15	1012.5	1304.25	846	599.85	847.45	166.5	704.4
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2018	11/22/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	11/23/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	11/24/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	11/25/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	11/26/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	11/27/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	11/28/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	11/29/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	11/30/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/1/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/2/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/3/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/4/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/5/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/6/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/7/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/8/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/9/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/10/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/11/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/12/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/13/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/14/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/15/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/16/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/17/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4

2018	12/18/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/19/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/20/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/21/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/22/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/23/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/24/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/25/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/26/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/27/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/28/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/29/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/30/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2018	12/31/2018	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/1/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/2/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/3/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/4/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/5/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/6/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/7/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/8/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/9/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/10/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/11/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/12/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/13/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/14/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/15/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/16/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/17/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/18/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/19/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/20/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/21/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/22/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/23/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/24/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/25/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/26/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/27/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/28/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/29/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/30/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	1/31/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/1/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/2/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/3/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/4/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/5/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/6/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/7/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/8/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/9/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/10/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/11/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/12/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/13/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/14/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/15/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/16/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/17/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4

2019	2/18/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/19/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/20/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/21/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/22/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/23/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/24/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/25/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/26/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/27/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	2/28/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/1/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/2/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/3/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/4/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/5/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/6/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/7/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/8/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/9/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/10/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/11/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/12/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/13/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/14/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/15/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/16/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/17/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/18/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/19/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/20/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/21/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/22/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/23/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/24/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/25/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/26/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/27/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/28/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/29/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/30/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	3/31/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	4/1/2019	2750.15	1050.5	1304.25	846	599.85	847.45	204.5	704.4
2019	4/2/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/3/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/4/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/5/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/6/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/7/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/8/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/9/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/10/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/11/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/12/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/13/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/14/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/15/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/16/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/17/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/18/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/19/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/20/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4

2019	4/21/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/22/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/23/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/24/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/25/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/26/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/27/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/28/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/29/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	4/30/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/1/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/2/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/3/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/4/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/5/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/6/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/7/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/8/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/9/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/10/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/11/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/12/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/13/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/14/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/15/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/16/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/17/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/18/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/19/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/20/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/21/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/22/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/23/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/24/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/25/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/26/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/27/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/28/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/29/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/30/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	5/31/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/1/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/2/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/3/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/4/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/5/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/6/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/7/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/8/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/9/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/10/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/11/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/12/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/13/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/14/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/15/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/16/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/17/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/18/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/19/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/20/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/21/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4

2019	6/22/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/23/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/24/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/25/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/26/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/27/2019	2750.15	1149.8	1304.25	926	599.85	847.45	223.8	704.4
2019	6/28/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	6/29/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	6/30/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/1/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/2/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/3/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/4/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/5/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/6/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/7/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/8/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/9/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/10/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/11/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/12/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/13/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/14/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/15/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/16/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/17/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/18/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/19/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/20/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/21/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/22/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/23/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/24/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/25/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/26/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/27/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/28/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/29/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/30/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	7/31/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/1/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/2/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/3/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/4/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/5/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/6/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/7/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/8/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/9/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/10/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/11/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/12/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/13/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/14/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/15/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/16/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/17/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/18/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/19/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/20/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/21/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/22/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4

2019	8/23/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/24/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/25/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/26/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/27/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/28/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/29/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/30/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	8/31/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/1/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/2/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/3/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/4/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/5/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/6/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/7/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/8/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/9/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/10/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/11/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/12/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/13/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/14/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/15/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/16/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/17/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/18/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/19/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/20/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/21/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/22/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/23/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/24/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/25/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/26/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/27/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/28/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/29/2019	2750.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	9/30/2019	2513.15	1207.4	1304.25	983.6	599.85	847.45	223.8	704.4
2019	10/1/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/2/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/3/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/4/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/5/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/6/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/7/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/8/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/9/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/10/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/11/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/12/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/13/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/14/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/15/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/16/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/17/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/18/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/19/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/20/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/21/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/22/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/23/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4

2019	10/24/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/25/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/26/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/27/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/28/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/29/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/30/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	10/31/2019	2750.15	1254.65	1304.25	983.6	599.85	847.45	271.05	704.4
2019	11/1/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/2/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/3/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/4/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/5/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/6/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/7/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/8/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/9/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/10/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/11/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/12/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/13/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/14/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/15/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/16/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/17/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/18/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/19/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/20/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/21/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/22/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/23/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/24/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/25/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/26/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/27/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/28/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/29/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	11/30/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/1/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/2/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/3/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/4/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/5/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/6/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/7/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/8/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/9/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/10/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/11/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/12/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/13/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/14/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/15/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/16/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/17/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/18/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/19/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/20/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/21/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/22/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/23/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/24/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4

2019	12/25/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/26/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/27/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/28/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/29/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/30/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4
2019	12/31/2019	2750.15	1264.65	1304.25	983.6	599.85	847.45	281.05	704.4

	Shaded cells are inputs	Reference (FERC Form 1 reference, attachment, or instruction)	2019 true-up 2019 Form 1 data true-up	Production FCR Notes
	Allocators			
	Wages & Salary Allocation Factor			
1	**Production** Wages Expense	354.20b	143,501,344	2019 value
2	Total Wages Expense	354.28b	362,000,992	2019 True-Up value
3	Less A&G Wages Expense	354.27b	42,795,683	2019 True-Up value
4	Total Wages Less A&G Wages Expense	(Line 2 - Line 3)	319,205,309	
5	**Wages & Salary Allocator**	(Line 1 / Line 4)	**44.9558%**	
	Plant Allocation Factors			
6	Electric Plant in Service	Attachment 5	28,268,028,991	Production-specific data - see attachment
7	Accumulated Depreciation (Total Electric Plant)	Attachment 5	10,105,063,657	Adjusted - see attachment
8	Accumulated Amortization	Attachment 5	633,756,885	2018 True-Up value
9	Total Accumulated Depreciation	(Line 7 + 8)	10,738,820,542	
10	Net Plant	(Line 6 - Line 9)	17,529,208,449	
11	**Production** Gross Plant (excluding Land Held for Future Use)	(Line 24 - Line 23)	13,435,566,407	
12	**Gross Plant Allocator (Production)**	(Line 11 / Line 6)	**47.5292%**	
13	**Production** Net Plant (excluding Land Held for Future Use)	(Line 32 - Line 23)	8,012,465,388	
14	**Net Plant Allocator**	(Line 13 / Line 10)	**45.7092%**	
	Plant Calculations			
	Plant In Service			
15	**Production** Plant In Service	Attachment 5	12,413,183,383	Production-specific data - see attachment
16	New Plant Additions for Current Calendar Year (weighted by months in service)		0	Applies only to projected rates
17	**Total Production Plant**	(Line 15 + Line 16)	**12,413,183,383**	
18	General Plant	Attachment 5	1,281,037,939	Adjusted - see attachment
19	Intangible Plant	Attachment 5	993,157,408	2018 True-Up value
20	Total General and Intangible Plant	(Line 18 + Line 19)	2,274,195,348	
21	Wage & Salary Allocator	(Line 5)	44.9558%	
22	General and Intangible Allocated to **Production**	(Line 20 * Line 21)	1,022,383,024	
23	**Plant/Land Held for Future Use - Production**	Attachment 5	**8,923,301**	Production-specific data - see attachment
24	**Total Plant In Rate Base (Production)**	(Line 17 + Line 22 + Line 23)	**13,444,489,708**	
	Accumulated Depreciation and Amortization			
25	**Production** Accumulated Depreciation (less buy downs)	Attachment 5	**4,918,697,425**	Production-specific data - see attachment
26	Accumulated General Depreciation	Attachment 5	488,241,699	Adjusted - see attachment
27	Accumulated Amortization	(Line 8)	633,756,885	2019 True-Up value
28	Accumulated General and Intangible Depreciation	(Line 26 + 27)	1,121,998,584	
29	Wage & Salary Allocator	(Line 5)	44.9558%	
30	Subtotal General and Intangible Accum. Depreciation Allocated to **Production**	(Line 28 * Line 29)	504,403,593	
31	**Total Accumulated Depreciation and Amortization**	(Line 25 + Line 30)	**5,423,101,019**	
32	**Total Net Property, Plant & Equipment**	(Line 24 - Line 31)	**8,021,388,689**	

	Shaded cells are inputs	Reference (FERC Form 1 reference, attachment, or instruction)	2019 true-up 2019 Form 1 data true-up	Production FCR Notes
	Adjustments To Rate Base			
	Accumulated Deferred Income Taxes			
33	ADIT net of FASB 106 and 109	Attachment 1A	**(1,335,421,331)**	Production-specific data - see attachment
33b	**Excess or Deficient ADIT Average Balance - Adjustment to Rate Base**	Attachment 1B	**(708,970,955)**	
	CWIP for Incentive Projects			
34	CWIP Balances for Current Rate Year	Attachment 6	**0**	Consistent with Transmission Formula treatment
	ITC Adjustment			
35	IRC 46(f)1 adjustment	Attachment 5	**(135,882)**	Production-specific data - see attachment
	Unfunded Reserves			
36	Unfunded Reserves	Attachment 16	**(82,062,312)**	Production-specific data - see attachment
	Prepayments			
37	Prepayments	Attachment 11	**16,921,236**	Production-specific data - see attachment
	Abandoned Plant			
38	Unamortized Abandoned Plant		0	Consistent with Transmission Formula treatment
	Materials and Supplies			
39	Undistributed Stores Expense	Attachment 5	0	Consistent with Transmission Formula treatment
40	Wage & Salary Allocator	(Line 5)	44.9558%	
41	Total Undistributed Stores Expense Allocated to **Production**	(Line 39 * Line 40)	0	
42	Construction Materials & Supplies	Attachment 5	161,872,917	Production-specific data - see attachment
43	Wage & Salary Allocator	(Line 5)	44.9558%	
44	Construction Materials & Supplies Allocated to **Production**	(Line 42 * Line 43)	72,771,287	
45	Production Materials & Supplies	Attachment 5	**65,383,871**	Production-specific data - see attachment
46	**Total Materials & Supplies Allocated to Production**	(Line 41 + Line 44 + Line 45)	**138,155,157**	
	Cash Working Capital			
47	Operation & Maintenance Expense	(Line 75)	95,119,212	
48	1/8th Rule	Zero	0.0%	
49	**Total Cash Working Capital Allocated to Production**	(Line 47 * Line 48)	**0**	Consistent with Transmission Formula treatment
	Network Upgrade Balance			
50	Network Upgrade Balance	Attachment 5	**0**	Transmission-Formula-only item; production value is zero
51	**Total Adjustment to Rate Base**	(Lines 33 + 33b+34 + 35 + 36 + 37 + 38 + 46 + 49 + 50)	**(1,971,514,086)**	
52	**Rate Base**	(Line 32 + Line 51)	**6,049,874,603**	

	Shaded cells are inputs	Reference (FERC Form 1 reference, attachment, or instruction)	2019 true-up 2019 Form 1 data true-up	Production FCR Notes
	Operations & Maintenance Expense			
	Production O&M			
53	**Production** O&M	Attachment 5	**44,593,260**	Lines 53-56: Annual cost for ancillary services only includes O&M fixed production expenses (with the exception of FERC 557). These are calculated separately in Attachment B, page1, of the Exhibit No. PAC-17.
54	Less: Cost of Providing Ancillary Services Accounts 561.0-5	Attachment 5	0	
55	Less: Account 565	Attachment 5	0	
56	**Production O&M**	(Lines 53 - 55)	**44,593,260**	
	Allocated Administrative & General Expenses			
57	Total A&G	323.197b	115,628,648	2019 True-Up value
58	Less Actual PBOP Expense Adjustment	Attachment 5	0	Consistent with Transmission Formula treatment
59	Less Property Insurance Account 924	323.185b	4,737,084	2019 True-Up value
60	Less Regulatory Asset Amortizations Account 930.2	Attachment 5	0	2019 True-Up value
61	Less Regulatory Commission Exp Account 928 - FERC	Attachment 5	8,609,543	Adjusted - see attachment. Adjustment to remove (non production) FERC regulatory expenses reported in FERC Form No.1, page 350.
62	Less General Advertising Exp Account 930.1	323.191b	55,028	2019 True-Up value
63	Less Membership Dues	Attachment 5	758,638	Production specific value
64	Administrative & General Expenses	(Line 57 - Sum (Lines 58 to 63))	101,468,355	
65	Wage & Salary Allocator	(Line 5)	44.9558%	
66	**Administrative & General Expenses Allocated to Production**	(Line 64 * Line 65)	**45,615,925**	
	Directly Assigned A&G			
67	Regulatory Commission Exp Account 928	Attachment 5	2,658,529	Production-specific data - no items assigned to production
68	General Advertising Exp Account 930.1 - Safety-related Advertising	Attachment 5	0	Production-specific data - see attachment
69	**Subtotal - Accounts 928 and 930.1 - Production Related**	(Line 67 + Line 68)	**2,658,529**	
70	Property Insurance Account 924	Attachment 5	4,737,084	Production-specific data - Adjustment includes only property insurance premiums. Property insurance storm damage expenses (FERC 924.0-924.2) are not included as those damages primarily occur in transmission and distribution functions.
71	General Advertising Exp Account 930.1 - Education and Outreach	Attachment 5	0	Production-specific data - see attachment
72	Total Accounts 924 and 930.1 - General	(Line 70 + Line 71)	4,737,084	
73	Gross Plant Allocator	(Line 12)	47.5292%	
74	**A&G Directly Assigned to Production**	(Line 72 * Line 73)	**2,251,498**	
75	**Total Production O&M**	(Lines 56 + 66 + 69 + 74)	**95,119,212**	
	Depreciation & Amortization Expense			
	Depreciation Expense			
76	**Production** Depreciation Expense Including Amortization of Limited Term Plant	Attachment 5	**438,485,946**	Production-specific data - see attachment
77	General Depreciation Expense Including Amortization of Limited Term Plant	Attachment 5	43,110,635	2019 True-Up value
78	Intangible Amortization	Attachment 5	48,671,914	2019 True-Up value
79	Total	(Line 77 + Line 78)	91,782,549	
80	Wage & Salary Allocator	(Line 5)	44.9558%	
81	**General Depreciation and Intangible Amortization Functionalized to Production**	(Line 79 * Line 80)	**41,261,592**	
82	Abandoned Plant Amortization		0	Transmission-Formula-only item; production value is zero
83	**Total Production Depreciation & Amortization**	(Lines 76 + 81 + 82)	**479,747,538**	

	Shaded cells are inputs	Reference (FERC Form 1 reference, attachment, or instruction)		2019 true-up 2019 Form 1 data true-up	Production FCR Notes
Taxes Other Than Income					
84	**Taxes Other than Income Taxes**	Attachment 2		**68,045,665**	Production-specific data - see attachment
85	**Total Taxes Other than Income Taxes**	(Line 84)		**68,045,665**	
Return \ Capitalization Calculations					
	Long-Term Debt				
86	Account 221 Bonds	Attachment 14		7,451,428,846	2019 True-Up value
87	Less Account 222 Reacquired Bonds	Attachment 14		0	2019 True-Up value
88	Account 223 Long-term Advances from Associated Cos.	Attachment 14		0	2019 True-Up value
89	Account 224 Other Long-term Debt	Attachment 14		0	2019 True-Up value
90	**Gross Proceeds Outstanding Long-term Debt**	Sum Lines 86 through 89		**7,451,428,846**	
91	Less Account 226 Unamortized Discount	Attachment 14		13,080,345	2019 True-Up value
92	Less Account 181 Unamortized Debt Expense	Attachment 14		33,427,807	2019 True-Up value
93	Less Account 189 Unamortized Loss on Reacquired Debt	Attachment 14		4,262,741	2019 True-Up value
94	Plus Account 225 Unamortized Premium	Attachment 14		30,509	2019 True-Up value
95	Plus Account 257 Unamortized Gain on Reacquired Debt	Attachment 14		0	2019 True-Up value
96	**Net Proceeds Long Term Debt**	Sum Lines 90 through 95		**7,400,688,463**	
	Long Term Debt Cost				
97	Accounts 427 and 430 Long Term Interest Expense	Attachment 14		369,853,259	2019 True-Up value
98	Less Hedging Expense	Attachment 14		0	2019 True-Up value
99	Account 428 Amortized Debt Discount and Expense	Attachment 14		3,892,240	2019 True-Up value
100	Account 428.1 Amortized Loss on Reacquired Debt	Attachment 14		583,695	2019 True-Up value
101	Less Account 429 Amortized Premium	Attachment 14		11,026	2019 True-Up value
102	Less Account 429.1 Amortized Gain on Reacquired Debt	Attachment 14		0	2019 True-Up value
103	**Total Long Term Debt Cost**	Sum Lines 97 through 102		**374,318,168**	
	Preferred Stock and Dividend				
104	Account 204 Preferred Stock Issued	Attachment 14		2,397,600	2019 True-Up value
105	Less Account 217 Reacquired Capital Stock (preferred)	Attachment 14		0	2019 True-Up value
106	Account 207 Premium on Preferred Stock	Attachment 14		0	2019 True-Up value
107	Account 207-208 Other Paid-In Capital (preferred)	Attachment 14		0	2019 True-Up value
108	Less Account 213 Discount on Capital Stock (preferred)	Attachment 14		0	2019 True-Up value
109	Less Account 214 Capital Stock Expense (preferred)	Attachment 14		0	2019 True-Up value
110	**Total Preferred Stock**	Sum Lines 104 through 109		**2,397,600**	
111	**Preferred Dividend**	Attachment 14	(Enter positive)	**161,902**	2019 True-Up value
	Common Stock				
112	Proprietary Capital	Attachment 14		8,083,782,146	2019 True-Up value
113	Less: Total Preferred Stock	(Line 110)		2,397,600	2019 True-Up value
114	Less: Account 216.1 Unappropriated Undistributed Subsidiary Earnings	Attachment 14		117,471,234	2019 True-Up value
115	Less: Account 219	Attachment 14		(12,642,903)	2019 True-Up value
116	**Total Common Stock**	Sum Lines 112 through 115		**7,976,556,215**	

	Shaded cells are inputs		Reference (FERC Form 1 reference, attachment, or instruction)	2019 true-up 2019 Form 1 data true-up	Production FCR Notes
117	Debt percent	Total Long Term Debt	(Line 90 / (Lines 90 + 110 +116))	48.29%	
118	Preferred percent	Preferred Stock	(Line 110 / (Lines 90 + 110 +116))	0.02%	
119	Common percent	Common Stock	(Line 116 / (Lines 90 + 110 +116))	51.69%	
120	Debt Cost	Long Term Debt Cost = Long Term Debt Cost / Net Proceeds Long Term Debt	(Line 103 / Line 96)	5.06%	
121	Preferred Cost	Preferred Stock cost = Preferred Dividends / Total Preferred Stock	(Line 111 / Line 110)	6.75%	
122	Common Cost	Common Stock	Fixed	9.80%	2019 True-Up value
123	Weighted Cost of Debt	Total Long Term Debt (WCLTD)	(Line 117 * Line 120)	2.44%	
124	Weighted Cost of Preferred	Preferred Stock	(Line 118 * Line 121)	0.00%	
125	Weighted Cost of Common	Common Stock	(Line 119 * Line 122)	5.07%	
126	**Rate of Return on Rate Base (ROR)**		(Sum Lines 123 to 125)	**7.5095%**	
127	**Investment Return = Rate Base * Rate of Return**		(Line 52 * Line 126)	**454,317,052**	
	Composite Income Taxes				
	Income Tax Rates				
128	FIT = Federal Income Tax Rate			21.00%	2019 True-Up value
129	SIT = State Income Tax Rate or Composite		Attachment 5	4.54%	2019 True-Up value
130	p	(percent of federal income tax deductible for state purposes)	Per state tax code	0.00%	2019 True-Up value
131	T	T = 1 - {[(1 - SIT) * (1 - FIT)] / (1 - SIT * FIT * p)} =		24.587%	
132	T / (1-T)			32.602%	
	ITC Adjustment				
133	Amortized Investment Tax Credit - **Production** Related		Attachment 5	(1,251,850)	Adjusted - see attachment
134	**ITC Adjust. Allocated to Production - Grossed Up**	ITC Adjustment x 1 / (1-T)	Line 133 * (1 / (1 - Line 131))	**(1,659,983)**	
134b	Tax Impact of AFUDC Equity Permanent Difference		Attachment 5	3,651,318	
134c	1/(1-T)			132.60%	
134d	**Tax Impact of AFUDC Equity Permanent Grossed Up**	AFUDC Equity Permanent Difference * 1/ (1-T)	Line 134b * Line 134c	**4,841,736**	
135	**Income Tax Component =**	(T/1-T) * Investment Return * (1-(WCLTD/ROR)) =	[Line 132 * Line 127 * (1- (Line 123 / Line 126))]	**99,942,700**	
135b	Excess or Deficient ADIT Amortization		Attachment 1B	(44,683,765)	
135c	1/(1-T)			132.60%	
135d	Grossed up Excess or Deficient ADIT Amortization	Excess or Deficient ADIT Amortization Adjustment * 1 (1-T)	Line 135b * Line 135c	**(59,251,757)**	
136	**Total Income Taxes**		(Line 134 + Line 134d + Line 135+ Line 135d)	**43,872,696**	

	Shaded cells are inputs	Reference (FERC Form 1 reference, attachment, or instruction)	2019 true-up 2019 Form 1 data true-up	Production FCR Notes
Revenue Requirement				
	Summary			
137	Net Property, Plant & Equipment - **Production**	(Line 32)	8,021,388,689	
138	Total Adjustment to Rate Base - **Production**	(Line 51)	(1,971,514,086)	
139	Rate Base	(Line 52)	6,049,874,603	
140	Total **Production** O&M expenses	(Line 75)	95,119,212	
141	Total **Production** Depreciation & Amortization	(Line 83)	479,747,538	
142	Taxes Other than Income allocated to **Production**	(Line 85)	68,045,665	
143	Investment Return	(Line 127)	454,317,052	
144	Income Taxes	(Line 136)	43,872,696	
145	**Gross Revenue Requirement**	(Sum Lines 140 to 144)	**1,141,102,162**	
	Adjustment to Remove Revenue Requirements Associated with Excluded Production Facilities			
146	**Production** Plant In Service	(Line 15)	12,413,183,383	
147	Excluded Facilities	Attachment 15	0	Transmission-Formula-only item; production value is zero. This adjustment represents the value of GSU and Associated equipment excluded from Transmission facilities in the Formula rate.
148	Included **Production** Facilities	(Line 146 - Line 147)	12,413,183,383	
149	Inclusion Ratio	(Line 148 / Line 146)	100.00%	
150	Gross Revenue Requirement	(Line 145)	1,141,102,162	
151	**Adjusted Gross Revenue Requirement**	(Line 149 * Line 150)	**1,141,102,162**	
	Revenue Credits			
152	**Revenue Credits**	Attachment 3	**1,613,383**	Production-specific data - see attachment
153	**Net Revenue Requirement**	(Line 151 - Line 152)	**1,139,488,779**	
	Net Plant Carrying Charge			
154	Net Revenue Requirement	(Line 150)	1,139,488,779	
155	Net Production Plant	(Line 17 - Line 25 + Line 34)	7,494,485,958	
156	Net Plant Carrying Charge without O&M **(Production Fixed Charge Rate)**	(Line 154 / Line 155)	15.2044%	
157	Net Plant Carrying Charge without O&M and Depreciation	(Line 154 - Line 76) / Line 155	9.3536%	
158	Net Plant Carrying Charge without O&M Depreciation, Return, nor Income Taxes	(Line 154 - Line 76 - Line 127 - Line 136) / Line 155	2.7062%	

Description	Reference	Total Company	Dist. or Other	Production Related	Transmission Related	Plant Related	Labor Related	Total Production ADIT
(A)	(B)				(C)	(D)	(E)	(F)
ADIT-282	Sch. 282 Below	(4,040,256,110)	(1,837,024,036)	(1,322,966,782)	(741,013,526)	22,466,833	(161,718,599)	
ADIT-281	Sch. 281 Below	(180,339,430)	(180,339,430)	0	0	0	0	
ADIT-283	Sch. 283 Below	(285,780,597)	(278,136,048)	(272,714)	0	(6,842,227)	(529,608)	
ADIT-190	Sch. 190 Below	443,224,621	344,394,814	3,286,302	574,232	56,600,694	38,368,579	
Subtotal ADIT	Sum (Lines 1 to 4)	(4,063,151,516)	(1,951,104,700)	(1,319,953,194)	(740,439,294)	72,225,300	(123,879,628)	
Allocator (100% Production, 0% Transmission; Net Plant; Wages & Salary)	Attachment A		0.0000%	100.0000%	0.0000%	45.7092%	44.9558%	
Sub-total Production Related ADIT	Line 5 * Allocator		0	(1,319,953,194)	0	33,013,625	(55,691,095)	
Total Production ADIT							Attachment 1a input -->	(1,342,630,664)
			(63,410,871)	78,685,959				

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately.

Schedule ADIT-190

	A		B	C	D	E	F	G	H
Description	Form 1 Reference		Total Company	Gas, Prod, Dist Or Other Related	Production Related	Transmission Related	Plant Related	Labor Related	Justification
Account 190									
Employee Benefits									
287414	505.414	Accrued Retention Bonus	477,822	0	0	0	0	477,822	The amounts recorded in this account represent retention bonuses accrued for various employees.
287220	720.560	Pension	28,303,872	28,303,872	0	0	0	0	Regulatory liability established to record a pension liability for the Energy West Mining UMWA pension trust withdrawal obligation.
287300	920.182	LTIP - non current	5,102,064	0	0	0	0	5,102,064	Regulatory liability established to record the long-term portion of the BHE incentive plan liability related to PacifiCorp employees.
287323	505.400	Bonus Liab. Elec. - Cash Basis (2.5 mos)	34,404	0	0	0	0	34,404	Accrued expenses recorded for book purposes under PacifiCorp's Annual Incentive Plan (AIP), 401(k) match of AIP, payroll tax (employer portion), and LTI.
287324	720.200	Deferred Comp. Accrual	2,116,778	0	0	0	0	2,116,778	Non-qualified deferred compensation plan under IRC Subsection 409A.
287326	720.500	Severance Accrual - Cash Basis	326,417	0	0	0	0	326,417	Severance accruals related to regular employment downsizing. Amounts contained in these accounts represent accruals for both departing executives and rank and file employees.
287327	720.300	Pension/Retirement Accrual	415,630	415,630	0	0	0	0	Accrued retiree payment obligations outside of the regular PacifiCorp retirement plan, most constituting payments made above the IRC Subsection 415 limitations.
287332	505.600	Vacation Accrual-Cash Basis (2.5 mos)	6,431,421	0	0	0	0	6,431,421	Accruals recorded for book purposes for unused vacation and sick leave due to employees in future periods or upon termination.
287373	910.580	Wasach workers comp reserve	654,818	0	0	0	0	654,818	Accrued liability for the expected claims related to workers compensation previously held by Wasatch Crest. PacifiCorp holds this liability due to the insolvency of Wasatch Crest.
287399	920.150	FAS 112 Book Reserve - Post	6,381,362	0	0	0	0	6,381,362	Accrued liability for worker's compensation benefits pursuant to FASB Statement No. 112.
287447	720.830	Western Coal Carr Ret Med Accrual	2,576,430	0	0	0	0	2,576,430	Accrued post-retirement liabilityies pursuant to FASB Statement No. 106 for Western Coal Carriers, a third-party carrier service that contracted with PacifiCorp to haul coal from the Trail Mountain Mine to the Hunter plant.
287460	720.800	FAS 158 Pension Liability	27,208,050	27,208,050	0	0		0	Total unfunded pension liability as required under FAS 158.
287461	720.810	FAS 158 Post-Retirement Liability	1,071,390	1,071,390	0	0	0	0	Total unfunded Other Post-Employment Benefit Obligation (OPEB) liability as required under FAS 158.
287462	720.820	FAS 158 SERP Liability	12,970,711	0	0	0	0	12,970,711	Total Supplemental Executive Retirement Plan (SERP) obligations, as required by FAS 158.
FAS 133 Derivatives:									
287336	730.120	FAS 133 Derivatives - Book	24,031,255	24,031,255	0	0	0	0	Unrealized derivative gains and losses under FASB Statement No. 133 which requires that certain financial instruments be valued at FMV for book purposes.
287249	415.839	NonCurr Liab - Frozen MTM	21,154,826	21,154,826	0	0	0	0	Reclass non-current liability from derivative regulatory liability to an other regulatory liability for frozen derivative.

Regulatory Liabilities:									
287051	705.340	RL Income Tax Deferral - CA	786,756	786,756	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. The law becomes effective for taxable years beginning after December 31, 2017. As a result of the change in law, the revenue requirement was recalculated by using the new income tax rate and the reduced revenue requirement will be given back to customers.
287052	705.431	RL Income Tax Deferral - ID	136,624	136,624	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. The law becomes effective for taxable years beginning after December 31, 2017. As a result of the change in law, the revenue requirement was recalculated by using the new income tax rate and the reduced revenue requirement will be given back to customers.
287053	705.342	RL Income Tax Deferral - OR	11,938,085	11,938,085	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. The law becomes effective for taxable years beginning after December 31, 2017. As a result of the change in law, the revenue requirement was recalculated by using the new income tax rate and the reduced revenue requirement will be given back to customers.
287054	705.343	RL Income Tax Deferral - UT	129,816	129,816	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. The law becomes effective for taxable years beginning after December 31, 2017. As a result of the change in law, the revenue requirement was recalculated by using the new income tax rate and the reduced revenue requirement will be given back to customers.
287055	705.344	RL Income Tax Deferral - WA	2,090,530	2,090,530	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. The law becomes effective for taxable years beginning after December 31, 2017. As a result of the change in law, the revenue requirement was recalculated by using the new income tax rate and the reduced revenue requirement will be given back to customers.
287056	705.345	RL Income Tax Deferral - WY	1,721,600	1,721,600	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. The law becomes effective for taxable years beginning after December 31, 2017. As a result of the change in law, the revenue requirement was recalculated by using the new income tax rate and the reduced revenue requirement will be given back to customers.
287061	705.346	CA - Protected PP&E ARAM	217,738	217,738	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. The law becomes effective for taxable years beginning after December 31, 2017. As a result of the change in tax rate, excess deferred income taxes related to protected property are required to be amortized via the Average Rate Assumption Method, or ARAM. Protected property differences are considered method/life depreciation differences on public utility property. ARAM amortization for protected property began on January 1, 2018 and is calculated by the PowerTax Fixed Assets software.
287062	705.347	ID - Protected PP&E ARAM	638,875	638,875	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. The law becomes effective for taxable years beginning after December 31, 2017. As a result of the change in tax rate, excess deferred income taxes related to protected property are required to be amortized via the Average Rate Assumption Method, or ARAM. Protected property differences are considered method/life depreciation differences on public utility property. ARAM amortization for protected property began on January 1, 2018 and is calculated by the PowerTax Fixed Assets software.
287063	705.348	OR - Protected PP&E ARAM	2,567,965	2,567,965	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. The law becomes effective for taxable years beginning after December 31, 2017. As a result of the change in tax rate, excess deferred income taxes related to protected property are required to be amortized via the Average Rate Assumption Method, or ARAM. Protected property differences are considered method/life depreciation differences on public utility property. ARAM amortization for protected property began on January 1, 2018 and is calculated by the PowerTax Fixed Assets software.
287064	705.349	UT - Protected PP&E ARAM	4,473,319	4,473,319	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. The law becomes effective for taxable years beginning after December 31, 2017. As a result of the change in tax rate, excess deferred income taxes related to protected property are required to be amortized via the Average Rate Assumption Method, or ARAM. Protected property differences are considered method/life depreciation differences on public utility property. ARAM amortization for protected property began on January 1, 2018 and is calculated by the PowerTax Fixed Assets software.

287065	705.350	WA - Protected PP&E ARAM	669,635	669,635	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. The law becomes effective for taxable years beginning after December 31, 2017. As a result of the change in tax rate, excess deferred income taxes related to protected property are required to be amortized via the Average Rate Assumption Method, or ARAM. Protected property differences are considered method/life depreciation differences on public utility property. ARAM amortization for protected property began on January 1, 2018 and is calculated by the PowerTax Fixed Assets software.
287066	705.351	WY - Protected PP&E ARAM	1,430,370	1,430,370	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. The law becomes effective for taxable years beginning after December 31, 2017. As a result of the change in tax rate, excess deferred income taxes related to protected property are required to be amortized via the Average Rate Assumption Method, or ARAM. Protected property differences are considered method/life depreciation differences on public utility property. ARAM amortization for protected property began on January 1, 2018 and is calculated by the PowerTax Fixed Assets software.
287184	705.605	RL OR Clean Fuels Program	119,860	119,860	0	0	0	0	As ordered by the Oregon Public Utility Commission (OPUC), PacifiCorp registered as an aggregator of residential Clean Fuels Program credits generated by customers in our Oregon service area. As an aggregator, PacifiCorp is allocated credits generated by residential customers who own electric cars on an annual basis by the Oregon Department of Environmental Quality (DEQ). PacifiCorp may then sell the credits to “regulated parties” that are required to comply with the regulations of the Clean Fuels Program through the purchase of such credits, in a manner that is consistent with the monetization principles adopted by the OPUC in December of 2017. Regulatory Liability Account 288190 was set up in 2018 for sales of credits to regulated parties.
287186	- - - - -	RL Non Protected PP&E EDIT - Gross Up	56,455,524	56,455,524	0	0	0	0	Gross Up of Nonprotected PP&E EDIT
287188	100.121	RL Income Tax Property Flowthru	365,813,273	365,813,273	0	0	0	0	The cash received by PacifiCorp for the sale of the credits will be used to fund programs consistent with the following six principles adopted by the OPUC: (1) support the goal of electrifying Oregon’s transportation sectors, (2) provide majority of benefits to residential customers, (3) provide benefits to traditionally underserved communities, (4) programs are designed to be independent from ratepayer support, (5) programs are developed collaboratively and transparently, and (6) maximize use of funds for implementation of programs. Revenue is to be recorded as “other revenue” using SAP Account 353001, OR Clean Fuel Credits Revenue. Amortization expense for program costs incurred for Oregon Clean Fuels program (offset in Clean Fuel Credits Revenue) is to be recorded to SAP Account 553475, OR Clean Fuel Program Amortz Expense.
287190	100.122	RL Income Tax Property Flowthru - PMI	2,488,577	2,488,577	0	0	0	0	A regulatory liability with respect to the excess deferred income taxes associated with property accumulated deferred income taxes, the effects of flow through from PP&E book/tax differences and other deferred items that do not have current provision impacts.
287191	705.280	RL Excess Deferred Income Taxes - CA	272,759	272,759	0	0	0	0	A regulatory liability established with respect to the excess deferred income taxes associated with the non-property accumulated deferred income taxes allocable to California resulting from the change in the income tax rate.
287192	705.281	RL Excess Deferred Income Taxes - ID	396,045	396,045	0	0	0	0	A regulatory liability established with respect to the excess deferred income taxes associated with the non-property accumulated deferred income taxes allocable to Idaho resulting from the change in the income tax rate.
287193	705.282	RL Excess Deferred Income Taxes - OR	3,876,975	3,876,975	0	0	0	0	A regulatory liability established with respect to the excess deferred income taxes associated with the non-property accumulated deferred income taxes allocable to Oregon resulting from the change in the income tax rate.
287194	705.283	RL Excess Deferred Income Taxes - UT	0	0	0	0	0	0	A regulatory liability established with respect to the excess deferred income taxes associated with the non-property accumulated deferred income taxes allocable to Utah resulting from the change in the income tax rate.
287195	705.284	RL Excess Deferred Income Taxes - WA	326,187	326,187	0	0	0	0	A regulatory liability established with respect to the excess deferred income taxes associated with the non-property accumulated deferred income taxes allocable to Washington resulting from the change in the income tax rate.
287196	705.285	RL Excess Deferred Income Taxes - WY	2,939,674	2,939,674	0	0	0	0	A regulatory liability established with respect to the excess deferred income taxes associated with the non-property accumulated deferred income taxes allocable to Wyoming resulting from the change in the income tax rate.
287197	705.286	RL Excess Deferred Income Taxes - FERC	4,334	4,334	0	0	0	0	A regulatory liability established with respect to the excess deferred income taxes associated with the non-property accumulated deferred income taxes resulting from the change in the income tax rate.
287198	320.279	RL FAS 158 Post-Retirement	0	0	0	0	0	0	A regulatory liability used to track future revenue associated with recoverable post-retirement welfare expenses.

287200	705.267	RL WA Decoupling Mechanism	816,792	816,792	0	0	0	0	A regulatory liability with respect to the Washington decoupling mechanism.
287206	415.710	RL - WA Accelerated Depreciation	6,646,837	6,646,837	0	0	0	0	Regulatory Liability established to record difference between the approved accelerated depreciation in the 2015 WA GRC and the current depreciation amounts from the last depreciation study for all units at the Jim Bridger Plant and Colstrip Unit 4.
287209	705.266	RL - Energy Savings Assistance (ESA) - CA	107,017	107,017	0	0	0	0	Regulatory Liability established to record Energy Savings Assistance (ESA) Program activities (ESA collections from California offset by ESA program expenditures incurred) in a regulatory liability balancing account for California.
287212	705.245	RL - OR Direct Access 5 Yr Opt out	893,442	893,442	0	0	0	0	Regulatory Liability established per Order No. 15-060 in Docket UE267, PacifiCorp is required to implement a 5 year customer opt-out plan. Customers that elect to go on the opt-out program and leave PacifiCorp's
287213	425.381	RL - BPA Balance Act - ID	826,933	826,933	0	0	0	0	Regulatory liability established as a balancing account for a pass-through benefit to Idaho customers from BPA (Bonneville Power Administration) under the Northwest Power Act where qualifying customers receive a credit to their bill.
287225	605.103	ARO/Reg Diff - Trojan - WA	(62,874)	(62,874)	0	0	0	0	This account is created to record a contra regulatory liability for Washington's share of the ARO regulatory difference on Trojan unrecovered plant and decommissioning costs . The reason for this contra account is that substantially all Trojan - related costs were disallowed in Washington; therefore, the Washington portion of any decommissioning costs associated with Trojan should be reflected below-the-line.
287227	705.531	RL UT Solar Feed-in Tariff - NC	5,898,994	5,898,994	0	0	0	0	Regulatory liability established to record UT solar Feed in Tarriff.
287229	705.527	RL CA Solar Feed-in Tariff - NC	153,231	153,231	0	0	0	0	Regulatory liability established to record CA solar Feed in Tarriff.
287230	705.521	RL - Deferred Excess NPC - WY - Noncurrent	0	0	0	0	0	0	Regulatory Liability established to record the costs in excess of base net power costs according to established calculations and were created to accommodate the recovery of excess net power costs through the
287231	705.519	RL WA Def NPC - Noncurrent	5,671,198	5,671,198	0	0	0	0	Regulatory liability established to record WA Def NPC.
287232	705.517	RL - Deferred Excess NPC - UT - Noncurrent	0	0	0	0	0	0	Regulatory Liability established to record the costs in excess of base net power costs according to established calculations and were created to accommodate the recovery of excess net power costs through the UT Energy Cost Adjustment Mechanism, or UT ECAM.
287233	705.515	RL - Deferred Excess NPC - OR - noncurrent	7,488,062	7,488,062	0	0	0	0	Regulatory liability established for noncurrent portion of recoverable net power costs in Oregon pursuant to an energy cost adjustment mechanism.
287237	705.755	RL-Noncurrent Reclass-Other	26,525	26,525	0	0	0	0	This account is to reclass the noncurrent portion of regulatory assets for insurance reserves and intervenor fees to liabilityies when the balance of the regulatory assets result in a credit balance instead of a debit balance, or vice versa.
287238	705.420	RL - CA GHG Allowance Rev	829,837	829,837	0	0	0	0	Regulatory liability established to record noncurrent portion of reg liability for purchase of California greenhouse gas pollution emission allowances .
287253	705.400	Reg Lia - OR Inj & Dam Reserve	1,976,773	1,976,773	0		0		Regulatory liability used to record the Oregon allocation of injury and damage insurance recovered in excess of insurance claims incurred.
287257	705.453	Reg Lia - ID Property Ins Reserve	190,832	190,832	0	0	0	0	Regulatory liability used to record the Idaho allocation of storm-related property damage recovered in excess of insurance claims incurred.
287258	705.454	Reg Lia - UT Property Ins Reserve	1,732,015	1,732,015	0	0	0	0	Regulatory liability used to record the Utah allocation of storm-related property damage recovered in excess of insurances claims incurred.
287259	705.455	RL - Property Insurance Reserve - WY	189,594	189,594	0	0	0	0	Regulatory liability used to record the Wyoming allocation of storm-related property damage recovered in excess of insurance claims incurred.
287262	100.100	RL ITC	495,889	495,889	0	0	0	0	Income tax gross-up on unamortized Investment Tax Credits pursuant to
287268	415.706	RL - 50% Bonus Tax Depr - WY	508,162	508,162	0	0	0	0	Regulatory liability for a Wyoming revenue requirement adjustment related to bonus tax depreciation.
287284	610.147	Reg Liability-Other - Balance Reclass	201,696	201,696	0	0	0	0	Reclass of miscellaneous regulatory assets/liabilityies that have flipped to
287299	705.265	RL - OR Energy Conserv Chrg	1,075,744	1,075,744	0	0	0	0	Regulatory liability established to record the Oregon Energy Conservation Charge and related expenses which are predominantly remitted to the Energy Trust of Oregon (ETO) for energy efficiency programs.
287304	610.146	OR Reg Asset/Liab Cons	(65,343)	(65,343)	0	0	0	0	Regulatory liability established to consolidate small inactive Oregon specific regulatory balances, which are then amortized into book income per approved rate order or tariff.
287312	105.402	ARO Reg Liabilities	264,602	264,602	0	0	0	0	Regulatory liability used to record the depreciation/accretion associated with FAS 143 asset retirement obligations.
287316	715.720	NW Power Act - WA	115,544	115,544	0	0	0	0	NW Power Act is funded by Bonneville Power Administration (BPA). Qualifying customers receive a benefit on their bill from the Company which is subsequently reimbursed by BPA. The Company receives a fixed monthly payment from BPA. The payment is deferred as a credit in this balancing account.
287374	100.105	Income Tax WA Flow-through	181,679	181,679	0	0	0	0	Regulatory liability established for flow-through accounting of income taxes required by the state of Washington on certain non-property related temporary book-tax differences.
287389	610.145	RL- DSM Balance Reclass	5,131,927	5,131,927	0	0	0	0	Reclass of miscellaneous regulatory assets/liabilityies that have flipped to
287441	605.100	Trojan Decom Cost-Regulatory Asset	1,319,363	1,319,363	0	0	0	0	Regulatory asset/liability established for the Asset Retirement Obligation (ARO) Liability representing future reclamation costs associated with the decommissioning of the Trojan Nuclear Plant that are in excess of those approved for recovery by regulatory authorities.
287445	610.142	RL - UT Home Energy LifeLine	371,395	371,395	0	0	0	0	Regulatory liability established to record revenues received from customers which are then granted to qualifying low income recipients through bill credits.
287453	610.143	RL - WA Low Energy Program	123,924	123,924	0	0	0	0	Regulatory liability established to record revenues received from customers which are then granted to qualifying low income recipients through bill credits.
287473	705.270	RL - Blue Sky Program OR	630,271	630,271	0	0	0	0	Regulatory liability established to record revenues received from customers participating in the company's Blue Sky renewable energy program, which are then used to purchase renewable energy certificates.

287474	705.271	RL - Blue Sky Program WA	93,650	93,650	0	0	0	0	Regulatory liability established to record revenues received from customers participating in the company's Blue Sky renewable energy program, which are then used to purchase renewable energy certificates.
287475	705.272	RL - Blue Sky Program CA	52,721	52,721	0	0	0	0	Regulatory liability established to record revenues received from customers participating in the company's Blue Sky renewable energy program, which are then used to purchase renewable energy certificates.
287476	705.273	RL - Blue Sky Program UT	2,456,455	2,456,455	0	0	0	0	Regulatory liability established to record revenues received from customers participating in the company's Blue Sky renewable energy program, which are then used to purchase renewable energy certificates.
287477	705.274	RL - Blue Sky Program ID	59,385	59,385	0	0	0	0	Regulatory liability established to record revenues received from customers participating in the company's Blue Sky renewable energy program, which are then used to purchase renewable energy certificates.
287478	705.275	RL - Blue Sky Program WY	114,658	114,658	0	0	0	0	Regulatory liability established to record revenues received from customers participating in the company's Blue Sky renewable energy program, which are then used to purchase renewable energy certificates.
287486	415.926	RL - Depre	1,284,244	1,284,244	0	0	0	0	Regulatory liability established to record Oregon's share of the deferral of decreased depreciation due to the implementation of new rates on January 1, 2014.
287487	415.927	RL - Depre	(1,635)	(1,635)	0	0	0	0	Regulatory liability established to record Washington's share of the deferral of decreased depreciation due to the implementation of new rates on January 1, 2014.
287848	320.281	RA - Post Retirement Settlement Loss	0	0	0	0	0	0	Regulatory asset established to record a FAS 106 regulatory asset for the settlement loss on retiree medical obligations.
287933	320.282	RA - Post Retirement Settlement Loss CC - UT	0	0	0	0	0	0	Regulatroy asset established to segregate the accumulated Utah carrying charges to be recovered on Utah's allocable share of the post-retirement medical settlement loss.
287934	320.283	RA - Post Retirement Settlement Loss - CC -WY	0	0	0	0	0	0	Regulatory asset established to segregate the accumulated Wyoming carrying charges to be recovered on Wyoming's allocable share of the post-retirement medical settlement loss.
287584	415.827	RA - Post-Ret MMT - OR	0	0	0	0	0	0	Regulatory asset established for the Oregon allocated share of a post-retirement benefits measurement date change transitional adjustment recorded in December 2008.
287588	415.831	RA - Post-Ret MMT - CA	0	0	0	0	0	0	Regulatory asset established for the California allocated share of a post-retirement benefits measurement date change transitional adjustment recorded in December 2008.
State Carryforwards									
287280	DTA State Charitable Contribution Limit		187,100	187,100	0	0	0	0	Charitable contribution carryforward for state income tax purposes.
287437	DTA Net Operating Loss Carryforwrd-State		72,551,413	0	0	0	72,551,413	0	State net operating loss carryforward for income tax purposes.
287449	DTA Federal Detriment of State NOL		(15,275,088)	0	0	0	(15,275,088)	0	Federal income benefit for the deduction state taxes associated with state net operating loss carryforward.
287371	DTA 930.100 Oregon BETC Credits		1,599,420	1,599,420	0	0	0	0	Accrued liability for purchased Oregon Business Energy Tax Credits (BETC's).
287491	DTA BETC Purchased Credits		1,611,177	0	1,611,177	0	0	0	Oregon state income tax credit carryforward.
287497	DTA BETC Purchased Gain		354,878	354,878	0	0	0	0	Book-tax difference related to the Gain on purchased Business Energy Tax Credits.
287494	DTA Idaho ITC Carryforward		15,240,731	15,240,731	0	0	0	0	Idaho state income tax credit carryforward.
287269	DTA Colorado Tax Credit Carryforward		224,138	224,138	0	0	0	0	Colorado state income tax credit carryforward.
287281	DTA CA AMT Credit Carryforward		255,284	255,284	0	0	0	0	California state income tax credit carryforward.
Loss Contingencies									
287970	415.815	Ins Rec Accrual	0	0	0	0	0	0	Accrued liability established reserves (contingent liabilities) for anticipated injury and damage expenses.
287341	910.530	Injuries & Damages	3,872,782	0	0	0	0	3,872,782	Accrued liability established as a reserve for anticipated injury and damage expense.
Asset Retirement Obligations									
287339	105.400	FAS 143 ARO Liability	53,101,152	53,101,152	0	0	0	0	Asset Retirement Obligation liability accrued pursuant to FASB Statement No. 143.

Other Deferred Assets:									
287100	- - - - -	Valuation Allowance for State Credit DTA	(13,930,382)	(13,930,382)	0	0	0	0	Valuation allowance against state income tax credits that may not be realized before they expire.
287199	220.101	Bad Debt	(40,763)	(40,763)	0	0	0	0	Accrued liability established to reserve for accounts receivable for which collection is not expected and for which the accumulated deferred income tax liablity is expected to be reversed upon audit by the Internal Revenue Service.
287210	505.115	Sales & Use Tax Audit Exp	61,707	61,707	0	0	0	0	Accrual to reserve for sales and use tax.
287211	425.226	Deferred Revenue - Other	360,275	360,275	0	0	0	0	Advanced payments recognized for tax and not for book.
287214	910.245	Contra Rec Joint Owners	430,058	430,058	0	0	0	0	Reserve against receivable due from joint owners.
287216	605.715	Trapper Mine Contract Oblig	1,562,198	0	1,562,198	0	0	0	Accrued final reclamation expenditures for the Trapper mine.
287219	715.810	Chehalis Mitigation Oblig	127,166	127,166	0	0	0	0	Accrued liabilities related to the purchase of the Chehalis plant not currently deductible for income tax purposes.
287240	605.301	Environmental Liab- Reg	13,647,196	13,647,196	0	0	0	0	Regulated environmental remediation costs required at various abandoned/closed mines and other work sites.
287241	605.302	Environmental Liab- NonReg	660,571	660,571	0	0	0	0	Non-regulated environmental remediation costs required at various abandoned/closed mines and other work sites.
287270	- - - - -	Valuation Allowance for DTA	(675,631)	0	0	0	(675,631)	0	Valuation allowance against items that may not be realized before they expire.
287290	425.150	Lewis River- LWD Fund Liab	267,814	267,814	0	0	0	0	Accrued liability associated with the acceptance of the Lewis River FERC license for habitat enhancement.
287297	505.155	Deferred Revenue - Citibank	69,114	69,114	0	0	0	0	Accrued liability used to defer credits for book purposes that are received from Citibank in connection with PacifiCorp's use of the Citibank One Card. The credits from Citibank are deferred until such time as it is known that requisite spending thresholds have been met and PacifiCorp is entitled to the credits.
287298	205.210	ERC Impairment Reserve	501,567	501,567	0	0	0	0	The reserve was established to record the impairment loss of PacifiCorp Energy write off $2.0M of emmission reduction credit.
287321	100.100	ITC	1,863,169	1,863,169	0	0	0	0	Unamortized Investment Tax Credits pursuant to IRC Subsection 46(f)(2).
287337	715.105	MCI F.O.G. Wire Lease	137,194	137,194	0	0	0	0	Accrued liability for paid, but unearned lease revenue. The lease revenue is recognized ratably over the annual service agreement period.
287338	415.110	Def Reg Asset-Transmission	574,232	0	0	574,232	0	0	Accrued liability for refundable cash deposits received from customers who wish to reserve transmission line services. These deposits are fully refundable. The deposits are recognized as income when the service contract is fulfilled.
287340	220.100	Bad Debts Allowance - Cash Basis	2,261,919	2,261,919	0	0	0	0	Accrued liability established to reserve for accounts receivable for which collection is not expected.
287354	505.150	Misc Current & Accrued Liab	1,161,582	1,161,582	0	0	0	0	Miscellaneous accrued liabilities related to PacifiCorp.
287370	425.215	Unearned Joint Use Pole Con	707,283	707,283	0	0	0	0	Accrued liability for prepaid rents on company owned utility poles.
287391	425.320	N Umpqua Settlement Agmt	5,840,431	5,840,431	0	0	0	0	Accrued liability associated with the acceptance of the North Umpqua FERC license for habitat enhancement.
287392	425.120	Bear River Settlement Agreement	4,155,873	4,155,873	0	0	0	0	Accrued liability associated with the acceptance of the Bear River FERC license for various settlement obligations.
287393	425.110	Tenant Lease Allowances	38,185	38,185	0	0	0	0	Cash received for improvements to the Lloyd Center Mall Learning Center leased by PacifiCorp will be amortized as expenses are incurred.
287415	205.200	M&S Inventory Write-off	534,687	421,760	112,927	0	0	0	Accrued liability for estimated obsolete or excess inventory that will be sold for scrap.
287417	605.710	Reverse Accrued Final Reclamation	2,121,972	2,121,972	0	0	0	0	Accrued liability for various reclamation costs for the site reclamation of the closed mines.
287430	505.125	Accrued Royalties	1,768,604	1,768,604	0	0	0	0	Accrued liability for royalty payments to the Mineral Management Service on coal production.
287479	105.221	Safe Harbor Leases - Cholla	19,734,360	19,734,360	0	0	0	0	Book-tax difference for safe harbor lease agreement between PacifiCorp and General Electric Credit Corp for the Cholla generation plant.
287482	205.025	PMI Fuel Cost Adjustment	0	0	0	0	0	0	Book-tax difference related to the reporting of book income from Bridger Coal Company on the books of PacifiCorp.
287489	910.515	Deseret Settlement Rec	18,808	18,808	0	0	0	0	A settlement receivable from Deseret Generation and Transmission Cooperative (Deseret) regarding a payment dispute over pollution upgrades at the Hunter Unit 2 coal plant.
287807	- - - - -	Non-curr def fed tax cor ben of int	162,294	162,294	0	0	0	0	Non-current federal benefit of interest on corrections.
287817	- - - - -	Non-curr def fed unc tax pos ben of int	23,634	23,634	0	0	0	0	Non-current federal benefit of interest on uncertain positions.
287827	- - - - -	Non-curr def sta tax cor ben of int	35,086	35,086	0	0	0	0	Non-current state benefit of interest on corrections.
287837	- - - - -	Non-curr def sta unc tax pos ben of int	5,112	5,112	0	0	0	0	Non-current state benefit of interest on uncertain positions.
Rounding			0	0	0	0	0	0	
Subtotal - p234			824,459,612	723,053,375	3,286,302	574,232	56,600,694	40,945,009	
Less FASB 109 Above if not separately removed			378,658,561	378,658,561	0	0	0	0	
Less FASB 106 Above if not separately removed			2,576,430	0	0	0	0	2,576,430	
Total			443,224,621	344,394,814	3,286,302	574,232	56,600,694	38,368,579	

Instructions for Account 190:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

shall be excluded.

PacifiCorp

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet
Schedule ADIT-281

A	B	C	D	E	F	G	H
	Total Company	Gas, Prod, Dist Or Other Related	Production Related	Transmission Related	Plant Related	Labor Related	Justification
Account 281							
Electric:							
287960 - - - - - Accelerated Pollution Control Facilities Depreciation	(180,339,430)	(180,339,430)	0	0	0	0	Depreciation on pollution control facilities.
Rounding	0	0	0	0	0	0	
Subtotal - p275	(180,339,430)	(180,339,430)	0	0	0	0	
Less FASB 109 Above if not separately removed	0	0	0	0	0	0	
Less FASB 106 Above if not separately removed	0	0	0	0	0	0	
Total	(180,339,430)	(180,339,430)	0	0	0	0	

Instructions for Account 281:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount

PacifiCorp

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet
Schedule ADIT-282

			A	B	C	D	E	F	G	H
				Total Company	Gas, Prod, Dist Or Other Related	Production Related	Transmission Related	Plant Related	Labor Related	Justification
Account 282										
287605	105.147	§1031 Exchange		(111,999)	(111,999)	0	0	0	0	Book-tax difference for a taxable gain or loss that is deferred pursuant to Internal Revenue Code Section 1031, otherwise knows as a "like-kind exchange."
287599	105.160	§1031 & 1033 Exchange Normalization Adjustment		(4,524,862)	(4,524,862)	0	0	0	0	Exclusion of ADIT from §1031 & 1033 Exchanges pursuant to the income tax normalization rules.
287766	610.101	Amortization NOPAs 99-00 RAR		69,021	0	69,021	0	0	0	Book-tax difference for the capitalization and depreciation of legal fees associated with the re-licensing of specific hydro generation facilities.
287610	105.403	ARO Removal Costs		(24,192,983)	(24,192,983)	0	0	0	0	Regulatory liability related to removal costs.
287605	105.142	Avoided Costs		163,640,792	163,640,792	0	0	0	0	Book-tax basis difference for the capitalization of interest for income tax purposes.
287704	105.143	Basis Intangible Difference		(1,083,823)	0	(1,083,823)	0	0	0	Book-tax basis difference for the capitalization of interest for income tax purposes specifically related to hydro-relicensing costs transferred to plant-in-service.
287605	105.120	Book Depreciation		2,351,250,809	2,351,250,809	0	0	0	0	Book-tax difference for book depreciation.
287605	105.470	Book Fixed Asset Gain/Loss		16,149,731	16,149,731	0	0	0	0	Book-tax difference related to land sales.
287605	105.146	Capitalization of Test Energy		3,393,596	3,393,596	0	0	0	0	Book-tax basis difference related to test energy revenues which are received/earned for power produced by generating plants during the construction period and sold or used by the utility.
287605	105.137	Capitalized Depreciation		(18,356,159)	(18,356,159)	0	0	0	0	Book-tax basis difference for the capitalization of vehicle depreciation.
287605	105.100	Capitalized labor and benefit costs		22,999,656	22,999,656	0	0	0	0	Book-tax basis difference related to the amount of labor costs capitalized to fixed assets.
287605	105.101	Capitalized labor costs - Medicare Subsidy		1,565,135	1,565,135	0	0	0	0	Book-tax basis difference related to the amount of labor overhead costs capitalized to fixed assets.
287605	- - - - -	Direct Assignment: Transmission Fixed Assets		0	745,178,166	0	(745,178,166)	0	0	PowerTax Report #257: Transmission Book Allocation Group.
287605	- - - - -	Direct Assignment: Intangible Fixed Assets		0	34,347,817	0	0	0	(34,347,817)	PowerTax Report #257: Intangible Book Allocation Group.
287605	- - - - -	Direct Assignment: General Fixed Assets		0	123,531,078	0	0	0	(123,531,078)	PowerTax Report #257: General Book Allocation Group.
287605	- - - - -	Direct Assignment: Production Fixed Assets		0	1,319,921,319	(1,319,921,319)	0	0	0	PowerTax Report #257: Production Book Allocation Group.
287605	- - - - -	Direct Assignment: Cholla Production Assets		0	(40,517,431)	40,517,431	0	0	0	PowerTax Report #257: Production Book Allocation Group contains Cholla steam plant ADIT. Because the Cholla steam plant has been excluded from the ancillary rate making formula, this line item removes the related ADIT balance.
287605	- - - - -	Direct Assignment: UT plant buy-down Production Assets		0	42,703,026	(42,703,026)	0	0	0	PowerTax Report #257: Production Book Allocation Group contains ADIT related to a Utah jurisdictional plant buy-down. Because this retail jurisdiction only plant buy-down has been excluded from the ancillary rate making formula, this line item removes the related ADIT balance.
287608	105.222	Cholla SHL (Amortization of SHL Gain)		(1,598,585)	(1,598,585)	0	0	0	0	PowerTax Report #257: Production Book Allocation Group contains assets related to assets included in plant buy-downs as agreed to with the OR Commissiion. These plant buy-downs hav been excluded from the ancillary rate making formula and accordingly, the ADIT related is removed from the Direct Assigned Production.
287608	105.223	Cholla SHL NOPA (Lease Amortization)		647,446	647,446	0	0	0	0	Book-tax difference for safe harbor lease agreement between PacifiCorp and General Electric Credit Corp for the Cholla generation plant.
287605	105.165	Coal Mine Development		0	0	0	0	0	0	Book-tax basis difference for coal mine development costs, which are capitalized for book purposes. For income tax purposes, 70% of coal mine development costs are deductible in the year incurred and the remaining 30% are capitalized for tax and amortized over 60 months.
287605	105.170	Coal Mine Extension Costs		0	0	0	0	0	0	Book-tax difference basis difference for costs incurred to maintain normal mine production in view of the recession of the working face of the mine. For book purposes, these costs are capitalized. For income tax purposes the costs are deductible in the period paid or incurred.
287605	105.153	Contract LiabilityBasis Adj - Chehalis		(127,166)	(127,166)	0	0	0	0	Accrued liabilities related to the purchase of the Chehalis plant not currently deductible for income tax purposes.
287605	105.151	Contract LiabilityBasis Adj - Eagle Mountain		(482,732)	(482,732)	0	0	0	0	Eagle Mountain contract liabilities not currently deductible for income tax purposes.
287605	105.130	Contribution in Aid of Construction		245,315,425	245,315,425	0	0	0	0	Book-tax basis difference related to contributions in aid of construction.
287605	105.175	Cost of Removal		(191,061,776)	(191,061,776)	0	0	0	0	Book-tax difference for removal costs, which are applied to the depreciation/depreciation reserve for book purposes and are deductible for income tax purposes in the year paid and incurred.
287224	145.030	CWIP Reserve		1,378,419	1,378,419	0	0	0	0	PacifiCorp will open a customer work order for construction of a capital project and capitalize various costs incurred on these utility-related projects (i.e., generation facilities, transmission and distribution facilities, mining operations and corporate operations) for book purposes. Projects with less than 5% activity within the prior 6-month period are deemed inactive. Those inactive projects with capitalized costs are analyzed for potential recovery. For the amounts not expected to be recovered, a reserve is established, CWIP Reserve.
287605	105.141	Debt AFUDC		(163,018,214)	(163,018,214)	0	0	0	0	Book-tax basis difference related to the Allowance for Funds Used During Construction, which consists of a debt and equity component. Equity is not capitalizable or deductible for income tax purposes, and the Internal Revenue Code requires a different formula related to the capitalization of interest on debt.

287607	105.117	Effects of Ratemaking - Fixed Assets Fed only - PMI	(7,633,104)	(7,633,104)	0	0	0	0	Accounting adjustment to record the amount of deferred tax expense associated with fixed assets that have previously been paid by customers at a higher tax rate than the current tax rate and are probable of being refunded as the temporary book-tax differences reverse and result in higher taxable income as compared to book income.
287605	105.115	Effects of Ratemaking - Fixed Assets Flowthrough	(1,360,854,056)	(1,360,854,056)	0	0	0	0	Accounting adjustment to record the amount of deferred tax expense associated with fixed assets that have been previously been paid by customers at a tax rate higher than the current tax rate and are probable of being refunded as the temporary book-tax differenes reverse and the amount of tax benefits associated with fixed assets that have previously been flowed through to customers and are probable of recovery as the temporary book-tax differences reverse and result in higher taxable income as compared to book income.
287605	105.139	Equity AFUDC	(79,920,415)	(79,920,415)	0	0	0	0	Book-tax basis difference related to the Allowance for Funds Used During Construction, which consists of a debt and equity component. Equity is not capitalizable or deductible for income tax purposes, and the Internal Revenue Code requires a different formula related to the capitalization of interest on debt.
287928	425.310	Hydro Relicensing Obligation	(4,026,581)	0	0	0	0	(4,026,581)	PacifiCorp accrues a liability for various stream enhancement obligations entered into for the new North Umpqua FERC license pursuant to Financial Accounting Standard 143.
287605	105.125	Tax Depreciation	(4,621,421,000)	(4,621,421,000)	0	0	0	0	Book-tax difference for tax depreciation.
287605	105.152	Tax Fixed Asset Gain/Loss	(58,128,735)	(58,128,735)	0	0	0	0	book-tax difference related to the disposition of capital assets.
287605	105.129	Fixed Assets - State Modifications	22,466,833	0	0	0	22,466,833	0	Tax adjustment to account for the difference between federal and state depreciation methodologies; primarily resulting from states that have not adopted bonus depreciation.
287605	105.148	Mine Safety Sec. 179E Election	(306,514)	(306,514)	0	0	0	0	Book-tax basis difference for qualified advanced mine safety equipment, 50% of which is deductible in the period paid and incurred for income tax purposes.
287929	105.460	Non-ARO Removal Costs	(247,201,083)	(247,201,083)	0	0	0	0	Regulatory liability related to removal costs.
286691	105.106	NonProtected PP&E EDIT - CA	(6,748,788)	(6,748,788)	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. For GAAP purposes, the new tax rate was effective on the date of enactment, or December 31, 2017. As a result of the change in law, the deferred tax assets and liabilities were revalued at the new tax rate, which resulted in an amount referred to as Excess Deferred Income Taxes, or EDIT.
286697	105.113	NonProtected PP&E EDIT - FERC	(3,768,586)	(3,768,586)	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. For GAAP purposes, the new tax rate was effective on the date of enactment, or December 31, 2017. As a result of the change in law, the deferred tax assets and liabilities were revalued at the new tax rate, which resulted in an amount referred to as Excess Deferred Income Taxes, or EDIT.
286692	105.107	NonProtected PP&E EDIT - ID	(10,009,386)	(10,009,386)	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. For GAAP purposes, the new tax rate was effective on the date of enactment, or December 31, 2017. As a result of the change in law, the deferred tax assets and liabilities were revalued at the new tax rate, which resulted in an amount referred to as Excess Deferred Income Taxes, or EDIT.
286693	105.108	NonProtected PP&E EDIT - OR	(93,279,909)	(93,279,909)	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. For GAAP purposes, the new tax rate was effective on the date of enactment, or December 31, 2017. As a result of the change in law, the deferred tax assets and liabilities were revalued at the new tax rate, which resulted in an amount referred to as Excess Deferred Income Taxes, or EDIT.
286695	105.109	NonProtected PP&E EDIT - WA	(20,865,641)	(20,865,641)	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. For GAAP purposes, the new tax rate was effective on the date of enactment, or December 31, 2017. As a result of the change in law, the deferred tax assets and liabilities were revalued at the new tax rate, which resulted in an amount referred to as Excess Deferred Income Taxes, or EDIT.
286696	105.111	NonProtected PP&E EDIT - WY	(38,491,281)	(38,491,281)	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. For GAAP purposes, the new tax rate was effective on the date of enactment, or December 31, 2017. As a result of the change in law, the deferred tax assets and liabilities were revalued at the new tax rate, which resulted in an amount referred to as Excess Deferred Income Taxes, or EDIT.

286605	105.136	PP&E FIN 48 Balances	(383,923)	(383,923)	0	0	0	0	PP&E book to tax differences for which the accumulated deferred income tax liablity is expected to be reversed upon audit by the Internal Revenue Service.
287605	320.210	R & E - Sec.174 Deduction	(7,719,946)	(7,719,946)	0	0	0	0	Book-tax difference for eligible costs under Internal Revenue Code Section 174 for internally developed software which are deductible in the period paid and incurred for income tax purposes. These costs are capitalized for book
287605	100.110	RA- Solar ITC Basis Adj. - Fixed Assets	(27,337)	(27,337)	0	0	0	0	PacifiCorp installed solar arrays. The projects are qualified for the 30% solar investment tax credit (ITC). The tax basis of the solar arrays needs to be reduced by one-half of the solar ITC, therefore creating basis differences between book basis and tax basis for the solar arrays.
287605	105.158	Reclass to §1031 & 1033 Exchange Normalization Adj - General Fixed Assets	186,877	0	0	0	0	186,877	Reclass to separately state the exclusion of ADIT from §1031 & 1033 Exchanges pursuant to the income tax normalization rules.
287605	105.159	Reclass to §1031 &1033 Exchange Normalization Adj - Transmission	4,164,640	0	0	4,164,640	0	0	Reclass to separately state the exclusion of ADIT from §1031 & 1033 Exchanges pursuant to the income tax normalization rules.
287605	105.159	Reclass to §1031 &1033 Exchange Normalization Adj - Other Property	173,345	173,345	0	0	0	0	Reclass to separately state the exclusion of ADIT from §1031 & 1033 Exchanges pursuant to the income tax normalization rules.
287605	105.131	Reclass to Pollution Control Facilities Depreciation	180,339,430	180,339,430	0	0	0	0	Reclassification of pollution controls facilities depreciation from FERC account 282 to FERC account 281.
287605	105.140	Reimbursements	21,672,077	21,672,077	0	0	0	0	Book-tax basis difference related to relocation reimbursements, which depending on whether or not the benefit of the relocation is for the benefit of
287605	105.122	Repairs Deduction	(379,313,893)	(379,313,893)	0	0	0	0	Book-tax basis difference for expenditures which are capitalized and depreciation for book purposes and for income tax purposes are deductible in the period they are paid and incurred.
287221	415.933	RL - Contra-Carbon Decommissioning - ID	(306,766)	(306,766)	0	0	0	0	This account was set up to record a contra regulatory liability for Idaho's share of Carbon Plant's decommissioning accrual that was directed to be a regulatory asset per the Idaho general rate order/stipulation (Docket PAC-E-13-04).
287222	415.934	RL - Contra-Carbon Decommissioning - UT	(2,219,066)	(2,219,066)	0	0	0	0	This account was set up to record a contra regulatory liability for Utah's share of Carbon Plant's decommissioning accrual that was directed to be a regulatory asset per the Utah general rate order/stipulation (Docket 11-035-200).
287223	415.935	RL - Contra-Carbon Decommissioning - WY	(263,188)	(263,188)	0	0	0	0	This account was set up to record a contra regulatory liability for Wyoming's share of Carbon Plant's decommissioning accrual that was directed to be a regulatory asset per the Wyoming general rate order/stipulation (Docket 20000-405-ER11).
287189	100.122	RL - Effects of Ratemaking - Fixed Assets - PMI Fed Only	7,633,104	7,633,104	0	0	0	0	Accounting adjustment to record the amount of deferred tax expense associated with fixed assets that have previously been paid by customers at a higher tax rate than the current tax rate and are probable of being refunded as the temporary book-tax differences reverse and result in higher taxable income as compared to book income.
287187	100.121	RL - Effects of Ratemaking - Fixed Assets	1,122,042,940	1,122,042,940	0	0	0	0	Accounting adjustment to record the amount of deferred tax expense associated with fixed assets that have been previously been paid by customers at a tax rate higher than the current tax rate and are probable of being refunded as the temporary book-tax differenes reverse and the amount of tax benefits associated with fixed assets that have previously been flowed through to customers and are probable of recovery as the temporary book-tax differences reverse and result in higher taxable income as compared to book income.
287313	105.450	RL - Non-ARO Liability	247,201,083	247,201,083	0	0	0	0	Regulatory liability related to removal costs.
286691	100.123	RL - NonProtected PP&E EDIT - CA	6,748,788	6,748,788	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. For GAAP purposes, the new tax rate was effective on the date of enactment, or December 31, 2017. As a result of the change in law, the deferred tax assets and liabilities were revalued at the new tax rate, which resulted in an amount referred to as Excess Deferred Income Taxes, or EDIT.
286697	100.129	RL - NonProtected PP&E EDIT - FERC	3,768,586	3,768,586	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. For GAAP purposes, the new tax rate was effective on the date of enactment, or December 31, 2017. As a result of the change in law, the deferred tax assets and liabilities were revalued at the new tax rate, which resulted in an amount referred to as Excess Deferred Income Taxes, or EDIT.
286692	100.124	RL - NonProtected PP&E EDIT - ID	10,009,386	10,009,386	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. For GAAP purposes, the new tax rate was effective on the date of enactment, or December 31, 2017. As a result of the change in law, the deferred tax assets and liabilities were revalued at the new tax rate, which resulted in an amount referred to as Excess Deferred Income Taxes, or EDIT.
286693	100.125	RL - NonProtected PP&E EDIT - OR	93,279,909	93,279,909	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. For GAAP purposes, the new tax rate was effective on the date of enactment, or December 31, 2017. As a result of the change in law, the deferred tax assets and liabilities were revalued at the new tax rate, which resulted in an amount referred to as Excess Deferred Income Taxes, or EDIT.
286695	100.127	RL - NonProtected PP&E EDIT - WA	20,865,641	20,865,641	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. For GAAP purposes, the new tax rate was effective on the date of enactment, or December 31, 2017. As a result of the change in law, the deferred tax assets and liabilities were revalued at the new tax rate, which resulted in an amount referred to as Excess Deferred Income Taxes, or EDIT.

286696	100.128	RL - NonProtected PP&E EDIT - WY	38,491,281	38,491,281	0	0	0	0	On December 22, 2017, Tax Cuts and Jobs Act was signed into law by the President. One of the significant changes is the corporate income tax rate is reduced from 35% to 21%. For GAAP purposes, the new tax rate was effective on the date of enactment, or December 31, 2017. As a result of the change in law, the deferred tax assets and liabilities were revalued at the new tax rate, which resulted in an amount referred to as Excess Deferred Income Taxes, or EDIT.
287605	105.135	Safe Harbor Lease Rate Differential	(2,846,881)	(2,846,881)	0	0	0	0	Book-tax basis difference related to safe harbor lease rate differential. (Federal ONLY vs. Federal + State).
287605	105.123	Sec. 481a Adjustment - Repair Deduction	(154,568,137)	(154,568,137)	0	0	0	0	Book-tax difference related to a one-time adjustment required by the Internal Revenue Code for a change in accounting method for income tax purposes. In 2008, PacifiCorp changed its method of accounting for income tax purposes for certain expenditures which were previously being capitalized and depreciated. Under the new method of accounting, the expenditures are deductible for income tax purposes in the period they are paid and incurred.
287605	105.116	Solar ITC Basis Adjustment	(7,170)	(7,170)	0	0	0	0	The projects are qualified for the 30% solar investment tax credit (ITC). The tax basis of the solar arrays needs to be reduced by one-half of the solar ITC, therefore creating basis differences between book basis and tax basis for the solar arrays.
287771	110.205	Tax Depletion-SRC	154,934	0	154,934	0	0	0	Book-tax difference related to different methods for computing deductible periodic depletion for book and tax purposes.
287301	105.471	UT Klamath Relicensing Costs	8,680,735	8,680,735	0	0	0	0	Book-tax difference related to relicensing cost for Klammath Dam.
	Rounding		1	1	0	0	0	0	
Subtotal - p275			(2,910,580,066)	(707,347,992)	(1,322,966,782)	(741,013,526)	22,466,833	(161,718,599)	
Less FASB 109 Above if not separately removed			1,129,676,044	1,129,676,044	0	0	0	0	
Less FASB 106 Above if not separately removed			0	0	0	0	0	0	
Total			(4,040,256,110)	(1,837,024,036)	(1,322,966,782)	(741,013,526)	22,466,833	(161,718,599)	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

shall be excluded.

PacifiCorp

Attachment 1A - Accumulated Deferred Income Taxes (ADIT) Worksheet
Schedule ADIT-283

A			B	C	D	E	F	G	H
			Total Company	Gas, Prod, Dist Or Other Related	Production Related	Transmission Related	Plant Related	Labor Related	Justification
Account 283									
FERC 283 - Regulatory Assets									
287849	415.424	Contra RA - Deer Creek Abandonment	23,241,132	23,241,132	0	0	0	0	Regulatory asset used to record a contra regulatory asset for Deer Creek abandonment.
287841	415.411	Contra RA - Deer Creek Abandonment - CA	607,297	607,297	0	0	0	0	Regulatory asset to record CA contra regulatory asset for Deer Creek abandonment.
287842	415.412	Contra RA - Deer Creek Abandonment - ID	416,140	416,140	0	0	0	0	Regulatory asset to record ID contra regulatory asset for Deer Creek abandonment.
287843	415.413	Contra RA - Deer Creek Abandonment - OR	1,748,164	1,748,164	0	0	0	0	Regulatory asset to record OR contra regulatory asset for Deer Creek abandonment.
287844	415.414	Contra RA - Deer Creek Abandonment - UT	963,534	963,534	0	0	0	0	Regulatory asset to record UT contra regulatory asset for Deer Creek abandonment.
287845	415.415	Contra RA - Deer Creek Abandonment - WA	2,723,925	2,723,925	0	0	0	0	Regulatory asset to record WA contra regulatory asset for Deer Creek abandonment.
287846	415.416	Contra RA - Deer Creek Abandonment - WY	92,367	92,367	0	0	0	0	Regulatory asset to record WY contra regulatory asset for Deer Creek abandonment.
287850	415.425	Contra RA - UMWA Pension	1,168,493	1,168,493	0	0	0	0	Contra regulatory asset for all the recovery (amortization) and other adjustments to the UMWA pension trust withdrawal obligation regulatory asset included in the Deer Creek Mine disposition.
287851	415.417	Contra RA - UMWA Pension - CA	443,826	443,826	0	0	0	0	Contra regulatory asset for all the CA related recovery (amortization) and other adjustments to the UMWA pension trust withdrawal obligation regulatory asset included in the Deer Creek Mine disposition.
287855	415.421	Contra RA - UMWA Pension - WA	1,990,706	1,990,706	0	0	0	0	Contra regulatory asset for all the WA related recovery (amortization) and other adjustments to the UMWA pension trust withdrawal obligation regulatory asset included in the Deer Creek Mine disposition.
287747	705.240	RA - Alt Rate for Energy Program (CARE) - CA	(69,242)	(69,242)	0	0	0	0	Regulatory asset to record benefits and administrative costs related to the California Alternative Rate for Energy, or CARE, program.
287642	105.401	RA - ARO	(29,172,770)	(29,172,770)	0	0	0	0	Regulatory asset used to record the depreciation/accretion associated with FAS 143 asset retirement obligations.
287911	415.699	RA - BPA Balancing Account - OR	(1,752,861)	(1,752,861)	0	0	0	0	Regulatory asset to record the pass-through benefit to Oregon customers from the BPA. Qualifying customers, such as those who meet specified reductions in energy use during peak hours, are rewarded with a credit to their bill. Moved from 2014 account 137332.
287997	415.862	RA - CA Mobile Home Park Conversion	(48,856)	(48,856)	0	0	0	0	Balancing account to record the program costs for the conversion of master metered mobile home parks to direct utility service.
287935	415.936	RA - Carbon Plant Decomm/Inventory	(847,911)	(847,911)	0	0	0	0	Regulatory asset established to record the deferral of Carbon Plant's write off and sales proceeds of inventory from decommissioning.
286901	415.938	RA - Carbon Plant Decomm/Inventory - CA	12,797	12,797	0	0	0	0	Regulatory asset established to record CA's share of the deferral of Carbon Plant's write off and sales proceeds of inventory from decommissioning.
286900	415.937	RA - Carbon Plant Decomm/Inventory - WA	68,301	68,301	0	0	0	0	Regulatory asset established to record WA's share of the deferral of Carbon Plant's write off and sales proceeds of inventory from decommissioning.
287984	415.923	RA - Carbon Unrecovered Plant - ID	(235,362)	(235,362)	0	0	0	0	Regulatory asset established to record Idaho's share of the deferral of Carbon Plant's increased depreciation due to the implementation of new rates on January 1, 2014.
287985	415.924	RA - Carbon Unrecovered Plant - UT	(1,693,840)	(1,693,840)	0	0	0	0	Regulatory asset established to record Utah's share of the deferral of Carbon Plant's increased depreciation due to the implementation of new rates on January 1, 2014.
287986	415.925	RA - Carbon Unrecovered Plant - WY	(569,518)	(569,518)	0	0	0	0	Regulatory asset established to record Wyoming's share of the deferral of Carbon Plant's increased depreciation due to the implementation of new rates on January 1, 2014.
287581	415.824	RA - Contra Pension MMT & CTG - CA	0	0	0	0	0	0	Regulatory asset established for the California allocated share of a pension curtailment gain and measurement date change transitional adjustment recorded in December 2008.
287577	415.820	RA - Contra Pension MMT & CTG - OR	(1)	(1)	0	0	0	0	Regulatory asset established for the Oregon allocated share of a pension curtailment gain and measurement date change transitional adjustment recorded in December 2008.
286903	320.271	RA - Contra RA - Pension Plan CTG	403,462	403,462	0	0	0	0	Regulatory assett established to record a contra regulatory asset for the curtailment gain/loss on the elimination of the cash balance option in the company pension plan.
287781	415.870	RA - Deferred Excess NPC - CA - Noncurrent	(1,477,559)	(1,477,559)	0	0	0	0	Regulatory asset established for reclass non-current portion of CA Deferred Excess NPC.
287596	415.892	RA - Deferred Excess NPC - ID - Noncurrent	(4,469,102)	(4,469,102)	0	0	0	0	Regulatory asset established for noncurrent portion of recoverable net power costs in Idaho pursuant to an energy cost adjustment mechanism.
287896	415.875	RA - Deferred Excess NPC - UT - Noncurrent	(7,467,384)	(7,467,384)	0	0	0	0	Regulatory asset established for noncurrent portion of recoverable net power costs in Utah pursuant to an energy cost adjustment clause.
287593	415.874	RA - Deferred Excess NPC - WY '09 & After - Noncurrent	(1,355,403)	(1,355,403)	0	0	0	0	Regulatory asset established for noncurrent portion of recoverable net power costs in Wyoming pursuant to a power costs adjustment mechanism.
287783	415.880	RA - Deferred Independent Evaluator Fee - UT	26,525	26,525	0	0	0	0	Regulatory asset established for the Utah allocated share of evaluator fees and costs related to a request for proposal for new generation.
287570	415.701	RA - Deferred Intervenor Funding Grants - CA	(10,325)	(10,325)	0	0	0	0	Regulatory asset/liability established to record funding for qualifying intervenors that are collected from customers through California rates.
287647	425.100	RA - Deferred Intervenor Funding Grants - ID	(16,440)	(16,440)	0	0	0	0	Regulatory asset/liability established to record funding for qualifying intervenors that are collected from customers through Idaho rates.
287640	415.680	RA - Deferred Intervenor Funding Grants - OR	(227,906)	(227,906)	0	0	0	0	Regulatory asset/liability established to record funding for qualifying intervenors that are collected from customers through Oregon rates.

287861	415.857	RA - Deferred Overburden Costs - ID	(121,333)	(121,333)	0	0	0	0	Regulatory asset established for the Idaho allocated portion of overburden costs pursuant to a regulatory order.
287868	415.858	RA - Deferred Overburden Costs - WY	(341,401)	(341,401)	0	0	0	0	Regulatory asset established for the Wyoming allocated portion of overburden costs pursuant to a regulatory order.
287614	430.100	RA - Demand Side Management - Noncurrent	2,996,799	2,996,799	0	0	0	0	Regulatory asset established to record costs incurred for demand side management which are amortized according to guidelines established by each state regulatory jurisdiction.
287981	415.920	RA - Depreciation Increase - Idaho	21,367	21,367	0	0	0	0	Regulatory asset established to record Idaho's share of the deferral of increased depreciation due to the implementation of new rates on January 1, 2014.
287982	415.921	RA - Depreciation Increase - Utah	(393,518)	(393,518)	0	0	0	0	Regulatory asset established to record Utah's share of the deferral of increased depreciation due to the implementation of new rates on January 1, 2014.
287983	415.922	RA - Depreciation Increase - Wyoming	(1,358,996)	(1,358,996)	0	0	0	0	Regulatory asset established to record Wyoming's share of the deferral of
287576	430.110	RA - DSM Balance Reclass	(5,131,927)	(5,131,927)	0	0	0	0	Reclass of miscellaneous regulatory assets/liabilityies that have flipped to debit/credit balances.
287840	415.410	RA - Energy West Mining	(67,294,167)	(67,294,167)	0	0	0	0	In December 2014, abandonment costs were recorded in connection with the anticipated closure of the Deer Creek mine in Emery County, UT. The Company filed a deferred accounting application with the applicable state commissions.
287634	415.300	RA - Environmental Costs	(20,800,311)	(20,800,311)	0	0	0	0	Regulatory asset established to record costs incurred for environmental clean-up, which are amortized over a ten-year period for state regulatory purposes.
287591	415.301	RA - Environmental Costs - WA	502,643	502,643	0	0	0	0	Regulatory liability established for the portion of environmental remediation costs for which the state of Washington does not allow deferred treatment.
287738	320.270	RA - FAS 158 Pension Liability	(109,192,092)	(109,192,092)	0	0	0	0	Regulatory asset established to track the recoverable expenses associated with pension liability.
287739	320.280	RA - FAS 158 Post Retirement Liability	501,052	501,052	0	0	0	0	Regulatory asset established to track the recoverable expenses associated with post-retirement benefits liability.
287597	415.703	RA - Goodnoe Hills Settlement - WY	(78,370)	(78,370)	0	0	0	0	Regulatory asset for the Wyoming allocated portion of a settlement associated with damages sustained at the Goodnoe Hills generating plant.
286905	415.530	RA - ID 2017 Protocol - MSP Deferral	(36,880)	(36,880)	0	0	0	0	Regulatory asset established to record the Idaho multi-state protocol deferral assumed in 2018.
287897	425.400	RA - Klamath Hydroelectric Relicensing Costs - UT	(3,853,296)	(3,853,296)	0	0	0	0	The book-tax difference resulting from this regulatory asset.
287571	415.702	RA - Lake Side Settlement - WY	(193,192)	(193,192)	0	0	0	0	Regulatory asset for the Wyoming allocated portion of a settlement associated with damages sustained at the Lake Side generating plant.
287903	415.879	RA - Liquidation Damages - N2 - WY	(21,050)	(21,050)	0	0	0	0	Regulatory asset established to record Wyoming's share of liquidating damages on outages at Naughton 2 that are being returned to Wyoming customers on an accelerated basis through the 2013 Energy Cost Adjustment Mechanism (ECAM).
287977	415.885	RA - Noncurrent Reclass - Other	(26,525)	(26,525)	0	0	0	0	SAP account used for financial statement presentation purposes to reclass the current and noncurrent portion of regulatory assets to liabilities when the balance of the regulatory assets result in a credit balance.
287919	425.105	RA - OR Asset Sale Gain GB - Noncurrent	(266,633)	(266,633)	0	0	0	0	Regulatory asset established to reclass noncurrent portion of OR asset sale gain giveback
286910	415.200	RA - OR Trasnsportation Electrification Pilot	(11,996)	(11,996)	0	0	0	0	Pilot Program set up in March 2018 to record costs and collect fees
287942	430.112	RA - Other - Balance Reclass	(201,696)	(201,696)	0	0	0	0	Reclass of miscellaneous regulatory assets/liabilityies that have flipped to debit/credit balances.
287972	320.285	RA - Post Employment Costs	(212,004)	0	0	0	0	(212,004)	Regulatory asset established as an offset to the increase in post-employment obligations.
287675	740.100	RA - Post Merger Loss - Reacquired Debt	(1,119,888)	(1,119,888)	0	0	0	0	Asset accrued for required debt, amortized for book purposes over the remaining life of the original issuance, or over the life of the new issuance if the original issuance was refinanced.
287864	415.852	RA - Powerdale Decommissioning - ID	(12,719)	(12,719)	0	0	0	0	Regulatory asset established for the unrecovered portion of the Powerdale hydroelectric generating facility and decommissioning costs allocable to Idaho. The Powerdale hydroelectric facility was severely damaged by flooding and the related debris flow and is being removed rather than being repaired.
287858	415.676	RA - Preferred Stock Redemption - WY	(36,421)	(36,421)	0	0	0	0	Reg Asset - WY - Preferred Stock Redemption Cost was set up in August 2014 to record Utah's portion of redemption cost.
287996	415.675	RA - Preferred Stock Redemption Loss - UT	(105,685)	(105,685)	0	0	0	0	Reg Asset - UT - Preferred Stock Redemption Cost was set up in August 2014 to record Utah's portion of redemption cost.
287601	415.677	RA - Preferred Stock Redemption Loss - WA	(16,918)	(16,918)	0	0	0	0	Reg Asset established to record Washington's portion of stock redemption costs.
287978	415.906	RA - REC Sales Deferral - OR - Noncurrent	(28,299)	(28,299)	0	0	0	0	Regulatory asset established for noncurrent portion of deferral of Oregon prepaid renewable energy creidt purchases for Renewable Portfolio Standard compliance and the related interest income.
287887	415.881	RA - REC Sales Deferral - UT - Noncurrent	(255,342)	(255,342)	0	0	0	0	Regulatory asset established for the noncurrent portion of Utah renewable energy credits included in rates that differ from actual renewable energy credits.
287888	415.882	RA - REC Sales Deferral - WA - Noncurrent	(11,760)	(11,760)	0	0	0	0	Regulatory asset established to capture the noncurrent portion of the difference between renewable energy credits (RECs) included in rates and actual RECs for the Washington jurisdiction.
287889	415.883	RA - REC Sales Deferral - WY - Noncurrent	(187,897)	(187,897)	0	0	0	0	Regulatory asset established for the noncurrent portion of Wyoming renewable energy credits included in rates that differ from actual renewable energy credits.
287871	415.866	RA - Solar Feed-In Tariff Deferral - OR - Noncurrent	(1,260,259)	(1,260,259)	0	0	0	0	Regulatory asset established for the noncurrent portion of costs incurred with an Oregon photovoltaic feed-in tariff program (Oregon House Bill 3039).
287971	415.868	RA - Solar Incentive Program - UT - Noncurrent	(2,393,394)	(2,393,394)	0	0	0	0	Regulatory asset established for the UT Solar incentive program costs.
287927	100.110	RA - Solar ITC Basis Adjustment - Gross Up	(8,913)	(8,913)	0	0	0	0	The projects are qualified for the 30% solar investment tax credit (ITC). The tax basis of the solar arrays needs to be reduced by one-half of the solar ITC, therefore creating basis differences between book basis and tax basis for the solar arrays. This is the revenue requirement gross-up for that difference.

287960	415.855	RA - Storm Damage Deferral - CA	(535,843)	(535,843)	0	0	0	0	Regulatory Asset established based on CA Decision 16-03-015 whcih provided for a surcharge to recover $545,000 of costs recorded related to a storm in California.
286911	415.430	RA - Transportation Electrification Pilot - CA	112,508	112,508	0	0	0	0	Pilot Program approved in September 2018 to record costs and collect fees connected to Oregon transportation electrification pilot programs.
286906	415.531	RA - UT 2017 Protocol - MSP Deferral	(2,163,621)	(2,163,621)	0	0	0	0	Regulatory asset established to record the Utah multi-state protocol deferral assumed in 2017 and 2018.
287899	415.878	RA - UT Liquidation Damages	(129,080)	(129,080)	0	0	0	0	Regulatory asset established for Utah portion of liquidated damages payments for outages at Jim Bridger Unit4, Naughton Unit 1 and Unit 2.
287906	415.863	RA - UT Subscriber Solar Program	(408,955)	(408,955)	0	0	0	0	Regulatory asset established for the UT Subscriber Solar Program.
287939	415.115	RA - Utah STEP Pilot Program Balance Account	2,393,394	2,393,394	0	0	0	0	To record a regulatory asset balancing account for the costs and collections of the Utah Sustainable Transportation and Energy Plan (STEP) Pilot Programs.
287639	415.510	RA - WA Colstrip #3	(26,739)	(26,739)	0	0	0	0	Regulatory asset established for the Washington disallowed portion of AFUDC on the Colstrip #3 generating plant.
287857	415.545	RA - WA Merwin Project	844	844	0	0	0	0	Regulatory asset established torecord the deferral of the Merwin Project costs approved by the Washington Utility and Transportation Commission (WUTC).
286907	415.532	RA - WY 2017 Protocol - MSP Deferral	(590,078)	(590,078)	0	0	0	0	Regulatory asset established to record the Wyoming multi-state protocol deferral assumed in 2017 and 2018.
287848	320.281	RA - Post Retirement Settlement Loss	(1,592,384)	(1,592,384)	0	0	0	0	Regulatory asset established to record a FAS 106 regulatory asset for the settlement loss on retiree medical obligations.
287933	320.282	RA - Post Retirement Settlement Loss CC - UT	(307,906)	(307,906)	0	0	0	0	Regulatroy asset established to segregate the accumulated Utah carrying charges to be recovered on Utah's allocable share of the post-retirement medical settlement loss.
287934	320.283	RA - Post Retirement Settlement Loss - CC -WY	(5,469)	(5,469)	0	0	0	0	Regulatory asset established to segregate the accumulated Wyoming carrying charges to be recovered on Wyoming's allocable share of the post-retirement medical settlement loss.
287917	705.451	RL - Property Insurance Reserve - OR	(750,685)	(750,685)	0	0	0	0	Regulatory liability used to record the Oregon allocation of storm-related property damage recovered in excess of insurance claims incurred.
287649	730.170	RA - FAS133 Unrealized Gain/Loss	(23,548,525)	(23,548,525)	0	0	0	0	Regulatory assets established to record the effects of the accounting pursuant to FASB Statement No. 133, which requires that certain financial instruments be valued at FMV for book purposes.
287886	415.837	RA - Frozen MTM	(19,362,370)	(19,362,370)	0	0	0	0	Reclass of regulatory asset from derivative regulatory asset to an other regulatory asset for frozen derivative.
FERC 283 - Other									
287650	205.100	Coal Pile Inventory Adjustment	(27,155)	(27,155)	0	0	0	0	Regulaory asset established to reflect the book-tax difference in the cost of the Deer Creek and Trail Mountain coal inventory.
287936	205.025	Fuel Cost Adjustment	(89,756)	(89,756)	0	0	0	0	Beginning in May 2008, Bridger Coal/PMI earnings are recorded as a debit to investment in Bridger Coal and a credit to coal inventory.
287661	425.360	Hermiston Swap	(742,255)	(742,255)	0	0	0	0	Asset accrued for a deferred expense related to a termination fee incurred by PacifiCorp when it acquired a 50% interest in the Hermiston generating plant. For book purposes, the cost is being amortized over the remaining life of the plant.
286909	720.815	FAS 158 Post-Retirement Asset	0	0	0	0	0	0	The total overfunded Other Post-Employment Benefit Obligations (OPEB) asset, excluding Medicare subsidy, required under FAS 158.
287656	425.280	Joseph Settlement	0	0	0	0	0	0	Asset accrued for a deferred expense related to costs incurred for the termination of a power purchase agreement. For book purposes, the costs are being amortized over the remaining life of the original contract.
287669	210.180	Prepaid Membership Fees	(95,975)	0	(95,975)	0	0	0	Asset accrued for prepaid membership fees, amortized for book purposes
287907	210.185	Prepaid Aircraft Maintenance	0	0	0	0	0	0	Regulatory asset established for prepaid aircraft maintenance costs.
287665	210.130	Prepaid Taxes - ID PUC	(79,123)	(79,123)	0	0	0	0	Asset accrued for prepaid Idaho commission fee, amortized for book purposes over a period of 12 months or less.
287662	210.100	Prepaid Taxes - OR PUC	(261,203)	(261,203)	0	0	0	0	Asset accrued for prepaid Oregon commission fee, amortized for book purposes over a period of 12 months or less.
287708	210.200	Prepaid Taxes - Property Taxes	(3,450,433)	0	0	0	(3,450,433)	0	Book-tax difference associated with the timing of deductibility of property taxes.
286908	210.201	Prepaid Taxes - Property Tax FIN 48	(3,391,794)	0	0	0	(3,391,794)	0	Prepaid property tax book to tax differences for which the accumulated deferred income tax liablity is expected to be reversed upon audit by the Internal Revenue Service.
287664	210.120	Prepaid Taxes - UT PUC	(771,986)	(771,986)	0	0	0	0	Asset accrued for prepaid Utah commission fee, amortized for book purposes over a period of 12 months or less.
287908	210.190	Prepaid Water Rights	(176,739)	0	(176,739)	0	0	0	Regulatory asset accrued for prepaid water rights and water fees. Moved from 2014 account 137511.
287289	425.130	Rogue River-Habitat Enhance	(37,177)	(37,177)	0	0	0	0	Accrued liability associated with the acceptance of the Rogue River (Prospects 1, 2, & 4) FERC license, PacifiCorp is obligated to pay the Oregon Department of Fish and Wildlife $1,000,000, escalated, over a period of 9 years for habitat enhancement.
287653	425.250	TGS Buyout	(4,122)	(4,122)	0	0	0	0	Asset accrued for a deferred expense related to costs incurred for the termination of a power purchase agreement. For book purposes, the costs are being amortized over the remaining life of the original contract.

287770	120.205	Trapper Mining Stock Basis	(1,103,468)	(1,103,468)	0	0	0	0	Equity earnings for Trapper Mine. The equity method of accounting does not apply for income tax purposes.
287859	910.935	Def Comp Mark to Market Gain/Loss - Income Statement	(209,674)	0	0	0	0	(209,674)	Deferred compensation plan investments are being treated as "trading securities" where they are invested based upon the plan participants' personal investment elections. Starting in July 2010, the investments are reflected at fair market value and any unrealized gains or losses are reflected in earnings.
287217	910.937	LTIP Mark to Mkt Gain/Loss	(107,930)	0	0	0	0	(107,930)	To record unrealized gains/losses from the long term incentive plan.
287966	415.834	Noncurrent Asset - Frozen MTM	(1,792,457)	(1,792,457)	0	0	0	0	Regulatory liability established to record the reclass of a derivative regulatory asset to an other regulatory asset for frozen derivative.
287492	- - - - -	OR BETC - Purchased Credits - Non-Cash	(74,524)	(74,524)	0	0	0	0	Book-tax difference related to the Gain on purchased Business Energy Tax Credits.
Rounding			2	2	0	0	0	0	
Subtotal - p277			(285,789,510)	(278,144,961)	(272,714)	0	(6,842,227)	(529,608)	
Less FASB 109 Above if not separately removed			(8,913)	(8,913)	0	0	0	0	
Less FASB 106 Above if not separately removed			0	0	0	0	0	0	
Total			(285,780,597)	(278,136,048)	(272,714)	0	(6,842,227)	(529,608)	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or
Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E

4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount

Description	Reference	Total Company	Gas, Dist. or Other	Production Related	Transmission Related	Plant Related	Labor Related	Total Production ADIT
(A)	(B)				(C)	(D)	(E)	(F)
ADIT-282	Sch. 282 Below	(2,717,738,923)	(521,825,474)	(1,311,650,910)	(751,809,087)	19,912,567	(152,366,019)	
ADIT-281	Sch. 281 Below	(174,829,838)	(174,829,838)	0	0	0	0	
ADIT-283	Sch. 283 Below	(297,165,105)	(288,722,951)	(326,132)	0	(6,932,740)	(1,183,282)	
ADIT-190	Sch. 190 Below	831,227,995	735,021,953	6,294,322	527,179	50,906,125	38,478,416	
Subtotal ADIT	Sum (Lines 1 to 4)	(2,358,505,871)	(250,356,310)	(1,305,682,720)	(751,281,908)	63,885,952	(115,070,885)	
Allocator (100% Production, 0% Transmission; Net Plant; Wages & Salary)	Attachment A		0.0000%	100.0000%	0.0000%	45.7092%	44.9558%	
Sub-total Transmission Related ADIT	Line 5 * Allocator		0	(1,305,682,720)	0	29,201,774	(51,731,053)	
Total End of Year Transmission ADIT	Sum Cols. (C), (D), (E)							(1,328,211,999)
Beginning of Year Total (Attachment 1)								(1,342,630,664)
Attachment A, line 33 input	Line 8 for Projection and average of Lines 8 & 9 for True-Up							**(1,335,421,331)**

In filling out this attachment, a full and complete description of each item and justification for the allocation to Columns B-F and each separate ADIT item will be listed, dissimilar items with amounts exceeding $100,000 will be listed separately.

Schedule ADIT-190

	A			B	C	D	E	F	G	H
Description		Form 1 Reference		Total Company	Gas, Prod, Dist Or Other Related	Production Related	Transmission Related	Plant Related	Labor Related	Justification
Account 190										
Employee Benefits										
287414	505.700	Accrued Retention Bonus		27,772	0	0	0	0	27,772	The amounts recorded in this account represent retention bonuses accrued for various employees.
287220	720.560	Pension Liability UMWA Withdrawal		28,303,872	28,303,872	0	0	0	0	Regulatory liability established to record a pension liability for the Energy West Mining UMWA pension trust withdrawal obligation.
287300	920.182	LTIP - non current		5,402,412	0	0	0	0	5,402,412	Regulatory liability established to record the long-term portion of the BHE incentive plan liability related to PacifiCorp employees.
287323	505.400	Bonus Liab. Elec. - Cash Basis (2.5 mos)		3,071	0	0	0	0	3,071	Accrued expenses recorded for book purposes under PacifiCorp's Annual Incentive Plan (AIP), 401(k) match of AIP, payroll tax (employer portion), and LTI.
287324	720.200	Deferred Comp. Accrual - Cash Basis		2,473,185	0	0	0	0	2,473,185	Non-qualified deferred compensation plan under IRC Subsection 409A.
287326	720.500	Severance Accrual - Cash Basis		157,578	0	0	0	0	157,578	Severance accruals related to regular employment downsizing. Amounts contained in these accounts represent accruals for both departing executives and rank and file employees.
287327	720.300	Pension/Retirement Accrual - Cash Basis		397,298	397,298	0	0	0	0	Accrued retiree payment obligations outside of the regular PacifiCorp retirement plan, most constituting payments made above the IRC Subsection 415 limitations.
287332	505.600	Vacation Accrual-Cash Basis (2.5 mos)		6,227,380	0	0	0	0	6,227,380	Accruals recorded for book purposes for unused vacation and sick leave due to employees in future periods or upon termination.
287373	910.580	Wasatch workers comp reserve		610,677	0	0	0	0	610,677	Accrued liability for the expected claims related to workers compensation previously held by Wasatch Crest. PacifiCorp holds this liability due to the insolvency of Wasatch Crest.
287399	920.150	FAS 112 Book Reserve - Post Employee Benefits		6,962,522	0	0	0	0	6,962,522	Accrued liability for worker's compensation benefits pursuant to FASB Statement No. 112.
287447	720.830	Western Coal Carr Ret Med Accrual		2,615,031	0	0	0	0	2,615,031	Accrued post-retirement liabilityies pursuant to FASB Statement No. 106 for Western Coal Carriers, a third-party carrier service that contracted with PacifiCorp to haul coal from the Trail Mountain Mine to the Hunter plant.
287460	720.800	FAS 158 Pension Liability		18,536,580	18,536,580	0	0	0	0	Total unfunded pension liability as required under FAS 158.
287462	720.820	FAS 158 SERP Liability		13,672,129	0	0	0	0	13,672,129	Total Supplemental Executive Retirement Plan (SERP) obligations, as required by FAS 158.
FAS 133 Derivatives:										
287336	730.120	FAS 133 Derivatives - Book Unrealized		15,548,329	15,548,329	0	0	0	0	Unrealized derivative gains and losses under FASB Statement No. 133 which requires that certain financial instruments be valued at FMV for book purposes.
287249	415.839	NonCurr Liab - Frozen MTM		17,521,790	17,521,790	0	0	0	0	Reclass non-current liability from derivative regulatory liability to an other regulatory liability for frozen derivative.
Regulatory Liabilities:						0				
287051	705.340	RL Income Tax Deferral - CA		1,774,469	1,774,469	0	0	0	0	Regulatory liability established to record the deferral of retail revenue for excess income taxes in rates for California customers. The Tax Cuts and Jobs Act was enacted on December 22, 2017 and reduced the federal income tax rate from 35% to 21%.
287052	705.341	RL Income Tax Deferral - ID		198,629	198,629	0	0	0	0	Regulatory liability established to record the deferral of retail revenue for excess income taxes in rates for Idaho customers. The Tax Cuts and Jobs Act was enacted on December 22, 2017 and reduced the federal income tax rate from 35% to 21%.
287053	705.342	RL Income Tax Deferral - OR		12,527,831	12,527,831	0	0	0	0	Regulatory liability established to record the deferral of retail revenue for excess income taxes in rates for Oregon customers. The Tax Cuts and Jobs Act was enacted on December 22, 2017 and reduced the federal income tax rate from 35% to 21%.
287054	705.343	RL Income Tax Deferral - UT		162,012	162,012	0	0	0	0	Regulatory liability established to record the deferral of retail revenue for excess income taxes in rates for Utah customers. The Tax Cuts and Jobs Act was enacted on December 22, 2017 and reduced the federal income tax rate from 35% to 21%.

287055	705.344	RL Income Tax Deferral - WA	2,205,980	2,205,980	0	0	0	0	Regulatory liability established to record the deferral of retail revenue for excess income taxes in rates for Washington customers. The Tax Cuts and Jobs Act was enacted on December 22, 2017 and reduced the federal income tax rate from 35% to 21%.
287056	705.345	RL Income Tax Deferral - WY	572,721	572,721	0	0	0	0	Regulatory liability established to record the deferral of retail revenue for excess income taxes in rates for Wyoming customers. The Tax Cuts and Jobs Act was enacted on December 22, 2017 and reduced the federal income tax rate from 35% to 21%.
287061	705.346	RL - Protected PP&E EDIT Amortization - CA	819,472	819,472	0	0	0	0	Regulatory liability established to record the deferral of protected property related EDIT amortization for return to California customers pursuant to regulatory order.
287062	705.347	RL - Protected PP&E EDIT Amortization - ID	1,872,929	1,872,929	0	0	0	0	Regulatory liability established to record the deferral of protected property related EDIT amortization for return to Idaho customers pursuant to regulatory order.
287063	705.348	RL - Protected PP&E EDIT Amortization - OR	9,606,196	9,606,196	0	0	0	0	Regulatory liability established to record the deferral of protected property related EDIT amortization for return to Oregon customers pursuant to regulatory order.
287064	705.349	RL - Protected PP&E EDIT Amortization - UT	17,165,823	17,165,823	0	0	0	0	Regulatory liability established to record the deferral of protected property related EDIT amortization for return to Utah customers pursuant to regulatory order.
287065	705.350	RL - Protected PP&E EDIT Amortization - WA	2,624,129	2,624,129	0	0	0	0	Regulatory liability established to record the deferral of protected property related EDIT amortization for return to Washington customers pursuant to regulatory order.
287066	705.351	RL - Protected PP&E EDIT Amortization - WY	5,950,126	5,950,126	0	0	0	0	Regulatory liability established to record the deferral of protected property related EDIT amortization for return to Wyoming customers pursuant to regulatory order.
287111	705.287	RL - Protected PP&E EDIT - CA	8,843,563	8,843,563	0	0	0	0	Regulatory liability established to defer California's portion of protected property related EDIT recorded as a result of the Tax Cuts and Jobs Act, which reduced the federal income tax rate from 35% to 21%.
287112	705.288	RL - Protected PP&E EDIT - ID	22,969,779	22,969,779	0	0	0	0	Regulatory liability established to defer Idaho's portion of protected property related EDIT recorded as a result of the Tax Cuts and Jobs Act, which reduced the federal income tax rate from 35% to 21%.
287113	705.289	RL - Protected PP&E EDIT - OR	100,330,266	100,330,266	0	0	0	0	Regulatory liability established to defer Oregon's portion of protected property related EDIT recorded as a result of the Tax Cuts and Jobs Act, which reduced the federal income tax rate from 35% to 21%.
287114	705.290	RL - Protected PP&E EDIT - WA	24,203,327	24,203,327	0	0	0	0	Regulatory liability established to defer Washington's portion of protected property related EDIT recorded as a result of the Tax Cuts and Jobs Act, which reduced the federal income tax rate from 35% to 21%.
287115	705.291	RL - Protected PP&E EDIT - WY	56,221,284	56,221,284	0	0	0	0	Regulatory liability established to defer Wyoming's portion of protected property related EDIT recorded as a result of the Tax Cuts and Jobs Act, which reduced the federal income tax rate from 35% to 21%.
287116	705.292	RL - Protected PP&E EDIT - UT	177,211,110	177,211,110	0	0	0	0	Regulatory liability established to defer Utah's portion of protected property related EDIT recorded as a result of the Tax Cuts and Jobs Act, which reduced the federal income tax rate from 35% to 21%.
287121	705.294	RL - Non Protected PP&E EDIT- CA	1,033,880	1,033,880	0	0	0	0	Regulatory liability established to defer California's portion of non-protected property related EDIT recorded as a result of the Tax Cuts and Jobs Act, which reduced the federal income tax rate from 35% to 21%.
287122	705.295	RL - Non Protected PP&E EDIT- ID	3,720,223	3,720,223	0	0	0	0	Regulatory liability established to defer Idaho's portion of non-protected property related EDIT recorded as a result of the Tax Cuts and Jobs Act, which reduced the federal income tax rate from 35% to 21%.
287124	705.296	RL - Non Protected PP&E EDIT- WA	6,444,285	6,444,285	0	0	0	0	Regulatory liability established to defer Washington's portion of non-protected property related EDIT recorded as a result of the Tax Cuts and Jobs Act, which reduced the federal income tax rate from 35% to 21%.
287125	705.297	RL - Non Protected PP&E EDIT- WY	13,062,075	13,062,075	0	0	0	0	Regulatory liability established to defer Wyoming's portion of non-protected property related EDIT recorded as a result of the Tax Cuts and Jobs Act, which reduced the federal income tax rate from 35% to 21%.
287126	705.298	RL - Non Protected PP&E EDIT- UT	5,867,251	5,867,251	0	0	0	0	Regulatory liability established to defer Utah's portion of non-protected property related EDIT recorded as a result of the Tax Cuts and Jobs Act, which reduced the federal income tax rate from 35% to 21%.
287184	705.605	RL OR Clean Fuels Program	743,995	743,995	0	0	0	0	As ordered by the Oregon Public Utility Commission (OPUC), PacifiCorp registered as an aggregator of residential Clean Fuels Program credits generated by customers in our Oregon service area. As an aggregator, PacifiCorp is allocated credits generated by residential customers who own electric cars on an annual basis by the Oregon Department of Environmental Quality (DEQ). PacifiCorp may then sell the credits to "regulated parties" that are required to comply with the regulations of the Clean Fuels Program through the purchase of such credits, in a manner that is consistent with the monetization principles adopted by the OPUC in December of 2017. Regulatory Liability Account 288190 was set up in 2018 for sales of credits to regulated parties.
287188	100.121	RL Income Tax Property Flowthru	(57,682,274)	(57,682,274)	0	0	0	0	A regulatory liability with respect to the excess deferred income taxes associated with the effects of flow through from PP&E book/tax differences and other deferred items that do not have current provision impacts.
287190	100.122	RL Income Tax Property Flowthru - PMI	1,576,465	1,576,465	0	0	0	0	Regulatory liability established to account for the deferral of protected property-related EDIT for PMI's portion of Bridger Coal Company fixed assets
287191	705.280	RL Non-Property EDIT - CA	272,759	272,759	0	0	0	0	A regulatory liability established with respect to the excess deferred income taxes associated with the non-property accumulated deferred income taxes allocable to California resulting from the change in the income tax rate.
287192	705.281	RL Non-Property EDIT - ID	363,042	363,042	0	0	0	0	A regulatory liability established with respect to the excess deferred income taxes associated with the non-property accumulated deferred income taxes allocable to Idaho resulting from the change in the income tax rate.

287195	705.284	RL Non-Property EDIT - WA	326,187	326,187	0	0	0	0	A regulatory liability established with respect to the excess deferred income taxes associated with the non-property accumulated deferred income taxes allocable to Washington resulting from the change in the income tax rate.
287196	705.285	RL Non-Property EDIT - WY	2,939,674	2,939,674	0	0	0	0	A regulatory liability established with respect to the excess deferred income taxes associated with the non-property accumulated deferred income taxes allocable to Wyoming resulting from the change in the income tax rate.
287198	320.279	RL FAS 158 Post-Retirement	4,512,773	4,512,773	0	0	0	0	A regulatory liability used to track future revenue associated with recoverable post-retirement welfare expenses.
287200	705.267	RL WA Decoupling Mechanism	4,427,455	4,427,455	0	0	0	0	A regulatory liability with respect to the Washington decoupling mechanism.
287206	415.710	RL - WA Accelerated Depreciation	9,747,596	9,747,596	0	0	0	0	Regulatory Liability established to record difference between the approved accelerated depreciation in the 2015 WA GRC and the current depreciation amounts from the last depreciation study for all units at the Jim Bridger Plant and Colstrip Unit 4.
287209	705.266	RL - Energy Savings Assistance (ESA) - CA	156,804	156,804	0	0	0	0	Regulatory Liability established to record Energy Savings Assistance (ESA) Program activities (ESA collections from California offset by ESA program expenditures incurred) in a regulatory liability balancing account for
287212	705.245	RL - OR Direct Access 5 Yr Opt out	1,364,948	1,364,948	0	0	0	0	Regulatory Liability established per Order No. 15-060 in Docket UE267, PacifiCorp is required to implement a 5 year customer opt-out plan. Customers that elect to go on the opt-out program and leave PacifiCorp's system will be required to pay an opt-out charge for up to 5 years.
287213	425.381	RL - BPA Balance Act - ID	710,943	710,943	0	0	0	0	Regulatory liability established as a balancing account for a pass-through benefit to Idaho customers from BPA (Bonneville Power Administration) under the Northwest Power Act where qualifying customers receive a credit to their bill.
287225	605.103	ARO/Regulatory Difference - Trojan - WA	(62,340)	(62,340)	0	0	0	0	This account is created to record a contra regulatory liability for Washington's share of the ARO regulatory difference on Trojan unrecovered plant and decommissioning costs . The reason for this contra account is that substantially all Trojan - related costs were disallowed in Washington; therefore, the Washington portion of any decommissioning costs associated with Trojan should be reflected below-the-line.
287227	705.531	RL UT Solar Feed-in Tariff - NC	5,294,611	5,294,611	0	0	0	0	Regulatory liability established to record UT solar Feed in Tariff.
287229	705.527	RL CA Solar Feed-in Tariff - NC	153,231	153,231	0	0	0	0	Regulatory liability established to record CA solar Feed in Tariff.
287231	705.519	RL WA Def NPC - Noncurrent	2,148,707	2,148,707	0	0	0	0	Regulatory liability established to record WA Def NPC.
287233	705.515	RL OR Def NPC - Noncurrent	8,835,150	8,835,150	0	0	0	0	Regulatory liability established for noncurrent portion of recoverable net power costs in Oregon pursuant to an energy cost adjustment mechanism.
287237	705.755	RL-Noncurrent Reclass-Other	26,525	26,525	0	0	0	0	This account is to reclass the noncurrent portion of regulatory assets for insurance reserves and intervenor fees to liabilities when the balance of the regulatory assets result in a credit balance instead of a debit balance, or vice versa.
287238	705.420	RL - CA GHG Allowance Revenue	823,309	823,309	0	0	0	0	Regulatory liability established to record noncurrent portion of reg liability for purchase of California greenhouse gas pollution emission allowances .
287253	705.400	Reg Lia - OR Injuries & Damages Reserve	2,430,606	2,430,606	0	0	0	0	Regulatory liability used to record the Oregon allocation of injury and
287257	705.453	Reg Lia - ID Property Insurance Reserve	218,749	218,749	0	0	0	0	Regulatory liability used to record the Idaho allocation of storm-related property damage recovered in excess of insurance claims incurred.
287258	705.454	Reg Lia - UT Property Insurance Reserve	2,003,553	2,003,553	0	0	0	0	Regulatory liability used to record the Utah allocation of storm-related
287259	705.455	RL - Property Insurance Reserve - WY	275,600	275,600	0	0	0	0	Regulatory liability used to record the Wyoming allocation of storm-related property damage recovered in excess of insurance claims incurred.
287262	100.100	RL ITC	342,815	342,815	0	0	0	0	Income tax gross-up on unamortized Investment Tax Credits pursuant to IRC Subsection 46(f)(2).
287268	415.706	RL - 50% Bonus Tax Depreciation - WY	308,848	308,848	0	0	0	0	Regulatory liability for a Wyoming revenue requirement adjustment related to bonus tax depreciation.
287271	705.336	RL - Sale of RECs - UT	159,534	159,534	0	0	0	0	Regulatory Liability, a Revenue Balancing Account, or RBA, was established to track the difference between REC revenue included in rates and Utah's allocation of the actual REC revenue received by the Company.
287272	705.337	RL - Sale of RECs - WY	15,151	15,151	0	0	0	0	Regulatory Liability established to track the difference between REC revenue included in rates and Wyoming's allocation of the actual REC revenue received by the Company.
287274	705.261	RL - Sale of RECs - OR	5,566	5,566	0	0	0	0	Regulatory Liability established to track the difference between REC
287284	610.147	Reg Liability-Other - Balance Reclass	428,560	428,560	0	0	0	0	Reclass of miscellaneous regulatory assets/liabilities that have flipped to debit/credit balances.
287299	705.265	RL - OR Energy Conservation Charge	927,477	927,477	0	0	0	0	Regulatory liability established to record the Oregon Energy Conservation Charge and related expenses which are predominantly remitted to the Energy Trust of Oregon (ETO) for energy efficiency programs.
287304	610.146	OR Reg Asset/Liab Cons	(71,776)	(71,776)	0	0	0	0	Regulatory liability established to consolidate small inactive Oregon specific regulatory balances, which are then amortized into book income per approved rate order or tariff.
287312	105.402	ARO Reg Liabilities	152,347	152,347	0	0	0	0	Regulatory liability used to record the depreciation/accretion associated with FAS 143 asset retirement obligations.
287374	100.105	Income Tax WA Flow-through	292,186	292,186	0	0	0	0	Regulatory liability established for flow-through accounting of income taxes required by the state of Washington on certain non-property related temporary book-tax differences.
287389	610.145	RL- DSM Balance	5,053,830	5,053,830	0	0	0	0	Reclass of miscellaneous regulatory assets/liabilities that have flipped to debit/credit balances.
287441	605.100	Trojan Decommissioning Cost-Regulatory Asset	1,304,405	1,304,405	0	0	0	0	Regulatory asset/liability established for the Asset Retirement Obligation (ARO) Liability representing future reclamation costs associated with the decommissioning of the Trojan Nuclear Plant that are in excess of those approved for recovery by regulatory authorities.
287445	610.142	RL - UT Home Energy LifeLine	382,875	382,875	0	0	0	0	Regulatory liability established to record revenues received from customers which are then granted to qualifying low income recipients through bill credits.

287453	610.143	RL - WA Low Energy Program	(239,688)	(239,688)	0	0	0	0	Regulatory liability established to record revenues received from customers which are then granted to qualifying low income recipients through bill credits.

287473	705.270	RL - Blue Sky Program OR	600,042	600,042	0	0	0	0	Regulatory liability established to record revenues received from customers participating in the company's Blue Sky renewable energy program, which are then used to purchase renewable energy certificates.
287474	705.271	RL - Blue Sky Program WA	133,389	133,389	0	0	0	0	Regulatory liability established to record revenues received from customers participating in the company's Blue Sky renewable energy program, which are then used to purchase renewable energy certificates.
287475	705.272	RL - Blue Sky Program CA	66,708	66,708	0	0	0	0	Regulatory liability established to record revenues received from customers participating in the company's Blue Sky renewable energy program, which are then used to purchase renewable energy certificates.
287476	705.273	RL - Blue Sky Program UT	2,130,025	2,130,025	0	0	0	0	Regulatory liability established to record revenues received from customers participating in the company's Blue Sky renewable energy program, which are then used to purchase renewable energy certificates.
287477	705.274	RL - Blue Sky Program ID	72,164	72,164	0	0	0	0	Regulatory liability established to record revenues received from customers participating in the company's Blue Sky renewable energy program, which are then used to purchase renewable energy certificates.
287478	705.275	RL - Blue Sky Program WY	160,437	160,437	0	0	0	0	Regulatory liability established to record revenues received from customers participating in the company's Blue Sky renewable energy program, which are then used to purchase renewable energy certificates.
287486	415.926	RL - Depreciation Decrease - OR	1,604,984	1,604,984	0	0	0	0	Regulatory liability established to record Oregon's share of the deferral of decreased depreciation due to the implementation of new rates on January 1, 2014.
287487	415.927	RL - Depreciation Decrease - WA	(1,635)	(1,635)	0	0	0	0	Regulatory liability established to record Washington's share of the deferral of decreased depreciation due to the implementation of new rates on January 1, 2014.
State Carryforwards									
287280		DTA State Charitable Contribution Limit	154,143	154,143	0	0	0	0	Charitable contribution carryforward for state income tax purposes.
287437		DTA Net Operating Loss Carryforward-State	65,128,541		0	0	65,128,541	0	State net operating loss carryforward for income tax purposes.
287449		DTA Federal Detriment of State NOL	(13,709,364)	0	0	0	(13,709,364)	0	Federal income benefit for the deduction state taxes associated with state net operating loss carryforward.
287371		DTA 930.100 Oregon BETC Credits	1,233,359	1,233,359	0	0	0	0	Accrued liability for purchased Oregon Business Energy Tax Credits (BETC's).
287491		DTA BETC Purchased Credits	975,823	0	975,823	0	0	0	Oregon state income tax credit carryforward.
287497		DTA BETC Purchased Gain	217,417	217,417	0	0	0	0	Book-tax difference related to the Gain on purchased Business Energy Tax Credits.
287494		DTA Idaho ITC Carryforward	15,765,223	15,765,223	0	0	0	0	Idaho state income tax credit carryforward.
287269		DTA Colorado Tax Credit Carryforward	261,772	261,772	0	0	0	0	Colorado state income tax credit carryforward.
287281		DTA CA AMT Credit Carryforward	271,106	271,106	0	0	0	0	California state income tax credit carryforward.
Loss Contingencies									
287341	910.530	Injuries & Damages Accrual - Cash Basis	2,941,690	0	0	0	0	2,941,690	Accrued liability established as a reserve for anticipated injury and damage expense.
Asset Retirement Obligations					0				
287339	105.400	FAS 143 ARO Liability	60,936,151	60,936,151	0	0	0	0	Asset Retirement Obligation liability accrued pursuant to FASB Statement No. 143.
Other Deferred Assets:									
287100	- - - - -	Valuation Allowance for State Credit DTA	(12,730,201)	(12,730,201)	0	0	0	0	Valuation allowance against state income tax credits that may not be realized before they expire.
287181	205.201	Inventory Reserve - Cholla Unit 4	1,501,308	1,501,308	0	0	0	0	Accrued liability for estimated obsolete or excess inventory associated with the Cholla U4 closure.
287182	505.105	Liquidated Damages - Cholla Unit 4	4,820,466	4,820,466	0	0	0	0	Liability account established to record liquidated damages payable to Peabody Coal due the announced closure of Cholla Unit 4 in 2020.
287183	425.160	Lease Liability (Operating Lease)	2,933,696	0	2,933,696	0	0	0	Operating lease liabilities established pursuant to the new leasing accounting standards under ASC 842.
287199	220.101	Bad Debt	(40,763)	(40,763)	0	0	0	0	Accrued liability established to reserve for accounts receivable for which collection is not expected and for which the accumulated deferred income tax liability is expected to be reversed upon audit by the Internal Revenue Service.
287211	425.226	Deferred Revenue - Other	218,670	218,670	0	0	0	0	Advanced payments recognized for tax and not for book.
287214	910.245	Contra Receivable Joint Owners	266,405	266,405	0	0	0	0	Reserve against receivable due from joint owners.
287216	605.715	Trapper Mine Contract Obligation	1,637,226	0	1,637,226	0	0	0	Accrued final reclamation expenditures for the Trapper mine.
287219	715.810	Chehalis Mitigation Obligation	80,270	80,270	0	0	0	0	Accrued liabilities related to the purchase of the Chehalis plant not currently deductible for income tax purposes.
287240	605.301	Environmental Liability - Regulation	13,852,972	13,852,972	0	0	0	0	Regulated environmental remediation costs required at various abandoned/closed mines and other work sites.
287241	605.302	Environmental Liability- Non Regulation	604,603	604,603	0	0	0	0	Non-regulated environmental remediation costs required at various abandoned/closed mines and other work sites.
287270	- - - - -	Valuation Allowance for DTA	(513,052)	0	0	0	(513,052)	0	Valuation allowance against items that may not be realized before they expire.
287290	425.150	Lewis River- LWD Fund Liab	271,410	271,410	0	0	0	0	Accrued liability associated with the acceptance of the Lewis River FERC license for habitat enhancement.
287297	505.155	Deferred Revenue	17,279	17,279	0	0	0	0	Accrued liability used to signing bonuses from credit card providers that are deferred until such time as it is known that requisite spending thresholds have been met and PacifiCorp is entitled to the credits.
287298	205.210	ERC Impairment Reserve	501,567	501,567	0	0	0	0	The reserve was established to record the impairment loss of PacifiCorp Energy write off $2.0M of emission reduction credit.
287321	100.100	ITC	1,287,756	1,287,756	0	0	0	0	Unamortized Investment Tax Credits pursuant to IRC Subsection 46(f)(2).
287337	715.105	MCI F.O.G. Wire Lease	137,353	137,353	0	0	0	0	Accrued liability for paid, but unearned lease revenue. The lease revenue is recognized ratably over the annual service agreement period.
287338	415.110	Deferred Regulatory Asset-Transmission Service Deposit	527,179	0	0	527,179	0	0	Accrued liability for refundable cash deposits received from customers who wish to reserve transmission line services. These deposits are fully refundable. The deposits are recognized as income when the service contract is fulfilled.
287340	220.100	Bad Debts Allowance - Cash Basis	2,279,972	2,279,972	0	0	0	0	Accrued liability established to reserve for accounts receivable for which collection is not expected.
287354	505.150	Miscellaneous Current & Accrued Liability	744,516	744,516	0	0	0	0	Miscellaneous accrued liabilities related to PacifiCorp.

287370	425.215	Unearned Joint Use Pole Contract Revenue	745,550	745,550	0	0	0	0	Accrued liability for prepaid rents on company owned utility poles.

287391	425.320	N Umpqua Settlement Agreement	5,680,844	5,680,844	0	0	0	0	Accrued liability associated with the acceptance of the North Umpqua FERC license for habitat enhancement.
287392	425.120	Bear River Settlement Agreement	4,142,371	4,142,371	0	0	0	0	Accrued liability associated with the acceptance of the Bear River FERC license for various settlement obligations.
287393	425.110	Tenant Lease Allowances - PSU Cal	30,548	30,548	0	0	0	0	Cash received for improvements to the Lloyd Center Mall Learning Center leased by PacifiCorp will be amortized as expenses are incurred.
287415	205.200	M&S Inventory Write-off	747,577	0	747,577	0	0	0	Accrued liability for estimated obsolete or excess inventory that will be sold for scrap.
287417	605.710	Reverse Accrued Final Reclamation	745,852	745,852	0	0	0	0	Accrued liability for various reclamation costs for the site reclamation of the closed mines.
287430	505.125	Accrued Royalties	1,878,947	1,878,947	0	0	0	0	Accrued liability for royalty payments to the Mineral Management Service on coal production.
287479	105.221	Safe Harbor Leases - Cholla	17,437,141	17,437,141	0	0	0	0	Book-tax difference for safe harbor lease agreement between PacifiCorp and General Electric Credit Corp for the Cholla generation plant.
287807	- - - - -	Non-curr def fed tax cor ben of int	212,438	212,438	0	0	0	0	Non-current federal benefit of interest on corrections.
287817	- - - - -	Non-curr def fed unc tax pos ben of int	30,138	30,138	0	0	0	0	Non-current federal benefit of interest on uncertain positions.
287827	- - - - -	Non-curr def sta tax cor ben of int	45,926	45,926	0	0	0	0	Non-current state benefit of interest on corrections.
287837	- - - - -	Non-curr def sta unc tax pos ben of int	6,518	6,518	0	0	0	0	Non-current state benefit of interest on uncertain positions.
Rounding			(5)	(5)	0	0	0	0	
Subtotal - p234			783,561,636	684,740,563	6,294,322	527,179	50,906,125	41,093,447	
Less FASB 109 Above if not separately removed			(50,281,390)	(50,281,390)	0	0	0	0	
Less FASB 106 Above if not separately removed			2,615,031	0	0	0	0	2,615,031	
Total			831,227,995	735,021,953	6,294,322	527,179	50,906,125	38,478,416	

Instructions for Account 190:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

Schedule ADIT-281

A			B	C	D	E	F	G	H
			Total Company	Gas, Prod, Dist Or Other Related	Production Related	Transmission Related	Plant Related	Labor Related	Justification
Account 281									
Electric:									
287960	- - - - -	Accelerated Pollution Control Facilities Depreciation	(174,829,838)	(174,829,838)	0	0	0	0	Depreciation on pollution control facilities.
Rounding			0	0	0	0	0	0	
Subtotal - p275			(174,829,838)	(174,829,838)	0	0	0	0	
Less FASB 109 Above if not separately removed			0	0	0	0	0	0	
Less FASB 106 Above if not separately removed			0	0	0	0	0	0	
Total			(174,829,838)	(174,829,838)	0	0	0	0	

Instructions for Account 281:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

PacifiCorp
Accumulated Deferred Income Taxes
Average and End of Current Year

Schedule ADIT-282

A			B	C	D	E	F	G	H
			Total Company	Gas, Prod, Dist Or Other Related	Production Related	Transmission Related	Plant Related	Labor Related	Justification
Account 282									
287605	105.147	§1031 Exchange	(111,999)	(111,999)	0	0	0	0	Book-tax difference for a taxable gain or loss that is deferred pursuant to Internal Revenue Code Section 1031, otherwise knows as a "like-kind exchange."
287599	105.160	§1031 & 1033 Exchange Normalization Adjustment	(4,396,080)	(4,396,080)	0	0	0	0	Exclusion of ADIT from §1031 & 1033 Exchanges pursuant to the income tax normalization rules.
287766	610.101	Amortization NOPAs 99-00 RAR	53,209	0	53,209	0	0	0	Book-tax difference for the capitalization and depreciation of legal fees associated with the re-licensing of specific hydro generation facilities.
287610	105.403	ARO Removal Costs	(26,616,545)	(26,616,545)	0	0	0	0	Regulatory liability related to removal costs.
287605	105.142	Avoided Costs	180,276,646	180,276,646	0	0	0	0	Book-tax basis difference for the capitalization of interest for income tax purposes.
287704	105.143	Basis Intangible Difference	(1,149,249)	0	(1,149,249)	0	0	0	Book-tax basis difference for the capitalization of interest for income tax purposes specifically related to hydro-relicensing costs transferred to plant-in-service.
287605	105.120	Book Depreciation	2,583,224,642	2,583,224,642	0	0	0	0	Book-tax difference for book depreciation.
287605	105.470	Book Fixed Asset Gain/Loss	15,120,345	15,120,345	0	0	0	0	Book-tax difference related to land sales.
287605	105.146	Capitalization of Test Energy	4,409,120	4,409,120	0	0	0	0	Book-tax basis difference related to test energy revenues which are received/earned for power produced by generating plants during the construction period and sold or used by the utility.
287605	105.137	Capitalized Depreciation	(19,999,540)	(19,999,540)	0	0	0	0	Book-tax basis difference for the capitalization of vehicle depreciation.
287605	105.100	Capitalized labor and benefit costs	24,965,459	24,965,459	0	0	0	0	Book-tax basis difference related to the amount of labor costs capitalized to fixed assets.
287605	105.101	Capitalized labor costs - Medicare Subsidy	1,565,135	1,565,135	0	0	0	0	Book-tax basis difference related to the amount of labor overhead costs capitalized to fixed assets.
287605	- - - - -	Direct Assignment: Transmission Fixed Assets	0	755,854,774	0	(755,854,774)	0	0	PowerTax Report #257: Transmission Book Allocation Group.
287605	- - - - -	Direct Assignment: Intangible Fixed Assets	0	33,254,166	0	0	0	(33,254,166)	PowerTax Report #257: Intangible Book Allocation Group.
287605	- - - - -	Direct Assignment: General Fixed Assets	0	115,595,974	0	0	0	(115,595,974)	PowerTax Report #257: General Book Allocation Group.
287605	- - - - -	Direct Assignment: Production Fixed Assets	0	1,273,851,921	(1,273,851,921)	0	0	0	PowerTax Report #257: Production Book Allocation Group.
287605	- - - - -	Direct Assignment: Cholla Production Assets	0	(40,759,190)	40,759,190	0	0	0	PowerTax Report #257: Production Book Allocation Group contains Cholla steam plant ADIT. Because the Cholla steam plant has been excluded from the ancillary rate making formula, this line item removes the related ADIT balance.
287605	- - - - -	Direct Assignment: UT plant buy-down Production Assets	0	43,905,412	(43,905,412)	0	0	0	PowerTax Report #257: Production Book Allocation Group contains ADIT related to a Utah jurisdictional plant buy-down. Because this retail jurisdiction only plant buy-down has been excluded from the ancillary rate making formula, this line item removes the related ADIT balance.
287605	- - - - -	Direct Assignment: OR plant buy-down Production Assets	0	30,714,063	(30,714,063)	0	0	0	PowerTax Report #257: Production Book Allocation Group contains ADIT related to an Oregon jurisdictional plant buy-down. Because this retail jurisdiction only plant buy-down has been excluded from the ancillary rate making formula, this line item removes the related ADIT balance.
287608	105.222	Cholla SHL (Amortization of SHL Gain)	(1,249,802)	(1,249,802)	0	0	0	0	Book-tax difference for safe harbor lease agreement between PacifiCorp and General Electric Credit Corp for the Cholla generation plant.
287608	105.223	Cholla SHL NOPA (Lease Amortization)	554,727	554,727	0	0	0	0	Book-tax difference for safe harbor lease agreement between PacifiCorp and General Electric Credit Corp for the Cholla generation plant.
286922	415.732	Contra PP&E Cholla U4 Closure	6,215,869	6,215,869	0	0	0	0	Contra PP&E accounts established in order to record the impairment of Cholla U4 assets for non-recoverable jurisdictions.
287605	105.153	Contract Liability Basis Adj - Chehalis	(80,270)	(80,270)	0	0	0	0	Accrued liabilities related to the purchase of the Chehalis plant not currently deductible for income tax purposes.
287605	105.151	Contract Liability Basis Adj - Eagle Mountain	(280,477)	(280,477)	0	0	0	0	Eagle Mountain contract liabilities not currently deductible for income tax purposes.
287605	105.130	Contribution in Aid of Construction	273,504,977	273,504,977	0	0	0	0	Book-tax basis difference related to contributions in aid of construction.
287605	105.175	Cost of Removal	(208,192,051)	(208,192,051)	0	0	0	0	Book-tax difference for removal costs, which are applied to the depreciation/depreciation reserve for book purposes and are deductible for income tax purposes in the year paid and incurred.
287224	145.030	CWIP Reserve	2,013,897	2,013,897	0	0	0	0	PacifiCorp will open a customer work order for construction of a capital project and capitalize various costs incurred on these utility-related projects (i.e., generation facilities, transmission and distribution facilities, mining operations and corporate operations) for book purposes. Projects with less than 5% activity within the prior 6-month period are deemed inactive. Those inactive projects with capitalized costs are analyzed for potential recovery. For the amounts not expected to be recovered, a reserve is established, CWIP Reserve.
287605	105.141	Debt AFUDC	(171,917,417)	(171,917,417)	0	0	0	0	Book-tax basis difference related to the Allowance for Funds Used During Construction, which consists of a debt and equity component. Equity is not capitalizable or deductible for income tax purposes, and the Internal Revenue Code requires a different formula related to the capitalization of interest on debt.
287607	105.117	Effects of Ratemaking - Fixed Assets Fed only - PMI	(4,835,423)	(4,835,423)	0	0	0	0	Deferred tax balance associated with the protected property-related excess deferred income tax balances for PMI's portion of Bridger Coal Company's
287605	105.115	Effects of Ratemaking - Fixed Assets Flowthrough	(61,884,737)	(61,884,737)	0	0	0	0	Accounting adjustment to record the amount of deferred tax expense associated with fixed assets that have been previously been paid by customers at a tax rate higher than the current tax rate and are probable of being refunded as the temporary book-tax differences reverse and the amount of tax benefits associated with fixed assets that have previously been flowed through to customers and are probable of recovery as the temporary book-tax differences reverse and result in higher taxable income as compared to book income.

287605	105.139	Equity AFUDC	(97,657,175)	(97,657,175)	0	0	0	0	Book-tax basis difference related to the Allowance for Funds Used During Construction, which consists of a debt and equity component. Equity is not capitalizable or deductible for income tax purposes, and the Internal Revenue Code requires a different formula related to the capitalization of interest on debt.
287928	425.310	Hydro Relicensing Obligation	(3,699,347)	0	0	0	0	(3,699,347)	PacifiCorp accrues a liability for various stream enhancement obligations entered into for the new North Umpqua FERC license pursuant to Financial Accounting Standard 143.
287605	105.125	Tax Depreciation	(4,784,152,172)	(4,784,152,172)	0	0	0	0	Book-tax difference for tax depreciation.
287605	105.152	Tax Fixed Asset Gain/Loss	(62,118,620)	(62,118,620)	0	0	0	0	book-tax difference related to the disposition of capital assets.
287605	105.129	Fixed Assets - State Modifications	19,912,567	0	0	0	19,912,567	0	Tax adjustment to account for the difference between federal and state depreciation methodologies; primarily resulting from states that have not adopted bonus depreciation.
287605	105.148	Mine Safety Sec. 179E Election	(306,514)	(306,514)	0	0	0	0	Book-tax basis difference for qualified advanced mine safety equipment, 50% of which is deductible in the period paid and incurred for income tax purposes.
287929	105.460	Non-ARO Removal Costs	(253,053,650)	(253,053,650)	0	0	0	0	Regulatory liability related to removal costs.
286605	105.136	PP&E FIN 48 Balances	(383,923)	(383,923)	0	0	0	0	PP&E book to tax differences for which the accumulated deferred income tax liability is expected to be reversed upon audit by the Internal Revenue Service.
287605	320.210	R & E - Sec.174 Deduction	(7,719,946)	(7,719,946)	0	0	0	0	Book-tax difference for eligible costs under Internal Revenue Code Section 174 for internally developed software which are deductible in the period paid and incurred for income tax purposes. These costs are capitalized for book purposes.
286914	415.525	RA - Lease Depreciation - Timing Difference	(132,528)	(132,528)	0	0	0	0	Regulatory asset established to account for the cumulative GAAP to FERC timing difference in depreciation expense, by finance lease agreement. GAAP reflects monthly depreciation straight line over the term of the lease vs. FERC where monthly depreciation expense is derived by the net of the lease payment less accrued lease interest.
287605	100.110	RA- Solar ITC Basis Adj. - Fixed Assets	(25,900)	(25,900)	0	0	0	0	PacifiCorp installed solar arrays. The projects are qualified for the 30% solar investment tax credit (ITC). The tax basis of the solar arrays needs to be reduced by one-half of the solar ITC, therefore creating basis differences between book basis and tax basis for the solar arrays.
287605	105.158	Reclass to §1031 & 1033 Exchange Normalization Adj - General Fixed Assets	183,468	0	0	0	0	183,468	Reclass to separately state the exclusion of ADIT from §1031 & 1033 Exchanges pursuant to the income tax normalization rules.
287605	105.159	Reclass to §1031 &1033 Exchange Normalization Adj - Transmission	4,045,687	0	0	4,045,687	0	0	Reclass to separately state the exclusion of ADIT from §1031 & 1033 Exchanges pursuant to the income tax normalization rules.
287605	105.159	Reclass to §1031 &1033 Exchange Normalization Adj - Other Property	166,925	166,925	0	0	0	0	Reclass to separately state the exclusion of ADIT from §1031 & 1033 Exchanges pursuant to the income tax normalization rules.
287605	105.131	Reclass to Pollution Control Facilities Depreciation	174,829,838	174,829,838	0	0	0	0	Reclassification of pollution controls facilities depreciation from FERC account 282 to FERC account 281.
287605	105.140	Reimbursements	22,255,287	22,255,287	0	0	0	0	Book-tax basis difference related to relocation reimbursements, which depending on whether or not the benefit of the relocation is for the benefit of the general public may or may not be taxable and depreciable for income tax purposes.
287605	105.122	Repairs Deduction	(417,452,167)	(417,452,167)	0	0	0	0	Book-tax basis difference for expenditures which are capitalized and depreciation for book purposes and for income tax purposes are deductible in the period they are paid and incurred.
287221	415.933	RL - Contra-Carbon Decommissioning - ID	(298,254)	(298,254)	0	0	0	0	This account was set up to record a contra regulatory liability for Idaho's share of Carbon Plant's decommissioning accrual that was directed to be a regulatory asset per the Idaho general rate order/stipulation (Docket PAC-E-13-04).
287222	415.934	RL - Contra-Carbon Decommissioning - UT	(2,157,491)	(2,157,491)	0	0	0	0	This account was set up to record a contra regulatory liability for Utah's share of Carbon Plant's decommissioning accrual that was directed to be a regulatory asset per the Utah general rate order/stipulation (Docket 11-035-
287223	415.935	RL - Contra-Carbon Decommissioning - WY	(109,781)	(109,781)	0	0	0	0	This account was set up to record a contra regulatory liability for Wyoming's share of Carbon Plant's decommissioning accrual that was directed to be a regulatory asset per the Wyoming general rate order/stipulation (Docket 20000-405-ER11).
287189	100.122	RL - Effects of Ratemaking - Fixed Assets - PMI Fed Only	4,835,423	4,835,423	0	0	0	0	Regulatory liability established to account for the deferral of protected property-related EDIT for PMI's portion of Bridger Coal Company fixed assets
287187	100.121	RL - Effects of Ratemaking - Fixed Assets	(176,926,379)	(176,926,379)	0	0	0	0	Accounting adjustment to record the amount of deferred tax expense associated with fixed assets that have been previously been paid by customers at a tax rate higher than the current tax rate and are probable of being refunded as the temporary book-tax differences reverse and the amount of tax benefits associated with fixed assets that have previously been flowed through to customers and are probable of recovery as the temporary book-tax differences reverse and result in higher taxable income as compared to book income.
287313	105.450	RL - Non-ARO Liability	253,053,650	253,053,650	0	0	0	0	Regulatory liability related to removal costs.
286915	425.155	ROU Asset (Operating Lease)	(2,990,142)	0	(2,990,142)	0	0	0	Operating lease assets established pursuant to the new leasing accounting standards under ASC 842.
287605	105.135	Safe Harbor Lease Rate Differential	(2,623,171)	(2,623,171)	0	0	0	0	Book-tax basis difference related to safe harbor lease rate differential. (Federal ONLY vs. Federal + State).

287605	105.123	Sec. 481a Adjustment - Repair Deduction	(157,315,608)	(157,315,608)	0	0	0	0	Book-tax difference related to a one-time adjustment required by the Internal Revenue Code for a change in accounting method for income tax purposes. In 2008, PacifiCorp changed its method of accounting for income tax purposes for certain expenditures which were previously being capitalized and depreciated. Under the new method of accounting, the expenditures are deductible for income tax purposes in the period they are paid and incurred.
287605	105.116	Solar ITC Basis Adjustment	(8,607)	(8,607)	0	0	0	0	The projects are qualified for the 30% solar investment tax credit (ITC). The tax basis of the solar arrays needs to be reduced by one-half of the solar ITC, therefore creating basis differences between book basis and tax basis for the solar arrays.
287771	110.205	Tax Depletion-SRC	147,478	0	147,478	0	0	0	Book-tax difference related to different methods for computing deductible periodic depletion for book and tax purposes.
287301	105.471	UT Klamath Relicensing Costs	8,680,735	8,680,735	0	0	0	0	Book-tax difference related to relicensing cost for Klamath Dam.
	Rounding		2	2	0	0	0	0	
Subtotal - p275			(2,889,829,879)	(693,916,430)	(1,311,650,910)	(751,809,087)	19,912,567	(152,366,019)	
Less FASB 109 Above if not separately removed			(172,090,956)	(172,090,956)	0	0	0	0	
Less FASB 106 Above if not separately removed			0	0	0	0	0	0	
Total			(2,717,738,923)	(521,825,474)	(1,311,650,910)	(751,809,087)	19,912,567	(152,366,019)	

Instructions for Account 282:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F
5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

Schedule ADIT-283

A			B	C	D	E	F	G	H
			Total Company	Gas, Prod, Dist Or Other Related	Production Related	Transmission Related	Plant Related	Labor Related	Justification
Account 283									
FERC 283 - Regulatory Assets									
287849	415.424	Contra RA - Deer Creek Abandonment	25,123,884	25,123,884	0	0	0	0	Regulatory asset used to record a contra regulatory asset for Deer Creek abandonment.
287841	415.411	Contra RA - Deer Creek Abandonment - CA	602,713	602,713	0	0	0	0	Regulatory asset to record CA contra regulatory asset for Deer Creek
287842	415.412	Contra RA - Deer Creek Abandonment - ID	516,176	516,176	0	0	0	0	Regulatory asset to record ID contra regulatory asset for Deer Creek abandonment.
287843	415.413	Contra RA - Deer Creek Abandonment - OR	2,164,978	2,164,978	0	0	0	0	Regulatory asset to record OR contra regulatory asset for Deer Creek abandonment.
287844	415.414	Contra RA - Deer Creek Abandonment - UT	967,340	967,340	0	0	0	0	Regulatory asset to record UT contra regulatory asset for Deer Creek abandonment.
287845	415.415	Contra RA - Deer Creek Abandonment - WA	2,703,364	2,703,364	0	0	0	0	Regulatory asset to record WA contra regulatory asset for Deer Creek abandonment.
287846	415.416	Contra RA - Deer Creek Abandonment - WY	609,664	609,664	0	0	0	0	Regulatory asset to record WY contra regulatory asset for Deer Creek abandonment.
287850	415.425	Contra RA - UMWA Pension	1,168,493	1,168,493	0	0	0	0	Contra regulatory asset for all the recovery (amortization) and other adjustments to the UMWA pension trust withdrawal obligation regulatory asset included in the Deer Creek Mine disposition.
287851	415.417	Contra RA - UMWA Pension - CA	443,826	443,826	0	0	0	0	Contra regulatory asset for all the CA related recovery (amortization) and other adjustments to the UMWA pension trust withdrawal obligation regulatory asset included in the Deer Creek Mine disposition.
287855	415.421	Contra RA - UMWA Pension - WA	1,990,706	1,990,706	0	0	0	0	Contra regulatory asset for all the WA related recovery (amortization) and other adjustments to the UMWA pension trust withdrawal obligation regulatory asset included in the Deer Creek Mine disposition.
286921	415.731	Contra RA - Cholla U4 Closure WA/FERC	510,042	510,042	0	0	0	0	Contra regulatory asset established to account for the estimate of unrecoverable amounts in the Cholla U4 Regulatory asset (415.725)
287747	705.240	RA - Alt Rate for Energy Program (CARE) - CA	(2,376)	(2,376)	0	0	0	0	Regulatory asset to record benefits and administrative costs related to the California Alternative Rate for Energy, or CARE, program.
287642	105.401	RA - ARO	(34,471,952)	(34,471,952)	0	0	0	0	Regulatory asset used to record the depreciation/accretion associated with FAS 143 asset retirement obligations.
287911	415.699	RA - BPA Balancing Account - OR	(2,101,010)	(2,101,010)	0	0	0	0	Regulatory asset to record the pass-through benefit to Oregon customers from the BPA. Qualifying customers, such as those who meet specified reductions in energy use during peak hours, are rewarded with a credit to their bill. Moved from 2014 account 137332.
287914	715.721	RA - BPA Balancing Account - WA	(48,507)	(48,507)	0	0	0	0	Regulatory asset to record the pass-through benefit to Washington customers from the BPA. Qualifying customers, such as those who meet specified reductions in energy use during peak hours, are rewarded with a credit to their bill.
287997	415.862	RA - CA Mobile Home Park Conversion	(49,962)	(49,962)	0	0	0	0	Balancing account to record the program costs for the conversion of master metered mobile home parks to direct utility service.
287935	415.936	RA - Carbon Plant Decomm/Inventory	(847,911)	(847,911)	0	0	0	0	Regulatory asset established to record the deferral of Carbon Plant's write off and sales proceeds of inventory from decommissioning.
286901	415.938	RA - Carbon Plant Decomm/Inventory - CA	12,797	12,797	0	0	0	0	Regulatory asset established to record CA's share of the deferral of Carbon Plant's write off and sales proceeds of inventory from decommissioning.
286900	415.937	RA - Carbon Plant Decomm/Inventory - WA	68,301	68,301	0	0	0	0	Regulatory asset established to record WA's share of the deferral of Carbon Plant's write off and sales proceeds of inventory from decommissioning.
287984	415.923	RA - Carbon Unrecovered Plant - ID	(117,681)	(117,681)	0	0	0	0	Regulatory asset established to record Idaho's share of the deferral of Carbon Plant's increased depreciation due to the implementation of new rates on January 1, 2014.
287985	415.924	RA - Carbon Unrecovered Plant - UT	(846,920)	(846,920)	0	0	0	0	Regulatory asset established to record Utah's share of the deferral of Carbon Plant's increased depreciation due to the implementation of new rates on January 1, 2014.

287986	415.925	RA - Carbon Unrecovered Plant - WY	(284,759)	(284,759)	0	0	0	0	Regulatory asset established to record Wyoming's share of the deferral of Carbon Plant's increased depreciation due to the implementation of new rates on January 1, 2014.
286920	415.725	RA - Cholla U4 Closure	(6,776,576)	(6,776,576)	0	0	0	0	Regulatory asset established to account for the estimate of recoverable amounts related to the Cholla U4 closure.
286913	415.720	RA - Community Solar - OR	(122,373)	(122,373)	0	0	0	0	Regulatory asset established to account for the deferral of costs related to the Oregon Community Solar Program.
287781	415.870	RA - Deferred Excess NPC - CA - Noncurrent	(1,470,852)	(1,470,852)	0	0	0	0	Regulatory asset established for reclass non-current portion of CA Deferred Excess NPC.
287596	415.892	RA - Deferred Excess NPC - ID - Noncurrent	(6,156,691)	(6,156,691)	0	0	0	0	Regulatory asset established for noncurrent portion of recoverable net power costs in Idaho pursuant to an energy cost adjustment mechanism.
287882	415.892	RA - Deferred Excess NPC - OR - Noncurrent	(732,750)	(732,750)	0	0	0	0	Regulatory asset established for noncurrent portion of recoverable net power costs in Idaho pursuant to an energy cost adjustment mechanism.
287896	415.875	RA - Deferred Excess NPC - UT - Noncurrent	(13,037,905)	(13,037,905)	0	0	0	0	Regulatory asset established for noncurrent portion of recoverable net power costs in Utah pursuant to an energy cost adjustment clause.
287593	415.874	RA - Deferred Excess NPC - WY '09 & After - Noncurrent	(4,616,333)	(4,616,333)	0	0	0	0	Regulatory asset established for noncurrent portion of recoverable net power costs in Wyoming pursuant to a power costs adjustment mechanism.
287783	415.880	RA - Deferred Independent Evaluator Fee - UT	26,525	26,525	0	0	0	0	Regulatory asset established for the Utah allocated share of evaluator fees and costs related to a request for proposal for new generation.
287570	415.701	RA - Deferred Intervenor Funding Grants - CA	(10,756)	(10,756)	0	0	0	0	Regulatory asset/liability established to record funding for qualifying intervenors that are collected from customers through California rates.
287647	425.100	RA - Deferred Intervenor Funding Grants - ID	(16,440)	(16,440)	0	0	0	0	Regulatory asset/liability established to record funding for qualifying intervenors that are collected from customers through Idaho rates.
287640	415.680	RA - Deferred Intervenor Funding Grants - OR	(368,012)	(368,012)	0	0	0	0	Regulatory asset/liability established to record funding for qualifying intervenors that are collected from customers through Oregon rates.
287861	415.857	RA - Deferred Overburden Costs - ID	(92,979)	(92,979)	0	0	0	0	Regulatory asset established for the Idaho allocated portion of overburden costs pursuant to a regulatory order.
287868	415.858	RA - Deferred Overburden Costs - WY	(261,619)	(261,619)	0	0	0	0	Regulatory asset established for the Wyoming allocated portion of overburden costs pursuant to a regulatory order.
287614	430.100	RA - Demand Side Management - Noncurrent	3,042,963	3,042,963	0	0	0	0	Regulatory asset established to record costs incurred for demand side management which are amortized according to guidelines established by each state regulatory jurisdiction.
287981	415.920	RA - Depreciation Increase - Idaho	18,902	18,902	0	0	0	0	Regulatory asset established to record Idaho's share of the deferral of increased depreciation due to the implementation of new rates on January 1, 2014.
287982	415.921	RA - Depreciation Increase - Utah	(362,037)	(362,037)	0	0	0	0	Regulatory asset established to record Utah's share of the deferral of increased depreciation due to the implementation of new rates on January 1, 2014.
287983	415.922	RA - Depreciation Increase - Wyoming	(1,250,277)	(1,250,277)	0	0	0	0	Regulatory asset established to record Wyoming's share of the deferral of increased depreciation due to the implementation of new rates on January
287576	430.110	RA - DSM Balance Reclass	(5,053,830)	(5,053,830)	0	0	0	0	Reclass of miscellaneous regulatory assets/liabilities that have flipped to debit/credit balances.
287840	415.410	RA - Energy West Mining	(67,001,831)	(67,001,831)	0	0	0	0	In December 2014, abandonment costs were recorded in connection with the anticipated closure of the Deer Creek mine in Emery County, UT. The Company filed a deferred accounting application with the applicable state commissions.
287634	415.300	RA - Environmental Costs	(21,521,009)	(21,521,009)	0	0	0	0	Regulatory asset established to record costs incurred for environmental clean-up, which are amortized over a ten-year period for state regulatory purposes.
287591	415.301	RA - Environmental Costs - WA	537,160	537,160	0	0	0	0	Regulatory liability established for the portion of environmental remediation costs for which the state of Washington does not allow deferred treatment.
287738	320.270	RA - FAS 158 Pension Liability	(103,373,649)	(103,373,649)	0	0	0	0	Regulatory asset established to track the recoverable expenses associated with pension liability.
287739	320.280	RA - FAS 158 Post Retirement Liability	1,885,101	1,885,101	0	0	0	0	Regulatory asset established to track the recoverable expenses associated with post-retirement benefits liability.
286917	415.260	RA - Fire Risk Mitigation - CA	(780,256)	(780,256)	0	0	0	0	Regulatory asset established for the defered costs related to the California Fire Risk Mitigation Memorandum Account pursuant to Docket 19-05-042.
287597	415.703	RA - Goodnoe Hills Settlement - WY	(73,145)	(73,145)	0	0	0	0	Regulatory asset for the Wyoming allocated portion of a settlement associated with damages sustained at the Goodnoe Hills generating plant.
286905	415.530	RA - ID 2017 Protocol - MSP Deferral	(73,760)	(73,760)	0	0	0	0	Regulatory asset established to record the Idaho multi-state protocol deferral assumed in 2018.
287897	425.400	RA - Klamath Hydroelectric Relicensing Costs - UT	(2,951,084)	(2,951,084)	0	0	0	0	The book-tax difference resulting from this regulatory asset.
287571	415.702	RA - Lake Side Settlement - WY	(186,472)	(186,472)	0	0	0	0	Regulatory asset for the Wyoming allocated portion of a settlement associated with damages sustained at the Lake Side generating plant.
287903	415.879	RA - Liquidation Damages - N2 - WY	(19,646)	(19,646)	0	0	0	0	Regulatory asset established to record Wyoming's share of liquidating
287977	415.885	RA - Noncurrent Reclass - Other	(26,525)	(26,525)	0	0	0	0	SAP account used for financial statement presentation purposes to reclass the current and noncurrent portion of regulatory assets to liabilities when the balance of the regulatory assets result in a credit balance.
287919	425.105	RA - OR Asset Sale Gain GB - Noncurrent	(231,784)	(231,784)	0	0	0	0	Regulatory asset established to reclass noncurrent portion of OR asset sale gain giveback
286910	415.200	RA - OR Transportation Electrification Pilot	(200,968)	(200,968)	0	0	0	0	Pilot Program set up in March 2018 to record costs and collect fees connected to Oregon transportation electrification pilot programs.
287942	430.112	RA - Other - Balance Reclass	(428,560)	(428,560)	0	0	0	0	Reclass of miscellaneous regulatory assets/liabilityies that have flipped to debit/credit balances.
287583	415.826	RA - Pension Settlement - WA	(348,899)	(348,899)	0	0	0	0	Regulatory asset established to recover Washington's portion of a $22m pension settlement that occurred in 2018.
287972	320.285	RA - Post Employment Costs	(110,411)	0	0	0	0	(110,411)	Regulatory asset established as an offset to the increase in post-employment obligations.
287675	740.100	RA - Post Merger Loss - Reacquired Debt	(976,377)	(976,377)	0	0	0	0	Asset accrued for required debt, amortized for book purposes over the

287864	415.852	RA - Powerdale Decommissioning - ID	(6,867)	(6,867)	0	0	0	0	Regulatory asset established for the unrecovered portion of the Powerdale hydroelectric generating facility and decommissioning costs allocable to Idaho. The Powerdale hydroelectric facility was severely damaged by flooding and the related debris flow and is being removed rather than being repaired.
287858	415.676	RA - Preferred Stock Redemption - WY	(29,428)	(29,428)	0	0	0	0	Reg Asset - WY - Preferred Stock Redemption Cost was set up in August 2014 to record Utah's portion of redemption cost.
287996	415.675	RA - Preferred Stock Redemption Loss - UT	(85,393)	(85,393)	0	0	0	0	Reg Asset - UT - Preferred Stock Redemption Cost was set up in August 2014 to record Utah's portion of redemption cost.
287601	415.677	RA - Preferred Stock Redemption Loss - WA	(13,643)	(13,643)	0	0	0	0	Reg Asset established to record Washington's portion of stock redemption costs.
287888	415.882	RA - REC Sales Deferral - WA - Noncurrent	(11,778)	(11,778)	0	0	0	0	Regulatory asset established to capture the noncurrent portion of the difference between renewable energy credits (RECs) included in rates and actual RECs for the Washington jurisdiction.
287889	415.883	RA - REC Sales Deferral - WY - Noncurrent	(42,427)	(42,427)	0	0	0	0	Regulatory asset established for the noncurrent portion of Wyoming renewable energy credits included in rates that differ from actual renewable energy credits.
287871	415.866	RA - Solar Feed-In Tariff Deferral - OR - Noncurrent	(1,385,219)	(1,385,219)	0	0	0	0	Regulatory asset established for the noncurrent portion of costs incurred
287971	415.868	RA - Solar Incentive Program - UT - Noncurrent	(3,634,221)	(3,634,221)	0	0	0	0	Regulatory asset established for the UT Solar incentive program costs.
287927	100.110	RA - Solar ITC Basis Adjustment - Gross Up	(8,444)	(8,444)	0	0	0	0	The projects are qualified for the 30% solar investment tax credit (ITC). The tax basis of the solar arrays needs to be reduced by one-half of the solar ITC, therefore creating basis differences between book basis and tax basis for the solar arrays. This is the revenue requirement gross-up for that difference.
287960	415.855	RA - Storm Damage Deferral - CA	(258,922)	(258,922)	0	0	0	0	Regulatory Asset established based on CA Decision 16-03-015 which provided for a surcharge to recover $545,000 of costs recorded related to a storm in California.
286911	415.430	RA - Transportation Electrification Pilot - CA	97,350	97,350	0	0	0	0	Pilot Program approved in September 2018 to record costs and collect fees connected to transportation electrification pilot programs.
286912	415.431	RA - Transportation Electrification Pilot - WA	(33,687)	(33,687)	0	0	0	0	Pilot Program approved in September 2018 to record costs and collect fees connected to transportation electrification pilot programs.
286906	415.531	RA - UT 2017 Protocol - MSP Deferral	(3,245,431)	(3,245,431)	0	0	0	0	Regulatory asset established to record the Utah multi-state protocol deferral assumed in 2017 and 2018.
287899	415.878	RA - UT Liquidation Damages	(120,474)	(120,474)	0	0	0	0	Regulatory asset established for Utah portion of liquidated damages payments for outages at Jim Bridger Unit4, Naughton Unit 1 and Unit 2.
287906	415.863	RA - UT Subscriber Solar Program	(424,094)	(424,094)	0	0	0	0	Regulatory asset established for the UT Subscriber Solar Program.
287939	415.115	RA - Utah STEP Pilot Program Balance Account	3,634,221	3,634,221	0	0	0	0	To record a regulatory asset balancing account for the costs and collections of the Utah Sustainable Transportation and Energy Plan (STEP) Pilot Programs.
287639	415.510	RA - WA Colstrip #3	(13,908)	(13,908)	0	0	0	0	Regulatory asset established for the Washington disallowed portion of AFUDC on the Colstrip #3 generating plant.
287857	415.545	RA - WA Merwin Project	844	844	0	0	0	0	Regulatory asset established to record the deferral of the Merwin Project costs approved by the Washington Utility and Transportation Commission (WUTC).
286907	415.532	RA - WY 2017 Protocol - MSP Deferral	(983,464)	(983,464)	0	0	0	0	Regulatory asset established to record the Wyoming multi-state protocol deferral assumed in 2017 and 2018.
287848	320.281	RA - Post Retirement Settlement Loss	(1,505,574)	(1,505,574)	0	0	0	0	Regulatory asset established to record a FAS 106 regulatory asset for the settlement loss on retiree medical obligations.
287933	320.282	RA - Post Retirement Settlement Loss CC - UT	(379,526)	(379,526)	0	0	0	0	Regulatory asset established to segregate the accumulated Utah carrying charges to be recovered on Utah's allocable share of the post-retirement medical settlement loss.
287917	705.451	RL - Property Insurance Reserve - OR	(2,617,810)	(2,617,810)	0	0	0	0	Regulatory liability used to record the Oregon allocation of storm-related property damage recovered in excess of insurance claims incurred.
287649	730.170	RA - FAS133 Unrealized Gain/Loss	(15,267,854)	(15,267,854)	0	0	0	0	Regulatory assets established to record the effects of the accounting pursuant to FASB Statement No. 133, which requires that certain financial instruments be valued at FMV for book purposes.
287886	415.837	RA - Frozen MTM	(14,792,317)	(14,792,317)	0	0	0	0	Reclass of regulatory asset from derivative regulatory asset to an other regulatory asset for frozen derivative.
FERC 283 - Other									
287936	205.025	Fuel Cost Adjustment	(35,837)	(35,837)	0	0	0	0	Beginning in May 2008, Bridger Coal/PMI earnings are recorded as a debit to investment in Bridger Coal and a credit to coal inventory.
287661	425.360	Hermiston Swap	(700,041)	(700,041)	0	0	0	0	Asset accrued for a deferred expense related to a termination fee incurred by PacifiCorp when it acquired a 50% interest in the Hermiston generating plant. For book purposes, the cost is being amortized over the remaining life of the plant.
286909	720.815	FAS 158 Post-Retirement Asset	(6,654,594)	(6,654,594)	0	0	0	0	The total overfunded Other Post-Employment Benefit Obligations (OPEB) asset, excluding Medicare subsidy, required under FAS 158.
286918	210.175	Prepaid - FSA O&M - East	(62,069)	0	(62,069)	0	0	0	Prepaid account established to record prepaid operating and maintenance advance payments for the east side repowered wind facilities.
287669	210.180	Prepaid Membership Fees	(126,970)	0	(126,970)	0	0	0	Asset accrued for prepaid membership fees, amortized for book purposes over a period of 12 months or less.
287907	210.185	Prepaid Aircraft Maintenance	(80,462)	(80,462)	0	0	0	0	Regulatory asset established for prepaid aircraft maintenance costs.
287665	210.130	Prepaid Taxes - ID PUC	(88,988)	(88,988)	0	0	0	0	Asset accrued for prepaid Idaho commission fee, amortized for book purposes over a period of 12 months or less.
287662	210.100	Prepaid Taxes - OR PUC	(248,396)	(248,396)	0	0	0	0	Asset accrued for prepaid Oregon commission fee, amortized for book purposes over a period of 12 months or less.
287708	210.200	Prepaid Taxes - Property Taxes	(3,540,946)	0	0	0	(3,540,946)	0	Book-tax difference associated with the timing of deductibility of property taxes.
286908	210.201	Prepaid Taxes - Property Tax FIN 48	(3,391,794)	0	0	0	(3,391,794)	0	Prepaid property tax book to tax differences for which the accumulated deferred income tax liability is expected to be reversed upon audit by the Internal Revenue Service.
287664	210.120	Prepaid Taxes - UT PUC	(763,250)	(763,250)	0	0	0	0	Asset accrued for prepaid Utah commission fee, amortized for book purposes over a period of 12 months or less.
287908	210.190	Prepaid Water Rights	(137,093)	0	(137,093)	0	0	0	Regulatory asset accrued for prepaid water rights and water fees. Moved from 2014 account 137511.

287289	425.130	Rogue River-Habitat Enhance	(55,282)	(55,282)	0	0	0	0	Accrued liability associated with the acceptance of the Rogue River (Prospects 1, 2, & 4) FERC license, PacifiCorp is obligated to pay the Oregon Department of Fish and Wildlife $1,000,000, escalated, over a period of 9 years for habitat enhancement.
287653	425.250	TGS Buyout	(318)	(318)	0	0	0	0	Asset accrued for a deferred expense related to costs incurred for the termination of a power purchase agreement. For book purposes, the costs are being amortized over the remaining life of the original contract.
287770	120.205	Trapper Mining Stock Basis	(1,299,489)	(1,299,489)	0	0	0	0	Equity earnings for Trapper Mine. The equity method of accounting does not apply for income tax purposes.
287859	910.935	Def Comp Mark to Market Gain/Loss - Income Statement	(499,060)	0	0	0	0	(499,060)	Deferred compensation plan investments are being treated as "trading securities" where they are invested based upon the plan participants' personal investment elections. Starting in July 2010, the investments are reflected at fair market value and any unrealized gains or losses are reflected in earnings.
287217	910.937	LTIP Mark to Mkt Gain/Loss	(573,811)	0	0	0	0	(573,811)	To record unrealized gains/losses from the long term incentive plan.
287966	415.834	Noncurrent Asset - Frozen MTM	(2,729,473)	(2,729,473)	0	0	0	0	Regulatory liability established to record the reclass of a derivative
287492	- - - - -	OR BETC - Purchased Credits - Non-Cash	(45,658)	(45,658)	0	0	0	0	Book-tax difference related to the Gain on purchased Business Energy Tax Credits.
Rounding			(3)	(3)	0	0	0	0	
Subtotal - p277			(297,173,549)	(288,731,395)	(326,132)	0	(6,932,740)	(1,183,282)	
Less FASB 109 Above if not separately removed			(8,444)	(8,444)	0	0	0	0	
Less FASB 106 Above if not separately removed			0	0	0	0	0	0	
Total			(297,165,105)	(288,722,951)	(326,132)	0	(6,932,740)	(1,183,282)	

Instructions for Account 283:
1. ADIT items related only to Non-Electric Operations (e.g., Gas, Water, Sewer) or Production are directly assigned to Column C
2. ADIT items related only to Transmission are directly assigned to Column D
3. ADIT items related to Plant and not in Columns C & D are included in Column E
4. ADIT items related to labor and not in Columns C & D are included in Column F

5. Deferred income taxes arise when items are included in taxable income in different periods than they are included in rates, therefore if the item giving rise to the ADIT is not included in the formula, the associated ADIT amount shall be excluded.

Excess Deferred Income Tax Summary

Line	Item	Generation	General	Intangible	Total
1	Total Excess Deferred Income Tax (Protected & Non-Protected)	(734,237,784)	(70,076,680)	(19,572,375)	(823,886,840)
2	Allocable to Production	100%	44.9292% A	44.9292% A	
3	**Production Allocable Excess Deferred Income Tax**	**(734,237,784)**	**(31,484,866)**	**(8,793,704)**	**(774,516,354)**
4	EDIT Amortization: 12/31/2018	(40,670,273)	(1,980,180)	(553,063)	(43,203,517)
5	EDIT Amortization: 12/31/2019	(42,150,521)	(1,980,180)	(553,063)	(44,683,765)
6	EDIT Amortization: 12/31/2020	(41,488,199)	(1,980,180)	(553,063)	(44,021,442)
7	EDIT Amortization: 12/31/2021	(39,108,703)	(1,435,074)	(400,815)	(40,944,593)
8	EDIT Amortization: 12/31/2022	(39,108,703)	(1,435,074)	(400,815)	(40,944,593)
9	EDIT Amortization: 12/31/2023	(39,108,703)	(1,435,074)	(400,815)	(40,944,593)
10	EDIT Amortization: 12/31/2024	(39,108,703)	(1,435,074)	(400,815)	(40,944,593)
11	EDIT Amortization: 12/31/2025	(39,072,524)	(1,435,074)	(400,815)	(40,908,413)

A 2017 Wage Allocation Factor

Note 1 Production allocable excess deferred income tax, both protected and non-protected, are being amortized over the remaining regulatory life of the related asset or group of assets using the Reverse South Georgia Method (RSGM).

Note 2 PacfiCorp uses jurisdictionally specific remaining regulatory lives to amortize protected excess deferred income tax. Rather than using multiple regulatory lives for an asset or group of asset, the Company is using the longest jurisdictional regulatory life to amortize excess deferred income tax for each asset or group of assets.

	Year	Beginning Balance	Annual Amortization	Ending Balance	Beg. / End. Avg.	
12	2018	(774,516,354)	(43,203,517)	(731,312,837)	(365,656,419)	B
13	2019	(731,312,837)	(44,683,765)	(686,629,073)	(708,970,955)	
14	2020	(686,629,073)	(44,021,442)	(642,607,630)	(664,618,351)	
15	2021	(642,607,630)	(40,944,593)	(601,663,038)	(622,135,334)	
16	2022	(601,663,038)	(40,944,593)	(560,718,445)	(581,190,741)	
17	2023	(560,718,445)	(40,944,593)	(519,773,852)	(540,246,148)	
18	2024	(519,773,852)	(40,944,593)	(478,829,259)	(499,301,556)	
19	2025	(478,829,259)	(40,908,413)	(437,920,846)	(458,375,052)	

B For the calendar year ended December 31, 2018, the balance is included in in FERC Acct. 282. Accordingly, it is excluded from the separately reported rate base adjustment in Appendix A to avoid being double counted.

20	**Total Production excess or deficient ADIT amortization**	**2019**	**(44,683,765)**	**Attachment A, line 135b input**
21	**Total Production excess or deficient ADIT Average Balance**		**(708,970,955)**	**Attachment A, line 33b input**

Note 1: For the calendar year ended December 31, 2018, the excess ADIT balance is included in in FERC Acct. 282. Accordingly, it is excluded from the separately reported rate base adjustment in Attachment A to avoid being double counted.

PacifiCorp
Taxes Other Than Income Taxes

Line	Other Taxes	Page 263, Col (i)	Allocator	Allocated Amount	
	Plant Related		Production Net Plant Allocator		
1	Real Property	148,291,559			2019 True-Up value
2	Possessory taxes	497,828			2019 True-Up value
3					
4	**Total Plant Related**	148,789,387	45.7092%	68,010,476	
	Labor Related		Wages & Salary Allocator		
5	Federal FICA	0			2019 True-Up value
6	Federal Unemployment	0			2019 True-Up value
7	State Unemployment	0			2019 True-Up value
8					
9	**Total Labor Related**	0	44.9558%	0	
	Other Included		Production Net Plant Allocator		
10	Annual Report	76,984			2019 True-Up value
11					
12	**Total Other Included**	76,984	45.7092%	35,189	
13	**Attachment A input: Total Included Taxes (Lines 4 + 9 + 12)**	148,866,371		**68,045,665**	<--Attachment A input
	Currently Excluded				
14	Local Franchise	33,375,023			2019 True-Up value
15	Montana Energy License	228,670			2019 True-Up value
16	Montana Wholesale Energy	162,925			2019 True-Up value
17	Idaho Generation Tax (KWh)	58,058			2019 True-Up value
18	Oregon Department of Energy	1,611,450			2019 True-Up value
19	Wyoming Wind Generation Tax	2,050,814			2019 True-Up value
20	Washington Public Utility Tax	12,517,338			2019 True-Up value
21	Other (Navajo Nation, Business & Occupation, Other)	266,377			2019 True-Up value
22					
23	**Subtotal Excluded Taxes**	50,270,655			
24	**Total Other Taxes Included and Excluded (Line 13 + Line 23)**	199,137,026			
	Total Other Taxes				
25	114.14c	199,137,026			<--2019 value (FERC 408.1)
26	Difference (Line 24 - Line 25)	0			<--should indicate only rounding error

Line	Description	Notes	Reference	Value	Production FCR Notes
	Account 454 - Rent from Electric Property				
1	Rent from Elelctric Property - **Production** Related			750,295	Rent revenues from steam and hydro generating facilities.
2	Pole Attachments - Transmission Related			0	Pole attachments are transmission-related revenues. Value for production is zero.
3	Distribution Underbuild - Transmission Related		*detail below*	0	Distribution underbuild revenues are transmission-related revenues. Value for production is zero.
4	Various Rents - Transmission Related			0	No rental revenues at production facilities except for revenues included in line 1.
5	Miscellaneous General Revenues - allocated to **Production**		*detail below*	863,089	Adjusted for production using allocator
6	**Account 454 subtotal**		(Sum Lines 1-5)	**1,613,383**	
	Account 456 - Other Electric Revenues (Note 1)				
7	Transmission for Others	Note 3	Attachment 13	0	Lines 7-11 are not included in production revenue credits as all items are transmission-related.
8	Net revenues associated with Network Integration Transmission Service (NITS) for which the load is not included in the divisor	Note 3		0	
9	Short-term firm and non-firm service revenues for which the load is not included in the divisor received by Transmission Owner		Attachment 13	0	
10	Facilities Charges including Interconnection Agreements	Note 2		0	
11	Transmission maintenance revenue		Account 456.2	0	
12	**Account 456 subtotal**		(Sum Lines 7-11)	**0**	
13	**Attachment A input: Gross Revenue Credits**		(Sum Lines 6 &12)	**1,613,383**	<--'Attachment A' input

Detail for selected items above

	Miscellaneous General Revenues			
14	Rents - General		131,256	2019 True-Up value
15	One Utah Center and North Temple office subleases		672,664	2019 True-Up value
16	Parking Rent: Lloyd Center, Portland, Oregon		1,117,440	2019 True-Up value
17	Rents - Common Affiliate - Kern River		0	2019 True-Up value
18	Rents - Non-Common		(1,500)	2019 True-Up value
19	Total Miscellaneous General Revenue		1,919,860	
20	Wages & Salary Allocator		44.96%	
21	**Total Allocated Miscellaneous General Revenue**		**863,089**	
	Distribution Underbuild			Distribution underbuild revenues are transmission-related revenues. Value for production is zero.
22	Third party attachments		0	
23	Common pole location fixed annual revenue credit	fixed	0	
24	**Distribution Underbuild - Transmission related**		**0**	

Notes

Note 1 All revenues related to transmission that are received as a transmission owner (i.e., not received as a LSE), for which the cost of the service is recovered under this formula, except as specifically provided for elsewhere in this Attachment or elsewhere in the formula, will be included as a revenue credit or included in the peak on line 170 of Attachment A.

Note 2 If the costs associated with the Directly Assigned Transmission Facility Charges are included in the Rates, the associated revenues are included in the Rates. If the costs associated with the Directly Assigned Transmission Facility Charges are not included in the Rates, the associated revenues are not included in the Rates.

Note 3 If the facilities associated with the revenues are not included in the formula, the revenue is shown here, but not included in the total above and explained in the Cost Support, (e.g., revenues associated with distribution facilities).

Line

Plant in Service Worksheet

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions						Detail/notes
		Calculation of Transmission Plant In Service	Source	Year	**PPE w/o ARO**	Source
	1	December	Monthly Balances	2018	6,353,044,980	206.58b footnote
	2	January	Monthly Balances	2019	6,382,517,910	
	3	February	Monthly Balances	2019	6,395,075,643	
	4	March	Monthly Balances	2019	6,422,160,076	
	5	April	Monthly Balances	2019	6,424,859,087	
	6	May	Monthly Balances	2019	6,438,770,948	
	7	June	Monthly Balances	2019	6,446,904,302	
	8	July	Monthly Balances	2019	6,457,267,789	
	9	August	Monthly Balances	2019	6,459,718,800	
	10	September	Monthly Balances	2019	6,464,387,691	
	11	October	Monthly Balances	2019	6,469,126,298	
	12	November	Monthly Balances	2019	6,480,051,693	
	13	December	Monthly Balances	2019	6,478,620,080	207.58g footnote
15	14	**Transmission Plant In Service**	(sum lines 1-13) /13	true-up	6,436,346,561	Attachment A input
		Calculation of Distribution Plant In Service	Source	Year	Balance	Source
	15	December	Monthly Balances	2018	7,017,942,816	206.75b footnote
	16	January	Monthly Balances	2019	7,040,503,650	
	17	February	Monthly Balances	2019	7,057,601,913	
	18	March	Monthly Balances	2019	7,075,349,163	
	19	April	Monthly Balances	2019	7,093,346,892	
	20	May	Monthly Balances	2019	7,117,529,665	
	21	June	Monthly Balances	2019	7,138,586,565	
	22	July	Monthly Balances	2019	7,162,720,373	
	23	August	Monthly Balances	2019	7,181,341,253	
	24	September	Monthly Balances	2019	7,204,927,187	
	25	October	Monthly Balances	2019	7,233,755,772	
	26	November	Monthly Balances	2019	7,257,042,176	
	27	December	Monthly Balances	2019	7,295,300,652	207.75g footnote
	28	**Distribution Plant In Service**	(sum lines 15-27) /13	true-up	7,144,303,698	
		Calculation of Intangible Plant In Service	Source	Year	Balance	Source
	29	December	Monthly Balances	2018	970,432,021	204.5b footnote
	30	December	Monthly Balances	2019	1,015,882,796	205.5g footnote
19	31	**Intangible Plant In Service**	(sum lines 29 & 30) /2	true-up	**993,157,408**	Attachment A input
		Calculation of General Plant In Service	Source	Year	Balance	Source
	32	December	Monthly Balances	2018	1,274,442,961	206.99b footnote
	33	December	Monthly Balances	2019	1,287,632,918	207.99g footnote
18	34	**General Plant In Service**	(sum lines 32 & 33) /2	true-up	**1,281,037,939**	Attachment A input
		Calculation of Production Plant In Service	Source	Year	Balance	Source
	35	December	Monthly Balances	2018	12,454,178,186	204.46b footnote
	36	January	Monthly Balances	2019	12,397,051,849	
	37	February	Monthly Balances	2019	12,397,545,132	
	38	March	Monthly Balances	2019	12,394,271,581	
	39	April	Monthly Balances	2019	12,401,790,999	
	40	May	Monthly Balances	2019	12,436,193,972	
	41	March	Monthly Balances	2019	12,429,933,622	
	42	April	Monthly Balances	2019	12,433,762,247	
	43	August	Monthly Balances	2019	12,442,257,212	
	44	September	Monthly Balances	2019	12,408,860,367	
	45	October	Monthly Balances	2019	12,394,905,600	
	46	November	Monthly Balances	2019	12,409,756,392	
	47	December	Monthly Balances	2019	12,370,876,825	205.46g footnote
	48	**Production Plant In Service**	(sum lines 35-47) /13	true-up	**12,413,183,383**	
	49	Electric Plant Sold	206.102g		0	206.102g
6	50	**Total Plant In Service**	(sum lines 14, 28, 31, 34, 48, & 49)	true-up	**28,268,028,991**	Attachment A input

Accumulated Depreciation Worksheet

		Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions				Notes
		Calculation of Transmission Accumulated Depreciation	Source	Year	**A/D w/o ARO**	Source
	51	December	Monthly Balances	2018	1,768,531,625	Prior year 219.25c
	52	January	Monthly Balances	2019	1,774,729,573	
	53	February	Monthly Balances	2019	1,782,515,762	
	54	March	Monthly Balances	2019	1,790,562,280	
	55	April	Monthly Balances	2019	1,798,970,618	
	56	May	Monthly Balances	2019	1,807,203,295	
	57	June	Monthly Balances	2019	1,813,309,737	
	58	July	Monthly Balances	2019	1,821,620,513	
	59	August	Monthly Balances	2019	1,829,599,489	
	60	September	Monthly Balances	2019	1,837,582,020	
	61	October	Monthly Balances	2019	1,846,106,986	
	62	November	Monthly Balances	2019	1,855,006,768	
	63	December	Monthly Balances	2019	1,863,152,998	219.25c
25	64	**Transmission Accumulated Depreciation**	(sum lines 51-63) /13	true-up	1,814,530,128	Attachment A input
		Calculation of Distribution Accumulated Depreciation	Source	Year	Balance	Source
	65	December	Monthly Balances	2018	2,847,150,664	Prior year 219.26c
	66	January	Monthly Balances	2019	2,852,878,569	
	67	February	Monthly Balances	2019	2,857,929,658	
	68	March	Monthly Balances	2019	2,864,040,932	
	69	April	Monthly Balances	2019	2,867,950,469	
	70	May	Monthly Balances	2019	2,874,196,116	
	71	June	Monthly Balances	2019	2,880,985,998	
	72	July	Monthly Balances	2019	2,888,465,826	
	73	August	Monthly Balances	2019	2,895,368,802	
	74	September	Monthly Balances	2019	2,902,472,457	
	75	October	Monthly Balances	2019	2,910,787,593	
	76	November	Monthly Balances	2019	2,918,554,464	
	77	December	Monthly Balances	2019	2,925,945,710	219.26c
	78	**Distribution Accumulated Depreciation**	(sum lines 65-77) /13	true-up	2,883,594,404	
		Calculation of Intangible Accumulated Depreciation	Source	Year	Balance	Source
	79	December	Monthly Balances	2018	614,571,347	Prior year 200.21c
	80	December	Monthly Balances	2019	652,942,422	200.21c
8	81	**Accumulated Intangible Depreciation**	(sum lines 79 & 80) /2	true-up	**633,756,885**	Attachment A input
		Calculation of General Accumulated Depreciation	Source	Year	Balance	Source
	82	December	Monthly Balances	2018	482,727,327	Prior year 219.28c
	83	December	Monthly Balances	2019	493,756,071	219.28c
26	84	**Accumulated General Depreciation**	(sum lines 82 & 83) /2	true-up	**488,241,699**	Attachment A input

		Calculation of Production Accumulated Depreciation	Source	Year	Balance	Source	Adjustments to Eliminate State Generation NBV Buydowns - See Below	Adjusted Balance
	85	December	Monthly Balances	2018	4,967,942,643	Prior year 219.20 through 219.24	173,684,144	4,794,258,499
	86	January	Monthly Balances	2019	5,290,902,203		173,684,144	5,117,218,059
	87	February	Monthly Balances	2019	5,147,918,488		173,684,144	4,974,234,344
	88	March	Monthly Balances	2019	5,176,143,454		173,684,144	5,002,459,310
	89	April	Monthly Balances	2019	5,207,980,256		173,684,144	5,034,296,112
	90	May	Monthly Balances	2019	5,237,207,898		173,684,144	5,063,523,754
	91	June	Monthly Balances	2019	5,256,172,294		173,684,144	5,082,488,150
	92	July	Monthly Balances	2019	5,285,654,749		173,684,144	5,111,970,605
	93	August	Monthly Balances	2019	5,318,526,551		173,684,144	5,144,842,407
	94	September	Monthly Balances	2019	5,027,950,439		238,297,256	4,789,653,183
	95	October	Monthly Balances	2019	4,961,041,697		238,297,256	4,722,744,441
	96	November	Monthly Balances	2019	4,910,885,543		238,297,256	4,672,588,287
	97	December	Monthly Balances	2019	4,731,395,492	219.20 through 219.24	298,606,110	4,432,789,382
	98	**Production Accumulated Depreciation**	(sum lines 85-97) /13	true-up	**5,116,901,670**			**4,918,697,425**
7	99	**Accumulated Depreciation (Total Electric Plant)**	(sum lines 64, 78, 84, & 98)	true-up	**10,105,063,657**	Attachment A input		
	100	**Total Accumulated Depreciation**	(sum lines 64, 78, 81, 84, & 98)	true-up	10,738,820,542			

Materials & Supplies

		Attachment A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount		
	101	Undistributed Stores Expense	Prior Year	227.16c	0		Consistent with Transmission Formula treatment
	102		Current Year	227.16c	0		Consistent with Transmission Formula treatment
39	103		**Attachment A input**	true-up	**0**	beg-of-year and end-of-year average	
	104	Construction Materials & Supplies	Prior Year	227.5c	161,139,297		Prodution-specific data
	105		Current Year	227.5c	162,606,537		Prodution-specific data
42	106		**Attachment A input**	true-up	**161,872,917**	beg-of-year and end-of-year average	
	107	Production Materials & Supplies	Prior Year	227.7c	63,541,336		Prodution-specific data
	108		Current Year	227.7c	67,226,405		Prodution-specific data
45	109		**Attachment A input**	true-up	**65,383,871**	beg-of-year and end-of-year average	

ITC Adjustment

		Attachment A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions		Form No. 1 Amount	Production related portion	**Attachment A input**	Details
		ed Investment Tax Credit			Net Plant Allocator		
133	110	Utility Investment Tax Credit Adj. - Net (411.4)	114.19c	(2,738,724)	45.71%	**(1,251,850)**	Adjusted using production allocator
133b	111	Tax Impact of AFUDC Equity Permanent Difference			**Attachment A, line 134b input**	**3,651,318**	
		te Base Adjustment					
		Internal Revenue Code (IRC) 46(f)(1) adjustment to rate base					
	112		Current beg of year balance	266 footnotes, 266.6b	320,410		
	113		Current end of year balance	266 footnotes, 267.6h	274,139		
35	114	Internal Revenue Code (IRC) 46(f)(1) adjustment to rate base	Average	297,275	45.71%	**135,882**	(enter negative in Attachn Adjusted using production allocator

Production / Non-transmission Cost Support

		Attachment A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Form No. 1 Amount	Production Related	Non-Production Related	Details
		ld for Future Use - Production						
	115		Prior Year	214.47d	26,415,220	**8,923,301**	17,491,919	Detail for production-related value on Attachment 12
	116		Current Year	214.47d	25,890,060	**8,923,301**	16,966,759	Detail for production-related value on Attachment 12
23	117		**Attachment A input**	true-up		**8,923,301**		beg-of-year and end-of-ye Adjusted using production allocator

Adjustments to A & G Expense

		Attachment A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions		Adjusted Total			Details
Membership Dues Expense							
	118	Page 335, Line 1 (Industry Association Dues)		**Total**	**Included**	**Excluded**	
	119	American Wind Energy Association	component of 335 Ln 1b	25,000	25,000		
	120	Centre for Energy Advancement through Technological Innovation (CEATI)	component of 335 Ln 1b	33,000		33,000	
	121	Edison Electric Institute (EEI)	component of 335 Ln 1b	941,983	941,983		
	122	National Automated Clearing House	component of 335 Ln 1b	2,875		2,875	
	123	National Electric Energy Testing Research and Application Center (NEETRAC)	component of 335 Ln 1b	86,000		86,000	
	124	National Joint Utilities Notification System	component of 335 Ln 1b	11,813		11,813	
	125	North American Transmission Forum, Inc.	component of 335 Ln 1b	91,231		91,231	
	126	Northwest Public Power Association	component of 335 Ln 1b	1,625	1,625		
	127	Northwest Hydroelectric Association	component of 335 Ln 1b	1,200	1,200		
	128	Pacific Northwest Utilities Conference Committee	component of 335 Ln 1b	83,449		83,449	
	129	Rocky Mountain Electrical League	component of 335 Ln 1b	18,000		18,000	
	130	Smart Electric Power Alliance	component of 335 Ln 1b	10,250		10,250	
	131	Sustainable Electrified Transportation Center	component of 335 Ln 1b	10,000		10,000	
	132	The National Hydropower Association, Inc.	component of 335 Ln 1b	34,350	34,350		
	133	Western Energy Supply Transmission Associates	component of 335 Ln 1b	25,685		25,685	
	134		Page 335, Line 1 Subtotal	1,376,461			
	135						
	136	Page 335, Lines 9 - 32 (Business/Economic Dev. and Corp. Memberships & Subscriptions)					
	137	Lines 9 - 31	Page 335, Lines 9 - 31	229,848		229,848	
	138	Other (Individually less than $5,000)	Page 335, Line 32	137,596		137,596	
	139						
	140	Directors' Fees - Regional Advisory Board	Page 335, Line 42	18,872		18,872	
	141						
	142	Rating Agency and Trustee Fees	Page 335, Lines 35-40	481,275	481,275		
	143						
	144	General: Other	Page 335, Line 44	20		20	
	145						
63	146	Total		**Appendix A Input**		**758,638**	Attachment A Input

		PBOP						
	147	Fixed PBOP expense	Annual Update Informational Filing		1,306,656			
	148	Actual PBOP expense	Attachement 17		1,306,656			
58	149	Adjusted total (Current year actual)	**Attachment A Input**	true-up	**0**	Authorized Filled Expense minus Actual Expense	Consistent with Transmission Formula treatment	
		Property Insurance						
	150	Property Insurance - premiums (Account 924.3)			4,737,084	Attachment A Input		
	151	Total Property Insurance Account 924	323.185b		4,737,084			
70	152		**Attachment A Input**		**4,737,084**			

Regulatory Expense Related to Transmission Cost Support

Attachment A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Form No. 1 Amount			Details
		Directly Assigned A&G					
		Specific Transmission related Regulatory Expenses					
		Federal Energy Regulatory Commission:			Production related		
	153	Annual Fee	350.37d	2,468,009			
	154	Annual Fee - hydro	350.38d		2,658,529		Cost of production
	155	Transmission Rate Case	350.39d	245,707			
	156	Other Regulatory	350.40d	3,237,297			
67	157	**Total**	sum	5,951,014	2,658,529	8,609,543	Adjustment to remove FERC regulatory expenses reported in FERC Form

Safety Related Advertising Cost Support

Attachment A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Form No. 1 Amount	Safety Related Attachment A Input	Non-safety Related	Details
		Directly Assigned A&G					
68	158	General Advertising Exp Account 930.1 - Safety-related Advertising	323.191b	55,028	**0**	55,028	Based on FERC 930.1 download

Education and Out Reach Cost Support - N/A

Attachment A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Form No. 1 Amount	Education & Outreach Attachment A Input	Other	Details
		Directly Assigned A&G					
71	159	General Advertising Exp Account 930.1 - Education and Outreach	323.191b	55,028	**0**	55,028	Based on FERC 930.1 download

Multistate worksheet

Attachment A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions			Details	
		Income Tax Rates		
129	160	SIT = State Income Tax Rate or Composite	4.54%	Enter Average State Income Tax Rate

Adjustments to Production O&M

Attachment A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				Total	Plus adjustments	Production Related Attachment A input	Details
53	161	**Production O&M**	321.78b	44,593,260	0	**44,593,260**	Only FERC 557-contains costs for being a supplier of electricity to retail and wholesale customers. As such, it includes costs related to providing ancillary services. The only O&M included in the FCR formula is ferc account 557, all other production O&M is included on the cost support formula by generating facility: Annual cost calculation for ancillary services includes only fixed O&M production expenses which are calculated separately in Attachment B.
		Adjustment for Ancillary Services Accounts 561-561.5 - Not applicable as this adjustment applys only to Transmission.					
	162	(561) Load Dispatching	321.84b	0			Transmission-Formula-only item; production value is zero
	163	(561.1) Load Dispatch-Reliability	321.85b	0			Transmission-Formula-only item; production value is zero
	164	(561.2) Load Dispatch-Monitor and Operate Transmission System	321.86b	0			Transmission-Formula-only item; production value is zero
	165	(561.3) Load Dispatch-Transmission Service and Scheduling	321.87b	0			Transmission-Formula-only item; production value is zero
	166	(561.4) Scheduling, System Control and Dispatch Services	321.88b	0			Transmission-Formula-only item; production value is zero
	167	(561.5) Reliability, Planning and Standards Development	321.89b	0			Transmission-Formula-only item; production value is zero
54	168	**Less: Cost of Providing Ancillary Services Accounts 561.0-5**	sum	0	0	**0**	
55	169	**Less: Account 565 - Not applicable as this adjustment applys only to Transmission.**	321.96b	0	0	**0**	Transmission-Formula-only item; production value is zero

Facility Credits under Section 30.9 of the OATT - Interest on Network upgrade facilities - N/A

Attachment A Line #s, Descriptions, Notes, Form 1 Page #s and Instructions			Amount	Description & Documentation	
		Net Revenue Requirement			
166	170	Facility Credits under Section 30.9 of the OATT	**0**	Attachment A Input	Transmission-Formula-only item; production value is zero
168	171	Interest on Network Upgrade Facilities	**0**	Attachment A Input	Transmission-Formula-only item; production value is zero

Other adjustments to rate base - Network Upgrade Balance

		Form No. 1 Page #s and Instructions			Amount		
		Network Upgrade Balance					
			Prior Year	Enter negative	0		
			Current Year	Enter negative	0		
50	172	Network Upgrade Balance	Attachment A input	true-up	**0**	beg-of-year and end-of-year average	Transmission-Formula-only item; production value is zero

Depreciation Expense

		nment A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions		Total		
		Production Plant				
	173	Depreciation expense (403)	sum of 336.2b, 336.4b, 336.6b	563,096,216		Prodution-specific data - see FERC Form No. 1 reference
	174	Less: Eliminate Impact of Buy-down		124,921,966		See Adjustment to Eliminate State Generation NBV Buydowns
	175	Amortization of limited term electric plant (404)	336.4d	311,696		Prodution-specific data - see FERC Form No. 1 reference
76	176	**Production Depreciation Expense Including Amortization of Limited Term Plant**	sum	**438,485,946**	Attachment A Input	
		General Plant				
	177	Depreciation expense (403)	336.10b	42,404,362		2019 True-Up value
	178	Amortization of limited term electric plant (404)	336.10d	706,273		2019 True-Up value
77	179	**General Depreciation Expense Including Amortization of Limited Term Plant**	sum	**43,110,635**	Attachment A Input	
		Intangible plant				
	180	Amortization of limited term electric plant (404)	336.1d	48,671,914		2019 True-Up value
	181	Amortization of other electric plant (405)	336.1e	0		2019 True-Up value
78	182	**Total Intangible Amortization**	sum	**48,671,914**	Attachment A Input	

Less Regulatory Asset Amortizations Account 930.2

		nment A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions		Amount		
	183	Generating Plant Liquidated Damages-WY (detail below)	232.29e	0		2019 True-Up value
	184	Lake Side Settlement		0		2019 True-Up value
	185	Goodnoe Hills Settlement		0		2019 True-Up value
	186	Wyoming 2013 Settlement (Naughton Plant)		0		2019 True-Up value
	187	Generating Plant Liquidated Damages-UT (detail below)	232.30e	0		2019 True-Up value
	188	Utah 2013 EBA Settlement (Naughton Plant)		0		2019 True-Up value
61	189	Total	sum	**0**	Attachment A Input	

Adjustments to Eliminate State Generation Net Book Value Buydowns

		nment A Line #s, Descriptions, Notes, Form No. 1 Page #s and Instructions				
			Month		**Accumulated amount**	see line 7
	190	Impact to Accumulated Depreciation	31-Dec-18	173,684,144	173,684,144	
	191		31-Jan-19	-	173,684,144	
	192		28-Feb-19	-	173,684,144	
	193		31-Mar-19	-	173,684,144	
	194		30-Apr-19	-	173,684,144	
	195		31-May-19	-	173,684,144	
61	196		30-Jun-19	-	173,684,144	
	197		31-Jul-19	-	173,684,144	
	198		31-Aug-19	-	173,684,144	
	199		30-Sep-19	64,613,112	238,297,256	
	200		31-Oct-19	-	238,297,256	
	201		30-Nov-19	-	238,297,256	
	202		31-Dec-19	60,308,854	298,606,110	
	203	Impact to Depreciation Expense - 2019		**124,921,966**		Adjustment to Production Depreciation expense (see line 76)

PacifiCorp
Prepayments

Line	FERC Account	Account Number	Account Description	Category	Prior Year-end Balance	Current Year-end Balance	BoY-EoY Average	Other	100% Production	100% Transmission	Plant-related	Labor-related
1	1651000	132008	Prep Ins-Publ Liab & Prop Damage	Plant-related	$ 2,105,196	$ 3,633,108	$ 2,869,152				$ 2,869,152	
2		132012	Prep Ins-All Purpose Insurance	Plant-related	$ 3,068,113	$ 2,203,885	$ 2,635,999				$ 2,635,999	
3		132013	Prep Ins-D&O Liability	Labor-related	$ -	$ -	$ -					$ -
4		132016	Prep Ins-Minority Owned Plants	100% Production	$ 364,355	$ 496,419	$ 430,387		$ 430,387			
5		132045	Prepaid Workers Compensation	Labor-related	$ 152,361	$ 138,751	$ 145,556					$ 145,556
6		132055	Prepaid Employee Benefit Costs	Labor-related	$ 91,461	$ 58,203	$ 74,832					$ 74,832
7		132722	I/C Prepaid Captive Prop Insur - MEHC	Plant-related	$ -	$ -	$ -				$ -	
8		132723	I/C Prepaid Captive Liab Insur - MEHC	Plant-related	$ -	$ -	$ -				$ -	
9	1652000	132101	OR-Prepaid Property Tax	Plant-related	$ 13,011,465	$ 13,406,626	$ 13,209,045				$ 13,209,045	
10		132200	Prepaid Taxes (Federal, State, Local)	Other	$ -	$ -	$ -	$ -				
11		132924	Other Prepayments - Oregon DOE Fee	Other	$ 861,755	$ 749,695	$ 805,725	$ 805,725				
12	1652100	132095	Prepaid Emissions Permit Fees (UT)	100% Production	$ 591,742	$ 594,320	$ 593,031		$ 593,031			
13		132096	Prepaid RECs for RPS (WA)	Other	$ -	$ -	$ -	$ -				
14		132097	Prepaid CA GHG Cap & Trade Allowances Retail	Other	$ 5,060,826	$ 12,638,215	$ 8,849,521	$ 8,849,521				
15		132098	Prepaid CA GHG Cap & Trade Allowances Wholesa	Other	$ 1,702,640	$ 5,643,997	$ 3,673,318	$ 3,673,318				
16		132310	Prepaid Rating Agency Fees	Plant-related	$ 44,125	$ 42,760	$ 43,442				$ 43,442	
17		132320	Prepaid Surety Bond	Other	$ -	$ -	$ -	$ -				
18		132580	Prepaid Seven Mile I	100% Production	$ -	$ 210,909	$ 105,454		$ 105,454			
19		132581	Prepaid Seven Mile II	100% Production	$ -	$ 41,543	$ 20,771		$ 20,771			
20		132603	Other Prepay-Ashton Plant Land	Other	$ -	$ -	$ -	$ -				
21		132606	Other Prepay - Lease Commissions	Other	$ -	$ -	$ -	$ -				
22		132620	Prepayments - Water Rights Lease	100% Production	$ 1,458,826	$ 1,113,352	$ 1,286,089		$ 1,286,089			
23		132621	Prepayments - Water Rights (Ferron Canal)	100% Production	$ 557,594	$ 557,594	$ 557,594		$ 557,594			
24		132622	Prepayments - Water Rights (Hntngtn-Clev)	100% Production	$ -	$ -	$ -		$ -			
25		132623	Prepaid Lake Side CUWCD Water Fee	100% Production	$ 161,250	$ -	$ 80,625		$ 80,625			
26		132630	Prepaid OR Renewal & Habitat Restoration	Other	$ -	$ -	$ -	$ -				
27		132650	Prepaid Dues	Other	$ 26,000	$ 20,000	$ 23,000	$ 23,000				
28		132700	Prepaid Rent	Plant-related	$ 42,667	$ 42,667	$ 42,667				$ 42,667	
29		132704	Prepaid Leaning Juniper	100% Production	$ -		$ -		$ -			
30		132705	Prepaid Pole Contact Rental	Other	$ 326,145	$ 324,730	$ 325,437	$ 325,437				
31		132740	Prepaid O&M - Wind	100% Production	$ 49,227	$ 96,134	$ 72,680		$ 72,680			
32		132755	Prepaid Aircraft Maint	Labor-related	$ -	$ 327,259	$ 163,629					$ 163,629
33		132825	Prepaid LGIA Transmission	Other	$ -	$ -	$ -	$ -				
34		132831	Prepaid BPA Transmission - Wine Country	Other	$ 983,688	$ 983,688	$ 983,688	$ 983,688				
35		132900	Prepayments - Other	Labor-related	$ 1,561,463	$ 1,686,356	$ 1,623,910					$ 1,623,910
36		132901	Prep Fees-Oregon Pub Util Commission	Other	$ 1,062,379	$ 1,010,288	$ 1,036,333	$ 1,036,333				
37		132903	Prep Fees-Utah Public Service Commission	Other	$ 3,139,868	$ 3,104,333	$ 3,122,101	$ 3,122,101				
38		132904	Prep Fees-Idaho Pub Util Commission	Other	$ 321,814	$ 361,935	$ 341,875	$ 341,875				
39		132909	Prepaid Vehicle Licensing Fees	Labor-related	$ -	$ -	$ -					$ -
40		132910	Prepayments - Hardware & Software	Labor-related	$ 8,673,044	$ 10,500,249	$ 9,586,647					$ 9,586,647
41		132926	Prepaid Royalties	100% Production	$ -	$ -	$ -		$ -			
42		132998	Prepayments - Insurance - Reclass to L-T	Plant-related	$ (79,023)	$ (57,950)	$ (68,486)				$ (68,486)	
43		132999	Prepayments - Reclass to Long-Term	Other	$ (874,500)	$ (1,585,645)	$ (1,230,073)	$ (1,230,073)				
44		134000	Long-Term Prepayments - Reclass from Current	Other	$ 953,523	$ 1,643,595	$ 1,298,559	$ 1,298,559				
45	1653000	132303	Prepaid Interest Company-Owned Life Ins	Other	$ 2,586,030	$ 2,531,871	$ 2,558,950	$ 2,558,950				
46		132304	Prepaid Interest - SERP Life Insurance	Other	$ -	$ -	$ -	$ -				
47		203000	Discount on Short-Term Securities	Other	$ 16,625	$ 66,625	$ 41,625	$ 41,625				
48	1655000	132400	Prepaid Mining Costs	100% Production	$ -	$ -	$ -		$ -			
49			Total Prepayments		$ 48,020,659	$ 62,585,510	$ 55,303,084	$ 21,830,060	$ 3,146,632	$ -	$ 18,731,819	$ 11,594,573
50				Allocator				0.000%	100.000%	0.000%	45.709%	44.956%
51				Total Allocated to Production by Category				$ -	$ 3,146,632	$ -	$ 8,562,169	$ 5,212,435
52				**Attachment A input: Total Allocated to Production**			**$ 16,921,236**					

Production Plant/Land Held For Future Use - Assets associated with Production at December 31

		Prior year	Current year
Wild Horse Wind Plant	214.3d	6,763,094	6,763,094
Twelve Mile Wind Plant	214.4d	2,160,207	2,160,207
Attachment 5 input: **Total - Production**		**8,923,301**	**8,923,301**

		Prior year	Current year
Total - PacifiCorp	214.47d	26,415,220	25,890,060

Line	Attachment A Line	Operation to apply to monthly input columns at right	Attachment A input value (result of operation specified in column to left on monthly data)	Description (Account)	Reference	Prior Year (month end) December	Current Year (month end) January	February	March	April	May	June	July	August	September	October	November	December
1	86	13-month average	7,451,428,846	Bonds (221)	Form 1, pg 112, ln 18 c,d	7,055,275,000	6,705,275,000	6,705,275,000	7,705,275,000	7,705,275,000	7,705,275,000	7,705,275,000	7,705,275,000	7,705,275,000	7,705,275,000	7,705,275,000	7,705,275,000	7,055,275,000
2	87	13-month average	0	Reacquired Bonds (222)	Form 1, pg 112, ln 19 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
3	88	13-month average	0	Advances from Associated Companies (223)	Form 1, pg 256, various ln, col a,b	0	0	0	0	0	0	0	0	0	0	0	0	0
4	89	13-month average	0	Other Long-Term Debt (224)	Form 1, pg 112, ln 21 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
5	91	13-month average	13,080,345	Unamortized Discount (226)	Form 1, pg 112, ln 23 c,d	10,793,807	10,731,877	10,669,948	14,124,482	14,049,016	13,973,550	13,898,084	13,822,618	13,747,153	13,671,687	13,596,221	13,520,755	13,445,289
6	92	13-month average	33,427,807	Unamortized Debt Expense (181)	Form 1, pg 111, ln 69 c,d	29,412,802	29,187,295	28,961,787	35,412,230	35,340,923	35,113,758	35,208,318	34,953,011	34,695,953	34,454,318	34,197,504	33,940,366	33,683,227
7	93	13-month average	4,262,741	Unamortized Loss On Reacquired Debt (189)	Form 1, pg 111, ln 81 c,d	4,554,871	4,506,128	4,457,384	4,408,641	4,359,897	4,311,154	4,262,410	4,213,871	4,165,332	4,116,793	4,068,254	4,019,715	3,971,176
8	94	13-month average	30,509	Unamortized Premium (225)	Form 1, pg 112, ln 22 c,d	36,022	35,103	34,185	33,266	32,347	31,428	30,509	29,590	28,672	27,753	26,834	25,915	24,996
9	95	13-month average	0	Unamortized Gain On Reacquired Debt (257)	Form 1, pg 113, ln 61 c,d	0	0	0	0	0	0	0	0	0	0	0	0	0
10	97	12-month sum	369,853,259	Interest on Long Term (427) and Associated Companies (430) **LONG TERM ONLY**	Form 1, pg 257, ln 33 i	29,752,845	28,845,061	28,121,960	31,243,041	31,366,027	31,341,433	31,341,090	31,283,532	31,270,360	31,286,086	31,278,534	31,215,968	31,260,168
11	98	12-month sum	0	Hedging Expense (as noted in Attachment A, Note R)	Company records	0	0	0	0	0	0	0	0	0	0	0	0	0
12	99	12-month sum	3,892,240	Amort Debt Discount and Expense (428)	Form 1, pg 117, ln 63 c (portion)	346,591	287,437	287,437	329,385	330,284	330,422	332,165	332,172	332,524	332,602	332,604	332,604	332,604
13	100	12-month sum	583,695	Amort Loss on Reacquired Debt (428.1)	Form 1, pg 117, ln 64 c (portion)	48,743	48,744	48,743	48,744	48,743	48,744	48,744	48,539	48,539	48,539	48,539	48,539	48,539
14	101	12-month sum	11,026	Amort Premium (429)	Form 1, pg 117, ln 65 c (portion)	919	919	919	919	919	919	919	919	919	919	919	919	919
15	102	12-month sum	0	Amort Gain on Reacquired Debt (429.1)	Form 1, pg 117, ln 66 c (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
16	104	13-month average	2,397,600	Preferred Stock Issued (204)	Form 1, pg 112, ln 3 c, d	2,397,600	2,397,600	2,397,600	2,397,600	2,397,600	2,397,600	2,397,600	2,397,600	2,397,600	2,397,600	2,397,600	2,397,600	2,397,600
17	105	13-month average	0	Reacquired Capital Stock (217) **PREFERRED ONLY**	Form 1, pg 112, ln 13 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
18	106	13-month average	0	Premium on Preferred Stock (207)	Form 1, pg 112, ln 6 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
19	107	13-month average	0	Other Paid-In Capital (207-208) **PREFERRED ONLY**	Form 1, pg 112, ln 7 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
20	108	13-month average	0	Discount on Capital Stock (213) **PREFERRED ONLY**	Form 1, pg 112, ln 9 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
21	109	13-month average	0	Capital Stock Expense (214) **PREFERRED ONLY**	Form 1, pg 112, ln 10 c, d (portion)	0	0	0	0	0	0	0	0	0	0	0	0	0
22	111	12-month sum (enter positive)	161,902	Preferred Dividend	Form 1, pg 118, ln 29 c	40,475	0	0	40,475	0	0	40,475	0	0	40,475	0	0	40,475
23	112	13-month average	8,083,782,146	Total Proprietary Capital	Form 1, pg 112, ln 16 c,d	7,845,040,095	7,919,723,041	7,797,497,596	7,849,674,209	7,881,518,677	7,933,361,500	8,017,152,407	8,130,203,351	8,230,032,109	8,295,315,926	8,348,176,274	8,403,683,786	8,437,788,932
24	114	13-month average	117,471,234	Unappropriated Undistributed Subsidiary Earnings (216.1)	Form 1, pg 112, ln 12 c, d	104,399,246	109,177,232	112,306,249	115,761,062	116,802,035	115,947,351	116,041,303	119,056,866	121,185,953	121,748,473	122,967,367	126,167,671	125,565,230
25	115	13-month average (enter negative)	(12,642,903)	Accumulated Other Comprehensive Income (219)	Form 1, pg 112, ln 15 c, d	(12,635,042)	(12,586,870)	(12,538,697)	(12,490,524)	(12,442,351)	(12,394,178)	(12,346,005)	(12,297,832)	(12,249,660)	(12,201,487)	(12,153,314)	(12,105,141)	(15,916,633)
26	n/a	-	-	Common Stock Issued (201)	Company records	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896	3,417,945,896
27	n/a	-	-	Other Paid-In Capital (211)	Company records	1,102,063,956	1,102,063,956	1,102,063,956	1,102,063,956	1,102,063,956	1,102,063,956	1,102,063,956	1,102,063,956	1,102,063,956	1,102,063,956	1,102,063,956	1,102,063,956	1,102,063,956

Description		Total	Interest Locks	Other
Unamortized balance for gains and losses on hedges.	(Note R)	0	0	0
Annual amortization for gains and losses on hedges.	(Note R)	0	0	0

PacifiCorp
Unfunded Reserves

Unfunded Reserve Balances
(Dollar values in millions)

Line	Description	Account Calculation	Reserve type	Accrued Liability: SAP Account	Accrued Liability: FERC Account	Charged to: SAP Account	Charged to: FERC Account	Prior year December month end	Current Year >> January month end	February month end	March month end	April month end	May month end	June month end	July month end	August month end	September month end	October month end	November month end	Current Year December month end	true-up 13-month Average	By Category: Category	100% Production	100% Transmission	Plant	Labor	Other	Total Production-related Unfunded Reserves
1	CA GHG Retail Obligation	Estimate by C&T	Unfunded	248020	242	546526	555.67	(5.7)	(6.2)	(7.0)	(7.5)	(7.9)	(8.2)	(8.7)	(9.5)	(10.3)	(13.0)	(11.3)	(11.9)	(12.6)	(9.2)	Other	0				(9.214)	
2	CA GHG Wholesale Obligation	Estimate by C&T	Unfunded	248028	242	546516	555.67	(1.7)	(2.4)	(3.2)	(4.0)	(4.5)	(4.7)	(4.8)	(4.8)	(5.2)	(5.5)	(5.0)	(5.4)	(6.0)	(4.4)	Other	0				(4.393)	
3	Lidar (Wood Hollow)	Estimate by PE Legal	Unfunded	248070	242	545510	426.3	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	(2.0)	Other	0				(2.000)	
4	Employment Claims	Estimate by PE Legal	Unfunded	248070	242	545500	598	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Other	0				0.000	
5	L-T Accrued Settlement Provision (USA Power Settlement)	Estimate by PE Legal	Unfunded	289950	253.99	545502	426.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Other	0				0.000	
6	Deseret Physical Loss - Reserve for Dispute	Estimate by C&T	Unfunded	248025	242	505206	555.25	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	Other	0				(0.204)	
7	BPA Short Distance Discount (SDD)	Estimate by C&T	Unfunded	248025	242	506050	565.46	(3.6)	(3.6)	(3.6)	(3.6)	(3.6)	(3.6)	(10.1)	(10.1)	(10.2)	(10.3)	(1.4)	(0.0)	(0.0)	(4.9)	Other	0				(4.927)	
8	Accum Provision for Rate Refunds	Estimate by PacTrans	Unfunded	284100	229	301913	456.199	(2.6)	(2.6)	(2.6)	(2.6)	(2.6)	(2.0)	(1.2)	(0.5)	(0.5)	(0.5)	(0.5)	(0.0)	0.0	(1.5)	Other	0				(1.459)	
9	Trapper Mine Reclamation Obligation	Estimate based upon 54¢ per ton of c	Unfunded	289517	253.3	515100	501.1	(6.5)	(6.5)	(6.5)	(6.6)	(6.6)	(6.6)	(6.6)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.6)	100% Production	0	(6.623)				
10	Accrued Right-of-Way Obligation (100% Transmission)	Estimate by RMP Finance	Unfunded	289955	253.99	582300 (ORD 240193)	566 / 567 / 569	(1.1)	(1.1)	(1.1)	(1.1)	(1.2)	(1.2)	(1.2)	(1.2)	(1.2)	(1.3)	(1.3)	(1.3)	(1.3)	(1.2)	100% Transmission	0		(1.190)			
11	Accrued Right-of-Way Obligation (Other)	Estimate by RMP Finance	Unfunded	289955	253.99	2300 (ORD 240192 & 2405	589	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(1.5)	(1.5)	(1.5)	(1.5)	(1.5)	(1.4)	Other	0				(1.436)	
12																												
13	Injuries & Damages Reserve Risk ("Labor")	Estimates by Legal ("Labor")	Unfunded	280311	228.21	545050	925	(15.8)	(15.7)	(15.6)	(15.6)	(16.2)	(16.0)	(16.3)	(14.2)	(13.2)	(12.3)	(12.5)	(12.5)	(12.0)	(14.4)	Labor	0				(14.441)	
14	Injuries & Damages Reserve Risk ("Other")	Estimates by Legal ("Other")	Unfunded	280311	228.21	545050	426.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Other	0				0.000	
15	Injuries & Damages Reserve Risk (Insurance Recovery-"Labor")	Estimates by Legal ("Labor")	Unfunded	116925	228.25	545050	925	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Labor	0				0.000	
16	Injuries & Damages Reserve Risk (Insurance Recovery-"Other")	Estimates by Legal ("Other")	Unfunded	116925	228.25	545050	426.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Other	0				0.000	
17																												
18	Provision for Customer A/R (CSS)	Calculated and Known Items	Unfunded	118100	144	550750	904	(7.2)	(7.8)	(8.2)	(9.1)	(9.3)	(9.1)	(9.2)	(9.4)	(9.0)	(9.4)	(7.6)	(6.6)	(6.4)	(8.3)	Other	0				(8.316)	
19	Provision for Other A/R (OAR)	Calculated and Known Items	Unfunded	118150	144	550750	904	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.8)	(0.9)	(0.9)	(0.8)	(0.3)	Other	0				(0.297)	
20	Provision for Other A/R (Joint Use)	Accrual based on 100% of Fines & Sa	Unfunded	118155	172	301869	454.1	(0.1)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.1)	(0.1)	(0.8)	(0.7)	(0.7)	(0.2)	Other	0				(0.212)	
21	Bad Debt Reserve - Pole Contracts	Uncollectible pole contact revenue - c	Unfunded	118157	144	550776	904.2	(0.4)	(0.4)	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	Other	0				(0.195)	
22	Provision for Doubtful Debts - Other	Known	Unfunded	118168	144	550750	904	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.2)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	Other	0				(0.133)	
23	Bad Debt Reserve - Transmission	Known	Unfunded	118175	144	550775	904	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(1.0)	(0.1)	Other	0				(0.105)	
24	Provision for Unbilled Revenue PP	Calculated and Known Items	Unfunded	118200	173	301119	440.1	(0.2)	(0.3)	(0.3)	(0.3)	(0.2)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	Other					(0.281)	
25	Provision for Unbilled Revenue RMP	Calculated and Known Items	Unfunded	118300	173	301119	440.1	(0.4)	(0.4)	(0.4)	(0.3)	(0.3)	(0.4)	(0.5)	(0.6)	(0.5)	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)	Other	0				(0.413)	
26																												
27	Inventory Reserve - Power Supply	Known - Calculated	Unfunded	120930	154.99	516400	557	(0.5)	(0.5)	(0.5)	(0.8)	(0.8)	(0.8)	(1.1)	(1.0)	(1.0)	(0.3)	(0.3)	(0.3)	(0.5)	(0.6)	100% Production	0	(0.628)				
28	Inventory Reserve - RMP (T&D)	Calc by RMP Finance	Unfunded	120932	154.99	516900	707.1 / 707.2	(0.9)	(0.9)	(1.0)	(1.0)	(1.0)	(1.0)	(0.9)	(0.8)	(0.9)	(0.9)	(0.8)	(1.0)	(0.9)	(0.9)	Other	0				(0.911)	
29	Inventory Reserve - PP (T&D)	Calc by PP Finance	Unfunded	120933	154.99	516900	707.1 / 707.2	(0.8)	(0.8)	(0.8)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.9)	(0.8)	(0.6)	(0.8)	Other	0				(0.849)	
30	Construction Work-in-Progress (CWIP) Reserve (Production Only)	Calculated		148001	107	545990	557	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.1)	(1.1)	(1.3)	(2.2)	(1.6)	100% Production	0	(1.612)				
31	Construction Work-in-Progress (CWIP) Reserve (Other)	Calculated		148001	107	545990	598 / Other	(3.9)	(4.1)	(4.2)	(4.1)	(4.2)	(4.4)	(4.2)	(4.5)	(4.7)	(4.2)	(4.2)	(4.4)	(5.3)	(4.3)	Other	0				(4.340)	
32	CWIP Reserve-Disallowance Loss	Calc by RMP Finance		148019	107	554702	426.5	0.0	0.0	0.0	(0.4)	(0.4)	(0.3)	(0.3)	(0.3)	(0.3)	(1.0)	(1.0)	(1.0)	(0.8)	(0.5)	100% Production		(0.453)				
33	Contra PP&E - Cholla U4 - CWIP	Calc by PP Finance		148907	107	185861	182.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(1.8)	(0.1)	100% Production		(0.142)				
34	Uncollectible Weatherization Loans Reserve	Historical Trend Judgment	Unfunded	162010	124.9	550750	904	(0.2)	(0.2)	(0.2)	(0.3)	(0.3)	(0.3)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	Other	0				(0.245)	
35																												
36	Provision for Unbilled Severance Tax Cap (Chevron Mining Co.)	Estimate by Mining	Unfunded	210649	232	515100	501.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Other	0				0.000	
37																												
38	Accrued Liquidated Damages (Current) - Naughton	Fuel Management		210675	232	515100	501.1	0.0	0.0	0.0	0.0	0.0	0.0	(4.3)	(4.3)	(4.3)	(4.3)	(4.3)	(4.3)	(9.9)	(2.8)	100% Production	0	(2.761)				
39	Accrued Liquidated Damages (Current) - Cholla	Fuel Management		210678	232	515100	501.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(19.6)	(1.5)	100% Production	0	(1.508)				
40	Accrual - Severance Payments	Known	Unfunded	235190	232	500700	920	(1.3)	(1.2)	(1.1)	(1.1)	(1.0)	(1.0)	(1.0)	(0.9)	(0.9)	(1.0)	(0.9)	(0.9)	(0.6)	(1.0)	Labor	0				(0.990)	
41	Annual Incentive Plan (AIP)	Calculated plus CEO Discretion	Unfunded	235510	232	500410	Follows Labor	0.0	(2.7)	(5.4)	(8.0)	(10.7)	(13.4)	(16.2)	(18.9)	(21.8)	(24.5)	(27.2)	(27.3)	0.0	(13.5)	Labor					(13.542)	
42	401(K) Discretionary 1% Company Match	Calculated plus CEO Discretion	Unfunded	215078	232	501250	Follows Labor	(1.9)	(1.9)	(0.5)	(0.6)	(0.8)	(0.9)	(1.1)	(1.3)	(1.3)	(1.6)	(1.7)	(1.9)	(1.9)	(1.3)	Labor	0				(1.331)	
43	Safety Awards Payable	Calculated plus CEO Discretion	Unfunded	235599	232	500400	Follows Labor	(1.4)	(0.3)	(0.5)	(0.7)	(0.9)	(1.1)	(1.3)	(1.5)	(0.9)	(1.0)	(1.1)	(1.2)	(1.2)	(1.0)	Labor					(1.003)	
44	Citi Card Signing Bonus & Usage Bonus (Deferred Revenue)	Estimate by A/P	Prefunded	289000	253.99	550500	921	(0.3)	(0.3)	(0.3)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.9)	(0.9)	(0.8)	(0.7)	(0.4)	Labor	0				(0.374)	
45	Accrued Liquidated Damages (NonCurrent) - Naughton	Fuel Management		289540	253.99	515100	501.1	0.0	0.0	0.0	(11.0)	(11.0)	(11.0)	(11.0)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.7)	(6.5)	100% Production	0	(6.457)				
46	Environmental Liabilities - Centralia Plant	Estimate by Environmental Engrg	Unfunded / Gains Given Back to Customers	288601	253.99	140709	102	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Other	0				0.000	
47	Environmental Liabilities - Centralia Mine (J.O.)	Estimate by Environmental Engrg	Unfunded / Gains Given Back to Customers	288602	253.99	140709	102	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Other	0				0.000	
48	Environmental Liabilities - Centralia Mine (PCorp)	Estimate by Environmental Engrg	Unfunded / Gains Given Back to Customers	288603	253.99	140709	102	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Other	0				0.000	
49																												
50	Vacation Accrual IBEW 57	Calculated by Payroll	Unfunded	248181	242	500515	Follows Labor	(2.7)	(3.2)	(3.6)	(4.0)	(4.2)	(4.3)	(4.3)	(3.8)	(3.6)	(3.5)	(3.3)	(3.4)	(2.5)	(3.6)	Labor	0				(3.569)	
51	Vacation Accrual IBEW 125	Calculated by Payroll	Unfunded	248182	242	500517	Follows Labor	(1.9)	(1.9)	(2.0)	(2.1)	(2.1)	(2.1)	(2.1)	(2.0)	(2.0)	(1.9)	(2.0)	(2.0)	(1.9)	(2.0)	Labor	0				(2.001)	
52	Vacation Accrual IBEW 659	Calculated by Payroll	Unfunded	248183	242	500520	Follows Labor	(2.1)	(2.1)	(2.2)	(2.3)	(2.4)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.3)	(2.2)	(2.3)	Labor					(2.268)	
53	Personal Time Accrual IBEW 57 - Laramie	Calculated by Payroll	Unfunded	248186	242	500515	Follows Labor	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	Labor	0				(0.039)	
54	Personal Time Accrual UWUA 127	Calculated by Payroll	Unfunded	248187	242	500518	Follows Labor	(3.7)	(3.8)	(3.9)	(4.0)	(4.1)	(4.2)	(4.0)	(3.8)	(3.7)	(3.7)	(3.6)	(3.7)	(3.5)	(3.8)	Labor	0				(3.833)	
55	Personal Time Accrual UWUA 197	Calculated by Payroll	Unfunded	248188	242	500519	Follows Labor	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.2)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	Labor	0				(0.138)	
56	Personal Time Accrual Non-Union	Calculated by Payroll	Unfunded	248189	242	500516	Follows Labor	(15.3)	(15.4)	(15.7)	(15.8)	(16.0)	(16.0)	(16.0)	(15.6)	(15.5)	(15.5)	(15.5)	(15.8)	(15.8)	(15.7)	Labor	0				(15.682)	
57	Sick Leave Accrual IBEW 57	Calculated by Payroll	Unfunded	248195	242	500515	Follows Labor	(6.1)	(6.3)	(6.2)	(6.3)	(6.3)	(6.3)	(6.3)	(5.6)	(5.6)	(5.6)	(5.5)	(5.5)	(6.1)	(6.0)	Labor	0				(5.976)	
58																												
59	Supplemental Pension Benefits (Retirement Allowances)	Pension - Known by HR/Payroll	Unfunded	280349	228.3	501106	426.5	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.7)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.6)	(1.7)	Other	0				(1.653)	
60	Pension - Local 57	Pension - Calculated - Actuary	Unfunded	280350	228.35	501105	Follows Labor	(0.6)	(1.2)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	(0.6)	Labor	0				(0.612)	
61																												
62	FAS 158 SERP Liability	SERP - Calculated - Actuary	Unfunded	280465	228.35	501115	920 / 426.5	(52.8)	(0.5)	(52.4)	(52.2)	(52.0)	(51.8)	(51.6)	(51.4)	(51.2)	(51.1)	(50.9)	(50.7)	(55.6)	(48.0)	Labor	0				(48.012)	
63	FAS 158 SERP Accumulated Other Comprehensive Income	SERP - Calculated - Actuary	Accum OCI/partially ofsetting unfunded SERP liability	299107	219	0	0	16.8	16.7	16.6	16.6	16.5	16.4	16.4	16.3	16.2	(16.2)	(16.1)	(16.1)	(21.1)	6.1	Labor					6.080	
64																							0					
65	FAS 112 Book Reserve	Post-Employ - Calculated - Actuary	Unfunded	280330	228.3	501160	920	(26.0)	(25.7)	(25.8)	(25.9)	(27.6)	(27.4)	(27.8)	(27.8)	(28.1)	(28.1)	(28.2)	(28.4)	(28.3)	(27.3)	Labor	0				(27.305)	
66	Wasatch Worker's Compensation Reserve	Post-Employ - Calculated - Actuary	Unfunded	280490	228.3	501160	920	(2.7)	(2.7)	(2.7)	(2.7)	(2.7)	(2.7)	(2.7)	(2.6)	(2.6)	(2.6)	(2.5)	(2.5)	(2.5)	(2.6)	Labor	0				(2.607)	
67																												
68	Totals							(160.4)	(113.4)	(169.2)	(186.5)	(193.3)	(196.0)	(210.6)	(205.5)	(207.8)	(245.6)	(235.8)	(235.4)	(248.5)	(204.4)			(20.184)	(1.190)	0.000	(137.642)	(41.584)	

	100% Production	100% Transmission	Plant	Labor	Other	
Allocators	100.000%	0.000%	47.529%	44.956%	0.000%	
Total ($ millions)	(20.184)	0.000	0.000	(61.878)	0.000	(82.062)

Attachment A input **(82,062,312)**

PacifiCorp
Post Retirement Benefits Other Than Pensions

Line	FERC Acct	Description	2019 Expense
1	4265000	OTHER DEDUCTIONS	(3)
2	5020000	STEAM EXPENSES	76
3	5060000	MISC STEAM PWR EXP	337,770
4	5063000	MISC STEAM JVA CR	(40,745)
5	5120000	MANT OF BOILR PLNT	865
6	5140000	MAINT MISC STM PLN	1,727
7	5350000	OPER SUPERV & ENG	20,981
8	5390000	MSC HYD PWR GEN EX	17,314
9	5480000	GENERATION EXP	2,574
10	5490000	MIS OTH PWR GEN EX	3,563
11	5530000	MNT GEN & ELEC PLT	1,347
12	5560000	SYS CTRL & LD DISP	3,431
13	5570000	OTHER EXPENSES	76,749
14	5600000	OPER SUPERV & ENG	35,288
15	5612000	LD - MONITOR & OPER	4,407
16	5615000	REL PLAN & STDS DEV	1,886
17	5680000	MNT SUPERV & ENG	6,355
18	5700000	MAINT STATION EQIP	1,134
19	5710000	MAINT OVHD LINES	795
20	5800000	OPER SUPERV & ENG	42,035
21	5810000	LOAD DISPATCHING	24,958
22	5850000	STRT LGHT-SGNL SYS	1,243
23	5880000	MSC DISTR EXPENSES	7,645
24	5900000	MAINT SUPERV & ENG	38,852
25	5920000	MAINT STAT EQUIP	12,645
26	5930000	MAINT OVHD LINES	3,806
27	5950000	MAINT LINE TRNSFRM	6,753
28	5970000	MNT OF METERS	2,126
29	5980000	MNT MISC DIST PLNT	5,944
30	7071000	LBR CLR - RMP	282,336
31	7072000	LBR CLR - PACPWR	150,945
32	7081000	Stores Exp CLR - RMP	22,458
33	7082000	Stores Exp CLR - PP	14,808
34	9010000	SUPRV (CUST ACCT)	9,405
35	9020000	METER READING EXP	4,823
36	9030000	CUST RCRD/COLL EXP	941
37	9031000	CUST RCRD/CUST SYS	2,785
38	9032000	CUST ACCTG/BILL	4,077
39	9033000	CUST ACCTG/COLL	8,609
40	9036000	CUST ACCTG/COMMON	25,932
41	9070000	SUPRV (CUST SERV)	108
42	9084000	DSM DIRECT	3,124
43	9086000	CUST SERV	13,940
44	9090000	INFOR/INSTRCT ADV	367
45	9200000	ADMIN & GEN SALARY	140,398
46	9350000	MAINT GENERAL PLNT	78
47			
48			
49			
50		Attachment 5 input: **Total PBOP**	**1,306,656**

Notes:

Total expense was a net debit for 2018 & 2019
Total expense was a net benefit (negative) for 2014-2017.
Amounts are net of joint-venture cutback, do not include expenses for the mining companies and do not reflect amounts capitalized through activity rates or capital surcharge.
The decrease in expense in 2019 as compared to 2018 is primarily due to changes in actuarial assumptions.

Ties to SAP company code 1000 - accounts 501153-501158. Excludes 501144 (State Situs) and 501149 (Western Coal Carrier-Other power supply actuarial costs).

Title of Worksheet	Tab Name	Attachment #
Reactive Power Revenue Requirement and Rates	RP RR and Rate	2
Thermal Facilities Reactive Power Revenue Requirement - Summary	Thermal RP RR	3
Reactive Power Revenue Requirement for Individual Thermal Facilities	Facility Name	3a-3p
Hydro Facilities Reactive Power Revenue Requirement - Summary	Hydro RP RR	4
Reactive Power Revenue Requirement for Individual Hydro Facilities	Facility Name	4a-4r
Wind Facilities Reactive Power Revenue Requirement - Summary	Wind RP RR	5
Reactive Power Revenue Requirement for Individual Wind Facilities	Facility Name	5a-5m
Purchase Power Agreeements Reactive Power Costs	PP RP RR	6
Reactive Power Allocation Factor and Balance of Plant Allocation Factor	RP and BOP Allocators	7
Wind Facility Power Factors	Wind PF	7a
MOD-25 Test Results	MOD-25 Test Results	7b
Summary Investment Data	Summary Investment Data	8
Detail Investment Data	Detail Investment Data	8a
Turbogenerator Investment Data	Turbogen Investment Data	8b
Additional Turbogenerator Investment Data	Add'l TG Data	8c
Additional Generator Step-up Transformer Investment Data	Add'l GSU Data	8d
Summary Accessory Electric Equipment Investment Data - Hydro	Sum AEE Data - Hydro	8e
Detail Accessory Electric Equipment Investment Data - Hydro	AEE Data - Hydro	8f
Capacitor Investment Data	Capacitor Invest Data	8g
Investment Data for New and Repowered Wind Facilities	Wind Facility Name	8h-8m
Fixed Charge Items - Apply to All Facilities	Fixed Charge Items	9
Operations and Maintenance Expense by Facility	O&M By Facility	10
Depreciation Expense Adjustments	Depreciation Expense Adj	11
Book Lives	Book Lives	12
Tax Depreciation - MACRS Schedules	Tax Depreciation Rates	13
Network Load and Firm Point-to-Point Arrangements	Network Load Plus Firm P2P	14
Summary of Heating Losses	Heating Losses	15
Heating Losses for Thermal Generating Facilities	Thermal Unit	15a-15ee

		MVA		Amount	Reference
1	Thermal Generating Facilities	8,750	$	10,363,603	Thermal RP RR
2	Hydroelectric Generating Facilities	1,158		3,083,453	Hydro RP RR
3	Wind Generating Facilities	2,537		6,956,246	Wind RP RR
4	Subtotal PAC Facilities	12,444		20,403,302	(Sum of Lines 1 through 3)
5	Purchased Power Agreements	447		2,149,672	PPA RP RR
6	Total	12,891	$	22,552,974	(Sum of Lines 4 and 5)
7	Network Load Plus Firm Point-to-Point - kW			13,450,317	Network Load Plus Firm P2P Times 1,000

Proposed Reactive Power Rates:

8	Annual	Charge:	$1.677	per	kW-Year
9	Monthly	Charge:	0.140	per	kW-Month
10	Weekly	Charge:	0.032	per	kW-Week
11	Daily	Charge:	0.005	per	kW-Day
12	Hourly	Charge:	0.191	per	MWh

Current Reactive Power Rates:

13	Annual	Charge:	$0.550	per	kW-Year
14	Monthly	Charge:	0.046	per	kW-Month
15	Weekly	Charge:	0.011	per	kW-Week
16	Daily	Charge:	0.001	per	kW-Day
17	Hourly	Charge:	0.063	per	MWh

Filed in ER11-3643 Reactive Power Rates

Annual	Charge:	$1.136	per	kW-Year
Monthly	Charge:	0.095	per	kW-Month
Weekly	Charge:	0.022	per	kW-Week
Daily	Charge:	0.003	per	kW-Day
Hourly	Charge:	0.130	per	MWh

	Name of Facility	Type of Facility	In Service	Number of Units	MVA Rating - PacifiCorp Share	Annual Revenue Requirement		Annual Revenue Requirement	
1	**Blundell**	**Steam - Geothermal**	**1984-2007**	**2**	**44.8**	**$ 406,468**			
2	**Chehalis**	**Combined Cycle**	**2003**	**3**	**698.0**	**In BPA BAA**	(pseuda-tied to PAC - in Bonneville BAA)	$ 1,301,375	
3	**Cholla**	**Steam - Coal**	**1981**	**1**	**460.0**	**In APS BAA**	(pseudo-tied to PAC - in Arizona Public Service BAA)	-	Ceasing operation December 2020
4	**Colstrip**	**Steam - Coal**	**1984-1986**	**2**	**163.8**	**In Northwestern BAA**	(pseudo-tied to PAC - in Northwestern BAA)	239,795	
5	**Currant Creek**	**Combined Cycle**	**2005-2006**	**3**	**649.0**	**1,107,512**			
6	**Dave Johnston**	**Steam - Coal**	**1959-1972**	**4**	**922.4**	**800,553**			
7	**Gadsby**	**Combustion Turbine and Steam-NG**	**1951-2002**	**6**	**514.8**	**1,136,123**			
8	**Hermiston**	**Combined Cycle**	**1996**	**4**	**310.7**	**In BPA BAA**	(pseudo-tied to PAC - in Bonneville BAA)	676,726	
9	**Hunter**	**Steam - Coal**	**1978-1983**	**3**	**1,336.0**	**1,283,818**			
10	**Huntington**	**Steam - Coal**	**1974-1977**	**2**	**1,116.3**	**986,518**			
11	**Jim Bridger**	**Steam - Coal**	**1974-1979**	**4**	**1,628.0**	**912,259**			
12	**Lake Side**	**Combined Cycle**	**2007-2014**	**6**	**1,385.0**	**2,436,372**			
13	**Naughton**	**Steam-Coal and Steam-NG**	**1963-1971**	**3**	**832.0**	**893,459**			
14	**Craig**	**Steam - Coal**	**1979-1980**	**2**	**191.3**	**In WAPA BAA**		121,583	
15	**Hayden**	**Steam - Coal**	**1965-1976**	**2**	**88.2**	**In PSCO BAA**		62,046	
16	**Wyodak**	**Steam - Coal**	**1978**	**1**	**321.8**	**400,521**			
17	**Total Thermal in PAC BA**				**8,750.2**	**$ 10,363,603**			

The following are PacifiCorp percent ownership of generating facilities where ownership is less than 100%.
The revenue requirements in this reactive power analyses reflect only the PacifiCorp ownership share.

Colstrip 3 and 4	10.00%
Craig 1 and 2	19.28%
Hayden 1	24.50%
Hayden 2	12.60%
Hunter 1	93.75%
Hunter 2	60.31%
Jim Bridger 1-4	66.67%
Wyodak	80.00%
Hermiston	50.00%

Facility Name **Blundell** **Cost Year:** 2019
Plant Type: Steam - Geothermal

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	8,146,941
2	RP Capability Allocator	RP and BOP Allocators	27.75%
3	**RP - Generator/Exciter**	(Line 1 * 2)	2,260,776
4			
5	GSU Transformer	Summary Investment	1,504,131
6	RP Capability Allocator	RP and BOP Allocators	27.75%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	417,396
8			
9	Accessory Electric Equipment	Summary Investment	8,620,816
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	862,082
12	RP Capability Allocator	RP and BOP Allocators	27.75%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	239,228
14	Total Plant Investment	Summary Investment	154,986,314
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	144,473,161
16	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
17	**RP - Balance of Plant**	(Line 15 * 16)	38,724
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	2,956,124
19	RP Fixed Charge Percent	(Line 11(h))	13.7500%
20	Subtotal	(Line 18 * 19)	406,468
21	**Heating Losses**	Heating Losses	-
22	**Reactive Power Revenue Requirement**	(Line 20 + 21)	**$ 406,468**

	Depreciation			
23	Annual Depreciation Expense (D)	$	4,263,907	
24	Gross Plant Investment (F)		154,986,314	(Line 14)
25	SLDP=DE/F		2.7512%	(Line 23 / 24)
26	Depreciable years =1/SLDP		36	
27	Book Life (n)		45	Book Lives
28	SLDP for Book Life = 1/n		2.22%	
29	SFDP=(R/((1+R)^n-1)		0.31%	R=Return

	Income Taxes		
	Income Tax Factor to Include in Fixed Charge		
30	Factor	1.2485%	Based Upon Book Life
	[(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]		CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment						
			Amount	Investment	FCR %	
O&M	O&M by Facility	$	7,294,460	$ 154,986,314	4.7065%	(f)/(g)
A&G	Fixed Charge Items				0.4475%	
Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)				0.0567%	
Prepayments	Fixed Charge Items				0.0203%	
Materials and Supplies	Fixed Charge Items				0.1029%	
General and Intangible Plant	Fixed Charge Items				1.1057%	
Other Taxes	Fixed Charge Items				0.5233%	
Depreciation	(Line 29)				0.3069%	
Return	Fixed Charge Items				7.5512%	
Income Taxes	Line 30				1.2485%	
ADIT	Line 34(i)		(3,594,802)	154,986,314	-2.3194%	
Total RP Fixed Charge Percent					13.7500%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
31	Investment	$ 154,986,314	Summary Investment						
32	Straight-line Tax Life	45	(Line 27)						
33	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$45,807,029
34	In Service Year	1996	1984-2007			Levelized Revenue Requirement			3,594,802
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35	1996	$ 3,444,140	20.000%	$ 30,997,263	$ 27,553,123	$ 10,456,686	$ 10,456,686	10.69%	$ 558,880
36	1997	3,444,140	32.000%	49,595,621	46,151,480	17,514,948	27,971,634	10.69%	2,053,883
37	1998	3,444,140	19.200%	29,757,372	26,313,232	9,986,135	37,957,769	10.69%	3,523,737
38	1999	3,444,140	11.520%	17,854,423	14,410,283	5,468,847	43,426,615	10.69%	4,349,761
39	2000	3,444,140	11.520%	17,854,423	14,410,283	5,468,847	48,895,462	10.69%	4,934,349
40	2001	3,444,140	5.760%	8,927,212	5,483,071	2,080,880	50,976,342	10.69%	5,337,860
41	2002	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	49,669,256	10.69%	5,379,217
42	2003	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	48,362,171	10.69%	5,239,498
43	2004	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	47,055,085	10.69%	5,099,778
44	2005	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	45,747,999	10.69%	4,960,058
45	2006	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	44,440,914	10.69%	4,820,338
46	2007	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	43,133,828	10.69%	4,680,618
47	2008	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	41,826,742	10.69%	4,540,898
48	2009	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	40,519,656	10.69%	4,401,178
49	2010	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	39,212,571	10.69%	4,261,458
50	2011	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	37,905,485	10.69%	4,121,738
51	2012	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	36,598,399	10.69%	3,982,018
52	2013	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	35,291,314	10.69%	3,842,298
53	2014	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	33,984,228	10.69%	3,702,578
54	2015	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	32,677,142	10.69%	3,562,858
55	2016	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	31,370,057	10.69%	3,423,138
56	2017	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	30,062,971	10.69%	3,283,418
57	2018	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	28,755,885	9.22%	2,712,725
58	2019	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	27,448,800	9.22%	2,592,160
59	2020	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	26,141,714	9.22%	2,471,594
60	2021	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	24,834,628	9.22%	2,351,029
61	2022	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	23,527,542	9.22%	2,230,463
62	2023	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	22,220,457	9.22%	2,109,897
63	2024	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	20,913,371	9.22%	1,989,332
64	2025	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	19,606,285	9.22%	1,868,766
65	2026	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	18,299,200	9.22%	1,748,201
66	2027	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	16,992,114	9.22%	1,627,635
67	2028	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	15,685,028	9.22%	1,507,070
68	2029	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	14,377,943	9.22%	1,386,504
69	2030	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	13,070,857	9.22%	1,265,938
70	2031	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	11,763,771	9.22%	1,145,373
71	2032	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	10,456,686	9.22%	1,024,807
72	2033	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	9,149,600	9.22%	904,242
73	2034	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	7,842,514	9.22%	783,676
74	2035	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	6,535,428	9.22%	663,111
75	2036	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	5,228,343	9.22%	542,545
76	2037	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	3,921,257	9.22%	421,979
77	2038	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	2,614,171	9.22%	301,414
78	2039	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	1,307,086	9.22%	180,848
79	2040	3,444,140	0.000%	-	(3,444,140)	(1,307,086)	0	9.22%	60,283
80		$ 154,986,314	100%	$ 154,986,314	$ 0	$ 0			$ 121,949,151

Facility Name Chehalis **Cost Year:** 2019
Plant Type: Combined Cycle

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	21,738,227
2	RP Capability Allocator	RP and BOP Allocators	27.75%
3	**RP - Generator/Exciter**	(Line 1 * 2)	6,032,358
4			
5	GSU Transformer	Summary Investment	12,401,911
6	RP Capability Allocator	RP and BOP Allocators	27.75%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	3,441,530
8			
9	Accessory Electric Equipment	Summary Investment	38,588,536
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	3,858,854
12	RP Capability Allocator	RP and BOP Allocators	27.75%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	1,070,832
14	Total Plant Investment	Summary Investment	370,317,831
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	332,318,839
16	Balance of Plant Allocator	RP and BOP Allocators	0.0186%
17	**RP - Balance of Plant**	(Line 15 * 16)	61,851
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	10,606,571
19	RP Fixed Charge Percent	(Line 12(h))	12.2695%
20	Subtotal	(Line 18 * 19)	1,301,375
21	**Heating Losses**	Heating Losses	-
22	**Total Reactive Power Revenue Requirement**	(Line 20 + 21)	**$ 1,301,375**

	Depreciation			
23	Annual Depreciation Expense (D)	$	10,646,670	
24	Gross Plant Investment (F)		370,317,831	(Line 14)
25	SLDP=DE/F		2.8750%	(Line 23 / 24)
26	Depreciable years =1/SLDP		35	
27	Book Life (n)		40	Book Lives
28	SLDP for Book Life = 1/n		2.50%	
29	SFDP=(R/((1+R)^n-1)		0.44%	R=Return

	Income Taxes		
30	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.2168%	Based Upon Book Life CTR=Composite Tax Rate

(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment					
		Amount	Investment	FCR %	
O&M	O&M by Facility	$ 4,729,119	$ 370,317,831	1.2770%	(f)/(g)
A&G	Fixed Charge Items			0.4475%	
Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0189%	
Prepayments	Fixed Charge Items			0.0203%	
Maintenance Prepayments	(Line 17 g)	1,551,169	370,317,831	0.4189%	
Materials and Supplies	Fixed Charge Items			0.1029%	
General and Intangible Plant	Fixed Charge Items			1.1057%	
Other Taxes	Fixed Charge Items			0.5233%	
Depreciation	(Line 29)			0.4416%	
Return	Fixed Charge Items			7.5512%	
Income Taxes	Line 30			1.2168%	
ADIT	Line 34(i)	(3,164,668)	370,317,831	-0.8546%	
Total RP Fixed Charge Percent				12.2695%	

Maintenance Prepayment		
Amount	FF1, page 233.13f	$ 17,691,254
Return and Income Taxes	(Line 9 h + Line 10 h)	8.77%
Annual Revenue Requirement	(Line 15 h * Line 16 h)	$ 1,551,169

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes									
31	Investment		$ 370,317,831	Summary Investment						
32	Straight-line Tax Life		40	(Line 27)						
33	Composite Tax Rate (CTR)		24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$39,630,757
34	In Service Year		2003				Levelized Revenue Requirement			3,164,668
	Year		SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
			Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35		2003	$ 9,257,946	3.750%	$ 13,886,919	$ 4,628,973	$ 1,756,742	$ 1,756,742	10.69%	$ 93,893
36		2004	9,257,946	7.219%	26,733,244	17,475,298	6,632,051	8,388,792	10.69%	542,250
37		2005	9,257,946	6.677%	24,726,122	15,468,176	5,870,327	14,259,119	10.69%	1,210,466
38		2006	9,257,946	6.177%	22,874,532	13,616,587	5,167,631	19,426,750	10.69%	1,800,413
39		2007	9,257,946	5.713%	21,156,258	11,898,312	4,515,528	23,942,279	10.69%	2,317,950
40		2008	9,257,946	5.285%	19,571,297	10,313,352	3,914,020	27,856,299	10.69%	2,768,485
41		2009	9,257,946	4.888%	18,101,136	8,843,190	3,356,079	31,212,378	10.69%	3,157,051
42		2010	9,257,946	4.522%	16,745,772	7,487,827	2,841,705	34,054,083	10.69%	3,488,304
43		2011	9,257,946	4.462%	16,523,582	7,265,636	2,757,381	36,811,464	10.69%	3,787,559
44		2012	9,257,946	4.461%	16,519,878	7,261,933	2,755,976	39,567,440	10.69%	4,082,233
45		2013	9,257,946	4.462%	16,523,582	7,265,636	2,757,381	42,324,822	10.69%	4,376,906
46		2014	9,257,946	4.461%	16,519,878	7,261,933	2,755,976	45,080,798	10.69%	4,671,579
47		2015	9,257,946	4.462%	16,523,582	7,265,636	2,757,381	47,838,179	10.69%	4,966,252
48		2016	9,257,946	4.461%	16,519,878	7,261,933	2,755,976	50,594,155	10.69%	5,260,925
49		2017	9,257,946	4.462%	16,523,582	7,265,636	2,757,381	53,351,537	10.69%	5,555,598
50		2018	9,257,946	4.461%	16,519,878	7,261,933	1,785,462	55,136,999	9.22%	5,003,491
51		2019	9,257,946	4.462%	16,523,582	7,265,636	1,786,373	56,923,372	9.22%	5,168,224
52		2020	9,257,946	4.461%	16,519,878	7,261,933	1,785,462	58,708,834	9.22%	5,332,957
53		2021	9,257,946	4.462%	16,523,582	7,265,636	1,786,373	60,495,207	9.22%	5,497,690
54		2022	9,257,946	4.461%	16,519,878	7,261,933	1,785,462	62,280,669	9.22%	5,662,423
55		2023	9,257,946	2.231%	8,261,791	(996,155)	(244,921)	62,035,749	9.22%	5,733,473
56		2024	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	58,770,709	9.22%	5,571,593
57		2025	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	55,505,670	9.22%	5,270,426
58		2026	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	52,240,630	9.22%	4,969,259
59		2027	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	48,975,591	9.22%	4,668,092
60		2028	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	45,710,552	9.22%	4,366,924
61		2029	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	42,445,512	9.22%	4,065,757
62		2030	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	39,180,473	9.22%	3,764,590
63		2031	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	35,915,433	9.22%	3,463,423
64		2032	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	32,650,394	9.22%	3,162,256
65		2033	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	29,385,355	9.22%	2,861,088
66		2034	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	26,120,315	9.22%	2,559,921
67		2035	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	22,855,276	9.22%	2,258,754
68		2036	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	19,590,236	9.22%	1,957,587
69		2037	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	16,325,197	9.22%	1,656,420
70		2038	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	13,060,158	9.22%	1,355,252
71		2039	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	9,795,118	9.22%	1,054,085
72		2040	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	6,530,079	9.22%	752,918
73		2041	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	3,265,039	9.22%	451,751
74		2042	9,257,946	0.000%	-	(9,257,946)	(3,265,039)	0	9.22%	150,584
75			$ 370,317,831	100%	$ 370,317,831	$ 0	$ 0			$ 134,838,798

Facility Name Cholla **Cost Year:** 2019
Plant Type: Steam - Coal

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	12,254,447
2	RP Capability Allocator	RP and BOP Allocators	19.00%
3	**RP - Generator/Exciter**	(Line 1 * 2)	2,328,345
4			
5	GSU Transformer	Summary Investment	7,730,928
6	RP Capability Allocator	RP and BOP Allocators	19.00%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	1,468,876
8			
9	Accessory Electric Equipment	Summary Investment	68,822,098
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	6,882,210
12	RP Capability Allocator	RP and BOP Allocators	19.00%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	1,307,620
14	Total Plant Investment	Summary Investment	560,381,683
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	533,514,099
16	Balance of Plant Allocator	RP and BOP Allocators	0.0000%
17	**RP - Balance of Plant**	(Line 15 * 16)	0
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	5,104,841
19	RP Fixed Charge Percent	(Line 11(h))	12.8069%
20	Subtotal	(Line 18 * 19)	653,772
21	**Heating Losses**	Heating Losses	-
22	**Reactive Power Revenue Requirement**	(Line 20 + 21)	**$ 653,772**

	Depreciation			
23	Annual Depreciation Expense (D)	$	15,290,516	
24	Gross Plant Investment (F)		560,381,683	(Line 14)
25	SLDP=DE/F		2.7286%	(Line 23 / 24)
26	Depreciable years =1/SLDP		37	
27	Book Life (n)		60	Book Lives
28	SLDP for Book Life = 1/n		1.67%	
29	SFDP=(R/((1+R)^n-1)		0.10%	R=Return

	Income Taxes		
30	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.3264%	Based Upon Book Life CTR=Composite Tax Rate

(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment					
		Amount	Investment	FCR %	
O&M	O&M by Facility	$ 16,148,284	$ 560,381,683	2.8817%	(f)/(g)
A&G	Fixed Charge Items			0.4475%	
Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0369%	
Prepayments	Fixed Charge Items			0.0203%	
Materials and Supplies	Fixed Charge Items			0.1029%	
General and Intangible Plant	Fixed Charge Items			1.1057%	
Other Taxes	Fixed Charge Items			0.5233%	
Depreciation	(Line 29)			0.1030%	
Return	Fixed Charge Items			7.5512%	
Income Taxes	Line 30			1.3264%	
ADIT	Line 34(i)	(7,239,822)	560,381,683	-1.2919%	
Total RP Fixed Charge Percent				12.8069%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
31	Investment	$ 560,381,683	Summary Investment						
32	Straight-line Tax Life	60	(Line 27)						
33	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$94,660,991
34	In Service Year	1981				Levelized Revenue Requirement			7,239,822
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35	1981	$ 9,339,695	3.750%	$ 21,014,313	$ 11,674,618	$ 4,430,634	$ 4,430,634	10.69%	$ 236,805
36	1982	9,339,695	7.219%	40,453,954	31,114,259	11,808,172	16,238,807	10.69%	1,104,722
37	1983	9,339,695	6.677%	37,416,685	28,076,990	10,655,499	26,894,305	10.69%	2,305,341
38	1984	9,339,695	6.177%	34,614,777	25,275,082	9,592,146	36,486,452	10.69%	3,387,519
39	1985	9,339,695	5.713%	32,014,606	22,674,911	8,605,355	45,091,807	10.69%	4,360,123
40	1986	9,339,695	5.285%	29,616,172	20,276,477	7,695,126	52,786,933	10.69%	5,231,337
41	1987	9,339,695	4.888%	27,391,457	18,051,762	6,850,824	59,637,757	10.69%	6,008,776
42	1988	9,339,695	4.522%	25,340,460	16,000,765	6,072,450	65,710,208	10.69%	6,699,488
43	1989	9,339,695	4.462%	25,004,231	15,664,536	5,944,848	71,655,056	10.69%	7,341,778
44	1990	9,339,695	4.461%	24,998,627	15,658,932	5,942,721	77,597,777	10.69%	7,977,134
45	1991	9,339,695	4.462%	25,004,231	15,664,536	5,944,848	83,542,625	10.69%	8,612,491
46	1992	9,339,695	4.461%	24,998,627	15,658,932	5,942,721	89,485,346	10.69%	9,247,847
47	1993	9,339,695	4.462%	25,004,231	15,664,536	5,944,848	95,430,194	10.69%	9,883,203
48	1994	9,339,695	4.461%	24,998,627	15,658,932	5,942,721	101,372,916	10.69%	10,518,560
49	1995	9,339,695	4.462%	25,004,231	15,664,536	5,944,848	107,317,764	10.69%	11,153,916
50	1996	9,339,695	4.461%	24,998,627	15,658,932	5,942,721	113,260,485	10.69%	11,789,272
51	1997	9,339,695	4.462%	25,004,231	15,664,536	5,944,848	119,205,333	10.69%	12,424,629
52	1998	9,339,695	4.461%	24,998,627	15,658,932	5,942,721	125,148,055	10.69%	13,059,985
53	1999	9,339,695	4.462%	25,004,231	15,664,536	5,944,848	131,092,903	10.69%	13,695,341
54	2000	9,339,695	4.461%	24,998,627	15,658,932	5,942,721	137,035,624	10.69%	14,330,698
55	2001	9,339,695	2.231%	12,502,115	3,162,421	1,200,170	138,235,794	10.69%	14,712,465
56	2002	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	134,691,287	10.69%	14,587,167
57	2003	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	131,146,779	10.69%	14,208,279
58	2004	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	127,602,272	10.69%	13,829,392
59	2005	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	124,057,764	10.69%	13,450,504
60	2006	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	120,513,256	10.69%	13,071,617
61	2007	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	116,968,749	10.69%	12,692,729
62	2008	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	113,424,241	10.69%	12,313,842
63	2009	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	109,879,734	10.69%	11,934,955
64	2010	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	106,335,226	10.69%	11,556,067
65	2011	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	102,790,719	10.69%	11,177,180
66	2012	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	99,246,211	10.69%	10,798,292
67	2013	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	95,701,704	10.69%	10,419,405
68	2014	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	92,157,196	10.69%	10,040,517
69	2015	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	88,612,689	10.69%	9,661,630
70	2016	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	85,068,181	10.69%	9,282,742
71	2017	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	81,523,673	10.69%	8,903,855
72	2018	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	77,979,166	9.22%	7,356,270
73	2019	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	74,434,658	9.22%	7,029,325
74	2020	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	70,890,151	9.22%	6,702,379
75	2021	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	67,345,643	9.22%	6,375,434
76	2022	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	63,801,136	9.22%	6,048,489
77	2023	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	60,256,628	9.22%	5,721,543
78	2024	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	56,712,121	9.22%	5,394,598
79	2025	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	53,167,613	9.22%	5,067,653
80	2026	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	49,623,106	9.22%	4,740,707
81	2027	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	46,078,598	9.22%	4,413,762
82	2028	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	42,534,091	9.22%	4,086,817
83	2029	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	38,989,583	9.22%	3,759,871
84	2030	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	35,445,075	9.22%	3,432,926
85	2031	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	31,900,568	9.22%	3,105,981
86	2032	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	28,356,060	9.22%	2,779,035
87	2033	9,339,695	0.000%	-	(9,339,695)	(3,544,508)	24,811,553	9.22%	2,452,090

88	2034	9,339,695	0.000%		-	(9,339,695)	(3,544,508)	21,267,045	9.22%	2,125,145
89	2035	9,339,695	0.000%		-	(9,339,695)	(3,544,508)	17,722,538	9.22%	1,798,199
90	2036	9,339,695	0.000%		-	(9,339,695)	(3,544,508)	14,178,030	9.22%	1,471,254
91	2037	9,339,695	0.000%		-	(9,339,695)	(3,544,508)	10,633,523	9.22%	1,144,309
92	2038	9,339,695	0.000%		-	(9,339,695)	(3,544,508)	7,089,015	9.22%	817,363
93	2039	9,339,695	0.000%		-	(9,339,695)	(3,544,508)	3,544,508	9.22%	490,418
94	2040	9,339,695	0.000%		-	(9,339,695)	(3,544,508)	0	9.22%	163,473
95		$ 560,381,683		100%	$ 560,381,683	$ (0)	$ 0			$ 448,486,645

Facility Name Colstrip **Cost Year:** 2019
Plant Type: Steam - Coal

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	6,281,957
2	RP Capability Allocator	RP and BOP Allocators	9.75%
3	**RP - Generator/Exciter**	(Line 1 * 2)	612,491
4			
5	GSU Transformer	Summary Investment	7,730,928
6	RP Capability Allocator	RP and BOP Allocators	9.75%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	753,765
8			
9	Accessory Electric Equipment	Summary Investment	68,822,098
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	6,882,210
12	RP Capability Allocator	RP and BOP Allocators	9.75%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	671,015
14	Total Plant Investment	Summary Investment	245,036,407
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	224,141,313
16	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
17	**RP - Balance of Plant**	(Line 15 * 16)	60,077
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	2,097,349
19	RP Fixed Charge Percent	(Line 11(h))	11.4332%
20	Subtotal	(Line 18 * 19)	239,795
21	**Heating Losses**	Heating Losses	-
22	**Reactive Power Revenue Requirement**	(Line 20 * 21)	**$ 239,795**

	Depreciation			
23	Annual Depreciation Expense (D)	$	5,166,314	
24	Gross Plant Investment (F)		245,036,407	(Line 14)
25	SLDP=DE/F		2.1084%	(Line 23 / 24)
26	Depreciable years =1/SLDP		47	
27	Book Life (n)		60	Book Lives
28	SLDP for Book Life = 1/n		1.67%	
29	SFDP=(R/((1+R)^n-1)		0.10%	R=Return

	Income Taxes		
30	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.3264%	Based Upon Book Life CTR=Composite Tax Rate

(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment					
		Amount	Investment	FCR %	
O&M	O&M by Facility	$ 3,718,968	$ 245,036,407	1.5177%	(f)/(g)
A&G	Fixed Charge Items			0.4475%	
Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0218%	
Prepayments	Fixed Charge Items			0.0203%	
Materials and Supplies	Fixed Charge Items			0.1029%	
General and Intangible Plant	Fixed Charge Items			1.1057%	
Other Taxes	Fixed Charge Items			0.5233%	
Depreciation	(Line 29)			0.1030%	
Return	Fixed Charge Items			7.5512%	
Income Taxes	Line 30			1.3264%	
ADIT	Line 34(i)	(3,152,537)	245,036,407	-1.2866%	
Total RP Fixed Charge Percent				11.4332%	

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes									
31	Investment		$ 245,036,407	Summary Investment						
32	Straight-line Tax Life		60	(Line 27)						
33	Composite Tax Rate (CTR)		24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$41,219,566
34	In Service Year		1985	1984-1986			Levelized Revenue Requirement			3,152,537
	Year		SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
			Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35		1985	$ 4,083,940	3.750%	$ 9,188,865	$ 5,104,925	$ 1,937,370	$ 1,937,370	10.69%	$ 103,547
36		1986	4,083,940	7.219%	17,689,178	13,605,238	5,163,324	7,100,694	10.69%	483,059
37		1987	4,083,940	6.677%	16,361,081	12,277,141	4,659,298	11,759,992	10.69%	1,008,049
38		1988	4,083,940	6.177%	15,135,899	11,051,959	4,194,329	15,954,321	10.69%	1,481,250
39		1989	4,083,940	5.713%	13,998,930	9,914,990	3,762,838	19,717,158	10.69%	1,906,538
40		1990	4,083,940	5.285%	12,950,174	8,866,234	3,364,824	23,081,983	10.69%	2,287,491
41		1991	4,083,940	4.888%	11,977,380	7,893,439	2,995,639	26,077,622	10.69%	2,627,439
42		1992	4,083,940	4.522%	11,080,546	6,996,606	2,655,282	28,732,904	10.69%	2,929,465
43		1993	4,083,940	4.462%	10,933,524	6,849,584	2,599,486	31,332,390	10.69%	3,210,317
44		1994	4,083,940	4.461%	10,931,074	6,847,134	2,598,556	33,930,946	10.69%	3,488,137
45		1995	4,083,940	4.462%	10,933,524	6,849,584	2,599,486	36,530,431	10.69%	3,765,958
46		1996	4,083,940	4.461%	10,931,074	6,847,134	2,598,556	39,128,987	10.69%	4,043,778
47		1997	4,083,940	4.462%	10,933,524	6,849,584	2,599,486	41,728,473	10.69%	4,321,598
48		1998	4,083,940	4.461%	10,931,074	6,847,134	2,598,556	44,327,029	10.69%	4,599,419
49		1999	4,083,940	4.462%	10,933,524	6,849,584	2,599,486	46,926,515	10.69%	4,877,239
50		2000	4,083,940	4.461%	10,931,074	6,847,134	2,598,556	49,525,071	10.69%	5,155,060
51		2001	4,083,940	4.462%	10,933,524	6,849,584	2,599,486	52,124,556	10.69%	5,432,880
52		2002	4,083,940	4.461%	10,931,074	6,847,134	2,598,556	54,723,112	10.69%	5,710,700
53		2003	4,083,940	4.462%	10,933,524	6,849,584	2,599,486	57,322,598	10.69%	5,988,521
54		2004	4,083,940	4.461%	10,931,074	6,847,134	2,598,556	59,921,154	10.69%	6,266,341
55		2005	4,083,940	2.231%	5,466,762	1,382,822	524,795	60,445,949	10.69%	6,433,275
56		2006	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	58,896,052	10.69%	6,378,486
57		2007	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	57,346,156	10.69%	6,212,811
58		2008	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	55,796,260	10.69%	6,047,136
59		2009	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	54,246,364	10.69%	5,881,461
60		2010	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	52,696,468	10.69%	5,715,786
61		2011	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	51,146,572	10.69%	5,550,112
62		2012	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	49,596,676	10.69%	5,384,437
63		2013	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	48,046,780	10.69%	5,218,762
64		2014	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	46,496,883	10.69%	5,053,087
65		2015	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	44,946,987	10.69%	4,887,412
66		2016	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	43,397,091	10.69%	4,721,737
67		2017	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	41,847,195	10.69%	4,556,062
68		2018	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	40,297,299	9.22%	3,788,504
69		2019	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	38,747,403	9.22%	3,645,541
70		2020	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	37,197,507	9.22%	3,502,579
71		2021	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	35,647,611	9.22%	3,359,616
72		2022	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	34,097,715	9.22%	3,216,654
73		2023	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	32,547,818	9.22%	3,073,692
74		2024	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	30,997,922	9.22%	2,930,729
75		2025	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	29,448,026	9.22%	2,787,767
76		2026	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	27,898,130	9.22%	2,644,804
77		2027	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	26,348,234	9.22%	2,501,842
78		2028	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	24,798,338	9.22%	2,358,880
79		2029	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	23,248,442	9.22%	2,215,917
80		2030	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	21,698,546	9.22%	2,072,955
81		2031	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	20,148,650	9.22%	1,929,992
82		2032	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	18,598,753	9.22%	1,787,030
83		2033	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	17,048,857	9.22%	1,644,068
84		2034	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	15,498,961	9.22%	1,501,105
85		2035	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	13,949,065	9.22%	1,358,143
86		2036	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	12,399,169	9.22%	1,215,180
87		2037	4,083,940	0.000%	-	(4,083,940)	(1,549,896)	10,849,273	9.22%	1,072,218

88	2038	4,083,940	0.000%		-	(4,083,940)	(1,549,896)	9,299,377	9.22%	929,256
89	2039	4,083,940	0.000%		-	(4,083,940)	(1,549,896)	7,749,481	9.22%	786,293
90	2040	4,083,940	0.000%		-	(4,083,940)	(1,549,896)	6,199,584	9.22%	643,331
91	2041	4,083,940	0.000%		-	(4,083,940)	(1,549,896)	4,649,688	9.22%	500,368
92	2042	4,083,940	0.000%		-	(4,083,940)	(1,549,896)	3,099,792	9.22%	357,406
93	2043	4,083,940	0.000%		-	(4,083,940)	(1,549,896)	1,549,896	9.22%	214,444
94	2044	4,083,940	0.000%		-	(4,083,940)	(1,549,896)	0	9.22%	71,481
95		$ 245,036,407		100%	$ 245,036,407	$ 0	$ 0			$ 193,837,145

Facility Name Currant Creek **Cost Year:** 2019
Plant Type: Combined Cycle

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	26,635,454
2	RP Capability Allocator	RP and BOP Allocators	23.43%
3	**RP - Generator/Exciter**	(Line 1 * 2)	6,241,250
4			
5	GSU Transformer	Summary Investment	7,053,477
6	RP Capability Allocator	RP and BOP Allocators	23.43%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	1,652,779
8			
9	Accessory Electric Equipment	Summary Investment	43,011,421
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	4,301,142
12	RP Capability Allocator	RP and BOP Allocators	23.43%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	1,007,848
14	Total Plant Investment	Summary Investment	362,536,068
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	324,545,995
16	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
17	**RP - Balance of Plant**	(Line 15 * 16)	86,989
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	8,988,866
19	RP Fixed Charge Percent	(Line 12(h))	12.1763%
20	Subtotal	(Line 18 * 19)	1,094,516
21	**Heating Losses**	Heating Losses	12,996
22	**Reactive Power Revenue Requirement**	(Line 20 + 21)	**$ 1,107,512**

	Depreciation			
23	Annual Depreciation Expense (D)	$	7,913,488	
24	Gross Plant Investment (F)		362,536,068	(Line 14)
25	SLDP=DE/F		2.1828%	(Line 23 / 24)
26	Depreciable years =1/SLDP		46	
27	Book Life (n)		40	Book Lives
28	SLDP for Book Life = 1/n		2.50%	
29	SFDP=(R/((1+R)^n-1)		0.44%	R=Return

	Income Taxes		
30	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.2168%	Based Upon Book Life CTR=Composite Tax Rate

(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment					
		Amount	Investment	FCR %	
O&M	O&M by Facility	$ 4,238,089	$ 362,536,068	1.1690%	(f)/(g)
A&G	Fixed Charge Items			0.4475%	
Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0177%	
Prepayments	Fixed Charge Items			0.0203%	
Maintenance Prepayments	(Line 17 h)	1,491,205	362,536,068	0.4113%	
Materials and Supplies	Fixed Charge Items			0.1029%	
General and Intangible Plant	Fixed Charge Items			1.1057%	
Other Taxes	Fixed Charge Items			0.5233%	
Depreciation	(Line 29)			0.4416%	
Return	Fixed Charge Items			7.5512%	
Income Taxes	Line 30			1.2168%	
ADIT	Line 34(i)	(3,012,622)	362,536,068	-0.8310%	
Total RP Fixed Charge Percent				12.1763%	

Maintenance Prepayment			
Amount	FF1, page 233.14f	$	17,007,357
Return and Income Taxes	(Line 9 h + Line 10 h)		8.77%
Annual Revenue Requirement	(Line 15 h * Line 16 h)	$	1,491,205

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
31	Investment	$ 362,536,068	Summary Investment						
32	Straight-line Tax Life	40	(Line 27)						
33	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$37,726,700
34	In Service Year	2005	2005-2006			Levelized Revenue Requirement			3,012,622

	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35	2005	$ 9,063,402	3.750%	$ 13,595,103	$ 4,531,701	$ 1,719,826	$ 1,719,826	10.69%	$ 91,920
36	2006	9,063,402	7.219%	26,171,479	17,108,077	6,492,686	8,212,512	10.69%	530,855
37	2007	9,063,402	6.677%	24,206,533	15,143,132	5,746,970	13,959,482	10.69%	1,185,029
38	2008	9,063,402	6.177%	22,393,853	13,330,451	5,059,040	19,018,522	10.69%	1,762,579
39	2009	9,063,402	5.713%	20,711,686	11,648,284	4,420,640	23,439,162	10.69%	2,269,241
40	2010	9,063,402	5.285%	19,160,031	10,096,630	3,831,772	27,270,934	10.69%	2,710,309
41	2011	9,063,402	4.888%	17,720,763	8,657,361	3,285,555	30,556,489	10.69%	3,090,709
42	2012	9,063,402	4.522%	16,393,881	7,330,479	2,781,990	33,338,479	10.69%	3,415,002
43	2013	9,063,402	4.462%	16,176,359	7,112,958	2,699,439	36,037,918	10.69%	3,707,969
44	2014	9,063,402	4.461%	16,172,734	7,109,332	2,698,063	38,735,980	10.69%	3,996,450
45	2015	9,063,402	4.462%	16,176,359	7,112,958	2,699,439	41,435,419	10.69%	4,284,930
46	2016	9,063,402	4.461%	16,172,734	7,109,332	2,698,063	44,133,482	10.69%	4,573,411
47	2017	9,063,402	4.462%	16,176,359	7,112,958	2,699,439	46,832,920	10.69%	4,861,892
48	2018	9,063,402	4.461%	16,172,734	7,109,332	1,747,943	48,580,863	9.22%	4,400,483
49	2019	9,063,402	4.462%	16,176,359	7,112,958	1,748,834	50,329,698	9.22%	4,561,755
50	2020	9,063,402	4.461%	16,172,734	7,109,332	1,747,943	52,077,641	9.22%	4,723,026
51	2021	9,063,402	4.462%	16,176,359	7,112,958	1,748,834	53,826,475	9.22%	4,884,297
52	2022	9,063,402	4.461%	16,172,734	7,109,332	1,747,943	55,574,418	9.22%	5,045,569
53	2023	9,063,402	4.462%	16,176,359	7,112,958	1,748,834	57,323,253	9.22%	5,206,840
54	2024	9,063,402	4.461%	16,172,734	7,109,332	1,747,943	59,071,196	9.22%	5,368,111
55	2025	9,063,402	2.231%	8,088,180	(975,222)	(239,774)	58,831,422	9.22%	5,437,668
56	2026	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	55,735,031	9.22%	5,283,804
57	2027	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	52,638,641	9.22%	4,998,193
58	2028	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	49,542,250	9.22%	4,712,582
59	2029	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	46,445,859	9.22%	4,426,971
60	2030	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	43,349,469	9.22%	4,141,360
61	2031	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	40,253,078	9.22%	3,855,749
62	2032	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	37,156,688	9.22%	3,570,138
63	2033	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	34,060,297	9.22%	3,284,527
64	2034	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	30,963,906	9.22%	2,998,916
65	2035	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	27,867,516	9.22%	2,713,305
66	2036	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	24,771,125	9.22%	2,427,694
67	2037	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	21,674,734	9.22%	2,142,083
68	2038	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	18,578,344	9.22%	1,856,472
69	2039	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	15,481,953	9.22%	1,570,861
70	2040	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	12,385,563	9.22%	1,285,250
71	2041	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	9,289,172	9.22%	999,639
72	2042	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	6,192,781	9.22%	714,028
73	2043	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	3,096,391	9.22%	428,417
74	2044	9,063,402	0.000%	-	(9,063,402)	(3,096,391)	(0)	9.22%	142,806
75		$ 362,536,068	100%	$ 362,536,068	$ 0	$ (0)			$ 127,660,838

Facility Name Dave Johnston **Cost Year:** 2019
Plant Type: Steam - Coal

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	12,059,103
2	RP Capability Allocator	RP and BOP Allocators	21.37%
3	**RP - Generator/Exciter**	(Line 1 * 2)	2,576,611
4			
5	GSU Transformer	Summary Investment	10,842,240
6	RP Capability Allocator	RP and BOP Allocators	21.37%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	2,316,609
8			
9	Accessory Electric Equipment	Summary Investment	63,497,074
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	6,349,707
12	RP Capability Allocator	RP and BOP Allocators	21.37%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	1,356,712
14	Total Plant Investment	Summary Investment	1,084,175,649
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	1,054,924,599
16	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
17	**RP - Balance of Plant**	(Line 15 * 16)	282,755
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	6,532,687
19	RP Fixed Charge Percent	(Line 11(h))	12.1832%
20	Subtotal	(Line 18 * 19)	795,891
21	**Heating Losses**	Heating Losses	4,662
22	**Reactive Power Revenue Requirement**	(Line 20 + 21)	**$ 800,553**

	Depreciation			
23	Annual Depreciation Expense (D)	$	58,503,910	
24	Gross Plant Investment (F)		1,084,175,649	(Line 14)
25	SLDP=DE/F		5.3962%	(Line 23 / 24)
26	Depreciable years =1/SLDP		19	
27	Book Life (n)		60	Book Lives
28	SLDP for Book Life = 1/n		1.67%	
29	SFDP=(R/((1+R)^n-1)		0.10%	R=Return

	Income Taxes		
30	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.3264%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment						
			Amount	Investment	FCR %	
O&M	O&M by Facility	$	24,630,677	$ 1,084,175,649	2.2718%	(f)/(g)
A&G	Fixed Charge Items				0.4475%	
Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)				0.0302%	
Prepayments	Fixed Charge Items				0.0203%	
Materials and Supplies	Fixed Charge Items				0.1029%	
General and Intangible Plant	Fixed Charge Items				1.1057%	
Other Taxes	Fixed Charge Items				0.5233%	
Depreciation	(Line 29)				0.1030%	
Return	Fixed Charge Items				7.5512%	
Income Taxes	Line 30				1.3264%	
ADIT	Line 34(i)		(14,083,955)	1,084,175,649	-1.2990%	
Total RP Fixed Charge Percent					12.1832%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
31	Investment	$ 1,084,175,649	Summary Investment						
32	Straight-line Tax Life	60	(Line 27)						
33	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$184,148,340
34	In Service Year	1966	1959-1972			Levelized Revenue Requirement			14,083,955
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35	1966	$ 18,069,594	3.750%	$ 40,656,587	$ 22,586,993	$ 8,571,990	$ 8,571,990	10.69%	$ 458,148
36	1967	18,069,594	7.219%	78,266,640	60,197,046	22,845,381	31,417,371	10.69%	2,137,316
37	1968	18,069,594	6.677%	72,390,408	54,320,814	20,615,292	52,032,663	10.69%	4,460,164
38	1969	18,069,594	6.177%	66,969,530	48,899,936	18,558,015	70,590,677	10.69%	6,553,864
39	1970	18,069,594	5.713%	61,938,955	43,869,361	16,648,861	87,239,538	10.69%	8,435,571
40	1971	18,069,594	5.285%	57,298,683	39,229,089	14,887,832	102,127,370	10.69%	10,121,116
41	1972	18,069,594	4.888%	52,994,506	34,924,912	13,254,353	115,381,723	10.69%	11,625,235
42	1973	18,069,594	4.522%	49,026,423	30,956,829	11,748,426	127,130,149	10.69%	12,961,561
43	1974	18,069,594	4.462%	48,375,917	30,306,323	11,501,553	138,631,702	10.69%	14,204,206
44	1975	18,069,594	4.461%	48,365,076	30,295,482	11,497,438	150,129,140	10.69%	15,433,436
45	1976	18,069,594	4.462%	48,375,917	30,306,323	11,501,553	161,630,693	10.69%	16,662,666
46	1977	18,069,594	4.461%	48,365,076	30,295,482	11,497,438	173,128,131	10.69%	17,891,895
47	1978	18,069,594	4.462%	48,375,917	30,306,323	11,501,553	184,629,684	10.69%	19,121,125
48	1979	18,069,594	4.461%	48,365,076	30,295,482	11,497,438	196,127,122	10.69%	20,350,355
49	1980	18,069,594	4.462%	48,375,917	30,306,323	11,501,553	207,628,675	10.69%	21,579,585
50	1981	18,069,594	4.461%	48,365,076	30,295,482	11,497,438	219,126,113	10.69%	22,808,815
51	1982	18,069,594	4.462%	48,375,917	30,306,323	11,501,553	230,627,666	10.69%	24,038,045
52	1983	18,069,594	4.461%	48,365,076	30,295,482	11,497,438	242,125,104	10.69%	25,267,274
53	1984	18,069,594	4.462%	48,375,917	30,306,323	11,501,553	253,626,657	10.69%	26,496,504
54	1985	18,069,594	4.461%	48,365,076	30,295,482	11,497,438	265,124,095	10.69%	27,725,734
55	1986	18,069,594	2.231%	24,187,959	6,118,365	2,321,981	267,446,075	10.69%	28,464,342
56	1987	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	260,588,484	10.69%	28,221,927
57	1988	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	253,730,892	10.69%	27,488,890
58	1989	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	246,873,300	10.69%	26,755,853
59	1990	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	240,015,709	10.69%	26,022,816
60	1991	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	233,158,117	10.69%	25,289,779
61	1992	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	226,300,525	10.69%	24,556,742
62	1993	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	219,442,934	10.69%	23,823,705
63	1994	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	212,585,342	10.69%	23,090,668
64	1995	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	205,727,750	10.69%	22,357,630
65	1996	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	198,870,159	10.69%	21,624,593
66	1997	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	192,012,567	10.69%	20,891,556
67	1998	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	185,154,975	10.69%	20,158,519
68	1999	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	178,297,384	10.69%	19,425,482
69	2000	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	171,439,792	10.69%	18,692,445
70	2001	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	164,582,200	10.69%	17,959,408
71	2002	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	157,724,609	10.69%	17,226,371
72	2003	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	150,867,017	10.69%	16,493,334
73	2004	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	144,009,425	10.69%	15,760,297
74	2005	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	137,151,834	10.69%	15,027,260
75	2006	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	130,294,242	10.69%	14,294,223
76	2007	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	123,436,650	10.69%	13,561,186
77	2008	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	116,579,058	10.69%	12,828,149
78	2009	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	109,721,467	10.69%	12,095,112
79	2010	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	102,863,875	10.69%	11,362,075
80	2011	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	96,006,283	10.69%	10,629,037
81	2012	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	89,148,692	10.69%	9,896,000
82	2013	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	82,291,100	10.69%	9,162,963
83	2014	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	75,433,508	10.69%	8,429,926
84	2015	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	68,575,917	10.69%	7,696,889
85	2016	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	61,718,325	10.69%	6,963,852
86	2017	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	54,860,733	10.69%	6,230,815
87	2018	18,069,594	0.000%	-	(18,069,594)	(6,857,592)	48,003,142	9.22%	4,744,081

88	2019	18,069,594	0.000%		-	(18,069,594)	(6,857,592)	41,145,550	9.22%	4,111,537
89	2020	18,069,594	0.000%		-	(18,069,594)	(6,857,592)	34,287,958	9.22%	3,478,993
90	2021	18,069,594	0.000%		-	(18,069,594)	(6,857,592)	27,430,367	9.22%	2,846,449
91	2022	18,069,594	0.000%		-	(18,069,594)	(6,857,592)	20,572,775	9.22%	2,213,905
92	2023	18,069,594	0.000%		-	(18,069,594)	(6,857,592)	13,715,183	9.22%	1,581,360
93	2024	18,069,594	0.000%		-	(18,069,594)	(6,857,592)	6,857,592	9.22%	948,816
94	2025	18,069,594	0.000%		-	(18,069,594)	(6,857,592)	0	9.22%	316,272
95		$ 1,084,175,649		100%	$ 1,084,175,649	$ (0)	$ 0			$ 891,055,874

Facility Name Gadsby **Cost Year:** 2019
Plant Type: ıbustion Turbine and Steam-NG

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	19,974,963
2	RP Capability Allocator	RP and BOP Allocators	29.06%
3	**RP - Generator/Exciter**	(Line 1 * 2)	5,804,367
4			
5	GSU Transformer	Summary Investment	4,913,813
6	RP Capability Allocator	RP and BOP Allocators	29.06%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	1,427,866
8			
9	Accessory Electric Equipment	Summary Investment	11,520,577
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	1,152,058
12	RP Capability Allocator	RP and BOP Allocators	29.06%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	334,767
14	Total Plant Investment	Summary Investment	176,981,749
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	150,940,916
16	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
17	**RP - Balance of Plant**	(Line 15 * 16)	40,457
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	7,607,457
19	RP Fixed Charge Percent	(Line 11(h))	14.9025%
20	Subtotal	(Line 18 * 19)	1,133,704
21	**Heating Losses**	Heating Losses	2,419
22	**Reactive Power Revenue Requirement**	(Line 20 + 21)	**$ 1,136,123**

	Depreciation			
23	Annual Depreciation Expense (D)	$ 5,284,323		
24	Gross Plant Investment (F)	176,981,749		(Line 14)
25	SLDP=DE/F	2.9858%		(Line 23 / 24)
26	Depreciable years =1/SLDP	33		
27	Book Life (n)	40		Book Lives
28	SLDP for Book Life = 1/n	2.50%		
29	SFDP=(R/((1+R)^n-1)	0.44%		R=Return

	Income Taxes		
30	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.2168%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 7,740,392	$ 176,981,749	4.3736%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0528%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 29)			0.4416%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 30			1.2168%	
	ADIT	Line 34(i)	(1,651,468)	176,981,749	-0.9331%	
	Total RP Fixed Charge Percent				14.9025%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
31	Investment	$ 176,981,749	Summary Investment						
32	Straight-line Tax Life	40	(Line 27)						
33	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$20,681,141
34	In Service Year	1977	1951-2002			Levelized Revenue Requirement			1,651,468

	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35	1977	$ 4,424,544	3.750%	$ 6,636,816	$ 2,212,272	$ 839,579	$ 839,579	10.69%	$ 44,873
36	1978	4,424,544	7.219%	12,776,312	8,351,769	3,169,580	4,009,159	10.69%	259,151
37	1979	4,424,544	6.677%	11,817,071	7,392,528	2,805,538	6,814,697	10.69%	578,504
38	1980	4,424,544	6.177%	10,932,163	6,507,619	2,469,706	9,284,404	10.69%	860,451
39	1981	4,424,544	5.713%	10,110,967	5,686,424	2,158,055	11,442,458	10.69%	1,107,791
40	1982	4,424,544	5.285%	9,353,485	4,928,942	1,870,583	13,313,041	10.69%	1,323,110
41	1983	4,424,544	4.888%	8,650,868	4,226,324	1,603,932	14,916,973	10.69%	1,508,813
42	1984	4,424,544	4.522%	8,003,115	3,578,571	1,358,103	16,275,077	10.69%	1,667,125
43	1985	4,424,544	4.462%	7,896,926	3,472,382	1,317,804	17,592,880	10.69%	1,810,145
44	1986	4,424,544	4.461%	7,895,156	3,470,612	1,317,132	18,910,012	10.69%	1,950,975
45	1987	4,424,544	4.462%	7,896,926	3,472,382	1,317,804	20,227,816	10.69%	2,091,804
46	1988	4,424,544	4.461%	7,895,156	3,470,612	1,317,132	21,544,948	10.69%	2,232,634
47	1989	4,424,544	4.462%	7,896,926	3,472,382	1,317,804	22,862,752	10.69%	2,373,464
48	1990	4,424,544	4.461%	7,895,156	3,470,612	1,317,132	24,179,884	10.69%	2,514,293
49	1991	4,424,544	4.462%	7,896,926	3,472,382	1,317,804	25,497,687	10.69%	2,655,123
50	1992	4,424,544	4.461%	7,895,156	3,470,612	1,317,132	26,814,819	10.69%	2,795,953
51	1993	4,424,544	4.462%	7,896,926	3,472,382	1,317,804	28,132,623	10.69%	2,936,783
52	1994	4,424,544	4.461%	7,895,156	3,470,612	1,317,132	29,449,755	10.69%	3,077,612
53	1995	4,424,544	4.462%	7,896,926	3,472,382	1,317,804	30,767,559	10.69%	3,218,442
54	1996	4,424,544	4.461%	7,895,156	3,470,612	1,317,132	32,084,691	10.69%	3,359,272
55	1997	4,424,544	2.231%	3,948,463	(476,081)	(180,677)	31,904,013	10.69%	3,420,012
56	1998	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	30,224,855	10.69%	3,320,609
57	1999	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	28,545,696	10.69%	3,141,117
58	2000	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	26,866,537	10.69%	2,961,624
59	2001	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	25,187,379	10.69%	2,782,132
60	2002	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	23,508,220	10.69%	2,602,640
61	2003	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	21,829,062	10.69%	2,423,147
62	2004	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	20,149,903	10.69%	2,243,655
63	2005	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	18,470,744	10.69%	2,064,162
64	2006	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	16,791,586	10.69%	1,884,670
65	2007	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	15,112,427	10.69%	1,705,178
66	2008	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	13,433,269	10.69%	1,525,685
67	2009	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	11,754,110	10.69%	1,346,193
68	2010	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	10,074,952	10.69%	1,166,701
69	2011	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	8,395,793	10.69%	987,208
70	2012	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	6,716,634	10.69%	807,716
71	2013	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	5,037,476	10.69%	628,223
72	2014	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	3,358,317	10.69%	448,731
73	2015	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	1,679,159	10.69%	269,239
74	2016	4,424,544	0.000%	-	(4,424,544)	(1,679,159)	(0)	10.69%	89,746
75		$ 176,981,749	100%	$ 176,981,749	$ -	$ (0)			$ 74,184,705

Facility Name Hermiston **Cost Year:** 2019
Plant Type: Combined Cycle

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	18,964,806
2	RP Capability Allocator	RP and BOP Allocators	19.00%
3	**RP - Generator/Exciter**	(Line 1 * 2)	3,603,313
4			
5	GSU Transformer	Summary Investment	4,766,278
6	RP Capability Allocator	RP and BOP Allocators	19.00%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	905,593
8			
9	Accessory Electric Equipment	Summary Investment	9,781,188
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	978,119
12	RP Capability Allocator	RP and BOP Allocators	19.00%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	185,843
14	Total Plant Investment	Summary Investment	184,561,925
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	159,852,722
16	Balance of Plant Allocator	RP and BOP Allocators	0.0000%
17	**RP - Balance of Plant**	(Line 15 * 16)	0
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	4,694,749
19	RP Fixed Charge Percent	(Line 11(h))	14.4145%
20	Subtotal	(Line 18 * 19)	676,726
21	**Heating Losses**	Heating Losses	-
22	**Reactive Power Revenue Requirement**	(Line 20 + 21)	**$ 676,726**

	Depreciation			
23	Annual Depreciation Expense (D)	$ 5,955,573		
24	Gross Plant Investment (F)	184,561,925	(Line 14)	
25	SLDP=DE/F	3.2269%	(Line 23 / 24)	
26	Depreciable years =1/SLDP	31		
27	Book Life (n)	40	Book Lives	
28	SLDP for Book Life = 1/n	2.50%		
29	SFDP=(R/((1+R)^n-1)	0.44%	R=Return	

	Income Taxes		
30	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.2168%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 7,137,888	$ 184,561,925	3.8675%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0473%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 29)			0.4416%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 30			1.2168%	
	ADIT	Line 34(i)	(1,678,636)	184,561,925	-0.9095%	
	Total RP Fixed Charge Percent				14.4145%	

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes									
31	Investment		$ 184,561,925	Summary Investment						
32	Straight-line Tax Life		40	(Line 27)						
33	Composite Tax Rate (CTR)		24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$21,021,356
34	In Service Year		1996				Levelized Revenue Requirement			1,678,636
	Year		SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
			Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35		1996	$ 4,614,048	3.750%	$ 6,921,072	$ 2,307,024	$ 875,539	$ 875,539	10.69%	$ 46,795
36		1997	4,614,048	7.219%	13,323,525	8,709,477	3,305,334	4,180,872	10.69%	270,251
37		1998	4,614,048	6.677%	12,323,200	7,709,152	2,925,700	7,106,573	10.69%	603,281
38		1999	4,614,048	6.177%	11,400,390	6,786,342	2,575,485	9,682,057	10.69%	897,304
39		2000	4,614,048	5.713%	10,544,023	5,929,975	2,250,485	11,932,542	10.69%	1,155,238
40		2001	4,614,048	5.285%	9,754,098	5,140,050	1,950,700	13,883,242	10.69%	1,379,779
41		2002	4,614,048	4.888%	9,021,387	4,407,339	1,672,629	15,555,871	10.69%	1,573,436
42		2003	4,614,048	4.522%	8,345,890	3,731,842	1,416,271	16,972,143	10.69%	1,738,529
43		2004	4,614,048	4.462%	8,235,153	3,621,105	1,374,246	18,346,388	10.69%	1,887,674
44		2005	4,614,048	4.461%	8,233,307	3,619,259	1,373,545	19,719,933	10.69%	2,034,535
45		2006	4,614,048	4.462%	8,235,153	3,621,105	1,374,246	21,094,179	10.69%	2,181,397
46		2007	4,614,048	4.461%	8,233,307	3,619,259	1,373,545	22,467,724	10.69%	2,328,258
47		2008	4,614,048	4.462%	8,235,153	3,621,105	1,374,246	23,841,970	10.69%	2,475,120
48		2009	4,614,048	4.461%	8,233,307	3,619,259	1,373,545	25,215,515	10.69%	2,621,981
49		2010	4,614,048	4.462%	8,235,153	3,621,105	1,374,246	26,589,760	10.69%	2,768,843
50		2011	4,614,048	4.461%	8,233,307	3,619,259	1,373,545	27,963,305	10.69%	2,915,704
51		2012	4,614,048	4.462%	8,235,153	3,621,105	1,374,246	29,337,551	10.69%	3,062,566
52		2013	4,614,048	4.461%	8,233,307	3,619,259	1,373,545	30,711,096	10.69%	3,209,427
53		2014	4,614,048	4.462%	8,235,153	3,621,105	1,374,246	32,085,342	10.69%	3,356,289
54		2015	4,614,048	4.461%	8,233,307	3,619,259	1,373,545	33,458,887	10.69%	3,503,150
55		2016	4,614,048	2.231%	4,117,577	(496,472)	(188,416)	33,270,471	10.69%	3,566,492
56		2017	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	31,519,393	10.69%	3,462,832
57		2018	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	29,768,316	9.22%	2,826,589
58		2019	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	28,017,238	9.22%	2,665,069
59		2020	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	26,266,161	9.22%	2,503,550
60		2021	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	24,515,084	9.22%	2,342,031
61		2022	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	22,764,006	9.22%	2,180,511
62		2023	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	21,012,929	9.22%	2,018,992
63		2024	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	19,261,851	9.22%	1,857,473
64		2025	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	17,510,774	9.22%	1,695,953
65		2026	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	15,759,697	9.22%	1,534,434
66		2027	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	14,008,619	9.22%	1,372,915
67		2028	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	12,257,542	9.22%	1,211,395
68		2029	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	10,506,464	9.22%	1,049,876
69		2030	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	8,755,387	9.22%	888,356
70		2031	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	7,004,310	9.22%	726,837
71		2032	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	5,253,232	9.22%	565,318
72		2033	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	3,502,155	9.22%	403,798
73		2034	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	1,751,077	9.22%	242,279
74		2035	4,614,048	0.000%	-	(4,614,048)	(1,751,077)	(0)	9.22%	80,760
75			$ 184,561,925	100%	$ 184,561,925	$ -	$ (0)			$ 73,205,018

Facility Name Hunter **Cost Year:** 2019
Plant Type: Steam - Coal

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	51,622,900
2	RP Capability Allocator	RP and BOP Allocators	12.76%
3	**RP - Generator/Exciter**	(Line 1 * 2)	6,584,736
4			
5	GSU Transformer	Summary Investment	17,291,605
6	RP Capability Allocator	RP and BOP Allocators	12.76%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	2,205,623
8			
9	Accessory Electric Equipment	Summary Investment	108,106,282
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	10,810,628
12	RP Capability Allocator	RP and BOP Allocators	12.76%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	1,378,945
14	Total Plant Investment	Summary Investment	1,353,595,746
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	1,273,870,613
16	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
17	**RP - Balance of Plant**	(Line 15 * 16)	341,440
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	10,510,743
19	RP Fixed Charge Percent	(Line 11(h))	12.0257%
20	Subtotal	(Line 18 * 19)	1,263,989
21	**Heating Losses**	Heating Losses	19,830
22	**Reactive Power Revenue Requirement**	(Line 20 + 21)	**$ 1,283,818**

	Depreciation		
23	Annual Depreciation Expense (D)	$ 34,631,286	
24	Gross Plant Investment (F)	1,353,595,746	(Line 14)
25	SLDP=DE/F	2.5585%	(Line 23 / 24)
26	Depreciable years =1/SLDP	39	
27	Book Life (n)	60	Book Lives
28	SLDP for Book Life = 1/n	1.67%	
29	SFDP=(R/((1+R)^n-1)	0.10%	R=Return

	Income Taxes		
30	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.3264%	Based Upon Book Life CTR=Composite Tax Rate

(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment					
		Amount	Investment	FCR %	
O&M	O&M by Facility	$ 28,515,434	$ 1,353,595,746	2.1066%	(f)/(g)
A&G	Fixed Charge Items			0.4475%	
Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0283%	
Prepayments	Fixed Charge Items			0.0203%	
Materials and Supplies	Fixed Charge Items			0.1029%	
General and Intangible Plant	Fixed Charge Items			1.1057%	
Other Taxes	Fixed Charge Items			0.5233%	
Depreciation	(Line 29)			0.1030%	
Return	Fixed Charge Items			7.5512%	
Income Taxes	Line 30			1.3264%	
ADIT	Line 34(i)	(17,455,351)	1,353,595,746	-1.2896%	
Total RP Fixed Charge Percent				12.0257%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
31	Investment	$ 1,353,595,746	Summary Investment						
32	Straight-line Tax Life	60	(Line 27)						
33	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$228,229,490
34	In Service Year	1981	1978-1983			Levelized Revenue Requirement			17,455,351
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35	1981	$ 22,559,929	3.750%	$ 50,759,840	$ 28,199,911	$ 10,702,148	$ 10,702,148	10.69%	$ 571,999
36	1982	22,559,929	7.219%	97,716,077	75,156,148	28,522,510	39,224,658	10.69%	2,668,444
37	1983	22,559,929	6.677%	90,379,588	67,819,659	25,738,239	64,962,897	10.69%	5,568,525
38	1984	22,559,929	6.177%	83,611,609	61,051,680	23,169,723	88,132,620	10.69%	8,182,515
39	1985	22,559,929	5.713%	77,330,925	54,770,996	20,786,141	108,918,761	10.69%	10,531,829
40	1986	22,559,929	5.285%	71,537,535	48,977,606	18,587,491	127,506,252	10.69%	12,636,236
41	1987	22,559,929	4.888%	66,163,760	43,603,831	16,548,090	144,054,342	10.69%	14,514,132
42	1988	22,559,929	4.522%	61,209,600	38,649,671	14,667,936	158,722,278	10.69%	16,182,539
43	1989	22,559,929	4.462%	60,397,442	37,837,513	14,359,715	173,081,993	10.69%	17,733,983
44	1990	22,559,929	4.461%	60,383,906	37,823,977	14,354,578	187,436,570	10.69%	19,268,679
45	1991	22,559,929	4.462%	60,397,442	37,837,513	14,359,715	201,796,285	10.69%	20,803,376
46	1992	22,559,929	4.461%	60,383,906	37,823,977	14,354,578	216,150,862	10.69%	22,338,072
47	1993	22,559,929	4.462%	60,397,442	37,837,513	14,359,715	230,510,577	10.69%	23,872,768
48	1994	22,559,929	4.461%	60,383,906	37,823,977	14,354,578	244,865,155	10.69%	25,407,464
49	1995	22,559,929	4.462%	60,397,442	37,837,513	14,359,715	259,224,869	10.69%	26,942,161
50	1996	22,559,929	4.461%	60,383,906	37,823,977	14,354,578	273,579,447	10.69%	28,476,857
51	1997	22,559,929	4.462%	60,397,442	37,837,513	14,359,715	287,939,161	10.69%	30,011,553
52	1998	22,559,929	4.461%	60,383,906	37,823,977	14,354,578	302,293,739	10.69%	31,546,249
53	1999	22,559,929	4.462%	60,397,442	37,837,513	14,359,715	316,653,454	10.69%	33,080,946
54	2000	22,559,929	4.461%	60,383,906	37,823,977	14,354,578	331,008,031	10.69%	34,615,642
55	2001	22,559,929	2.231%	30,198,721	7,638,792	2,898,998	333,907,029	10.69%	35,537,796
56	2002	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	325,345,310	10.69%	35,235,140
57	2003	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	316,783,592	10.69%	34,319,941
58	2004	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	308,221,873	10.69%	33,404,743
59	2005	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	299,660,154	10.69%	32,489,544
60	2006	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	291,098,436	10.69%	31,574,346
61	2007	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	282,536,717	10.69%	30,659,147
62	2008	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	273,974,998	10.69%	29,743,949
63	2009	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	265,413,280	10.69%	28,828,751
64	2010	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	256,851,561	10.69%	27,913,552
65	2011	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	248,289,842	10.69%	26,998,354
66	2012	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	239,728,123	10.69%	26,083,155
67	2013	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	231,166,405	10.69%	25,167,957
68	2014	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	222,604,686	10.69%	24,252,758
69	2015	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	214,042,967	10.69%	23,337,560
70	2016	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	205,481,249	9.22%	19,348,455
71	2017	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	196,919,530	9.22%	18,558,722
72	2018	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	188,357,811	9.22%	17,768,989
73	2019	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	179,796,093	9.22%	16,979,256
74	2020	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	171,234,374	9.22%	16,189,523
75	2021	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	162,672,655	9.22%	15,399,791
76	2022	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	154,110,936	9.22%	14,610,058
77	2023	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	145,549,218	9.22%	13,820,325
78	2024	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	136,987,499	9.22%	13,030,592
79	2025	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	128,425,780	9.22%	12,240,859
80	2026	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	119,864,062	9.22%	11,451,126
81	2027	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	111,302,343	9.22%	10,661,393
82	2028	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	102,740,624	9.22%	9,871,661
83	2029	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	94,178,906	9.22%	9,081,928
84	2030	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	85,617,187	9.22%	8,292,195
85	2031	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	77,055,468	9.22%	7,502,462
86	2032	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	68,493,750	9.22%	6,712,729
87	2033	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	59,932,031	9.22%	5,922,996

88	2034	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	51,370,312	9.22%	5,133,264	
89	2035	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	42,808,593	9.22%	4,343,531	
90	2036	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	34,246,875	9.22%	3,553,798	
91	2037	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	25,685,156	9.22%	2,764,065	
92	2038	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	17,123,437	9.22%	1,974,332	
93	2039	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	8,561,719	9.22%	1,184,599	
94	2040	22,559,929	0.000%	-	(22,559,929)	(8,561,719)	0	9.22%	394,866	
95		$ 1,353,595,746	100%	$ 1,353,595,746	$ (0)	$ 0			$ 1,077,292,175	

Facility Name Huntington **Cost Year:** 2019
Plant Type: Steam - Coal

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	22,417,911
2	RP Capability Allocator	RP and BOP Allocators	17.19%
3	**RP - Generator/Exciter**	(Line 1 * 2)	3,852,888
4			
5	GSU Transformer	Summary Investment	15,642,571
6	RP Capability Allocator	RP and BOP Allocators	17.19%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	2,688,434
8			
9	Accessory Electric Equipment	Summary Investment	48,645,784
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	4,864,578
12	RP Capability Allocator	RP and BOP Allocators	17.19%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	836,058
14	Total Plant Investment	Summary Investment	918,256,508
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	875,331,447
16	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
17	**RP - Balance of Plant**	(Line 15 * 16)	234,618
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	7,611,998
19	RP Fixed Charge Percent	(Line 11(h))	12.7958%
20	Subtotal	(Line 18 * 19)	**974,013**
21	**Heating Losses**	Heating Losses	12,505
22	**Reactive Power Revenue Requirement**		**$ 986,518**

	Depreciation			
23	Annual Depreciation Expense (D)	$	29,996,439	
24	Gross Plant Investment (F)		918,256,508	(Line 14)
25	SLDP=DE/F		3.2667%	(Line 23 / 24)
26	Depreciable years =1/SLDP		31	
27	Book Life (n)		60	Book Lives
28	SLDP for Book Life = 1/n		1.67%	
29	SFDP=(R/((1+R)^n-1)		0.10%	R=Return

	Income Taxes		
30	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.3264%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment						
			Amount	Investment	FCR %	
O&M	O&M by Facility	$	26,396,082	$ 918,256,508	2.8746%	(f)/(g)
A&G	Fixed Charge Items				0.4475%	
Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)				0.0369%	
Prepayments	Fixed Charge Items				0.0203%	
Materials and Supplies	Fixed Charge Items				0.1029%	
General and Intangible Plant	Fixed Charge Items				1.1057%	
Other Taxes	Fixed Charge Items				0.5233%	
Depreciation	(Line 29)				0.1030%	
Return	Fixed Charge Items				7.5512%	
Income Taxes	Line 30				1.3264%	
ADIT	Line 34(i)		(11,900,098)	918,256,508	-1.2959%	
Total RP Fixed Charge Percent					12.7958%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
31	Investment	$ 918,256,508	Summary Investment						
32	Straight-line Tax Life	60	(Line 27)						
33	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$155,594,313
34	In Service Year	1976	1974-1977			Levelized Revenue Requirement			11,900,098

	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35	1976	$ 15,304,275	3.750%	$ 34,434,619	$ 19,130,344	$ 7,260,157	$ 7,260,157	10.69%	$ 388,034
36	1977	15,304,275	7.219%	66,288,937	50,984,662	19,349,189	26,609,346	10.69%	1,810,227
37	1978	15,304,275	6.677%	61,311,987	46,007,712	17,460,387	44,069,733	10.69%	3,777,593
38	1979	15,304,275	6.177%	56,720,704	41,416,429	15,717,949	59,787,682	10.69%	5,550,880
39	1980	15,304,275	5.713%	52,459,994	37,155,719	14,100,967	73,888,649	10.69%	7,144,615
40	1981	15,304,275	5.285%	48,529,856	33,225,581	12,609,440	86,498,089	10.69%	8,572,209
41	1982	15,304,275	4.888%	44,884,378	29,580,103	11,225,945	97,724,034	10.69%	9,846,142
42	1983	15,304,275	4.522%	41,523,559	26,219,284	9,950,481	107,674,515	10.69%	10,977,961
43	1984	15,304,275	4.462%	40,972,605	25,668,330	9,741,388	117,415,903	10.69%	12,030,435
44	1985	15,304,275	4.461%	40,963,423	25,659,148	9,737,903	127,153,806	10.69%	13,071,547
45	1986	15,304,275	4.462%	40,972,605	25,668,330	9,741,388	136,895,194	10.69%	14,112,659
46	1987	15,304,275	4.461%	40,963,423	25,659,148	9,737,903	146,633,097	10.69%	15,153,771
47	1988	15,304,275	4.462%	40,972,605	25,668,330	9,741,388	156,374,485	10.69%	16,194,883
48	1989	15,304,275	4.461%	40,963,423	25,659,148	9,737,903	166,112,388	10.69%	17,235,995
49	1990	15,304,275	4.462%	40,972,605	25,668,330	9,741,388	175,853,776	10.69%	18,277,107
50	1991	15,304,275	4.461%	40,963,423	25,659,148	9,737,903	185,591,679	10.69%	19,318,219
51	1992	15,304,275	4.462%	40,972,605	25,668,330	9,741,388	195,333,067	10.69%	20,359,331
52	1993	15,304,275	4.461%	40,963,423	25,659,148	9,737,903	205,070,970	10.69%	21,400,443
53	1994	15,304,275	4.462%	40,972,605	25,668,330	9,741,388	214,812,358	10.69%	22,441,555
54	1995	15,304,275	4.461%	40,963,423	25,659,148	9,737,903	224,550,261	10.69%	23,482,667
55	1996	15,304,275	2.231%	20,486,303	5,182,028	1,966,631	226,516,893	10.69%	24,108,241
56	1997	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	220,708,767	10.69%	23,902,924
57	1998	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	214,900,642	10.69%	23,282,069
58	1999	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	209,092,516	10.69%	22,661,214
59	2000	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	203,284,391	10.69%	22,040,358
60	2001	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	197,476,265	10.69%	21,419,503
61	2002	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	191,668,140	10.69%	20,798,648
62	2003	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	185,860,015	10.69%	20,177,793
63	2004	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	180,051,889	10.69%	19,556,938
64	2005	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	174,243,764	10.69%	18,936,083
65	2006	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	168,435,638	10.69%	18,315,227
66	2007	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	162,627,513	10.69%	17,694,372
67	2008	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	156,819,387	10.69%	17,073,517
68	2009	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	151,011,262	10.69%	16,452,662
69	2010	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	145,203,136	10.69%	15,831,807
70	2011	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	139,395,011	10.69%	15,210,952
71	2012	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	133,586,885	10.69%	14,590,096
72	2013	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	127,778,760	10.69%	13,969,241
73	2014	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	121,970,635	10.69%	13,348,386
74	2015	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	116,162,509	10.69%	12,727,531
75	2016	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	110,354,384	10.69%	12,106,676
76	2017	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	104,546,258	10.69%	11,485,821
77	2018	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	98,738,133	9.22%	9,375,475
78	2019	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	92,930,007	9.22%	8,839,734
79	2020	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	87,121,882	9.22%	8,303,992
80	2021	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	81,313,756	9.22%	7,768,251
81	2022	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	75,505,631	9.22%	7,232,509
82	2023	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	69,697,505	9.22%	6,696,768
83	2024	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	63,889,380	9.22%	6,161,026
84	2025	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	58,081,255	9.22%	5,625,285
85	2026	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	52,273,129	9.22%	5,089,544
86	2027	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	46,465,004	9.22%	4,553,802
87	2028	15,304,275	0.000%	-	(15,304,275)	(5,808,125)	40,656,878	9.22%	4,018,061

88		2029	15,304,275	0.000%		-	(15,304,275)	(5,808,125)	34,848,753	9.22%	3,482,319
89		2030	15,304,275	0.000%		-	(15,304,275)	(5,808,125)	29,040,627	9.22%	2,946,578
90		2031	15,304,275	0.000%		-	(15,304,275)	(5,808,125)	23,232,502	9.22%	2,410,836
91		2032	15,304,275	0.000%		-	(15,304,275)	(5,808,125)	17,424,376	9.22%	1,875,095
92		2033	15,304,275	0.000%		-	(15,304,275)	(5,808,125)	11,616,251	9.22%	1,339,354
93		2034	15,304,275	0.000%		-	(15,304,275)	(5,808,125)	5,808,125	9.22%	803,612
94		2035	15,304,275	0.000%		-	(15,304,275)	(5,808,125)	0	9.22%	267,871
95			$ 918,256,508		100%	$ 918,256,508	$ 0	$ 0			$ 743,626,445

Facility Name Jim Bridger **Cost Year:** 2019
Plant Type: Steam - Coal

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	53,873,964
2	RP Capability Allocator	RP and BOP Allocators	9.25%
3	**RP - Generator/Exciter**	(Line 1 * 2)	4,985,899
4			
5	GSU Transformer	Summary Investment	14,443,972
6	RP Capability Allocator	RP and BOP Allocators	9.25%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	1,336,753
8			
9	Accessory Electric Equipment	Summary Investment	61,499,002
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	6,149,900
12	RP Capability Allocator	RP and BOP Allocators	9.25%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	569,158
14	Total Plant Investment	Summary Investment	1,435,332,930
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	1,360,865,094
16	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
17	**RP - Balance of Plant**	(Line 15 * 16)	364,757
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	7,256,567
19	RP Fixed Charge Percent	(Line 11(h))	11.6959%
20	Subtotal	(Line 18 * 19)	848,724
21	**Heating Losses**	Heating Losses	63,535
22	**Reactive Power Revenue Requirement**	(Line 20 + 21)	**$ 912,259**

	Depreciation			
23	Annual Depreciation Expense (D)	$ 39,873,880		
24	Gross Plant Investment (F)	1,435,332,930		(Line 14)
25	SLDP=DE/F	2.7780%		(Line 23 / 24)
26	Depreciable years =1/SLDP	36		
27	Book Life (n)	60		Book Lives
28	SLDP for Book Life = 1/n	1.67%		
29	SFDP=(R/((1+R)^n-1)	0.10%		R=Return

	Income Taxes		
30	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.3264%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 25,697,140	$ 1,435,332,930	1.7903%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0248%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 29)			0.1030%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 30			1.3264%	
	ADIT	Line 34(i)	(18,651,568)	1,435,332,930	-1.2995%	
	Total RP Fixed Charge Percent				11.6959%	

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes									
31	Investment		$ 1,435,332,930	Summary Investment						
32	Straight-line Tax Life		60	(Line 27)						
33	Composite Tax Rate (CTR)		24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$243,870,088
34	In Service Year		1977	1974-1979			Levelized Revenue Requirement			18,651,568
	Year		SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
			Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35		1977	$ 23,922,215	3.750%	$ 53,824,985	$ 29,902,769	$ 11,348,400	$ 11,348,400	10.69%	$ 606,539
36		1978	23,922,215	7.219%	103,616,684	79,694,469	30,244,848	41,593,248	10.69%	2,829,579
37		1979	23,922,215	6.677%	95,837,180	71,914,964	27,292,448	68,885,696	10.69%	5,904,781
38		1980	23,922,215	6.177%	88,660,515	64,738,300	24,568,832	93,454,528	10.69%	8,676,618
39		1981	23,922,215	5.713%	82,000,570	58,078,355	22,041,316	115,495,844	10.69%	11,167,796
40		1982	23,922,215	5.285%	75,857,345	51,935,130	19,709,901	135,205,746	10.69%	13,399,278
41		1983	23,922,215	4.888%	70,159,074	46,236,858	17,547,350	152,753,096	10.69%	15,390,571
42		1984	23,922,215	4.522%	64,905,755	40,983,540	15,553,663	168,306,759	10.69%	17,159,725
43		1985	23,922,215	4.462%	64,044,555	40,122,340	15,226,829	183,533,588	10.69%	18,804,854
44		1986	23,922,215	4.461%	64,030,202	40,107,987	15,221,382	198,754,970	10.69%	20,432,223
45		1987	23,922,215	4.462%	64,044,555	40,122,340	15,226,829	213,981,799	10.69%	22,059,592
46		1988	23,922,215	4.461%	64,030,202	40,107,987	15,221,382	229,203,181	10.69%	23,686,961
47		1989	23,922,215	4.462%	64,044,555	40,122,340	15,226,829	244,430,010	10.69%	25,314,330
48		1990	23,922,215	4.461%	64,030,202	40,107,987	15,221,382	259,651,392	10.69%	26,941,700
49		1991	23,922,215	4.462%	64,044,555	40,122,340	15,226,829	274,878,221	10.69%	28,569,069
50		1992	23,922,215	4.461%	64,030,202	40,107,987	15,221,382	290,099,603	10.69%	30,196,438
51		1993	23,922,215	4.462%	64,044,555	40,122,340	15,226,829	305,326,432	10.69%	31,823,807
52		1994	23,922,215	4.461%	64,030,202	40,107,987	15,221,382	320,547,814	10.69%	33,451,177
53		1995	23,922,215	4.462%	64,044,555	40,122,340	15,226,829	335,774,644	10.69%	35,078,546
54		1996	23,922,215	4.461%	64,030,202	40,107,987	15,221,382	350,996,026	10.69%	36,705,915
55		1997	23,922,215	2.231%	32,022,278	8,100,062	3,074,055	354,070,080	10.69%	37,683,753
56		1998	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	344,991,360	10.69%	37,362,821
57		1999	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	335,912,640	10.69%	36,392,359
58		2000	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	326,833,920	10.69%	35,421,896
59		2001	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	317,755,200	10.69%	34,451,433
60		2002	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	308,676,480	10.69%	33,480,970
61		2003	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	299,597,760	10.69%	32,510,507
62		2004	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	290,519,040	10.69%	31,540,044
63		2005	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	281,440,320	10.69%	30,569,581
64		2006	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	272,361,600	10.69%	29,599,118
65		2007	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	263,282,880	10.69%	28,628,655
66		2008	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	254,204,160	10.69%	27,658,192
67		2009	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	245,125,440	10.69%	26,687,730
68		2010	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	236,046,720	10.69%	25,717,267
69		2011	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	226,968,000	10.69%	24,746,804
70		2012	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	217,889,280	10.69%	23,776,341
71		2013	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	208,810,560	10.69%	22,805,878
72		2014	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	199,731,840	10.69%	21,835,415
73		2015	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	190,653,120	10.69%	20,864,952
74		2016	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	181,574,400	10.69%	19,894,489
75		2017	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	172,495,680	10.69%	18,924,026
76		2018	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	163,416,960	10.69%	17,953,564
77		2019	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	154,338,240	10.69%	16,983,101
78		2020	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	145,259,520	10.69%	16,012,638
79		2021	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	136,180,800	10.69%	15,042,175
80		2022	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	127,102,080	10.69%	14,071,712
81		2023	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	118,023,360	10.69%	13,101,249
82		2024	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	108,944,640	10.69%	12,130,786
83		2025	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	99,865,920	10.69%	11,160,323
84		2026	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	90,787,200	10.69%	10,189,860
85		2027	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	81,708,480	10.69%	9,219,397
86		2028	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	72,629,760	10.69%	8,248,935
87		2029	23,922,215	0.000%	-	(23,922,215)	(9,078,720)	63,551,040	10.69%	7,278,472

88	2030	23,922,215	0.000%		-	(23,922,215)	(9,078,720)	54,472,320	10.69%	6,308,009
89	2031	23,922,215	0.000%		-	(23,922,215)	(9,078,720)	45,393,600	10.69%	5,337,546
90	2032	23,922,215	0.000%		-	(23,922,215)	(9,078,720)	36,314,880	10.69%	4,367,083
91	2033	23,922,215	0.000%		-	(23,922,215)	(9,078,720)	27,236,160	10.69%	3,396,620
92	2034	23,922,215	0.000%		-	(23,922,215)	(9,078,720)	18,157,440	10.69%	2,426,157
93	2035	23,922,215	0.000%		-	(23,922,215)	(9,078,720)	9,078,720	10.69%	1,455,694
94	2036	23,922,215	0.000%		-	(23,922,215)	(9,078,720)	(0)	10.69%	485,231
95		$ 1,435,332,930		100%	$ 1,435,332,930	$ (0)	$ (0)			$ 1,183,920,283

Facility Name Lake Side **Cost Year:** 2019
Plant Type: Combined Cycle

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	81,740,705
2	RP Capability Allocator	RP and BOP Allocators	19.00%
3	**RP - Generator/Exciter**	(Line 1 * 2)	15,530,734
4			
5	GSU Transformer	Summary Investment	10,669,330
6	RP Capability Allocator	RP and BOP Allocators	19.00%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	2,027,173
8			
9	Accessory Electric Equipment	Summary Investment	120,385,997
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	12,038,600
12	RP Capability Allocator	RP and BOP Allocators	19.00%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	2,287,334
14	Total Plant Investment	Summary Investment	1,033,365,351
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	928,916,717
16	Balance of Plant Allocator	Schedule 4 Inputs Line	0.0268%
17	**RP - Balance of Plant**	(Line 15 * 16)	248,981
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	20,094,221
19	RP Fixed Charge Percent	(Line 12(h))	12.0426%
20	Subtotal	(Line 18 * 19)	2,419,865
21	**Heating Losses**	Heating Losses	16,508
22	**Reactive Power Revenue Requirement**	(Line 20 + 21)	**$ 2,436,372**

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 10,174,815	$ 1,033,365,351	0.9846%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0157%	
	Prepayments	Fixed Charge Items			0.0203%	
	Maintenance Prepayments	(Line 17 h)	3,846,676	1,033,365,351	0.3722%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 29)			0.4416%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 30			1.2168%	
	ADIT	Line 34(i)	(7,639,253)	1,033,365,351	-0.7393%	
	Total RP Fixed Charge Percent				12.0426%	

Maintenance Prepayment		
Amount	FF1, page 233.11f + 12f	$ 43,871,759
Return and Income Taxes	(Line 9 h + Line 10 g)	8.77%
Annual Revenue Requirement	(Line 15 h * Line 16 h)	$ 3,846,676

	Depreciation		
23	Annual Depreciation Expense (D)	$ 30,385,025	
24	Gross Plant Investment (F)	1,033,365,351	(Line 14)
25	SLDP=DE/F	2.9404%	(Line 23 / 24)
26	Depreciable years =1/SLDP	34	
27	Book Life (n)	40	Book Lives
28	SLDP for Book Life = 1/n	2.50%	
29	SFDP=(R/((1+R)^n-1)	0.44%	R=Return

	Income Taxes		
30	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.2168%	Based Upon Book Life CTR=Composite Tax Rate

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
31	Investment	$ 1,033,365,351	Summary Investment						
32	Straight-line Tax Life	40	(Line 27)						
33	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$95,665,442
34	In Service Year	2011	2007-2014			Levelized Revenue Requirement			7,639,253

	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35	2011	$ 25,834,134	3.750%	$ 38,751,201	$ 12,917,067	$ 4,902,156	$ 4,902,156	10.69%	$ 262,006
36	2012	25,834,134	7.219%	74,598,645	48,764,511	18,506,620	23,408,776	10.69%	1,513,138
37	2013	25,834,134	6.677%	68,997,804	43,163,671	16,381,045	39,789,820	10.69%	3,377,783
38	2014	25,834,134	6.177%	63,830,978	37,996,844	14,420,182	54,210,003	10.69%	5,024,020
39	2015	25,834,134	5.713%	59,036,163	33,202,029	12,600,502	66,810,504	10.69%	6,468,198
40	2016	25,834,134	5.285%	54,613,359	28,779,225	10,922,004	77,732,508	10.69%	7,725,408
41	2017	25,834,134	4.888%	50,510,898	24,676,765	9,365,079	87,097,587	10.69%	8,809,694
42	2018	25,834,134	4.522%	46,728,781	20,894,647	5,137,283	92,234,870	9.22%	8,270,812
43	2019	25,834,134	4.462%	46,108,762	20,274,628	4,984,842	97,219,712	9.22%	8,737,644
44	2020	25,834,134	4.461%	46,098,428	20,264,295	4,982,301	102,202,013	9.22%	9,197,329
45	2021	25,834,134	4.462%	46,108,762	20,274,628	4,984,842	107,186,855	9.22%	9,657,014
46	2022	25,834,134	4.461%	46,098,428	20,264,295	4,982,301	112,169,156	9.22%	10,116,698
47	2023	25,834,134	4.462%	46,108,762	20,274,628	4,984,842	117,153,998	9.22%	10,576,383
48	2024	25,834,134	4.461%	46,098,428	20,264,295	4,982,301	122,136,299	9.22%	11,036,067
49	2025	25,834,134	4.462%	46,108,762	20,274,628	4,984,842	127,121,140	9.22%	11,495,752
50	2026	25,834,134	4.461%	46,098,428	20,264,295	4,982,301	132,103,442	9.22%	11,955,436
51	2027	25,834,134	4.462%	46,108,762	20,274,628	4,984,842	137,088,283	9.22%	12,415,121
52	2028	25,834,134	4.461%	46,098,428	20,264,295	4,982,301	142,070,584	9.22%	12,874,806
53	2029	25,834,134	4.462%	46,108,762	20,274,628	4,984,842	147,055,426	9.22%	13,334,490
54	2030	25,834,134	4.461%	46,098,428	20,264,295	4,982,301	152,037,727	9.22%	13,794,175
55	2031	25,834,134	2.231%	23,054,381	(2,779,753)	(683,447)	151,354,280	9.22%	13,992,438
56	2032	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	143,388,266	9.22%	13,593,525
57	2033	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	135,422,251	9.22%	12,858,740
58	2034	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	127,456,236	9.22%	12,123,955
59	2035	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	119,490,221	9.22%	11,389,169
60	2036	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	111,524,207	9.22%	10,654,384
61	2037	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	103,558,192	9.22%	9,919,599
62	2038	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	95,592,177	9.22%	9,184,814
63	2039	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	87,626,162	9.22%	8,450,029
64	2040	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	79,660,148	9.22%	7,715,244
65	2041	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	71,694,133	9.22%	6,980,459
66	2042	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	63,728,118	9.22%	6,245,674
67	2043	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	55,762,103	9.22%	5,510,888
68	2044	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	47,796,089	9.22%	4,776,103
69	2045	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	39,830,074	9.22%	4,041,318
70	2046	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	31,864,059	9.22%	3,306,533
71	2047	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	23,898,044	9.22%	2,571,748
72	2048	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	15,932,030	9.22%	1,836,963
73	2049	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	7,966,015	9.22%	1,102,178
74	2050	25,834,134	0.000%	-	(25,834,134)	(7,966,015)	0	9.22%	367,393
75		$ 1,033,365,351	100%	$ 1,033,365,351	$ 0	$ 0			$ 323,263,126

Facility Name Naughton **Cost Year:** 2019

Plant Type: Steam-Coal and Steam-NG

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	14,803,885
2	RP Capability Allocator	RP and BOP Allocators	27.75%
3	**RP - Generator/Exciter**	(Line 1 * 2)	4,108,078
4			
5	GSU Transformer	Summary Investment	4,112,697
6	RP Capability Allocator	RP and BOP Allocators	27.75%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	1,141,274
8			
9	Accessory Electric Equipment	Summary Investment	65,984,527
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	6,598,453
12	RP Capability Allocator	RP and BOP Allocators	27.75%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	1,831,071
14	Total Plant Investment	Summary Investment	755,860,804
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	730,345,769
16	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
17	**RP - Balance of Plant**	(Line 15 * 16)	195,757
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	7,276,179
19	RP Fixed Charge Percent	(Line 11(h))	12.0721%
20	Subtotal	(Line 18 * 19)	878,386
21	**Heating Losses**	Heating Losses	15,074
22	**Reactive Power Revenue Requirement**	(Line 20 + 21)	**$ 893,459**

	Depreciation		
23	Annual Depreciation Expense (D)	$ 35,041,322	
24	Gross Plant Investment (F)	755,860,804	(Line 14)
25	SLDP=DE/F	4.6359%	(Line 23 / 24)
26	Depreciable years =1/SLDP	22	
27	Book Life (n)	60	Book Lives
28	SLDP for Book Life = 1/n	1.67%	
29	SFDP=(R/((1+R)^n-1)	0.10%	R=Return

	Income Taxes		
30	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.3264%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 16,340,028	$ 755,860,804	2.1618%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0290%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 29)			0.1030%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 30			1.3264%	
	ADIT	Line 34(i)	(9,817,956)	755,860,804	-1.2989%	
	Total RP Fixed Charge Percent				12.0721%	

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes									
31	Investment		$ 755,860,804	Summary Investment						
32	Straight-line Tax Life		60	(Line 27)						
33	Composite Tax Rate (CTR)		24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$128,370,211
34	In Service Year		1967	1963-1971			Levelized Revenue Requirement			9,817,956
	Year		SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
			Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35		1967	$ 12,597,680	3.750%	$ 28,344,780	$ 15,747,100	$ 5,976,182	$ 5,976,182	10.69%	$ 319,410
36		1968	12,597,680	7.219%	54,565,591	41,967,911	15,927,242	21,903,424	10.69%	1,490,085
37		1969	12,597,680	6.677%	50,468,826	37,871,146	14,372,479	36,275,903	10.69%	3,109,518
38		1970	12,597,680	6.177%	46,689,522	34,091,842	12,938,195	49,214,097	10.69%	4,569,194
39		1971	12,597,680	5.713%	43,182,328	30,584,648	11,607,180	60,821,277	10.69%	5,881,074
40		1972	12,597,680	5.285%	39,947,244	27,349,563	10,379,433	71,200,710	10.69%	7,056,195
41		1973	12,597,680	4.888%	36,946,476	24,348,796	9,240,612	80,441,321	10.69%	8,104,830
42		1974	12,597,680	4.522%	34,180,026	21,582,345	8,190,716	88,632,037	10.69%	9,036,484
43		1975	12,597,680	4.462%	33,726,509	21,128,829	8,018,602	96,650,639	10.69%	9,902,826
44		1976	12,597,680	4.461%	33,718,950	21,121,270	8,015,733	104,666,373	10.69%	10,759,815
45		1977	12,597,680	4.462%	33,726,509	21,128,829	8,018,602	112,684,975	10.69%	11,616,804
46		1978	12,597,680	4.461%	33,718,950	21,121,270	8,015,733	120,700,708	10.69%	12,473,793
47		1979	12,597,680	4.462%	33,726,509	21,128,829	8,018,602	128,719,310	10.69%	13,330,782
48		1980	12,597,680	4.461%	33,718,950	21,121,270	8,015,733	136,735,043	10.69%	14,187,771
49		1981	12,597,680	4.462%	33,726,509	21,128,829	8,018,602	144,753,645	10.69%	15,044,760
50		1982	12,597,680	4.461%	33,718,950	21,121,270	8,015,733	152,769,378	10.69%	15,901,749
51		1983	12,597,680	4.462%	33,726,509	21,128,829	8,018,602	160,787,980	10.69%	16,758,738
52		1984	12,597,680	4.461%	33,718,950	21,121,270	8,015,733	168,803,714	10.69%	17,615,727
53		1985	12,597,680	4.462%	33,726,509	21,128,829	8,018,602	176,822,315	10.69%	18,472,716
54		1986	12,597,680	4.461%	33,718,950	21,121,270	8,015,733	184,838,049	10.69%	19,329,705
55		1987	12,597,680	2.231%	16,863,255	4,265,574	1,618,828	186,456,877	10.69%	19,844,645
56		1988	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	181,675,931	10.69%	19,675,639
57		1989	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	176,894,986	10.69%	19,164,583
58		1990	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	172,114,040	10.69%	18,653,528
59		1991	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	167,333,095	10.69%	18,142,472
60		1992	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	162,552,149	10.69%	17,631,417
61		1993	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	157,771,204	10.69%	17,120,361
62		1994	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	152,990,258	10.69%	16,609,305
63		1995	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	148,209,312	10.69%	16,098,250
64		1996	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	143,428,367	10.69%	15,587,194
65		1997	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	138,647,421	10.69%	15,076,139
66		1998	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	133,866,476	10.69%	14,565,083
67		1999	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	129,085,530	10.69%	14,054,028
68		2000	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	124,304,585	10.69%	13,542,972
69		2001	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	119,523,639	10.69%	13,031,917
70		2002	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	114,742,694	10.69%	12,520,861
71		2003	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	109,961,748	10.69%	12,009,805
72		2004	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	105,180,802	10.69%	11,498,750
73		2005	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	100,399,857	10.69%	10,987,694
74		2006	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	95,618,911	10.69%	10,476,639
75		2007	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	90,837,966	10.69%	9,965,583
76		2008	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	86,057,020	10.69%	9,454,528
77		2009	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	81,276,075	10.69%	8,943,472
78		2010	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	76,495,129	10.69%	8,432,417
79		2011	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	71,714,183	10.69%	7,921,361
80		2012	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	66,933,238	10.69%	7,410,306
81		2013	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	62,152,292	10.69%	6,899,250
82		2014	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	57,371,347	10.69%	6,388,194
83		2015	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	52,590,401	10.69%	5,877,139
84		2016	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	47,809,456	10.69%	5,366,083
85		2017	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	43,028,510	10.69%	4,855,028
86		2018	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	38,247,565	9.22%	3,748,452
87		2019	12,597,680	0.000%	-	(12,597,680)	(4,780,946)	33,466,619	9.22%	3,307,458

88	2020	12,597,680	0.000%		-	(12,597,680)	(4,780,946)	28,685,673	9.22%	2,866,463
89	2021	12,597,680	0.000%		-	(12,597,680)	(4,780,946)	23,904,728	9.22%	2,425,469
90	2022	12,597,680	0.000%		-	(12,597,680)	(4,780,946)	19,123,782	9.22%	1,984,475
91	2023	12,597,680	0.000%		-	(12,597,680)	(4,780,946)	14,342,837	9.22%	1,543,480
92	2024	12,597,680	0.000%		-	(12,597,680)	(4,780,946)	9,561,891	9.22%	1,102,486
93	2025	12,597,680	0.000%		-	(12,597,680)	(4,780,946)	4,780,946	9.22%	661,492
94	2026	12,597,680	0.000%		-	(12,597,680)	(4,780,946)	0	9.22%	220,497
95		$ 755,860,804		100%	$ 755,860,804	$ 0	$ 0			$ 620,626,890

Facility Name Craig **Cost Year:** 2019
Plant Type: Steam - Coal

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	7,116,975
2	RP Capability Allocator	RP and BOP Allocators	9.75%
3	**RP - Generator/Exciter**	(Line 1 * 2)	693,905
4			
5	GSU Transformer	Summary Investment	547,866
6	RP Capability Allocator	RP and BOP Allocators	9.75%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	53,417
8			
9	Accessory Electric Equipment	Summary Investment	14,743,623
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	1,474,362
12	RP Capability Allocator	RP and BOP Allocators	9.75%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	143,750
14	Total Plant Investment	Summary Investment	194,441,633
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	185,302,431
16	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
17	**RP - Balance of Plant**	(Line 15 * 16)	49,667
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	940,739
19	RP Fixed Charge Percent	(Line 11(h))	12.9242%
20	Subtotal	(Line 18 * 19)	121,583
21	**Heating Losses**	Heating Losses	-
22	**Reactive Power Revenue Requirement**	(Line 20 + 21)	**$ 121,583**

	Depreciation			
23	Annual Depreciation Expense (D)	$ 5,489,900		
24	Gross Plant Investment (F)	194,441,633		(Line 14)
25	SLDP=DE/F	2.8234%		(Line 23 / 24)
26	Depreciable years =1/SLDP	35		
27	Book Life (n)	60		Book Lives
28	SLDP for Book Life = 1/n	1.67%		
29	SFDP=(R/((1+R)^n-1)	0.10%		R=Return

	Income Taxes		
30	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.3264%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment						
			Amount	Investment	FCR %	
O&M	O&M by Facility	$	5,830,671	$ 194,441,633	2.9987%	(f)/(g)
A&G	Fixed Charge Items				0.4475%	
Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)				0.0382%	
Prepayments	Fixed Charge Items				0.0203%	
Materials and Supplies	Fixed Charge Items				0.1029%	
General and Intangible Plant	Fixed Charge Items				1.1057%	
Other Taxes	Fixed Charge Items				0.5233%	
Depreciation	(Line 29)				0.1030%	
Return	Fixed Charge Items				7.5512%	
Income Taxes	Line 30				1.3264%	
ADIT	Line 34(i)		(2,514,029)	194,441,633	-1.2929%	
Total RP Fixed Charge Percent					12.9242%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
31	Investment	$ 194,441,633	Summary Investment						
32	Straight-line Tax Life	60	(Line 27)						
33	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$32,871,043
34	In Service Year	1980	1979-1980			Levelized Revenue Requirement			2,514,029
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35	1980	$ 3,240,694	3.750%	$ 7,291,561	$ 4,050,867	$ 1,537,345	$ 1,537,345	10.69%	$ 82,167
36	1981	3,240,694	7.219%	14,036,742	10,796,048	4,097,208	5,634,553	10.69%	383,317
37	1982	3,240,694	6.677%	12,982,868	9,742,174	3,697,252	9,331,805	10.69%	799,909
38	1983	3,240,694	6.177%	12,010,660	8,769,966	3,328,290	12,660,095	10.69%	1,175,404
39	1984	3,240,694	5.713%	11,108,451	7,867,757	2,985,892	15,645,987	10.69%	1,512,879
40	1985	3,240,694	5.285%	10,276,240	7,035,546	2,670,060	18,316,047	10.69%	1,815,173
41	1986	3,240,694	4.888%	9,504,307	6,263,613	2,377,104	20,693,151	10.69%	2,084,929
42	1987	3,240,694	4.522%	8,792,651	5,551,957	2,107,023	22,800,174	10.69%	2,324,593
43	1988	3,240,694	4.462%	8,675,986	5,435,292	2,062,748	24,862,922	10.69%	2,547,455
44	1989	3,240,694	4.461%	8,674,041	5,433,347	2,062,010	26,924,932	10.69%	2,767,912
45	1990	3,240,694	4.462%	8,675,986	5,435,292	2,062,748	28,987,679	10.69%	2,988,368
46	1991	3,240,694	4.461%	8,674,041	5,433,347	2,062,010	31,049,689	10.69%	3,208,824
47	1992	3,240,694	4.462%	8,675,986	5,435,292	2,062,748	33,112,436	10.69%	3,429,281
48	1993	3,240,694	4.461%	8,674,041	5,433,347	2,062,010	35,174,446	10.69%	3,649,737
49	1994	3,240,694	4.462%	8,675,986	5,435,292	2,062,748	37,237,194	10.69%	3,870,194
50	1995	3,240,694	4.461%	8,674,041	5,433,347	2,062,010	39,299,203	10.69%	4,090,650
51	1996	3,240,694	4.462%	8,675,986	5,435,292	2,062,748	41,361,951	10.69%	4,311,106
52	1997	3,240,694	4.461%	8,674,041	5,433,347	2,062,010	43,423,961	10.69%	4,531,563
53	1998	3,240,694	4.462%	8,675,986	5,435,292	2,062,748	45,486,708	10.69%	4,752,019
54	1999	3,240,694	4.461%	8,674,041	5,433,347	2,062,010	47,548,718	10.69%	4,972,476
55	2000	3,240,694	2.231%	4,337,993	1,097,299	416,436	47,965,154	10.69%	5,104,941
56	2001	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	46,735,278	10.69%	5,061,465
57	2002	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	45,505,402	10.69%	4,929,999
58	2003	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	44,275,527	10.69%	4,798,532
59	2004	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	43,045,651	10.69%	4,667,066
60	2005	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	41,815,775	10.69%	4,535,599
61	2006	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	40,585,899	10.69%	4,404,132
62	2007	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	39,356,024	10.69%	4,272,666
63	2008	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	38,126,148	10.69%	4,141,199
64	2009	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	36,896,272	10.69%	4,009,732
65	2010	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	35,666,396	10.69%	3,878,266
66	2011	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	34,436,521	10.69%	3,746,799
67	2012	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	33,206,645	10.69%	3,615,332
68	2013	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	31,976,769	10.69%	3,483,866
69	2014	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	30,746,893	10.69%	3,352,399
70	2015	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	29,517,018	10.69%	3,220,933
71	2016	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	28,287,142	10.69%	3,089,466
72	2017	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	27,057,266	10.69%	2,957,999
73	2018	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	25,827,390	9.22%	2,439,040
74	2019	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	24,597,515	9.22%	2,325,596
75	2020	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	23,367,639	9.22%	2,212,153
76	2021	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	22,137,763	9.22%	2,098,709
77	2022	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	20,907,888	9.22%	1,985,265
78	2023	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	19,678,012	9.22%	1,871,821
79	2024	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	18,448,136	9.22%	1,758,378
80	2025	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	17,218,260	9.22%	1,644,934
81	2026	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	15,988,385	9.22%	1,531,490
82	2027	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	14,758,509	9.22%	1,418,047
83	2028	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	13,528,633	9.22%	1,304,603
84	2029	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	12,298,757	9.22%	1,191,159
85	2030	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	11,068,882	9.22%	1,077,715
86	2031	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	9,839,006	9.22%	964,272
87	2032	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	8,609,130	9.22%	850,828

88	2033	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	7,379,254	9.22%	737,384
89	2034	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	6,149,379	9.22%	623,940
90	2035	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	4,919,503	9.22%	510,497
91	2036	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	3,689,627	9.22%	397,053
92	2037	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	2,459,751	9.22%	283,609
93	2038	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	1,229,876	9.22%	170,166
94	2039	3,240,694	0.000%	-	(3,240,694)	(1,229,876)	0	9.22%	56,722
95		$ 194,441,633	100%	$ 194,441,633	$ (0)	$ 0			$ 156,021,729

Facility Name Hayden **Cost Year:** 2019
Plant Type: Steam - Coal

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	2,352,314
2	RP Capability Allocator	RP and BOP Allocators	14.64%
3	**RP - Generator/Exciter**	(Line 1 * 2)	344,285
4			
5	GSU Transformer	Summary Investment	844,101
6	RP Capability Allocator	RP and BOP Allocators	14.64%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	123,543
8			
9	Accessory Electric Equipment	Summary Investment	2,574,383
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	257,438
12	RP Capability Allocator	RP and BOP Allocators	14.64%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	37,679
14	Total Plant Investment	Summary Investment	116,345,189
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	112,891,336
16	Balance of Plant Allocator	RP and BOP Allocators	0.0000%
17	**RP - Balance of Plant**	(Line 15 * 16)	0
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	505,506
19	RP Fixed Charge Percent	(Line 11(h))	12.2739%
20	Subtotal	(Line 18 * 19)	62,046
21	**Heating Losses**	Heating Losses	-
22	**Reactive Power Revenue Requirement**	(Line 20 + 21)	**$ 62,046**

	Depreciation			
23	Annual Depreciation Expense (D)	$	3,888,622	
24	Gross Plant Investment (F)		116,345,189	(Line 14)
25	SLDP=DE/F		3.3423%	(Line 23 / 24)
26	Depreciable years =1/SLDP		30	
27	Book Life (n)		60	Book Lives
28	SLDP for Book Life = 1/n		1.67%	
29	SFDP=(R/((1+R)^n-1)		0.10%	R=Return

	Income Taxes		
30	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.3264%	Based Upon Book Life CTR=Composite Tax Rate

(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment					
		Amount	Investment	FCR %	
O&M	O&M by Facility	$ 2,746,430	$ 116,345,189	2.3606%	(f)/(g)
A&G	Fixed Charge Items			0.4475%	
Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0312%	
Prepayments	Fixed Charge Items			0.0203%	
Materials and Supplies	Fixed Charge Items			0.1029%	
General and Intangible Plant	Fixed Charge Items			1.1057%	
Other Taxes	Fixed Charge Items			0.5233%	
Depreciation	(Line 29)			0.1030%	
Return	Fixed Charge Items			7.5512%	
Income Taxes	Line 30			1.3264%	
ADIT	Line 34(i)	(1,510,220)	116,345,189	-1.2981%	
Total RP Fixed Charge Percent				12.2739%	

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes									
31	Investment		$ 116,345,189	Summary Investment						
32	Straight-line Tax Life		60	(Line 27)						
33	Composite Tax Rate (CTR)		24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$19,746,198
34	In Service Year		1971	1965-1976			Levelized Revenue Requirement			1,510,220
	Year		SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
			Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35		1971	$ 1,939,086	3.750%	$ 4,362,945	$ 2,423,858	$ 919,878	$ 919,878	10.69%	$ 49,165
36		1972	1,939,086	7.219%	8,398,959	6,459,873	2,451,586	3,371,465	10.69%	229,360
37		1973	1,939,086	6.677%	7,768,368	5,829,282	2,212,271	5,583,735	10.69%	478,630
38		1974	1,939,086	6.177%	7,186,642	5,247,556	1,991,500	7,575,235	10.69%	703,309
39		1975	1,939,086	5.713%	6,646,801	4,707,714	1,786,625	9,361,860	10.69%	905,239
40		1976	1,939,086	5.285%	6,148,843	4,209,757	1,597,645	10,959,505	10.69%	1,086,118
41		1977	1,939,086	4.888%	5,686,953	3,747,866	1,422,353	12,381,857	10.69%	1,247,529
42		1978	1,939,086	4.522%	5,261,129	3,322,043	1,260,749	13,642,606	10.69%	1,390,933
43		1979	1,939,086	4.462%	5,191,322	3,252,236	1,234,256	14,876,862	10.69%	1,524,283
44		1980	1,939,086	4.461%	5,190,159	3,251,072	1,233,814	16,110,677	10.69%	1,656,195
45		1981	1,939,086	4.462%	5,191,322	3,252,236	1,234,256	17,344,933	10.69%	1,788,106
46		1982	1,939,086	4.461%	5,190,159	3,251,072	1,233,814	18,578,747	10.69%	1,920,017
47		1983	1,939,086	4.462%	5,191,322	3,252,236	1,234,256	19,813,003	10.69%	2,051,929
48		1984	1,939,086	4.461%	5,190,159	3,251,072	1,233,814	21,046,818	10.69%	2,183,840
49		1985	1,939,086	4.462%	5,191,322	3,252,236	1,234,256	22,281,074	10.69%	2,315,751
50		1986	1,939,086	4.461%	5,190,159	3,251,072	1,233,814	23,514,888	10.69%	2,447,662
51		1987	1,939,086	4.462%	5,191,322	3,252,236	1,234,256	24,749,144	10.69%	2,579,574
52		1988	1,939,086	4.461%	5,190,159	3,251,072	1,233,814	25,982,959	10.69%	2,711,485
53		1989	1,939,086	4.462%	5,191,322	3,252,236	1,234,256	27,217,215	10.69%	2,843,396
54		1990	1,939,086	4.461%	5,190,159	3,251,072	1,233,814	28,451,029	10.69%	2,975,307
55		1991	1,939,086	2.231%	2,595,661	656,575	249,177	28,700,206	10.69%	3,054,569
56		1992	1,939,086	0.000%	-	(1,939,086)	(735,903)	27,964,303	10.69%	3,028,555
57		1993	1,939,086	0.000%	-	(1,939,086)	(735,903)	27,228,400	10.69%	2,949,891
58		1994	1,939,086	0.000%	-	(1,939,086)	(735,903)	26,492,498	10.69%	2,871,227
59		1995	1,939,086	0.000%	-	(1,939,086)	(735,903)	25,756,595	10.69%	2,792,564
60		1996	1,939,086	0.000%	-	(1,939,086)	(735,903)	25,020,692	10.69%	2,713,900
61		1997	1,939,086	0.000%	-	(1,939,086)	(735,903)	24,284,789	10.69%	2,635,236
62		1998	1,939,086	0.000%	-	(1,939,086)	(735,903)	23,548,887	10.69%	2,556,572
63		1999	1,939,086	0.000%	-	(1,939,086)	(735,903)	22,812,984	10.69%	2,477,909
64		2000	1,939,086	0.000%	-	(1,939,086)	(735,903)	22,077,081	10.69%	2,399,245
65		2001	1,939,086	0.000%	-	(1,939,086)	(735,903)	21,341,179	10.69%	2,320,581
66		2002	1,939,086	0.000%	-	(1,939,086)	(735,903)	20,605,276	10.69%	2,241,917
67		2003	1,939,086	0.000%	-	(1,939,086)	(735,903)	19,869,373	10.69%	2,163,253
68		2004	1,939,086	0.000%	-	(1,939,086)	(735,903)	19,133,470	10.69%	2,084,590
69		2005	1,939,086	0.000%	-	(1,939,086)	(735,903)	18,397,568	10.69%	2,005,926
70		2006	1,939,086	0.000%	-	(1,939,086)	(735,903)	17,661,665	10.69%	1,927,262
71		2007	1,939,086	0.000%	-	(1,939,086)	(735,903)	16,925,762	10.69%	1,848,598
72		2008	1,939,086	0.000%	-	(1,939,086)	(735,903)	16,189,860	10.69%	1,769,935
73		2009	1,939,086	0.000%	-	(1,939,086)	(735,903)	15,453,957	10.69%	1,691,271
74		2010	1,939,086	0.000%	-	(1,939,086)	(735,903)	14,718,054	10.69%	1,612,607
75		2011	1,939,086	0.000%	-	(1,939,086)	(735,903)	13,982,152	10.69%	1,533,943
76		2012	1,939,086	0.000%	-	(1,939,086)	(735,903)	13,246,249	10.69%	1,455,280
77		2013	1,939,086	0.000%	-	(1,939,086)	(735,903)	12,510,346	10.69%	1,376,616
78		2014	1,939,086	0.000%	-	(1,939,086)	(735,903)	11,774,443	10.69%	1,297,952
79		2015	1,939,086	0.000%	-	(1,939,086)	(735,903)	11,038,541	10.69%	1,219,288
80		2016	1,939,086	0.000%	-	(1,939,086)	(735,903)	10,302,638	10.69%	1,140,625
81		2017	1,939,086	0.000%	-	(1,939,086)	(735,903)	9,566,735	10.69%	1,061,961
82		2018	1,939,086	0.000%	-	(1,939,086)	(735,903)	8,830,833	9.22%	848,496
83		2019	1,939,086	0.000%	-	(1,939,086)	(735,903)	8,094,930	9.22%	780,616
84		2020	1,939,086	0.000%	-	(1,939,086)	(735,903)	7,359,027	9.22%	712,736
85		2021	1,939,086	0.000%	-	(1,939,086)	(735,903)	6,623,124	9.22%	644,857
86		2022	1,939,086	0.000%	-	(1,939,086)	(735,903)	5,887,222	9.22%	576,977
87		2023	1,939,086	0.000%	-	(1,939,086)	(735,903)	5,151,319	9.22%	509,097

88	2024	1,939,086	0.000%		-	(1,939,086)	(735,903)	4,415,416	9.22%	441,218
89	2025	1,939,086	0.000%		-	(1,939,086)	(735,903)	3,679,514	9.22%	373,338
90	2026	1,939,086	0.000%		-	(1,939,086)	(735,903)	2,943,611	9.22%	305,458
91	2027	1,939,086	0.000%		-	(1,939,086)	(735,903)	2,207,708	9.22%	237,579
92	2028	1,939,086	0.000%		-	(1,939,086)	(735,903)	1,471,805	9.22%	169,699
93	2029	1,939,086	0.000%		-	(1,939,086)	(735,903)	735,903	9.22%	101,819
94	2030	1,939,086	0.000%		-	(1,939,086)	(735,903)	(0)	9.22%	33,940
95		$ 116,345,189		100%	$ 116,345,189	$ (0)	$ (0)			$ 95,054,931

Facility Name Wyodak **Cost Year:** 2019
Plant Type: Steam - Coal

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	10,337,764
2	RP Capability Allocator	RP and BOP Allocators	19.00%
3	**RP - Generator/Exciter**	(Line 1 * 2)	1,964,175
4			
5	GSU Transformer	Summary Investment	4,426,087
6	RP Capability Allocator	RP and BOP Allocators	19.00%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	840,956
8			
9	Accessory Electric Equipment	Summary Investment	27,654,373
10	Factor to Determine Real and Reactive Power Portion	AEP Ratio	10%
11	Real and Reactive Power Portion	(Line 9 * 10)	2,765,437
12	RP Capability Allocator	RP and BOP Allocators	19.00%
13	**RP - Accesory Electric Equipment**	(Line 11 * 12)	525,433
14	Total Plant Investment	Summary Investment	471,519,749
15	Balance of Plant	(Line 14 - 11 - 5 - 1)	453,990,461
16	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
17	**RP - Balance of Plant**	(Line 15 * 16)	121,685
18	Total RP Investment	(Line 3 + 7 + 13 + 17)	3,452,249
19	RP Fixed Charge Percent	(Line 11(h))	11.4978%
20	Subtotal	(Line 18 * 19)	396,934
21	**Heating Losses**	Heating Losses	3,587
22	**Reactive Power Revenue Requirement**	(Line 20 + 21)	**$ 400,521**

	Depreciation			
23	Annual Depreciation Expense (D)	$	13,698,305	
24	Gross Plant Investment (F)		471,519,749	(Line 14)
25	SLDP=DE/F		2.9051%	(Line 23 / 24)
26	Depreciable years =1/SLDP		34	
27	Book Life (n)		60	Book Lives
28	SLDP for Book Life = 1/n		1.67%	
29	SFDP=(R/((1+R)^n-1)		0.10%	R=Return

	Income Taxes		
30	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.3264%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment						
			Amount	Investment	FCR %	
O&M	O&M by Facility	$	7,495,309	$ 471,519,749	1.5896%	(f)/(g)
A&G	Fixed Charge Items				0.4475%	
Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)				0.0226%	
Prepayments	Fixed Charge Items				0.0203%	
Materials and Supplies	Fixed Charge Items				0.1029%	
General and Intangible Plant	Fixed Charge Items				1.1057%	
Other Taxes	Fixed Charge Items				0.5233%	
Depreciation	(Line 29)				0.1030%	
Return	Fixed Charge Items				7.5512%	
Income Taxes	Line 30				1.3264%	
ADIT	Line 34(i)		(6,104,434)	471,519,749	-1.2946%	
Total RP Fixed Charge Percent					11.4978%	

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes									
31	Investment		$ 471,519,749	Summary Investment						
32	Straight-line Tax Life		60	(Line 27)						
33	Composite Tax Rate (CTR)		24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$79,815,743
34	In Service Year		1978				Levelized Revenue Requirement			6,104,434
	Year		SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
			Line 31 / 32	(Tax Depreciation Rates)	(Line 31 * Line 35c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
35		1978	$ 7,858,662	3.750%	$ 17,681,991	$ 9,823,328	$ 3,728,051	$ 3,728,051	10.69%	$ 199,254
36		1979	7,858,662	7.219%	34,039,011	26,180,348	9,935,704	13,663,755	10.69%	929,542
37		1980	7,858,662	6.677%	31,483,374	23,624,711	8,965,814	22,629,569	10.69%	1,939,774
38		1981	7,858,662	6.177%	29,125,775	21,267,112	8,071,082	30,700,651	10.69%	2,850,347
39		1982	7,858,662	5.713%	26,937,923	19,079,261	7,240,770	37,941,421	10.69%	3,668,721
40		1983	7,858,662	5.285%	24,919,819	17,061,156	6,474,879	44,416,301	10.69%	4,401,783
41		1984	7,858,662	4.888%	23,047,885	15,189,223	5,764,462	50,180,763	10.69%	5,055,941
42		1985	7,858,662	4.522%	21,322,123	13,463,461	5,109,518	55,290,281	10.69%	5,637,124
43		1986	7,858,662	4.462%	21,039,211	13,180,549	5,002,150	60,292,431	10.69%	6,177,563
44		1987	7,858,662	4.461%	21,034,496	13,175,834	5,000,361	65,292,791	10.69%	6,712,169
45		1988	7,858,662	4.462%	21,039,211	13,180,549	5,002,150	70,294,941	10.69%	7,246,774
46		1989	7,858,662	4.461%	21,034,496	13,175,834	5,000,361	75,295,302	10.69%	7,781,379
47		1990	7,858,662	4.462%	21,039,211	13,180,549	5,002,150	80,297,452	10.69%	8,315,985
48		1991	7,858,662	4.461%	21,034,496	13,175,834	5,000,361	85,297,813	10.69%	8,850,590
49		1992	7,858,662	4.462%	21,039,211	13,180,549	5,002,150	90,299,963	10.69%	9,385,196
50		1993	7,858,662	4.461%	21,034,496	13,175,834	5,000,361	95,300,323	10.69%	9,919,801
51		1994	7,858,662	4.462%	21,039,211	13,180,549	5,002,150	100,302,473	10.69%	10,454,406
52		1995	7,858,662	4.461%	21,034,496	13,175,834	5,000,361	105,302,834	10.69%	10,989,012
53		1996	7,858,662	4.462%	21,039,211	13,180,549	5,002,150	110,304,984	10.69%	11,523,617
54		1997	7,858,662	4.461%	21,034,496	13,175,834	5,000,361	115,305,344	10.69%	12,058,223
55		1998	7,858,662	2.231%	10,519,606	2,660,943	1,009,855	116,315,199	10.69%	12,379,451
56		1999	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	113,332,758	10.69%	12,274,022
57		2000	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	110,350,317	10.69%	11,955,216
58		2001	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	107,367,876	10.69%	11,636,411
59		2002	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	104,385,435	10.69%	11,317,605
60		2003	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	101,402,994	10.69%	10,998,799
61		2004	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	98,420,553	10.69%	10,679,993
62		2005	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	95,438,112	10.69%	10,361,188
63		2006	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	92,455,671	10.69%	10,042,382
64		2007	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	89,473,230	10.69%	9,723,576
65		2008	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	86,490,789	10.69%	9,404,770
66		2009	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	83,508,348	10.69%	9,085,964
67		2010	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	80,525,907	10.69%	8,767,159
68		2011	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	77,543,466	10.69%	8,448,353
69		2012	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	74,561,025	10.69%	8,129,547
70		2013	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	71,578,584	10.69%	7,810,741
71		2014	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	68,596,143	10.69%	7,491,936
72		2015	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	65,613,702	10.69%	7,173,130
73		2016	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	62,631,261	10.69%	6,854,324
74		2017	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	59,648,820	10.69%	6,535,518
75		2018	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	56,666,379	9.22%	5,364,456
76		2019	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	53,683,938	9.22%	5,089,356
77		2020	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	50,701,497	9.22%	4,814,256
78		2021	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	47,719,056	9.22%	4,539,155
79		2022	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	44,736,615	9.22%	4,264,055
80		2023	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	41,754,174	9.22%	3,988,955
81		2024	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	38,771,733	9.22%	3,713,854
82		2025	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	35,789,292	9.22%	3,438,754
83		2026	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	32,806,851	9.22%	3,163,654
84		2027	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	29,824,410	9.22%	2,888,553
85		2028	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	26,841,969	9.22%	2,613,453
86		2029	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	23,859,528	9.22%	2,338,353
87		2030	7,858,662	0.000%	-	(7,858,662)	(2,982,441)	20,877,087	9.22%	2,063,252

88	2031	7,858,662	0.000%		-	(7,858,662)	(2,982,441)	17,894,646	9.22%	1,788,152
89	2032	7,858,662	0.000%		-	(7,858,662)	(2,982,441)	14,912,205	9.22%	1,513,052
90	2033	7,858,662	0.000%		-	(7,858,662)	(2,982,441)	11,929,764	9.22%	1,237,951
91	2034	7,858,662	0.000%		-	(7,858,662)	(2,982,441)	8,947,323	9.22%	962,851
92	2035	7,858,662	0.000%		-	(7,858,662)	(2,982,441)	5,964,882	9.22%	687,751
93	2036	7,858,662	0.000%		-	(7,858,662)	(2,982,441)	2,982,441	9.22%	412,650
94	2037	7,858,662	0.000%		-	(7,858,662)	(2,982,441)	(0)	9.22%	137,550
95		$ 471,519,749		100%	$ 471,519,749	$ (0)	$ (0)			$ 380,187,350

	Name of Facility	In Service	Number of Units	MVA Rating	Annual Revenue Requirement
1	Merwin	1931-1958	4	170.0	$ 343,514
2	Yale	1953	2	137.4	74,184
3	Swift 1	1958	3	266.7	402,033
4	Lemolo	1955-1956	2	74.2	135,244
5	Toketee	1949-1950	3	50.0	172,148
6	Slide Creek	1951	1	21.2	153,375
7	Soda Springs	1952	1	12.9	23,355
8	Clearwater	1953	2	48.2	109,915
9	Fish Creek	1952	1	12.9	15,763
10	Prospect	1928	4	55.0	175,028
11	Copco	1918-1925	4	55.0	552,800
12	JC Boyle	1958	2	103.2	115,017
13	Irongate	1962	1	18.9	21,851
14	Ashton	1917	3	8.0	51,215
15	Soda	1924	2	16.4	99,430
16	Grace	1908-1923	3	36.7	110,875
17	Oneida	1915-1920	3	33.3	167,015
18	Cutler	1927	2	37.5	360,690
19	Total			1,158	$ 3,083,453

Facility Name Merwin **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	4,328,371
2	RP Capability Allocator	RP and BOP Allocators	36.00%
3	**RP - Generator/Exciter**	(Line 1 * 2)	1,558,214
4			
5	GSU Transformer	Summary Investment	2,145,545
6	RP Capability Allocator	RP and BOP Allocators	36.00%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	772,396
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	7,319,103
10	Real and Reactive Power Portion	Summary Investment	1,207,933
11	RP Capability Allocator	RP and BOP Allocators	36.00%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	434,856
13	Total Plant Investment	Summary Investment	139,189,039
14	Balance of Plant	(Line 13 - 10 - 5 - 1)	131,507,190
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 15 * 16)	35,248
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	2,800,714
18	RP Fixed Charge Percent	(Line 11(h))	12.2652%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 343,514**

	Depreciation			
20	Annual Depreciation Expense (D)	$	2,713,542	
21	Gross Plant Investment (F)		139,189,039	(Line 14)
22	SLDP=DE/F		1.9495%	(Line 20 / 21)
23	Depreciable years =1/SLDP		51	
24	Book Life (n)		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.4525%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 3,709,640	$ 139,189,039	2.6652%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0350%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.0056%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.4525%	
	ADIT	Line 31(i)	(2,288,243)	139,189,039	-1.6440%	
	Total RP Fixed Charge Percent				12.2652%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 139,189,039	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$30,282,198
31	In Service Year	1945	1931-1958			Levelized Revenue Requirement			2,288,243
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1945	$ 1,391,890	3.750%	$ 5,219,589	$ 3,827,699	$ 1,452,650	$ 1,452,650	10.69%	$ 77,640
33	1946	1,391,890	7.219%	10,048,057	8,656,166	3,285,102	4,737,752	10.69%	330,859
34	1947	1,391,890	6.677%	9,293,652	7,901,762	2,998,798	7,736,549	10.69%	666,715
35	1948	1,391,890	6.177%	8,597,707	7,205,817	2,734,679	10,471,229	10.69%	973,153
36	1949	1,391,890	5.713%	7,951,870	6,559,979	2,489,578	12,960,806	10.69%	1,252,375
37	1950	1,391,890	5.285%	7,356,141	5,964,250	2,263,493	15,224,299	10.69%	1,506,413
38	1951	1,391,890	4.888%	6,803,560	5,411,670	2,053,783	17,278,082	10.69%	1,737,159
39	1952	1,391,890	4.522%	6,294,128	4,902,238	1,860,448	19,138,530	10.69%	1,946,363
40	1953	1,391,890	4.462%	6,210,615	4,818,725	1,828,754	20,967,284	10.69%	2,143,540
41	1954	1,391,890	4.461%	6,209,223	4,817,333	1,828,226	22,795,510	10.69%	2,338,995
42	1955	1,391,890	4.462%	6,210,615	4,818,725	1,828,754	24,624,264	10.69%	2,534,450
43	1956	1,391,890	4.461%	6,209,223	4,817,333	1,828,226	26,452,490	10.69%	2,729,905
44	1957	1,391,890	4.462%	6,210,615	4,818,725	1,828,754	28,281,245	10.69%	2,925,361
45	1958	1,391,890	4.461%	6,209,223	4,817,333	1,828,226	30,109,470	10.69%	3,120,816
46	1959	1,391,890	4.462%	6,210,615	4,818,725	1,828,754	31,938,225	10.69%	3,316,271
47	1960	1,391,890	4.461%	6,209,223	4,817,333	1,828,226	33,766,451	10.69%	3,511,726
48	1961	1,391,890	4.462%	6,210,615	4,818,725	1,828,754	35,595,205	10.69%	3,707,181
49	1962	1,391,890	4.461%	6,209,223	4,817,333	1,828,226	37,423,431	10.69%	3,902,636
50	1963	1,391,890	4.462%	6,210,615	4,818,725	1,828,754	39,252,185	10.69%	4,098,091
51	1964	1,391,890	4.461%	6,209,223	4,817,333	1,828,226	41,080,411	10.69%	4,293,546
52	1965	1,391,890	2.231%	3,105,307	1,713,417	650,259	41,730,670	10.69%	4,426,014
53	1966	1,391,890	0.000%	-	(1,391,890)	(528,236)	41,202,433	10.69%	4,432,536
54	1967	1,391,890	0.000%	-	(1,391,890)	(528,236)	40,674,197	10.69%	4,376,070
55	1968	1,391,890	0.000%	-	(1,391,890)	(528,236)	40,145,961	10.69%	4,319,605
56	1969	1,391,890	0.000%	-	(1,391,890)	(528,236)	39,617,724	10.69%	4,263,139
57	1970	1,391,890	0.000%	-	(1,391,890)	(528,236)	39,089,488	10.69%	4,206,674
58	1971	1,391,890	0.000%	-	(1,391,890)	(528,236)	38,561,252	10.69%	4,150,208
59	1972	1,391,890	0.000%	-	(1,391,890)	(528,236)	38,033,015	10.69%	4,093,743
60	1973	1,391,890	0.000%	-	(1,391,890)	(528,236)	37,504,779	10.69%	4,037,278
61	1974	1,391,890	0.000%	-	(1,391,890)	(528,236)	36,976,543	10.69%	3,980,812
62	1975	1,391,890	0.000%	-	(1,391,890)	(528,236)	36,448,306	10.69%	3,924,347
63	1976	1,391,890	0.000%	-	(1,391,890)	(528,236)	35,920,070	10.69%	3,867,881
64	1977	1,391,890	0.000%	-	(1,391,890)	(528,236)	35,391,834	10.69%	3,811,416
65	1978	1,391,890	0.000%	-	(1,391,890)	(528,236)	34,863,597	10.69%	3,754,951
66	1979	1,391,890	0.000%	-	(1,391,890)	(528,236)	34,335,361	10.69%	3,698,485
67	1980	1,391,890	0.000%	-	(1,391,890)	(528,236)	33,807,125	10.69%	3,642,020
68	1981	1,391,890	0.000%	-	(1,391,890)	(528,236)	33,278,888	10.69%	3,585,554
69	1982	1,391,890	0.000%	-	(1,391,890)	(528,236)	32,750,652	10.69%	3,529,089
70	1983	1,391,890	0.000%	-	(1,391,890)	(528,236)	32,222,416	10.69%	3,472,623
71	1984	1,391,890	0.000%	-	(1,391,890)	(528,236)	31,694,179	10.69%	3,416,158
72	1985	1,391,890	0.000%	-	(1,391,890)	(528,236)	31,165,943	10.69%	3,359,693
73	1986	1,391,890	0.000%	-	(1,391,890)	(528,236)	30,637,707	10.69%	3,303,227
74	1987	1,391,890	0.000%	-	(1,391,890)	(528,236)	30,109,470	10.69%	3,246,762
75	1988	1,391,890	0.000%	-	(1,391,890)	(528,236)	29,581,234	10.69%	3,190,296
76	1989	1,391,890	0.000%	-	(1,391,890)	(528,236)	29,052,998	10.69%	3,133,831
77	1990	1,391,890	0.000%	-	(1,391,890)	(528,236)	28,524,761	10.69%	3,077,365
78	1991	1,391,890	0.000%	-	(1,391,890)	(528,236)	27,996,525	10.69%	3,020,900
79	1992	1,391,890	0.000%	-	(1,391,890)	(528,236)	27,468,289	10.69%	2,964,435
80	1993	1,391,890	0.000%	-	(1,391,890)	(528,236)	26,940,053	10.69%	2,907,969
81	1994	1,391,890	0.000%	-	(1,391,890)	(528,236)	26,411,816	10.69%	2,851,504
82	1995	1,391,890	0.000%	-	(1,391,890)	(528,236)	25,883,580	10.69%	2,795,038
83	1996	1,391,890	0.000%	-	(1,391,890)	(528,236)	25,355,344	10.69%	2,738,573
84	1997	1,391,890	0.000%	-	(1,391,890)	(528,236)	24,827,107	10.69%	2,682,108

85	1998	1,391,890	0.000%	-	(1,391,890)	(528,236)	24,298,871	10.69%	2,625,642
86	1999	1,391,890	0.000%	-	(1,391,890)	(528,236)	23,770,635	10.69%	2,569,177
87	2000	1,391,890	0.000%	-	(1,391,890)	(528,236)	23,242,398	10.69%	2,512,711
88	2001	1,391,890	0.000%	-	(1,391,890)	(528,236)	22,714,162	10.69%	2,456,246
89	2002	1,391,890	0.000%	-	(1,391,890)	(528,236)	22,185,926	10.69%	2,399,780
90	2003	1,391,890	0.000%	-	(1,391,890)	(528,236)	21,657,689	10.69%	2,343,315
91	2004	1,391,890	0.000%	-	(1,391,890)	(528,236)	21,129,453	10.69%	2,286,850
92	2005	1,391,890	0.000%	-	(1,391,890)	(528,236)	20,601,217	10.69%	2,230,384
93	2006	1,391,890	0.000%	-	(1,391,890)	(528,236)	20,072,980	10.69%	2,173,919
94	2007	1,391,890	0.000%	-	(1,391,890)	(528,236)	19,544,744	10.69%	2,117,453
95	2008	1,391,890	0.000%	-	(1,391,890)	(528,236)	19,016,508	10.69%	2,060,988
96	2009	1,391,890	0.000%	-	(1,391,890)	(528,236)	18,488,271	10.69%	2,004,522
97	2010	1,391,890	0.000%	-	(1,391,890)	(528,236)	17,960,035	10.69%	1,948,057
98	2011	1,391,890	0.000%	-	(1,391,890)	(528,236)	17,431,799	10.69%	1,891,592
99	2012	1,391,890	0.000%	-	(1,391,890)	(528,236)	16,903,562	10.69%	1,835,126
100	2013	1,391,890	0.000%	-	(1,391,890)	(528,236)	16,375,326	10.69%	1,778,661
101	2014	1,391,890	0.000%	-	(1,391,890)	(528,236)	15,847,090	10.69%	1,722,195
102	2015	1,391,890	0.000%	-	(1,391,890)	(528,236)	15,318,853	10.69%	1,665,730
103	2016	1,391,890	0.000%	-	(1,391,890)	(528,236)	14,790,617	10.69%	1,609,265
104	2017	1,391,890	0.000%	-	(1,391,890)	(528,236)	14,262,381	10.69%	1,552,799
105	2018	1,391,890	0.000%	-	(1,391,890)	(528,236)	13,734,144	9.22%	1,291,200
106	2019	1,391,890	0.000%	-	(1,391,890)	(528,236)	13,205,908	9.22%	1,242,475
107	2020	1,391,890	0.000%	-	(1,391,890)	(528,236)	12,677,672	9.22%	1,193,751
108	2021	1,391,890	0.000%	-	(1,391,890)	(528,236)	12,149,435	9.22%	1,145,026
109	2022	1,391,890	0.000%	-	(1,391,890)	(528,236)	11,621,199	9.22%	1,096,302
110	2023	1,391,890	0.000%	-	(1,391,890)	(528,236)	11,092,963	9.22%	1,047,577
111	2024	1,391,890	0.000%	-	(1,391,890)	(528,236)	10,564,726	9.22%	998,853
112	2025	1,391,890	0.000%	-	(1,391,890)	(528,236)	10,036,490	9.22%	950,128
113	2026	1,391,890	0.000%	-	(1,391,890)	(528,236)	9,508,254	9.22%	901,403
114	2027	1,391,890	0.000%	-	(1,391,890)	(528,236)	8,980,018	9.22%	852,679
115	2028	1,391,890	0.000%	-	(1,391,890)	(528,236)	8,451,781	9.22%	803,954
116	2029	1,391,890	0.000%	-	(1,391,890)	(528,236)	7,923,545	9.22%	755,230
117	2030	1,391,890	0.000%	-	(1,391,890)	(528,236)	7,395,309	9.22%	706,505
118	2031	1,391,890	0.000%	-	(1,391,890)	(528,236)	6,867,072	9.22%	657,781
119	2032	1,391,890	0.000%	-	(1,391,890)	(528,236)	6,338,836	9.22%	609,056
120	2033	1,391,890	0.000%	-	(1,391,890)	(528,236)	5,810,600	9.22%	560,332
121	2034	1,391,890	0.000%	-	(1,391,890)	(528,236)	5,282,363	9.22%	511,607
122	2035	1,391,890	0.000%	-	(1,391,890)	(528,236)	4,754,127	9.22%	462,883
123	2036	1,391,890	0.000%	-	(1,391,890)	(528,236)	4,225,891	9.22%	414,158
124	2037	1,391,890	0.000%	-	(1,391,890)	(528,236)	3,697,654	9.22%	365,434
125	2038	1,391,890	0.000%	-	(1,391,890)	(528,236)	3,169,418	9.22%	316,709
126	2039	1,391,890	0.000%	-	(1,391,890)	(528,236)	2,641,182	9.22%	267,985
127	2040	1,391,890	0.000%	-	(1,391,890)	(528,236)	2,112,945	9.22%	219,260
128	2041	1,391,890	0.000%	-	(1,391,890)	(528,236)	1,584,709	9.22%	170,536
129	2042	1,391,890	0.000%	-	(1,391,890)	(528,236)	1,056,473	9.22%	121,811
130	2043	1,391,890	0.000%	-	(1,391,890)	(528,236)	528,236	9.22%	73,087
131	2044	1,391,890	0.000%	-	(1,391,890)	(528,236)	0	9.22%	24,362
132		$ 139,189,039	100%	$ 139,189,039	$ (0)	$ 0			$ 224,917,995

Facility Name Yale **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	6,607,404
2	RP Capability Allocator	RP and BOP Allocators	4.94%
3	**RP - Generator/Exciter**	(Line 1 * 2)	326,241
4			
5	GSU Transformer	Summary Investment	2,145,545
6	RP Capability Allocator	RP and BOP Allocators	4.94%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	105,936
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	3,855,140
10	Real and Reactive Power Portion	Summary Investment	1,732,428
11	RP Capability Allocator	RP and BOP Allocators	4.94%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	85,539
13			
	Total Plant Investment	Summary Investment	84,037,148
14	Balance of Plant	(Line - 10 - 5 - 1)	73,551,770
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	19,714
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	537,430
18	RP Fixed Charge Percent	(Line 11(h))	13.8034%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 74,184**

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 3,517,446	$ 84,037,148	4.1856%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0521%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.0056%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.4525%	
	ADIT	Line 31(i)	(1,380,985)	84,037,148	-1.6433%	
	Total RP Fixed Charge Percent				13.8034%	

	Depreciation			
20	Annual Depreciation Expense (D)	$	1,147,070	
21	Gross Plant Investment (F)		84,037,148	(Line 14)
22	SLDP=DE/F		1.3650%	(Line 20 / 21)
23	Depreciable years =1/SLDP		73	
24	Book Life (n)		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.4525%	Based Upon Book Life CTR=Composite Tax Rate

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 84,037,148	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$18,275,707
31	In Service Year	1953				Levelized Revenue Requirement			1,380,985
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1953	$ 840,371	3.750%	$ 3,151,393	$ 2,311,022	$ 877,056	$ 877,056	10.69%	$ 46,876
33	1954	840,371	7.219%	6,066,642	5,226,270	1,983,422	2,860,478	10.69%	199,760
34	1955	840,371	6.677%	5,611,160	4,770,789	1,810,562	4,671,040	10.69%	402,538
35	1956	840,371	6.177%	5,190,975	4,350,603	1,651,097	6,322,137	10.69%	587,554
36	1957	840,371	5.713%	4,801,042	3,960,671	1,503,114	7,825,251	10.69%	756,137
37	1958	840,371	5.285%	4,441,363	3,600,992	1,366,612	9,191,864	10.69%	909,516
38	1959	840,371	4.888%	4,107,736	3,267,364	1,239,997	10,431,861	10.69%	1,048,832
39	1960	840,371	4.522%	3,800,160	2,959,788	1,123,269	11,555,130	10.69%	1,175,141
40	1961	840,371	4.462%	3,749,738	2,909,366	1,104,134	12,659,264	10.69%	1,294,190
41	1962	840,371	4.461%	3,748,897	2,908,526	1,103,815	13,763,078	10.69%	1,412,198
42	1963	840,371	4.462%	3,749,738	2,909,366	1,104,134	14,867,212	10.69%	1,530,207
43	1964	840,371	4.461%	3,748,897	2,908,526	1,103,815	15,971,026	10.69%	1,648,215
44	1965	840,371	4.462%	3,749,738	2,909,366	1,104,134	17,075,160	10.69%	1,766,224
45	1966	840,371	4.461%	3,748,897	2,908,526	1,103,815	18,178,975	10.69%	1,884,232
46	1967	840,371	4.462%	3,749,738	2,909,366	1,104,134	19,283,108	10.69%	2,002,240
47	1968	840,371	4.461%	3,748,897	2,908,526	1,103,815	20,386,923	10.69%	2,120,249
48	1969	840,371	4.462%	3,749,738	2,909,366	1,104,134	21,491,056	10.69%	2,238,257
49	1970	840,371	4.461%	3,748,897	2,908,526	1,103,815	22,594,871	10.69%	2,356,266
50	1971	840,371	4.462%	3,749,738	2,909,366	1,104,134	23,699,004	10.69%	2,474,274
51	1972	840,371	4.461%	3,748,897	2,908,526	1,103,815	24,802,819	10.69%	2,592,283
52	1973	840,371	2.231%	1,874,869	1,034,497	392,602	25,195,421	10.69%	2,672,262
53	1974	840,371	0.000%	-	(840,371)	(318,929)	24,876,492	10.69%	2,676,200
54	1975	840,371	0.000%	-	(840,371)	(318,929)	24,557,562	10.69%	2,642,108
55	1976	840,371	0.000%	-	(840,371)	(318,929)	24,238,633	10.69%	2,608,016
56	1977	840,371	0.000%	-	(840,371)	(318,929)	23,919,703	10.69%	2,573,924
57	1978	840,371	0.000%	-	(840,371)	(318,929)	23,600,774	10.69%	2,539,833
58	1979	840,371	0.000%	-	(840,371)	(318,929)	23,281,845	10.69%	2,505,741
59	1980	840,371	0.000%	-	(840,371)	(318,929)	22,962,915	10.69%	2,471,649
60	1981	840,371	0.000%	-	(840,371)	(318,929)	22,643,986	10.69%	2,437,558
61	1982	840,371	0.000%	-	(840,371)	(318,929)	22,325,057	10.69%	2,403,466
62	1983	840,371	0.000%	-	(840,371)	(318,929)	22,006,127	10.69%	2,369,374
63	1984	840,371	0.000%	-	(840,371)	(318,929)	21,687,198	10.69%	2,335,282
64	1985	840,371	0.000%	-	(840,371)	(318,929)	21,368,268	10.69%	2,301,191
65	1986	840,371	0.000%	-	(840,371)	(318,929)	21,049,339	10.69%	2,267,099
66	1987	840,371	0.000%	-	(840,371)	(318,929)	20,730,410	10.69%	2,233,007
67	1988	840,371	0.000%	-	(840,371)	(318,929)	20,411,480	10.69%	2,198,916
68	1989	840,371	0.000%	-	(840,371)	(318,929)	20,092,551	10.69%	2,164,824
69	1990	840,371	0.000%	-	(840,371)	(318,929)	19,773,621	10.69%	2,130,732
70	1991	840,371	0.000%	-	(840,371)	(318,929)	19,454,692	10.69%	2,096,640
71	1992	840,371	0.000%	-	(840,371)	(318,929)	19,135,763	10.69%	2,062,549
72	1993	840,371	0.000%	-	(840,371)	(318,929)	18,816,833	10.69%	2,028,457
73	1994	840,371	0.000%	-	(840,371)	(318,929)	18,497,904	10.69%	1,994,365
74	1995	840,371	0.000%	-	(840,371)	(318,929)	18,178,975	10.69%	1,960,274
75	1996	840,371	0.000%	-	(840,371)	(318,929)	17,860,045	10.69%	1,926,182
76	1997	840,371	0.000%	-	(840,371)	(318,929)	17,541,116	10.69%	1,892,090
77	1998	840,371	0.000%	-	(840,371)	(318,929)	17,222,186	10.69%	1,857,998
78	1999	840,371	0.000%	-	(840,371)	(318,929)	16,903,257	10.69%	1,823,907
79	2000	840,371	0.000%	-	(840,371)	(318,929)	16,584,328	10.69%	1,789,815
80	2001	840,371	0.000%	-	(840,371)	(318,929)	16,265,398	10.69%	1,755,723
81	2002	840,371	0.000%	-	(840,371)	(318,929)	15,946,469	10.69%	1,721,632
82	2003	840,371	0.000%	-	(840,371)	(318,929)	15,627,540	10.69%	1,687,540
83	2004	840,371	0.000%	-	(840,371)	(318,929)	15,308,610	10.69%	1,653,448
84	2005	840,371	0.000%	-	(840,371)	(318,929)	14,989,681	10.69%	1,619,356

85	2006	840,371	0.000%	-	(840,371)	(318,929)	14,670,751	10.69%	1,585,265
86	2007	840,371	0.000%	-	(840,371)	(318,929)	14,351,822	10.69%	1,551,173
87	2008	840,371	0.000%	-	(840,371)	(318,929)	14,032,893	10.69%	1,517,081
88	2009	840,371	0.000%	-	(840,371)	(318,929)	13,713,963	10.69%	1,482,990
89	2010	840,371	0.000%	-	(840,371)	(318,929)	13,395,034	10.69%	1,448,898
90	2011	840,371	0.000%	-	(840,371)	(318,929)	13,076,105	10.69%	1,414,806
91	2012	840,371	0.000%	-	(840,371)	(318,929)	12,757,175	10.69%	1,380,714
92	2013	840,371	0.000%	-	(840,371)	(318,929)	12,438,246	10.69%	1,346,623
93	2014	840,371	0.000%	-	(840,371)	(318,929)	12,119,316	10.69%	1,312,531
94	2015	840,371	0.000%	-	(840,371)	(318,929)	11,800,387	10.69%	1,278,439
95	2016	840,371	0.000%	-	(840,371)	(318,929)	11,481,458	10.69%	1,244,348
96	2017	840,371	0.000%	-	(840,371)	(318,929)	11,162,528	10.69%	1,210,256
97	2018	840,371	0.000%	-	(840,371)	(318,929)	10,843,599	9.22%	1,014,922
98	2019	840,371	0.000%	-	(840,371)	(318,929)	10,524,669	9.22%	985,504
99	2020	840,371	0.000%	-	(840,371)	(318,929)	10,205,740	9.22%	956,086
100	2021	840,371	0.000%	-	(840,371)	(318,929)	9,886,811	9.22%	926,668
101	2022	840,371	0.000%	-	(840,371)	(318,929)	9,567,881	9.22%	897,250
102	2023	840,371	0.000%	-	(840,371)	(318,929)	9,248,952	9.22%	867,832
103	2024	840,371	0.000%	-	(840,371)	(318,929)	8,930,023	9.22%	838,414
104	2025	840,371	0.000%	-	(840,371)	(318,929)	8,611,093	9.22%	808,996
105	2026	840,371	0.000%	-	(840,371)	(318,929)	8,292,164	9.22%	779,578
106	2027	840,371	0.000%	-	(840,371)	(318,929)	7,973,234	9.22%	750,160
107	2028	840,371	0.000%	-	(840,371)	(318,929)	7,654,305	9.22%	720,742
108	2029	840,371	0.000%	-	(840,371)	(318,929)	7,335,376	9.22%	691,324
109	2030	840,371	0.000%	-	(840,371)	(318,929)	7,016,446	9.22%	661,906
110	2031	840,371	0.000%	-	(840,371)	(318,929)	6,697,517	9.22%	632,488
111	2032	840,371	0.000%	-	(840,371)	(318,929)	6,378,588	9.22%	603,070
112	2033	840,371	0.000%	-	(840,371)	(318,929)	6,059,658	9.22%	573,652
113	2034	840,371	0.000%	-	(840,371)	(318,929)	5,740,729	9.22%	544,234
114	2035	840,371	0.000%	-	(840,371)	(318,929)	5,421,799	9.22%	514,816
115	2036	840,371	0.000%	-	(840,371)	(318,929)	5,102,870	9.22%	485,398
116	2037	840,371	0.000%	-	(840,371)	(318,929)	4,783,941	9.22%	455,980
117	2038	840,371	0.000%	-	(840,371)	(318,929)	4,465,011	9.22%	426,562
118	2039	840,371	0.000%	-	(840,371)	(318,929)	4,146,082	9.22%	397,144
119	2040	840,371	0.000%	-	(840,371)	(318,929)	3,827,153	9.22%	367,726
120	2041	840,371	0.000%	-	(840,371)	(318,929)	3,508,223	9.22%	338,307
121	2042	840,371	0.000%	-	(840,371)	(318,929)	3,189,294	9.22%	308,889
122	2043	840,371	0.000%	-	(840,371)	(318,929)	2,870,364	9.22%	279,471
123	2044	840,371	0.000%	-	(840,371)	(318,929)	2,551,435	9.22%	250,053
124	2045	840,371	0.000%	-	(840,371)	(318,929)	2,232,506	9.22%	220,635
125	2046	840,371	0.000%	-	(840,371)	(318,929)	1,913,576	9.22%	191,217
126	2047	840,371	0.000%	-	(840,371)	(318,929)	1,594,647	9.22%	161,799
127	2048	840,371	0.000%	-	(840,371)	(318,929)	1,275,718	9.22%	132,381
128	2049	840,371	0.000%	-	(840,371)	(318,929)	956,788	9.22%	102,963
129	2050	840,371	0.000%	-	(840,371)	(318,929)	637,859	9.22%	73,545
130	2051	840,371	0.000%	-	(840,371)	(318,929)	318,929	9.22%	44,127
131	2052	840,371	0.000%	-	(840,371)	(318,929)	0	9.22%	14,709
132		$ 84,037,148	100%	$ 84,037,148	$ 0	$ 0			$ 134,638,021

Facility Name Swift 1 **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	10,425,852
2	RP Capability Allocator	RP and BOP Allocators	19.00%
3	**RP - Generator/Exciter**	(Line 1 * 2)	1,980,912
4			
5	GSU Transformer	Summary Investment	3,565,636
6	RP Capability Allocator	RP and BOP Allocators	19.00%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	677,471
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	8,079,631
10	Real and Reactive Power Portion	Summary Investment	1,748,245
11	RP Capability Allocator	RP and BOP Allocators	19.00%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	332,167
13	Total Plant Investment	Summary Investment	169,064,982
14	Balance of Plant	(Line 13 - 12 - 5 - 1)	153,325,249
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	41,096
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	3,031,645
18	RP Fixed Charge Percent	(Line 11(h))	13.2612%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 402,033**

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 6,168,534	$ 169,064,982	3.6486%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0461%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.0056%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.4525%	
	ADIT	Line 31(i)	(2,776,879)	169,064,982	-1.6425%	
	Total RP Fixed Charge Percent				13.2612%	

	Depreciation			
20	Annual Depreciation Expense (D)	$	2,901,986	
21	Gross Plant Investment (F)		169,064,982	(Line 14)
22	SLDP=DE/F		1.7165%	(Line 20 / 21)
23	Depreciable years =1/SLDP		58	
24	Book Life (n)		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.4525%	Based Upon Book Life CTR=Composite Tax Rate

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes									
28	Investment		$ 169,064,982	Summary Investment						
29	Straight-line Tax Life		100	(Line 24)						
30	Composite Tax Rate (CTR)		24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$36,748,728
31	In Service Year		1958				Levelized Revenue Requirement			2,776,879
	Year		SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
			Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32		1958	$ 1,690,650	3.750%	$ 6,339,937	$ 4,649,287	$ 1,764,451	$ 1,764,451	10.69%	$ 94,305
33		1959	1,690,650	7.219%	12,204,801	10,514,151	3,990,226	5,754,676	10.69%	401,876
34		1960	1,690,650	6.677%	11,288,469	9,597,819	3,642,468	9,397,145	10.69%	809,821
35		1961	1,690,650	6.177%	10,443,144	8,752,494	3,321,659	12,718,804	10.69%	1,182,034
36		1962	1,690,650	5.713%	9,658,682	7,968,033	3,023,948	15,742,752	10.69%	1,521,188
37		1963	1,690,650	5.285%	8,935,084	7,244,434	2,749,335	18,492,087	10.69%	1,829,754
38		1964	1,690,650	4.888%	8,263,896	6,573,246	2,494,613	20,986,700	10.69%	2,110,028
39		1965	1,690,650	4.522%	7,645,118	5,954,469	2,259,780	23,246,480	10.69%	2,364,136
40		1966	1,690,650	4.462%	7,543,679	5,853,030	2,221,283	25,467,764	10.69%	2,603,636
41		1967	1,690,650	4.461%	7,541,989	5,851,339	2,220,642	27,688,405	10.69%	2,841,044
42		1968	1,690,650	4.462%	7,543,679	5,853,030	2,221,283	29,909,689	10.69%	3,078,452
43		1969	1,690,650	4.461%	7,541,989	5,851,339	2,220,642	32,130,330	10.69%	3,315,860
44		1970	1,690,650	4.462%	7,543,679	5,853,030	2,221,283	34,351,613	10.69%	3,553,268
45		1971	1,690,650	4.461%	7,541,989	5,851,339	2,220,642	36,572,255	10.69%	3,790,677
46		1972	1,690,650	4.462%	7,543,679	5,853,030	2,221,283	38,793,538	10.69%	4,028,085
47		1973	1,690,650	4.461%	7,541,989	5,851,339	2,220,642	41,014,180	10.69%	4,265,493
48		1974	1,690,650	4.462%	7,543,679	5,853,030	2,221,283	43,235,463	10.69%	4,502,901
49		1975	1,690,650	4.461%	7,541,989	5,851,339	2,220,642	45,456,105	10.69%	4,740,309
50		1976	1,690,650	4.462%	7,543,679	5,853,030	2,221,283	47,677,388	10.69%	4,977,717
51		1977	1,690,650	4.461%	7,541,989	5,851,339	2,220,642	49,898,030	10.69%	5,215,125
52		1978	1,690,650	2.231%	3,771,840	2,081,190	789,832	50,687,862	10.69%	5,376,026
53		1979	1,690,650	0.000%	-	(1,690,650)	(641,619)	50,046,244	10.69%	5,383,948
54		1980	1,690,650	0.000%	-	(1,690,650)	(641,619)	49,404,625	10.69%	5,315,363
55		1981	1,690,650	0.000%	-	(1,690,650)	(641,619)	48,763,007	10.69%	5,246,777
56		1982	1,690,650	0.000%	-	(1,690,650)	(641,619)	48,121,388	10.69%	5,178,192
57		1983	1,690,650	0.000%	-	(1,690,650)	(641,619)	47,479,770	10.69%	5,109,607
58		1984	1,690,650	0.000%	-	(1,690,650)	(641,619)	46,838,151	10.69%	5,041,021
59		1985	1,690,650	0.000%	-	(1,690,650)	(641,619)	46,196,533	10.69%	4,972,436
60		1986	1,690,650	0.000%	-	(1,690,650)	(641,619)	45,554,914	10.69%	4,903,851
61		1987	1,690,650	0.000%	-	(1,690,650)	(641,619)	44,913,296	10.69%	4,835,265
62		1988	1,690,650	0.000%	-	(1,690,650)	(641,619)	44,271,677	10.69%	4,766,680
63		1989	1,690,650	0.000%	-	(1,690,650)	(641,619)	43,630,059	10.69%	4,698,095
64		1990	1,690,650	0.000%	-	(1,690,650)	(641,619)	42,988,440	10.69%	4,629,509
65		1991	1,690,650	0.000%	-	(1,690,650)	(641,619)	42,346,822	10.69%	4,560,924
66		1992	1,690,650	0.000%	-	(1,690,650)	(641,619)	41,705,203	10.69%	4,492,339
67		1993	1,690,650	0.000%	-	(1,690,650)	(641,619)	41,063,585	10.69%	4,423,753
68		1994	1,690,650	0.000%	-	(1,690,650)	(641,619)	40,421,966	10.69%	4,355,168
69		1995	1,690,650	0.000%	-	(1,690,650)	(641,619)	39,780,348	10.69%	4,286,583
70		1996	1,690,650	0.000%	-	(1,690,650)	(641,619)	39,138,729	10.69%	4,217,997
71		1997	1,690,650	0.000%	-	(1,690,650)	(641,619)	38,497,111	10.69%	4,149,412
72		1998	1,690,650	0.000%	-	(1,690,650)	(641,619)	37,855,492	10.69%	4,080,827
73		1999	1,690,650	0.000%	-	(1,690,650)	(641,619)	37,213,874	10.69%	4,012,241
74		2000	1,690,650	0.000%	-	(1,690,650)	(641,619)	36,572,255	10.69%	3,943,656
75		2001	1,690,650	0.000%	-	(1,690,650)	(641,619)	35,930,637	10.69%	3,875,071
76		2002	1,690,650	0.000%	-	(1,690,650)	(641,619)	35,289,018	10.69%	3,806,486
77		2003	1,690,650	0.000%	-	(1,690,650)	(641,619)	34,647,400	10.69%	3,737,900
78		2004	1,690,650	0.000%	-	(1,690,650)	(641,619)	34,005,781	10.69%	3,669,315
79		2005	1,690,650	0.000%	-	(1,690,650)	(641,619)	33,364,163	10.69%	3,600,730
80		2006	1,690,650	0.000%	-	(1,690,650)	(641,619)	32,722,544	10.69%	3,532,144
81		2007	1,690,650	0.000%	-	(1,690,650)	(641,619)	32,080,926	10.69%	3,463,559
82		2008	1,690,650	0.000%	-	(1,690,650)	(641,619)	31,439,307	10.69%	3,394,974
83		2009	1,690,650	0.000%	-	(1,690,650)	(641,619)	30,797,689	10.69%	3,326,388
84		2010	1,690,650	0.000%	-	(1,690,650)	(641,619)	30,156,070	10.69%	3,257,803

85		2011	1,690,650	0.000%	-	(1,690,650)	(641,619)	29,514,452	10.69%	3,189,218
86		2012	1,690,650	0.000%	-	(1,690,650)	(641,619)	28,872,833	10.69%	3,120,632
87		2013	1,690,650	0.000%	-	(1,690,650)	(641,619)	28,231,215	10.69%	3,052,047
88		2014	1,690,650	0.000%	-	(1,690,650)	(641,619)	27,589,596	10.69%	2,983,462
89		2015	1,690,650	0.000%	-	(1,690,650)	(641,619)	26,947,977	10.69%	2,914,876
90		2016	1,690,650	0.000%	-	(1,690,650)	(641,619)	26,306,359	10.69%	2,846,291
91		2017	1,690,650	0.000%	-	(1,690,650)	(641,619)	25,664,740	10.69%	2,777,706
92		2018	1,690,650	0.000%		(1,690,650)	(641,619)	25,023,122	9.22%	2,337,724
93		2019	1,690,650	0.000%		(1,690,650)	(641,619)	24,381,503	9.22%	2,278,541
94		2020	1,690,650	0.000%		(1,690,650)	(641,619)	23,739,885	9.22%	2,219,358
95		2021	1,690,650	0.000%		(1,690,650)	(641,619)	23,098,266	9.22%	2,160,175
96		2022	1,690,650	0.000%		(1,690,650)	(641,619)	22,456,648	9.22%	2,100,992
97		2023	1,690,650	0.000%		(1,690,650)	(641,619)	21,815,029	9.22%	2,041,810
98		2024	1,690,650	0.000%		(1,690,650)	(641,619)	21,173,411	9.22%	1,982,627
99		2025	1,690,650	0.000%		(1,690,650)	(641,619)	20,531,792	9.22%	1,923,444
100		2026	1,690,650	0.000%		(1,690,650)	(641,619)	19,890,174	9.22%	1,864,261
101		2027	1,690,650	0.000%		(1,690,650)	(641,619)	19,248,555	9.22%	1,805,078
102		2028	1,690,650	0.000%		(1,690,650)	(641,619)	18,606,937	9.22%	1,745,895
103		2029	1,690,650	0.000%		(1,690,650)	(641,619)	17,965,318	9.22%	1,686,712
104		2030	1,690,650	0.000%		(1,690,650)	(641,619)	17,323,700	9.22%	1,627,529
105		2031	1,690,650	0.000%		(1,690,650)	(641,619)	16,682,081	9.22%	1,568,346
106		2032	1,690,650	0.000%		(1,690,650)	(641,619)	16,040,463	9.22%	1,509,164
107		2033	1,690,650	0.000%		(1,690,650)	(641,619)	15,398,844	9.22%	1,449,981
108		2034	1,690,650	0.000%		(1,690,650)	(641,619)	14,757,226	9.22%	1,390,798
109		2035	1,690,650	0.000%		(1,690,650)	(641,619)	14,115,607	9.22%	1,331,615
110		2036	1,690,650	0.000%		(1,690,650)	(641,619)	13,473,989	9.22%	1,272,432
111		2037	1,690,650	0.000%		(1,690,650)	(641,619)	12,832,370	9.22%	1,213,249
112		2038	1,690,650	0.000%		(1,690,650)	(641,619)	12,190,752	9.22%	1,154,066
113		2039	1,690,650	0.000%		(1,690,650)	(641,619)	11,549,133	9.22%	1,094,883
114		2040	1,690,650	0.000%		(1,690,650)	(641,619)	10,907,515	9.22%	1,035,700
115		2041	1,690,650	0.000%		(1,690,650)	(641,619)	10,265,896	9.22%	976,518
116		2042	1,690,650	0.000%	-	(1,690,650)	(641,619)	9,624,278	9.22%	917,335
117		2043	1,690,650	0.000%	-	(1,690,650)	(641,619)	8,982,659	9.22%	858,152
118		2044	1,690,650	0.000%	-	(1,690,650)	(641,619)	8,341,041	9.22%	798,969
119		2045	1,690,650	0.000%	-	(1,690,650)	(641,619)	7,699,422	9.22%	739,786
120		2046	1,690,650	0.000%	-	(1,690,650)	(641,619)	7,057,804	9.22%	680,603
121		2047	1,690,650	0.000%	-	(1,690,650)	(641,619)	6,416,185	9.22%	621,420
122		2048	1,690,650	0.000%	-	(1,690,650)	(641,619)	5,774,567	9.22%	562,237
123		2049	1,690,650	0.000%	-	(1,690,650)	(641,619)	5,132,948	9.22%	503,055
124		2050	1,690,650	0.000%	-	(1,690,650)	(641,619)	4,491,330	9.22%	443,872
125		2051	1,690,650	0.000%	-	(1,690,650)	(641,619)	3,849,711	9.22%	384,689
126		2052	1,690,650	0.000%	-	(1,690,650)	(641,619)	3,208,093	9.22%	325,506
127		2053	1,690,650	0.000%	-	(1,690,650)	(641,619)	2,566,474	9.22%	266,323
128		2054	1,690,650	0.000%	-	(1,690,650)	(641,619)	1,924,856	9.22%	207,140
129		2055	1,690,650	0.000%	-	(1,690,650)	(641,619)	1,283,237	9.22%	147,957
130		2056	1,690,650	0.000%		(1,690,650)	(641,619)	641,619	9.22%	88,774
131		2057	1,690,650	0.000%	-	(1,690,650)	(641,619)	0	9.22%	29,591
132			$ 169,064,982	100%	$ 169,064,982	$ (0)	$ 0			$ 269,100,289

Facility Name Lemolo **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	4,320,547
2	RP Capability Allocator	RP and BOP Allocators	9.75%
3	**RP - Generator/Exciter**	(Line 1 * 2)	421,253
4			
5	GSU Transformer	Summary Investment	3,777,087
6	RP Capability Allocator	RP and BOP Allocators	9.75%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	368,266
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	2,554,803
10	Real and Reactive Power Portion	Summary Investment	2,554,803
11	RP Capability Allocator	RP and BOP Allocators	9.75%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	249,093
13	Total Plant Investment	Summary Investment	79,134,237
14	Balance of Plant	(Line 13 - 12 - 5 - 1)	68,481,799
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	18,355
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	1,056,968
18	RP Fixed Charge Percent	(Line 11(h))	12.7955%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 135,244**

	Depreciation			
20	Annual Depreciation Expense (D)	$	2,534,063	
21	Gross Plant Investment (F)		79,134,237	(Line 14)
22	SLDP=DE/F		3.2022%	(Line 20 / 21)
23	Depreciable years =1/SLDP		31	
24	Book Life (n)		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
	Income Tax Factor to Include in Fixed Charge		
27	Factor	1.4525%	Based Upon Book Life
	[(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]		CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 2,523,146	$ 79,134,237	3.1884%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0409%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.0056%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.4525%	
	ADIT	Line 31(i)	(1,300,069)	79,134,237	-1.6429%	
	Total RP Fixed Charge Percent				12.7955%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 79,134,237	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$17,204,882
31	In Service Year	1956	1955-1956			Levelized Revenue Requirement			1,300,069
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1956	$ 791,342	3.750%	$ 2,967,534	$ 2,176,192	$ 825,886	$ 825,886	10.69%	$ 44,141
33	1957	791,342	7.219%	5,712,701	4,921,358	1,867,705	2,693,591	10.69%	188,106
34	1958	791,342	6.677%	5,283,793	4,492,451	1,704,930	4,398,521	10.69%	379,053
35	1959	791,342	6.177%	4,888,122	4,096,779	1,554,769	5,953,290	10.69%	553,274
36	1960	791,342	5.713%	4,520,939	3,729,597	1,415,419	7,368,709	10.69%	712,022
37	1961	791,342	5.285%	4,182,244	3,390,902	1,286,881	8,655,590	10.69%	856,453
38	1962	791,342	4.888%	3,868,082	3,076,739	1,167,653	9,823,244	10.69%	987,640
39	1963	791,342	4.522%	3,578,450	2,787,108	1,057,735	10,880,979	10.69%	1,106,581
40	1964	791,342	4.462%	3,530,970	2,739,627	1,039,716	11,920,695	10.69%	1,218,684
41	1965	791,342	4.461%	3,530,178	2,738,836	1,039,416	12,960,110	10.69%	1,329,807
42	1966	791,342	4.462%	3,530,970	2,739,627	1,039,716	13,999,826	10.69%	1,440,931
43	1967	791,342	4.461%	3,530,178	2,738,836	1,039,416	15,039,242	10.69%	1,552,055
44	1968	791,342	4.462%	3,530,970	2,739,627	1,039,716	16,078,958	10.69%	1,663,178
45	1969	791,342	4.461%	3,530,178	2,738,836	1,039,416	17,118,374	10.69%	1,774,302
46	1970	791,342	4.462%	3,530,970	2,739,627	1,039,716	18,158,089	10.69%	1,885,425
47	1971	791,342	4.461%	3,530,178	2,738,836	1,039,416	19,197,505	10.69%	1,996,549
48	1972	791,342	4.462%	3,530,970	2,739,627	1,039,716	20,237,221	10.69%	2,107,673
49	1973	791,342	4.461%	3,530,178	2,738,836	1,039,416	21,276,637	10.69%	2,218,796
50	1974	791,342	4.462%	3,530,970	2,739,627	1,039,716	22,316,353	10.69%	2,329,920
51	1975	791,342	4.461%	3,530,178	2,738,836	1,039,416	23,355,768	10.69%	2,441,043
52	1976	791,342	2.231%	1,765,485	974,142	369,697	23,725,465	10.69%	2,516,356
53	1977	791,342	0.000%	-	(791,342)	(300,322)	23,425,143	10.69%	2,520,064
54	1978	791,342	0.000%	-	(791,342)	(300,322)	23,124,820	10.69%	2,487,962
55	1979	791,342	0.000%	-	(791,342)	(300,322)	22,824,498	10.69%	2,455,859
56	1980	791,342	0.000%	-	(791,342)	(300,322)	22,524,176	10.69%	2,423,756
57	1981	791,342	0.000%	-	(791,342)	(300,322)	22,223,853	10.69%	2,391,653
58	1982	791,342	0.000%	-	(791,342)	(300,322)	21,923,531	10.69%	2,359,551
59	1983	791,342	0.000%	-	(791,342)	(300,322)	21,623,209	10.69%	2,327,448
60	1984	791,342	0.000%	-	(791,342)	(300,322)	21,322,886	10.69%	2,295,345
61	1985	791,342	0.000%	-	(791,342)	(300,322)	21,022,564	10.69%	2,263,242
62	1986	791,342	0.000%	-	(791,342)	(300,322)	20,722,242	10.69%	2,231,140
63	1987	791,342	0.000%	-	(791,342)	(300,322)	20,421,919	10.69%	2,199,037
64	1988	791,342	0.000%	-	(791,342)	(300,322)	20,121,597	10.69%	2,166,934
65	1989	791,342	0.000%	-	(791,342)	(300,322)	19,821,275	10.69%	2,134,831
66	1990	791,342	0.000%	-	(791,342)	(300,322)	19,520,952	10.69%	2,102,729
67	1991	791,342	0.000%	-	(791,342)	(300,322)	19,220,630	10.69%	2,070,626
68	1992	791,342	0.000%	-	(791,342)	(300,322)	18,920,308	10.69%	2,038,523
69	1993	791,342	0.000%	-	(791,342)	(300,322)	18,619,985	10.69%	2,006,421
70	1994	791,342	0.000%	-	(791,342)	(300,322)	18,319,663	10.69%	1,974,318
71	1995	791,342	0.000%	-	(791,342)	(300,322)	18,019,341	10.69%	1,942,215
72	1996	791,342	0.000%	-	(791,342)	(300,322)	17,719,018	10.69%	1,910,112
73	1997	791,342	0.000%	-	(791,342)	(300,322)	17,418,696	10.69%	1,878,010
74	1998	791,342	0.000%	-	(791,342)	(300,322)	17,118,374	10.69%	1,845,907
75	1999	791,342	0.000%	-	(791,342)	(300,322)	16,818,051	10.69%	1,813,804
76	2000	791,342	0.000%	-	(791,342)	(300,322)	16,517,729	10.69%	1,781,701
77	2001	791,342	0.000%	-	(791,342)	(300,322)	16,217,407	10.69%	1,749,599
78	2002	791,342	0.000%	-	(791,342)	(300,322)	15,917,084	10.69%	1,717,496
79	2003	791,342	0.000%	-	(791,342)	(300,322)	15,616,762	10.69%	1,685,393
80	2004	791,342	0.000%	-	(791,342)	(300,322)	15,316,439	10.69%	1,653,291
81	2005	791,342	0.000%	-	(791,342)	(300,322)	15,016,117	10.69%	1,621,188
82	2006	791,342	0.000%	-	(791,342)	(300,322)	14,715,795	10.69%	1,589,085
83	2007	791,342	0.000%	-	(791,342)	(300,322)	14,415,472	10.69%	1,556,982
84	2008	791,342	0.000%	-	(791,342)	(300,322)	14,115,150	10.69%	1,524,880

85	2009	791,342	0.000%	-	(791,342)	(300,322)	13,814,828	10.69%	1,492,777
86	2010	791,342	0.000%	-	(791,342)	(300,322)	13,514,505	10.69%	1,460,674
87	2011	791,342	0.000%	-	(791,342)	(300,322)	13,214,183	10.69%	1,428,571
88	2012	791,342	0.000%	-	(791,342)	(300,322)	12,913,861	10.69%	1,396,469
89	2013	791,342	0.000%	-	(791,342)	(300,322)	12,613,538	10.69%	1,364,366
90	2014	791,342	0.000%	-	(791,342)	(300,322)	12,313,216	10.69%	1,332,263
91	2015	791,342	0.000%	-	(791,342)	(300,322)	12,012,894	10.69%	1,300,161
92	2016	791,342	0.000%	-	(791,342)	(300,322)	11,712,571	10.69%	1,268,058
93	2017	791,342	0.000%	-	(791,342)	(300,322)	11,412,249	10.69%	1,235,955
94	2018	791,342	0.000%	-	(791,342)	(300,322)	11,111,927	9.22%	1,038,815
95	2019	791,342	0.000%	-	(791,342)	(300,322)	10,811,604	9.22%	1,011,113
96	2020	791,342	0.000%	-	(791,342)	(300,322)	10,511,282	9.22%	983,411
97	2021	791,342	0.000%	-	(791,342)	(300,322)	10,210,960	9.22%	955,710
98	2022	791,342	0.000%	-	(791,342)	(300,322)	9,910,637	9.22%	928,008
99	2023	791,342	0.000%	-	(791,342)	(300,322)	9,610,315	9.22%	900,306
100	2024	791,342	0.000%	-	(791,342)	(300,322)	9,309,993	9.22%	872,604
101	2025	791,342	0.000%	-	(791,342)	(300,322)	9,009,670	9.22%	844,903
102	2026	791,342	0.000%	-	(791,342)	(300,322)	8,709,348	9.22%	817,201
103	2027	791,342	0.000%	-	(791,342)	(300,322)	8,409,026	9.22%	789,499
104	2028	791,342	0.000%	-	(791,342)	(300,322)	8,108,703	9.22%	761,798
105	2029	791,342	0.000%	-	(791,342)	(300,322)	7,808,381	9.22%	734,096
106	2030	791,342	0.000%	-	(791,342)	(300,322)	7,508,059	9.22%	706,394
107	2031	791,342	0.000%	-	(791,342)	(300,322)	7,207,736	9.22%	678,692
108	2032	791,342	0.000%	-	(791,342)	(300,322)	6,907,414	9.22%	650,991
109	2033	791,342	0.000%	-	(791,342)	(300,322)	6,607,092	9.22%	623,289
110	2034	791,342	0.000%	-	(791,342)	(300,322)	6,306,769	9.22%	595,587
111	2035	791,342	0.000%	-	(791,342)	(300,322)	6,006,447	9.22%	567,885
112	2036	791,342	0.000%	-	(791,342)	(300,322)	5,706,125	9.22%	540,184
113	2037	791,342	0.000%	-	(791,342)	(300,322)	5,405,802	9.22%	512,482
114	2038	791,342	0.000%	-	(791,342)	(300,322)	5,105,480	9.22%	484,780
115	2039	791,342	0.000%	-	(791,342)	(300,322)	4,805,157	9.22%	457,079
116	2040	791,342	0.000%	-	(791,342)	(300,322)	4,504,835	9.22%	429,377
117	2041	791,342	0.000%	-	(791,342)	(300,322)	4,204,513	9.22%	401,675
118	2042	791,342	0.000%	-	(791,342)	(300,322)	3,904,190	9.22%	373,973
119	2043	791,342	0.000%	-	(791,342)	(300,322)	3,603,868	9.22%	346,272
120	2044	791,342	0.000%	-	(791,342)	(300,322)	3,303,546	9.22%	318,570
121	2045	791,342	0.000%	-	(791,342)	(300,322)	3,003,223	9.22%	290,868
122	2046	791,342	0.000%	-	(791,342)	(300,322)	2,702,901	9.22%	263,166
123	2047	791,342	0.000%	-	(791,342)	(300,322)	2,402,579	9.22%	235,465
124	2048	791,342	0.000%	-	(791,342)	(300,322)	2,102,256	9.22%	207,763
125	2049	791,342	0.000%	-	(791,342)	(300,322)	1,801,934	9.22%	180,061
126	2050	791,342	0.000%	-	(791,342)	(300,322)	1,501,612	9.22%	152,360
127	2051	791,342	0.000%	-	(791,342)	(300,322)	1,201,289	9.22%	124,658
128	2052	791,342	0.000%	-	(791,342)	(300,322)	900,967	9.22%	96,956
129	2053	791,342	0.000%	-	(791,342)	(300,322)	600,645	9.22%	69,254
130	2054	791,342	0.000%	-	(791,342)	(300,322)	300,322	9.22%	41,553
131	2055	791,342	0.000%	-	(791,342)	(300,322)	(0)	9.22%	13,851
132		$ 79,134,237		100% $ 79,134,237	$ (0)	$ (0)			$ 126,301,036

Facility Name Toketee **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	2,641,918
2	RP Capability Allocator	RP and BOP Allocators	27.75%
3	**RP - Generator/Exciter**	(Line 1 * 2)	733,132
4			
5	GSU Transformer	Summary Investment	354,719
6	RP Capability Allocator	RP and BOP Allocators	27.75%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	98,435
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	1,036,967
10	Real and Reactive Power Portion	Summary Investment	1,036,967
11	RP Capability Allocator	RP and BOP Allocators	27.75%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	287,758
13	Total Plant Investment	Summary Investment	24,132,441
14	Balance of Plant	(Line 13 - 12 - 5 - 1)	20,098,838
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	5,387
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	1,124,712
18	RP Fixed Charge Percent	(Line 11(h))	15.3059%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 172,148**

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 1,368,696	$ 24,132,441	5.6716%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0689%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.0056%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.4525%	
	ADIT	Line 31(i)	(396,624)	24,132,441	-1.6435%	
	Total RP Fixed Charge Percent				15.3059%	

	Depreciation			
20	Annual Depreciation Expense (D)	$	758,952	
21	Gross Plant Investment (F)		24,132,441	(Line 14)
22	SLDP=DE/F		3.1449%	(Line 20 / 21)
23	Depreciable years =1/SLDP		32	
24	Book Life (n)		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.4525%	Based Upon Book Life CTR=Composite Tax Rate

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 24,132,441	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$5,248,846
31	In Service Year	1950	1949-1950			Levelized Revenue Requirement			396,624
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1950	$ 241,324	3.750%	$ 904,967	$ 663,642	$ 251,859	$ 251,859	10.69%	$ 13,461
33	1951	241,324	7.219%	1,742,121	1,500,797	569,567	821,426	10.69%	57,364
34	1952	241,324	6.677%	1,611,323	1,369,999	519,928	1,341,354	10.69%	115,594
35	1953	241,324	6.177%	1,490,661	1,249,336	474,136	1,815,490	10.69%	168,724
36	1954	241,324	5.713%	1,378,686	1,137,362	431,640	2,247,130	10.69%	217,135
37	1955	241,324	5.285%	1,275,400	1,034,075	392,442	2,639,572	10.69%	261,180
38	1956	241,324	4.888%	1,179,594	938,269	356,083	2,995,655	10.69%	301,187
39	1957	241,324	4.522%	1,091,269	849,945	322,562	3,318,217	10.69%	337,458
40	1958	241,324	4.462%	1,076,790	835,465	317,067	3,635,284	10.69%	371,645
41	1959	241,324	4.461%	1,076,548	835,224	316,976	3,952,260	10.69%	405,532
42	1960	241,324	4.462%	1,076,790	835,465	317,067	4,269,328	10.69%	439,420
43	1961	241,324	4.461%	1,076,548	835,224	316,976	4,586,303	10.69%	473,308
44	1962	241,324	4.462%	1,076,790	835,465	317,067	4,903,371	10.69%	507,196
45	1963	241,324	4.461%	1,076,548	835,224	316,976	5,220,347	10.69%	541,084
46	1964	241,324	4.462%	1,076,790	835,465	317,067	5,537,414	10.69%	574,971
47	1965	241,324	4.461%	1,076,548	835,224	316,976	5,854,390	10.69%	608,859
48	1966	241,324	4.462%	1,076,790	835,465	317,067	6,171,457	10.69%	642,747
49	1967	241,324	4.461%	1,076,548	835,224	316,976	6,488,433	10.69%	676,635
50	1968	241,324	4.462%	1,076,790	835,465	317,067	6,805,500	10.69%	710,522
51	1969	241,324	4.461%	1,076,548	835,224	316,976	7,122,476	10.69%	744,410
52	1970	241,324	2.231%	538,395	297,070	112,741	7,235,217	10.69%	767,377
53	1971	241,324	0.000%	-	(241,324)	(91,585)	7,143,632	10.69%	768,508
54	1972	241,324	0.000%	-	(241,324)	(91,585)	7,052,047	10.69%	758,718
55	1973	241,324	0.000%	-	(241,324)	(91,585)	6,960,462	10.69%	748,928
56	1974	241,324	0.000%	-	(241,324)	(91,585)	6,868,877	10.69%	739,138
57	1975	241,324	0.000%	-	(241,324)	(91,585)	6,777,292	10.69%	729,348
58	1976	241,324	0.000%	-	(241,324)	(91,585)	6,685,707	10.69%	719,559
59	1977	241,324	0.000%	-	(241,324)	(91,585)	6,594,122	10.69%	709,769
60	1978	241,324	0.000%	-	(241,324)	(91,585)	6,502,537	10.69%	699,979
61	1979	241,324	0.000%	-	(241,324)	(91,585)	6,410,952	10.69%	690,189
62	1980	241,324	0.000%	-	(241,324)	(91,585)	6,319,367	10.69%	680,399
63	1981	241,324	0.000%	-	(241,324)	(91,585)	6,227,782	10.69%	670,609
64	1982	241,324	0.000%	-	(241,324)	(91,585)	6,136,197	10.69%	660,819
65	1983	241,324	0.000%	-	(241,324)	(91,585)	6,044,612	10.69%	651,029
66	1984	241,324	0.000%	-	(241,324)	(91,585)	5,953,027	10.69%	641,239
67	1985	241,324	0.000%	-	(241,324)	(91,585)	5,861,442	10.69%	631,449
68	1986	241,324	0.000%	-	(241,324)	(91,585)	5,769,857	10.69%	621,659
69	1987	241,324	0.000%	-	(241,324)	(91,585)	5,678,272	10.69%	611,870
70	1988	241,324	0.000%	-	(241,324)	(91,585)	5,586,687	10.69%	602,080
71	1989	241,324	0.000%	-	(241,324)	(91,585)	5,495,102	10.69%	592,290
72	1990	241,324	0.000%	-	(241,324)	(91,585)	5,403,517	10.69%	582,500
73	1991	241,324	0.000%	-	(241,324)	(91,585)	5,311,932	10.69%	572,710
74	1992	241,324	0.000%	-	(241,324)	(91,585)	5,220,347	10.69%	562,920
75	1993	241,324	0.000%	-	(241,324)	(91,585)	5,128,762	10.69%	553,130
76	1994	241,324	0.000%	-	(241,324)	(91,585)	5,037,177	10.69%	543,340
77	1995	241,324	0.000%	-	(241,324)	(91,585)	4,945,591	10.69%	533,550
78	1996	241,324	0.000%	-	(241,324)	(91,585)	4,854,006	10.69%	523,760
79	1997	241,324	0.000%	-	(241,324)	(91,585)	4,762,421	10.69%	513,970
80	1998	241,324	0.000%	-	(241,324)	(91,585)	4,670,836	10.69%	504,180
81	1999	241,324	0.000%	-	(241,324)	(91,585)	4,579,251	10.69%	494,391
82	2000	241,324	0.000%	-	(241,324)	(91,585)	4,487,666	10.69%	484,601
83	2001	241,324	0.000%	-	(241,324)	(91,585)	4,396,081	10.69%	474,811
84	2002	241,324	0.000%	-	(241,324)	(91,585)	4,304,496	10.69%	465,021

85	2003	241,324	0.000%	-	(241,324)	(91,585)	4,212,911	10.69%	455,231
86	2004	241,324	0.000%	-	(241,324)	(91,585)	4,121,326	10.69%	445,441
87	2005	241,324	0.000%	-	(241,324)	(91,585)	4,029,741	10.69%	435,651
88	2006	241,324	0.000%	-	(241,324)	(91,585)	3,938,156	10.69%	425,861
89	2007	241,324	0.000%	-	(241,324)	(91,585)	3,846,571	10.69%	416,071
90	2008	241,324	0.000%	-	(241,324)	(91,585)	3,754,986	10.69%	406,281
91	2009	241,324	0.000%	-	(241,324)	(91,585)	3,663,401	10.69%	396,491
92	2010	241,324	0.000%	-	(241,324)	(91,585)	3,571,816	10.69%	386,702
93	2011	241,324	0.000%	-	(241,324)	(91,585)	3,480,231	10.69%	376,912
94	2012	241,324	0.000%	-	(241,324)	(91,585)	3,388,646	10.69%	367,122
95	2013	241,324	0.000%	-	(241,324)	(91,585)	3,297,061	10.69%	357,332
96	2014	241,324	0.000%	-	(241,324)	(91,585)	3,205,476	10.69%	347,542
97	2015	241,324	0.000%	-	(241,324)	(91,585)	3,113,891	10.69%	337,752
98	2016	241,324	0.000%	-	(241,324)	(91,585)	3,022,306	10.69%	327,962
99	2017	241,324	0.000%	-	(241,324)	(91,585)	2,930,721	9.22%	274,554
100	2018	241,324	0.000%	-	(241,324)	(91,585)	2,839,136	9.22%	266,106
101	2019	241,324	0.000%	-	(241,324)	(91,585)	2,747,551	9.22%	257,658
102	2020	241,324	0.000%	-	(241,324)	(91,585)	2,655,966	9.22%	249,210
103	2021	241,324	0.000%	-	(241,324)	(91,585)	2,564,381	9.22%	240,762
104	2022	241,324	0.000%	-	(241,324)	(91,585)	2,472,796	9.22%	232,315
105	2023	241,324	0.000%	-	(241,324)	(91,585)	2,381,211	9.22%	223,867
106	2024	241,324	0.000%	-	(241,324)	(91,585)	2,289,626	9.22%	215,419
107	2025	241,324	0.000%	-	(241,324)	(91,585)	2,198,041	9.22%	206,971
108	2026	241,324	0.000%	-	(241,324)	(91,585)	2,106,456	9.22%	198,523
109	2027	241,324	0.000%	-	(241,324)	(91,585)	2,014,871	9.22%	190,076
110	2028	241,324	0.000%	-	(241,324)	(91,585)	1,923,286	9.22%	181,628
111	2029	241,324	0.000%	-	(241,324)	(91,585)	1,831,701	9.22%	173,180
112	2030	241,324	0.000%	-	(241,324)	(91,585)	1,740,116	9.22%	164,732
113	2031	241,324	0.000%	-	(241,324)	(91,585)	1,648,530	9.22%	156,284
114	2032	241,324	0.000%	-	(241,324)	(91,585)	1,556,945	9.22%	147,837
115	2033	241,324	0.000%	-	(241,324)	(91,585)	1,465,360	9.22%	139,389
116	2034	241,324	0.000%	-	(241,324)	(91,585)	1,373,775	9.22%	130,941
117	2035	241,324	0.000%	-	(241,324)	(91,585)	1,282,190	9.22%	122,493
118	2036	241,324	0.000%	-	(241,324)	(91,585)	1,190,605	9.22%	114,045
119	2037	241,324	0.000%	-	(241,324)	(91,585)	1,099,020	9.22%	105,598
120	2038	241,324	0.000%	-	(241,324)	(91,585)	1,007,435	9.22%	97,150
121	2039	241,324	0.000%	-	(241,324)	(91,585)	915,850	9.22%	88,702
122	2040	241,324	0.000%	-	(241,324)	(91,585)	824,265	9.22%	80,254
123	2041	241,324	0.000%	-	(241,324)	(91,585)	732,680	9.22%	71,806
124	2042	241,324	0.000%	-	(241,324)	(91,585)	641,095	9.22%	63,359
125	2043	241,324	0.000%	-	(241,324)	(91,585)	549,510	9.22%	54,911
126	2044	241,324	0.000%	-	(241,324)	(91,585)	457,925	9.22%	46,463
127	2045	241,324	0.000%	-	(241,324)	(91,585)	366,340	9.22%	38,015
128	2046	241,324	0.000%	-	(241,324)	(91,585)	274,755	9.22%	29,567
129	2047	241,324	0.000%	-	(241,324)	(91,585)	183,170	9.22%	21,120
130	2048	241,324	0.000%	-	(241,324)	(91,585)	91,585	9.22%	12,672
131	2049	241,324	0.000%	-	(241,324)	(91,585)	0	9.22%	4,224
132		$ 24,132,441		100% $ 24,132,441	$ 0	$ 0			$ 38,754,453

Facility Name Slide Creek **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	552,027
2	RP Capability Allocator	RP and BOP Allocators	27.75%
3	**RP - Generator/Exciter**	(Line 1 * 2)	153,187
4			
5	GSU Transformer	Summary Investment	1,559,207
6	RP Capability Allocator	RP and BOP Allocators	27.75%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	432,680
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	3,256,965
10	Real and Reactive Power Portion	Summary Investment	2,494,839
11	RP Capability Allocator	RP and BOP Allocators	27.75%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	692,318
13	Total Plant Investment	Summary Investment	26,787,264
14	Balance of Plant	(Line 13 - 12 - 5 - 1)	22,181,192
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	5,945
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	1,284,130
18	RP Fixed Charge Percent	(Line 11(h))	11.9439%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 153,375**

	Depreciation			
20	Annual Depreciation Expense (D)	$	868,668	
21	Gross Plant Investment (F)		26,787,264	(Line 14)
22	SLDP=DE/F		3.2428%	(Line 20 / 21)
23	Depreciable years =1/SLDP		31	
24	Book Life (n)		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
	Income Tax Factor to Include in Fixed Charge		
27	Factor	1.4525%	Based Upon Book Life
	[(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]		CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 628,692	$ 26,787,264	2.3470%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0315%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.0056%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.4525%	
	ADIT	Line 31(i)	(440,256)	26,787,264	-1.6435%	
	Total RP Fixed Charge Percent				11.9439%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 26,787,264	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$5,826,275
31	In Service Year	1951				Levelized Revenue Requirement			440,256
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1951	$ 267,873	3.750%	$ 1,004,522	$ 736,650	$ 279,566	$ 279,566	10.69%	$ 14,942
33	1952	267,873	7.219%	1,933,773	1,665,900	632,226	911,792	10.69%	63,675
34	1953	267,873	6.677%	1,788,586	1,520,713	577,126	1,488,917	10.69%	128,311
35	1954	267,873	6.177%	1,654,649	1,386,777	526,296	2,015,213	10.69%	187,286
36	1955	267,873	5.713%	1,530,356	1,262,484	479,125	2,494,338	10.69%	241,023
37	1956	267,873	5.285%	1,415,707	1,147,834	435,615	2,929,953	10.69%	289,913
38	1957	267,873	4.888%	1,309,361	1,041,489	395,255	3,325,208	10.69%	334,320
39	1958	267,873	4.522%	1,211,320	943,447	358,048	3,683,256	10.69%	374,582
40	1959	267,873	4.462%	1,195,248	927,375	351,948	4,035,204	10.69%	412,529
41	1960	267,873	4.461%	1,194,980	927,107	351,846	4,387,051	10.69%	450,145
42	1961	267,873	4.462%	1,195,248	927,375	351,948	4,738,999	10.69%	487,761
43	1962	267,873	4.461%	1,194,980	927,107	351,846	5,090,845	10.69%	525,377
44	1963	267,873	4.462%	1,195,248	927,375	351,948	5,442,793	10.69%	562,993
45	1964	267,873	4.461%	1,194,980	927,107	351,846	5,794,640	10.69%	600,608
46	1965	267,873	4.462%	1,195,248	927,375	351,948	6,146,588	10.69%	638,224
47	1966	267,873	4.461%	1,194,980	927,107	351,846	6,498,434	10.69%	675,840
48	1967	267,873	4.462%	1,195,248	927,375	351,948	6,850,382	10.69%	713,456
49	1968	267,873	4.461%	1,194,980	927,107	351,846	7,202,229	10.69%	751,072
50	1969	267,873	4.462%	1,195,248	927,375	351,948	7,554,177	10.69%	788,687
51	1970	267,873	4.461%	1,194,980	927,107	351,846	7,906,023	10.69%	826,303
52	1971	267,873	2.231%	597,624	329,751	125,144	8,031,167	10.69%	851,797
53	1972	267,873	0.000%	-	(267,873)	(101,660)	7,929,507	10.69%	853,052
54	1973	267,873	0.000%	-	(267,873)	(101,660)	7,827,847	10.69%	842,185
55	1974	267,873	0.000%	-	(267,873)	(101,660)	7,726,186	10.69%	831,318
56	1975	267,873	0.000%	-	(267,873)	(101,660)	7,624,526	10.69%	820,451
57	1976	267,873	0.000%	-	(267,873)	(101,660)	7,522,866	10.69%	809,584
58	1977	267,873	0.000%	-	(267,873)	(101,660)	7,421,205	10.69%	798,718
59	1978	267,873	0.000%	-	(267,873)	(101,660)	7,319,545	10.69%	787,851
60	1979	267,873	0.000%	-	(267,873)	(101,660)	7,217,885	10.69%	776,984
61	1980	267,873	0.000%	-	(267,873)	(101,660)	7,116,224	10.69%	766,117
62	1981	267,873	0.000%	-	(267,873)	(101,660)	7,014,564	10.69%	755,250
63	1982	267,873	0.000%	-	(267,873)	(101,660)	6,912,903	10.69%	744,383
64	1983	267,873	0.000%	-	(267,873)	(101,660)	6,811,243	10.69%	733,516
65	1984	267,873	0.000%	-	(267,873)	(101,660)	6,709,583	10.69%	722,649
66	1985	267,873	0.000%	-	(267,873)	(101,660)	6,607,922	10.69%	711,782
67	1986	267,873	0.000%	-	(267,873)	(101,660)	6,506,262	10.69%	700,915
68	1987	267,873	0.000%	-	(267,873)	(101,660)	6,404,602	10.69%	690,049
69	1988	267,873	0.000%	-	(267,873)	(101,660)	6,302,941	10.69%	679,182
70	1989	267,873	0.000%	-	(267,873)	(101,660)	6,201,281	10.69%	668,315
71	1990	267,873	0.000%	-	(267,873)	(101,660)	6,099,621	10.69%	657,448
72	1991	267,873	0.000%	-	(267,873)	(101,660)	5,997,960	10.69%	646,581
73	1992	267,873	0.000%	-	(267,873)	(101,660)	5,896,300	10.69%	635,714
74	1993	267,873	0.000%	-	(267,873)	(101,660)	5,794,640	10.69%	624,847
75	1994	267,873	0.000%	-	(267,873)	(101,660)	5,692,979	10.69%	613,980
76	1995	267,873	0.000%	-	(267,873)	(101,660)	5,591,319	10.69%	603,113
77	1996	267,873	0.000%	-	(267,873)	(101,660)	5,489,659	10.69%	592,246
78	1997	267,873	0.000%	-	(267,873)	(101,660)	5,387,998	10.69%	581,379
79	1998	267,873	0.000%	-	(267,873)	(101,660)	5,286,338	10.69%	570,513
80	1999	267,873	0.000%	-	(267,873)	(101,660)	5,184,678	10.69%	559,646
81	2000	267,873	0.000%	-	(267,873)	(101,660)	5,083,017	10.69%	548,779
82	2001	267,873	0.000%	-	(267,873)	(101,660)	4,981,357	10.69%	537,912
83	2002	267,873	0.000%	-	(267,873)	(101,660)	4,879,697	10.69%	527,045
84	2003	267,873	0.000%	-	(267,873)	(101,660)	4,778,036	10.69%	516,178

85	2004	267,873	0.000%	-	(267,873)	(101,660)	4,676,376	10.69%	505,311
86	2005	267,873	0.000%	-	(267,873)	(101,660)	4,574,716	10.69%	494,444
87	2006	267,873	0.000%	-	(267,873)	(101,660)	4,473,055	10.69%	483,577
88	2007	267,873	0.000%	-	(267,873)	(101,660)	4,371,395	10.69%	472,710
89	2008	267,873	0.000%	-	(267,873)	(101,660)	4,269,735	10.69%	461,843
90	2009	267,873	0.000%	-	(267,873)	(101,660)	4,168,074	10.69%	450,977
91	2010	267,873	0.000%	-	(267,873)	(101,660)	4,066,414	10.69%	440,110
92	2011	267,873	0.000%	-	(267,873)	(101,660)	3,964,753	10.69%	429,243
93	2012	267,873	0.000%	-	(267,873)	(101,660)	3,863,093	10.69%	418,376
94	2013	267,873	0.000%	-	(267,873)	(101,660)	3,761,433	10.69%	407,509
95	2014	267,873	0.000%	-	(267,873)	(101,660)	3,659,772	10.69%	396,642
96	2015	267,873	0.000%	-	(267,873)	(101,660)	3,558,112	10.69%	385,775
97	2016	267,873	0.000%	-	(267,873)	(101,660)	3,456,452	10.69%	374,908
98	2017	267,873	0.000%	-	(267,873)	(101,660)	3,354,791	10.69%	364,041
99	2018	267,873	0.000%	-	(267,873)	(101,660)	3,253,131	9.22%	304,757
100	2019	267,873	0.000%	-	(267,873)	(101,660)	3,151,471	9.22%	295,380
101	2020	267,873	0.000%	-	(267,873)	(101,660)	3,049,810	9.22%	286,003
102	2021	267,873	0.000%	-	(267,873)	(101,660)	2,948,150	9.22%	276,626
103	2022	267,873	0.000%	-	(267,873)	(101,660)	2,846,490	9.22%	267,249
104	2023	267,873	0.000%	-	(267,873)	(101,660)	2,744,829	9.22%	257,872
105	2024	267,873	0.000%	-	(267,873)	(101,660)	2,643,169	9.22%	248,494
106	2025	267,873	0.000%	-	(267,873)	(101,660)	2,541,509	9.22%	239,117
107	2026	267,873	0.000%	-	(267,873)	(101,660)	2,439,848	9.22%	229,740
108	2027	267,873	0.000%	-	(267,873)	(101,660)	2,338,188	9.22%	220,363
109	2028	267,873	0.000%	-	(267,873)	(101,660)	2,236,528	9.22%	210,986
110	2029	267,873	0.000%	-	(267,873)	(101,660)	2,134,867	9.22%	201,609
111	2030	267,873	0.000%	-	(267,873)	(101,660)	2,033,207	9.22%	192,232
112	2031	267,873	0.000%	-	(267,873)	(101,660)	1,931,547	9.22%	182,854
113	2032	267,873	0.000%	-	(267,873)	(101,660)	1,829,886	9.22%	173,477
114	2033	267,873	0.000%	-	(267,873)	(101,660)	1,728,226	9.22%	164,100
115	2034	267,873	0.000%	-	(267,873)	(101,660)	1,626,566	9.22%	154,723
116	2035	267,873	0.000%	-	(267,873)	(101,660)	1,524,905	9.22%	145,346
117	2036	267,873	0.000%	-	(267,873)	(101,660)	1,423,245	9.22%	135,969
118	2037	267,873	0.000%	-	(267,873)	(101,660)	1,321,584	9.22%	126,592
119	2038	267,873	0.000%	-	(267,873)	(101,660)	1,219,924	9.22%	117,214
120	2039	267,873	0.000%	-	(267,873)	(101,660)	1,118,264	9.22%	107,837
121	2040	267,873	0.000%	-	(267,873)	(101,660)	1,016,603	9.22%	98,460
122	2041	267,873	0.000%	-	(267,873)	(101,660)	914,943	9.22%	89,083
123	2042	267,873	0.000%	-	(267,873)	(101,660)	813,283	9.22%	79,706
124	2043	267,873	0.000%	-	(267,873)	(101,660)	711,622	9.22%	70,329
125	2044	267,873	0.000%	-	(267,873)	(101,660)	609,962	9.22%	60,951
126	2045	267,873	0.000%	-	(267,873)	(101,660)	508,302	9.22%	51,574
127	2046	267,873	0.000%	-	(267,873)	(101,660)	406,641	9.22%	42,197
128	2047	267,873	0.000%	-	(267,873)	(101,660)	304,981	9.22%	32,820
129	2048	267,873	0.000%	-	(267,873)	(101,660)	203,321	9.22%	23,443
130	2049	267,873	0.000%	-	(267,873)	(101,660)	101,660	9.22%	14,066
131	2050	267,873	0.000%	-	(267,873)	(101,660)	(0)	9.22%	4,689
132		$ 26,787,264	100%	$ 26,787,264	$ 0	$ (0)			$ 43,017,851

Facility Name Soda Springs **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	422,910
2	RP Capability Allocator	RP and BOP Allocators	27.75%
3	**RP - Generator/Exciter**	(Line 1 * 2)	117,358
4			
5	GSU Transformer	Summary Investment	109,437
6	RP Capability Allocator	RP and BOP Allocators	27.75%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	30,369
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	1,294,157
10	Real and Reactive Power Portion	Summary Investment	184,981
11	RP Capability Allocator	RP and BOP Allocators	27.75%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	51,332
13	Total Plant Investment	Summary Investment	99,631,721
14	Balance of Plant	(Line 13 - 12 - 5 - 1)	98,914,394
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	26,512
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	225,571
18	RP Fixed Charge Percent	(Line 11(h))	10.3539%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 23,355**

	Depreciation			
20	Annual Depreciation Expense (D)	$	2,934,226	
21	Gross Plant Investment (F)		99,631,721	(Line 14)
22	SLDP=DE/F		2.9451%	(Line 20 / 21)
23	Depreciable years (n)=1/SLDP		34	
24	Book Life (n)		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.4525%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 771,691	$ 99,631,721	0.7745%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0138%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.0056%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.4525%	
	ADIT	Line 31(i)	(1,637,369)	99,631,721	-1.6434%	
	Total RP Fixed Charge Percent				10.3539%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 99,631,721	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$21,668,653
31	In Service Year	1952				Levelized Revenue Requirement			1,637,369
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1952	$ 996,317	3.750%	$ 3,736,190	$ 2,739,872	$ 1,039,809	$ 1,039,809	10.69%	$ 55,575
33	1953	996,317	7.219%	7,192,414	6,196,097	2,351,481	3,391,290	10.69%	236,829
34	1954	996,317	6.677%	6,652,410	5,656,093	2,146,544	5,537,833	10.69%	477,236
35	1955	996,317	6.177%	6,154,251	5,157,934	1,957,488	7,495,321	10.69%	696,585
36	1956	996,317	5.713%	5,691,960	4,695,643	1,782,043	9,277,365	10.69%	896,452
37	1957	996,317	5.285%	5,265,536	4,269,219	1,620,211	10,897,576	10.69%	1,078,292
38	1958	996,317	4.888%	4,869,999	3,873,681	1,470,101	12,367,677	10.69%	1,243,461
39	1959	996,317	4.522%	4,505,346	3,509,029	1,331,712	13,699,388	10.69%	1,393,210
40	1960	996,317	4.462%	4,445,567	3,449,250	1,309,025	15,008,413	10.69%	1,534,349
41	1961	996,317	4.461%	4,444,571	3,448,254	1,308,647	16,317,060	10.69%	1,674,256
42	1962	996,317	4.462%	4,445,567	3,449,250	1,309,025	17,626,085	10.69%	1,814,163
43	1963	996,317	4.461%	4,444,571	3,448,254	1,308,647	18,934,732	10.69%	1,954,070
44	1964	996,317	4.462%	4,445,567	3,449,250	1,309,025	20,243,757	10.69%	2,093,977
45	1965	996,317	4.461%	4,444,571	3,448,254	1,308,647	21,552,404	10.69%	2,233,884
46	1966	996,317	4.462%	4,445,567	3,449,250	1,309,025	22,861,429	10.69%	2,373,791
47	1967	996,317	4.461%	4,444,571	3,448,254	1,308,647	24,170,075	10.69%	2,513,698
48	1968	996,317	4.462%	4,445,567	3,449,250	1,309,025	25,479,100	10.69%	2,653,606
49	1969	996,317	4.461%	4,444,571	3,448,254	1,308,647	26,787,747	10.69%	2,793,513
50	1970	996,317	4.462%	4,445,567	3,449,250	1,309,025	28,096,772	10.69%	2,933,420
51	1971	996,317	4.461%	4,444,571	3,448,254	1,308,647	29,405,419	10.69%	3,073,327
52	1972	996,317	2.231%	2,222,784	1,226,466	465,456	29,870,875	10.69%	3,168,147
53	1973	996,317	0.000%	-	(996,317)	(378,112)	29,492,763	10.69%	3,172,816
54	1974	996,317	0.000%	-	(996,317)	(378,112)	29,114,651	10.69%	3,132,398
55	1975	996,317	0.000%	-	(996,317)	(378,112)	28,736,538	10.69%	3,091,979
56	1976	996,317	0.000%	-	(996,317)	(378,112)	28,358,426	10.69%	3,051,561
57	1977	996,317	0.000%	-	(996,317)	(378,112)	27,980,314	10.69%	3,011,143
58	1978	996,317	0.000%	-	(996,317)	(378,112)	27,602,201	10.69%	2,970,725
59	1979	996,317	0.000%	-	(996,317)	(378,112)	27,224,089	10.69%	2,930,307
60	1980	996,317	0.000%	-	(996,317)	(378,112)	26,845,977	10.69%	2,889,889
61	1981	996,317	0.000%	-	(996,317)	(378,112)	26,467,864	10.69%	2,849,471
62	1982	996,317	0.000%	-	(996,317)	(378,112)	26,089,752	10.69%	2,809,053
63	1983	996,317	0.000%	-	(996,317)	(378,112)	25,711,640	10.69%	2,768,635
64	1984	996,317	0.000%	-	(996,317)	(378,112)	25,333,527	10.69%	2,728,217
65	1985	996,317	0.000%	-	(996,317)	(378,112)	24,955,415	10.69%	2,687,799
66	1986	996,317	0.000%	-	(996,317)	(378,112)	24,577,302	10.69%	2,647,381
67	1987	996,317	0.000%	-	(996,317)	(378,112)	24,199,190	10.69%	2,606,963
68	1988	996,317	0.000%	-	(996,317)	(378,112)	23,821,078	10.69%	2,566,545
69	1989	996,317	0.000%	-	(996,317)	(378,112)	23,442,965	10.69%	2,526,127
70	1990	996,317	0.000%	-	(996,317)	(378,112)	23,064,853	10.69%	2,485,709
71	1991	996,317	0.000%	-	(996,317)	(378,112)	22,686,741	10.69%	2,445,291
72	1992	996,317	0.000%	-	(996,317)	(378,112)	22,308,628	10.69%	2,404,873
73	1993	996,317	0.000%	-	(996,317)	(378,112)	21,930,516	10.69%	2,364,455
74	1994	996,317	0.000%	-	(996,317)	(378,112)	21,552,404	10.69%	2,324,037
75	1995	996,317	0.000%	-	(996,317)	(378,112)	21,174,291	10.69%	2,283,619
76	1996	996,317	0.000%	-	(996,317)	(378,112)	20,796,179	10.69%	2,243,201
77	1997	996,317	0.000%	-	(996,317)	(378,112)	20,418,067	10.69%	2,202,783
78	1998	996,317	0.000%	-	(996,317)	(378,112)	20,039,954	10.69%	2,162,365
79	1999	996,317	0.000%	-	(996,317)	(378,112)	19,661,842	10.69%	2,121,947
80	2000	996,317	0.000%	-	(996,317)	(378,112)	19,283,730	10.69%	2,081,529
81	2001	996,317	0.000%	-	(996,317)	(378,112)	18,905,617	10.69%	2,041,111
82	2002	996,317	0.000%	-	(996,317)	(378,112)	18,527,505	10.69%	2,000,693
83	2003	996,317	0.000%	-	(996,317)	(378,112)	18,149,393	10.69%	1,960,275
84	2004	996,317	0.000%	-	(996,317)	(378,112)	17,771,280	10.69%	1,919,857

85	2005	996,317	0.000%	-	(996,317)	(378,112)	17,393,168	10.69%	1,879,439
86	2006	996,317	0.000%	-	(996,317)	(378,112)	17,015,056	10.69%	1,839,020
87	2007	996,317	0.000%	-	(996,317)	(378,112)	16,636,943	10.69%	1,798,602
88	2008	996,317	0.000%	-	(996,317)	(378,112)	16,258,831	10.69%	1,758,184
89	2009	996,317	0.000%	-	(996,317)	(378,112)	15,880,719	10.69%	1,717,766
90	2010	996,317	0.000%	-	(996,317)	(378,112)	15,502,606	10.69%	1,677,348
91	2011	996,317	0.000%	-	(996,317)	(378,112)	15,124,494	10.69%	1,636,930
92	2012	996,317	0.000%	-	(996,317)	(378,112)	14,746,381	10.69%	1,596,512
93	2013	996,317	0.000%	-	(996,317)	(378,112)	14,368,269	10.69%	1,556,094
94	2014	996,317	0.000%	-	(996,317)	(378,112)	13,990,157	10.69%	1,515,676
95	2015	996,317	0.000%	-	(996,317)	(378,112)	13,612,044	10.69%	1,475,258
96	2016	996,317	0.000%	-	(996,317)	(378,112)	13,233,932	10.69%	1,434,840
97	2017	996,317	0.000%	-	(996,317)	(378,112)	12,855,820	10.69%	1,394,422
98	2018	996,317	0.000%	-	(996,317)	(378,112)	12,477,707	9.22%	1,168,382
99	2019	996,317	0.000%	-	(996,317)	(378,112)	12,099,595	9.22%	1,133,505
100	2020	996,317	0.000%	-	(996,317)	(378,112)	11,721,483	9.22%	1,098,628
101	2021	996,317	0.000%	-	(996,317)	(378,112)	11,343,370	9.22%	1,063,751
102	2022	996,317	0.000%	-	(996,317)	(378,112)	10,965,258	9.22%	1,028,874
103	2023	996,317	0.000%	-	(996,317)	(378,112)	10,587,146	9.22%	993,997
104	2024	996,317	0.000%	-	(996,317)	(378,112)	10,209,033	9.22%	959,120
105	2025	996,317	0.000%	-	(996,317)	(378,112)	9,830,921	9.22%	924,243
106	2026	996,317	0.000%	-	(996,317)	(378,112)	9,452,809	9.22%	889,366
107	2027	996,317	0.000%	-	(996,317)	(378,112)	9,074,696	9.22%	854,488
108	2028	996,317	0.000%	-	(996,317)	(378,112)	8,696,584	9.22%	819,611
109	2029	996,317	0.000%	-	(996,317)	(378,112)	8,318,472	9.22%	784,734
110	2030	996,317	0.000%	-	(996,317)	(378,112)	7,940,359	9.22%	749,857
111	2031	996,317	0.000%	-	(996,317)	(378,112)	7,562,247	9.22%	714,980
112	2032	996,317	0.000%	-	(996,317)	(378,112)	7,184,135	9.22%	680,103
113	2033	996,317	0.000%	-	(996,317)	(378,112)	6,806,022	9.22%	645,226
114	2034	996,317	0.000%	-	(996,317)	(378,112)	6,427,910	9.22%	610,349
115	2035	996,317	0.000%	-	(996,317)	(378,112)	6,049,798	9.22%	575,472
116	2036	996,317	0.000%	-	(996,317)	(378,112)	5,671,685	9.22%	540,595
117	2037	996,317	0.000%	-	(996,317)	(378,112)	5,293,573	9.22%	505,718
118	2038	996,317	0.000%	-	(996,317)	(378,112)	4,915,460	9.22%	470,841
119	2039	996,317	0.000%	-	(996,317)	(378,112)	4,537,348	9.22%	435,963
120	2040	996,317	0.000%	-	(996,317)	(378,112)	4,159,236	9.22%	401,086
121	2041	996,317	0.000%	-	(996,317)	(378,112)	3,781,123	9.22%	366,209
122	2042	996,317	0.000%	-	(996,317)	(378,112)	3,403,011	9.22%	331,332
123	2043	996,317	0.000%	-	(996,317)	(378,112)	3,024,899	9.22%	296,455
124	2044	996,317	0.000%	-	(996,317)	(378,112)	2,646,786	9.22%	261,578
125	2045	996,317	0.000%	-	(996,317)	(378,112)	2,268,674	9.22%	226,701
126	2046	996,317	0.000%	-	(996,317)	(378,112)	1,890,562	9.22%	191,824
127	2047	996,317	0.000%	-	(996,317)	(378,112)	1,512,449	9.22%	156,947
128	2048	996,317	0.000%	-	(996,317)	(378,112)	1,134,337	9.22%	122,070
129	2049	996,317	0.000%	-	(996,317)	(378,112)	756,225	9.22%	87,193
130	2050	996,317	0.000%	-	(996,317)	(378,112)	378,112	9.22%	52,316
131	2051	996,317	0.000%	-	(996,317)	(378,112)	(0)	9.22%	17,439
132		$ 99,631,721		100% $ 99,631,721	$ (0)	$ (0)			$ 159,813,642

Facility Name Clearwater **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	1,187,803
2	RP Capability Allocator	RP and BOP Allocators	27.75%
3	**RP - Generator/Exciter**	(Line 1 * 2)	329,615
4			
5	GSU Transformer	Summary Investment	1,386,748
6	RP Capability Allocator	RP and BOP Allocators	27.75%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	384,823
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	1,506,236
10	Real and Reactive Power Portion	Summary Investment	146,590
11	RP Capability Allocator	RP and BOP Allocators	27.75%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	40,679
13	Total Plant Investment	Summary Investment	28,629,870
14	Balance of Plant	(Line 13 - 10 - 5 - 1)	25,908,729
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	6,944
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	762,061
18	RP Fixed Charge Percent	(Line 11(h))	14.4234%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 109,915**

	Depreciation			
20	Annual Depreciation Expense (D)	$	895,732	
21	Gross Plant Investment (F)		28,629,870	(Line 13)
22	SLDP=DE/F		3.1287%	(Line 20 / 21)
23	Depreciable years =1/SLDP		32	
24	Book Life (n)		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.4525%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 1,373,842	$ 28,629,870	4.7986%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	#REF!			0.0590%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.0056%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.4525%	
	ADIT	Line 31(i)	(470,475)	28,629,870	-1.6433%	
	Total RP Fixed Charge Percent				14.4234%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 28,629,870	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$6,226,188
31	In Service Year	1953				Levelized Revenue Requirement			470,475
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1953	$ 286,299	3.750%	$ 1,073,620	$ 787,321	$ 298,796	$ 298,796	10.69%	$ 15,970
33	1954	286,299	7.219%	2,066,790	1,780,492	675,714	974,511	10.69%	68,055
34	1955	286,299	6.677%	1,911,616	1,625,318	616,824	1,591,335	10.69%	137,137
35	1956	286,299	6.177%	1,768,467	1,482,168	562,498	2,153,833	10.69%	200,168
36	1957	286,299	5.713%	1,635,624	1,349,326	512,083	2,665,915	10.69%	257,602
37	1958	286,299	5.285%	1,513,089	1,226,790	465,579	3,131,494	10.69%	309,855
38	1959	286,299	4.888%	1,399,428	1,113,129	422,444	3,553,938	10.69%	357,317
39	1960	286,299	4.522%	1,294,643	1,008,344	382,677	3,936,615	10.69%	400,348
40	1961	286,299	4.462%	1,277,465	991,166	376,157	4,312,772	10.69%	440,906
41	1962	286,299	4.461%	1,277,178	990,880	376,049	4,688,821	10.69%	481,109
42	1963	286,299	4.462%	1,277,465	991,166	376,157	5,064,978	10.69%	521,313
43	1964	286,299	4.461%	1,277,178	990,880	376,049	5,441,027	10.69%	561,516
44	1965	286,299	4.462%	1,277,465	991,166	376,157	5,817,185	10.69%	601,719
45	1966	286,299	4.461%	1,277,178	990,880	376,049	6,193,234	10.69%	641,922
46	1967	286,299	4.462%	1,277,465	991,166	376,157	6,569,391	10.69%	682,126
47	1968	286,299	4.461%	1,277,178	990,880	376,049	6,945,440	10.69%	722,329
48	1969	286,299	4.462%	1,277,465	991,166	376,157	7,321,597	10.69%	762,532
49	1970	286,299	4.461%	1,277,178	990,880	376,049	7,697,646	10.69%	802,735
50	1971	286,299	4.462%	1,277,465	991,166	376,157	8,073,803	10.69%	842,939
51	1972	286,299	4.461%	1,277,178	990,880	376,049	8,449,852	10.69%	883,142
52	1973	286,299	2.231%	638,732	352,434	133,752	8,583,604	10.69%	910,389
53	1974	286,299	0.000%	-	(286,299)	(108,653)	8,474,951	10.69%	911,731
54	1975	286,299	0.000%	-	(286,299)	(108,653)	8,366,298	10.69%	900,116
55	1976	286,299	0.000%	-	(286,299)	(108,653)	8,257,645	10.69%	888,502
56	1977	286,299	0.000%	-	(286,299)	(108,653)	8,148,991	10.69%	876,887
57	1978	286,299	0.000%	-	(286,299)	(108,653)	8,040,338	10.69%	865,273
58	1979	286,299	0.000%	-	(286,299)	(108,653)	7,931,685	10.69%	853,659
59	1980	286,299	0.000%	-	(286,299)	(108,653)	7,823,032	10.69%	842,044
60	1981	286,299	0.000%	-	(286,299)	(108,653)	7,714,379	10.69%	830,430
61	1982	286,299	0.000%	-	(286,299)	(108,653)	7,605,725	10.69%	818,815
62	1983	286,299	0.000%	-	(286,299)	(108,653)	7,497,072	10.69%	807,201
63	1984	286,299	0.000%	-	(286,299)	(108,653)	7,388,419	10.69%	795,587
64	1985	286,299	0.000%	-	(286,299)	(108,653)	7,279,766	10.69%	783,972
65	1986	286,299	0.000%	-	(286,299)	(108,653)	7,171,112	10.69%	772,358
66	1987	286,299	0.000%	-	(286,299)	(108,653)	7,062,459	10.69%	760,743
67	1988	286,299	0.000%	-	(286,299)	(108,653)	6,953,806	10.69%	749,129
68	1989	286,299	0.000%	-	(286,299)	(108,653)	6,845,153	10.69%	737,515
69	1990	286,299	0.000%	-	(286,299)	(108,653)	6,736,500	10.69%	725,900
70	1991	286,299	0.000%	-	(286,299)	(108,653)	6,627,846	10.69%	714,286
71	1992	286,299	0.000%	-	(286,299)	(108,653)	6,519,193	10.69%	702,671
72	1993	286,299	0.000%	-	(286,299)	(108,653)	6,410,540	10.69%	691,057
73	1994	286,299	0.000%	-	(286,299)	(108,653)	6,301,887	10.69%	679,443
74	1995	286,299	0.000%	-	(286,299)	(108,653)	6,193,234	10.69%	667,828
75	1996	286,299	0.000%	-	(286,299)	(108,653)	6,084,580	10.69%	656,214
76	1997	286,299	0.000%	-	(286,299)	(108,653)	5,975,927	10.69%	644,599
77	1998	286,299	0.000%	-	(286,299)	(108,653)	5,867,274	10.69%	632,985
78	1999	286,299	0.000%	-	(286,299)	(108,653)	5,758,621	10.69%	621,371
79	2000	286,299	0.000%	-	(286,299)	(108,653)	5,649,967	10.69%	609,756
80	2001	286,299	0.000%	-	(286,299)	(108,653)	5,541,314	10.69%	598,142
81	2002	286,299	0.000%	-	(286,299)	(108,653)	5,432,661	10.69%	586,527
82	2003	286,299	0.000%	-	(286,299)	(108,653)	5,324,008	10.69%	574,913
83	2004	286,299	0.000%	-	(286,299)	(108,653)	5,215,355	10.69%	563,299
84	2005	286,299	0.000%	-	(286,299)	(108,653)	5,106,701	10.69%	551,684

85		2006	286,299	0.000%	-	(286,299)	(108,653)	4,998,048	10.69%	540,070
86		2007	286,299	0.000%	-	(286,299)	(108,653)	4,889,395	10.69%	528,455
87		2008	286,299	0.000%	-	(286,299)	(108,653)	4,780,742	10.69%	516,841
88		2009	286,299	0.000%	-	(286,299)	(108,653)	4,672,088	10.69%	505,227
89		2010	286,299	0.000%	-	(286,299)	(108,653)	4,563,435	10.69%	493,612
90		2011	286,299	0.000%	-	(286,299)	(108,653)	4,454,782	10.69%	481,998
91		2012	286,299	0.000%	-	(286,299)	(108,653)	4,346,129	10.69%	470,383
92		2013	286,299	0.000%	-	(286,299)	(108,653)	4,237,476	10.69%	458,769
93		2014	286,299	0.000%	-	(286,299)	(108,653)	4,128,822	10.69%	447,155
94		2015	286,299	0.000%	-	(286,299)	(108,653)	4,020,169	10.69%	435,540
95		2016	286,299	0.000%	-	(286,299)	(108,653)	3,911,516	10.69%	423,926
96		2017	286,299	0.000%	-	(286,299)	(108,653)	3,802,863	10.69%	412,311
97		2018	286,299	0.000%	-	(286,299)	(108,653)	3,694,209	9.22%	345,765
98		2019	286,299	0.000%	-	(286,299)	(108,653)	3,585,556	9.22%	335,743
99		2020	286,299	0.000%	-	(286,299)	(108,653)	3,476,903	9.22%	325,721
100		2021	286,299	0.000%	-	(286,299)	(108,653)	3,368,250	9.22%	315,698
101		2022	286,299	0.000%	-	(286,299)	(108,653)	3,259,597	9.22%	305,676
102		2023	286,299	0.000%	-	(286,299)	(108,653)	3,150,943	9.22%	295,654
103		2024	286,299	0.000%	-	(286,299)	(108,653)	3,042,290	9.22%	285,632
104		2025	286,299	0.000%	-	(286,299)	(108,653)	2,933,637	9.22%	275,610
105		2026	286,299	0.000%	-	(286,299)	(108,653)	2,824,984	9.22%	265,588
106		2027	286,299	0.000%	-	(286,299)	(108,653)	2,716,330	9.22%	255,565
107		2028	286,299	0.000%	-	(286,299)	(108,653)	2,607,677	9.22%	245,543
108		2029	286,299	0.000%	-	(286,299)	(108,653)	2,499,024	9.22%	235,521
109		2030	286,299	0.000%	-	(286,299)	(108,653)	2,390,371	9.22%	225,499
110		2031	286,299	0.000%	-	(286,299)	(108,653)	2,281,718	9.22%	215,477
111		2032	286,299	0.000%	-	(286,299)	(108,653)	2,173,064	9.22%	205,455
112		2033	286,299	0.000%	-	(286,299)	(108,653)	2,064,411	9.22%	195,432
113		2034	286,299	0.000%	-	(286,299)	(108,653)	1,955,758	9.22%	185,410
114		2035	286,299	0.000%	-	(286,299)	(108,653)	1,847,105	9.22%	175,388
115		2036	286,299	0.000%	-	(286,299)	(108,653)	1,738,452	9.22%	165,366
116		2037	286,299	0.000%	-	(286,299)	(108,653)	1,629,798	9.22%	155,344
117		2038	286,299	0.000%	-	(286,299)	(108,653)	1,521,145	9.22%	145,321
118		2039	286,299	0.000%	-	(286,299)	(108,653)	1,412,492	9.22%	135,299
119		2040	286,299	0.000%	-	(286,299)	(108,653)	1,303,839	9.22%	125,277
120		2041	286,299	0.000%	-	(286,299)	(108,653)	1,195,185	9.22%	115,255
121		2042	286,299	0.000%	-	(286,299)	(108,653)	1,086,532	9.22%	105,233
122		2043	286,299	0.000%	-	(286,299)	(108,653)	977,879	9.22%	95,211
123		2044	286,299	0.000%	-	(286,299)	(108,653)	869,226	9.22%	85,188
124		2045	286,299	0.000%	-	(286,299)	(108,653)	760,573	9.22%	75,166
125		2046	286,299	0.000%	-	(286,299)	(108,653)	651,919	9.22%	65,144
126		2047	286,299	0.000%	-	(286,299)	(108,653)	543,266	9.22%	55,122
127		2048	286,299	0.000%	-	(286,299)	(108,653)	434,613	9.22%	45,100
		2049	286,299	0.000%	-	(286,299)	(108,653)	325,960	9.22%	35,078
128		2050	286,299	0.000%	-	(286,299)	(108,653)	217,306	9.22%	25,055
129		2051	286,299	0.000%	-	(286,299)	(108,653)	108,653	9.22%	15,033
130		2052	286,299	0.000%	-	(286,299)	(108,653)	0	9.22%	5,011
131			$ 28,629,870	100%	$ 28,629,870	$ (0)	$ 0			$ 45,868,633

Facility Name Fish Creek **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	293,192
2	RP Capability Allocator	RP and BOP Allocators	27.75%
3	**RP - Generator/Exciter**	(Line 1 * 2)	81,361
4			
5	GSU Transformer	Summary Investment	108,663
6	RP Capability Allocator	RP and BOP Allocators	27.75%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	30,154
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	1,844,126
10	Real and Reactive Power Portion	Summary Investment	56,301
11	RP Capability Allocator	RP and BOP Allocators	27.75%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	15,624
13	Total Plant Investment	Summary Investment	17,753,655
14	Balance of Plant	(Line 13 - 10 - 5 - 1)	17,295,500
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	4,636
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	131,774
18	RP Fixed Charge Percent	(Line 11(h))	11.9625%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 15,763**

	Depreciation			
20	Annual Depreciation Expense (D)	$	551,969	
21	Gross Plant Investment (F)		17,753,655	(Line 13)
22	SLDP=DE/F		3.1090%	(Line 20 / 21)
23	Depreciable years =1/SLDP		32	
24	Book Life (n)		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
	Income Tax Factor to Include in Fixed Charge		
27	Factor	1.4525%	Based Upon Book Life
	[(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]		CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 419,925	$ 17,753,655	2.3653%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	#REF!			0.0317%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.0056%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.4525%	
	ADIT	Line 31(i)	(291,767)	17,753,655	-1.6434%	
	Total RP Fixed Charge Percent				11.9625%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 17,753,655	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$3,861,198
31	In Service Year	1952				Levelized Revenue Requirement			291,767
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1952	$ 177,537	3.750%	$ 665,762	$ 488,226	$ 185,286	$ 185,286	10.69%	$ 9,903
33	1953	177,537	7.219%	1,281,636	1,104,100	419,017	604,303	10.69%	42,201
34	1954	177,537	6.677%	1,185,412	1,007,875	382,499	986,802	10.69%	85,040
35	1955	177,537	6.177%	1,096,643	919,107	348,810	1,335,612	10.69%	124,126
36	1956	177,537	5.713%	1,014,266	836,730	317,547	1,653,160	10.69%	159,741
37	1957	177,537	5.285%	938,281	760,744	288,710	1,941,870	10.69%	192,144
38	1958	177,537	4.888%	867,799	690,262	261,961	2,203,831	10.69%	221,576
39	1959	177,537	4.522%	802,820	625,284	237,301	2,441,132	10.69%	248,260
40	1960	177,537	4.462%	792,168	614,632	233,259	2,674,391	10.69%	273,410
41	1961	177,537	4.461%	791,991	614,454	233,191	2,907,583	10.69%	298,340
42	1962	177,537	4.462%	792,168	614,632	233,259	3,140,841	10.69%	323,271
43	1963	177,537	4.461%	791,991	614,454	233,191	3,374,033	10.69%	348,201
44	1964	177,537	4.462%	792,168	614,632	233,259	3,607,292	10.69%	373,132
45	1965	177,537	4.461%	791,991	614,454	233,191	3,840,483	10.69%	398,062
46	1966	177,537	4.462%	792,168	614,632	233,259	4,073,742	10.69%	422,993
47	1967	177,537	4.461%	791,991	614,454	233,191	4,306,933	10.69%	447,923
48	1968	177,537	4.462%	792,168	614,632	233,259	4,540,192	10.69%	472,853
49	1969	177,537	4.461%	791,991	614,454	233,191	4,773,384	10.69%	497,784
50	1970	177,537	4.462%	792,168	614,632	233,259	5,006,642	10.69%	522,714
51	1971	177,537	4.461%	791,991	614,454	233,191	5,239,834	10.69%	547,645
52	1972	177,537	2.231%	396,084	218,547	82,941	5,322,775	10.69%	564,541
53	1973	177,537	0.000%	-	(177,537)	(67,377)	5,255,398	10.69%	565,373
54	1974	177,537	0.000%	-	(177,537)	(67,377)	5,188,021	10.69%	558,171
55	1975	177,537	0.000%	-	(177,537)	(67,377)	5,120,644	10.69%	550,968
56	1976	177,537	0.000%	-	(177,537)	(67,377)	5,053,267	10.69%	543,766
57	1977	177,537	0.000%	-	(177,537)	(67,377)	4,985,890	10.69%	536,564
58	1978	177,537	0.000%	-	(177,537)	(67,377)	4,918,513	10.69%	529,362
59	1979	177,537	0.000%	-	(177,537)	(67,377)	4,851,137	10.69%	522,160
60	1980	177,537	0.000%	-	(177,537)	(67,377)	4,783,760	10.69%	514,957
61	1981	177,537	0.000%	-	(177,537)	(67,377)	4,716,383	10.69%	507,755
62	1982	177,537	0.000%	-	(177,537)	(67,377)	4,649,006	10.69%	500,553
63	1983	177,537	0.000%	-	(177,537)	(67,377)	4,581,629	10.69%	493,351
64	1984	177,537	0.000%	-	(177,537)	(67,377)	4,514,252	10.69%	486,149
65	1985	177,537	0.000%	-	(177,537)	(67,377)	4,446,875	10.69%	478,946
66	1986	177,537	0.000%	-	(177,537)	(67,377)	4,379,498	10.69%	471,744
67	1987	177,537	0.000%	-	(177,537)	(67,377)	4,312,121	10.69%	464,542
68	1988	177,537	0.000%	-	(177,537)	(67,377)	4,244,745	10.69%	457,340
69	1989	177,537	0.000%	-	(177,537)	(67,377)	4,177,368	10.69%	450,138
70	1990	177,537	0.000%	-	(177,537)	(67,377)	4,109,991	10.69%	442,935
71	1991	177,537	0.000%	-	(177,537)	(67,377)	4,042,614	10.69%	435,733
72	1992	177,537	0.000%	-	(177,537)	(67,377)	3,975,237	10.69%	428,531
73	1993	177,537	0.000%	-	(177,537)	(67,377)	3,907,860	10.69%	421,329
74	1994	177,537	0.000%	-	(177,537)	(67,377)	3,840,483	10.69%	414,127
75	1995	177,537	0.000%	-	(177,537)	(67,377)	3,773,106	10.69%	406,924
76	1996	177,537	0.000%	-	(177,537)	(67,377)	3,705,729	10.69%	399,722
77	1997	177,537	0.000%	-	(177,537)	(67,377)	3,638,352	10.69%	392,520
78	1998	177,537	0.000%	-	(177,537)	(67,377)	3,570,976	10.69%	385,318
79	1999	177,537	0.000%	-	(177,537)	(67,377)	3,503,599	10.69%	378,116
80	2000	177,537	0.000%	-	(177,537)	(67,377)	3,436,222	10.69%	370,913
81	2001	177,537	0.000%	-	(177,537)	(67,377)	3,368,845	10.69%	363,711
82	2002	177,537	0.000%	-	(177,537)	(67,377)	3,301,468	10.69%	356,509
83	2003	177,537	0.000%	-	(177,537)	(67,377)	3,234,091	10.69%	349,307
84	2004	177,537	0.000%	-	(177,537)	(67,377)	3,166,714	10.69%	342,105

85		2005	177,537	0.000%	-	(177,537)	(67,377)	3,099,337	10.69%	334,902
86		2006	177,537	0.000%	-	(177,537)	(67,377)	3,031,960	10.69%	327,700
87		2007	177,537	0.000%	-	(177,537)	(67,377)	2,964,583	10.69%	320,498
88		2008	177,537	0.000%	-	(177,537)	(67,377)	2,897,207	10.69%	313,296
89		2009	177,537	0.000%	-	(177,537)	(67,377)	2,829,830	10.69%	306,094
90		2010	177,537	0.000%	-	(177,537)	(67,377)	2,762,453	10.69%	298,891
91		2011	177,537	0.000%	-	(177,537)	(67,377)	2,695,076	10.69%	291,689
92		2012	177,537	0.000%	-	(177,537)	(67,377)	2,627,699	10.69%	284,487
93		2013	177,537	0.000%	-	(177,537)	(67,377)	2,560,322	10.69%	277,285
94		2014	177,537	0.000%	-	(177,537)	(67,377)	2,492,945	10.69%	270,083
95		2015	177,537	0.000%	-	(177,537)	(67,377)	2,425,568	10.69%	262,880
96		2016	177,537	0.000%	-	(177,537)	(67,377)	2,358,191	10.69%	255,678
97		2017	177,537	0.000%	-	(177,537)	(67,377)	2,290,815	10.69%	248,476
98		2018	177,537	0.000%	-	(177,537)	(67,377)	2,223,438	9.22%	208,197
99		2019	177,537	0.000%	-	(177,537)	(67,377)	2,156,061	9.22%	201,982
100		2020	177,537	0.000%	-	(177,537)	(67,377)	2,088,684	9.22%	195,768
101		2021	177,537	0.000%	-	(177,537)	(67,377)	2,021,307	9.22%	189,553
102		2022	177,537	0.000%	-	(177,537)	(67,377)	1,953,930	9.22%	183,338
103		2023	177,537	0.000%	-	(177,537)	(67,377)	1,886,553	9.22%	177,123
104		2024	177,537	0.000%	-	(177,537)	(67,377)	1,819,176	9.22%	170,908
105		2025	177,537	0.000%	-	(177,537)	(67,377)	1,751,799	9.22%	164,693
106		2026	177,537	0.000%	-	(177,537)	(67,377)	1,684,422	9.22%	158,479
107		2027	177,537	0.000%	-	(177,537)	(67,377)	1,617,046	9.22%	152,264
108		2028	177,537	0.000%	-	(177,537)	(67,377)	1,549,669	9.22%	146,049
109		2029	177,537	0.000%	-	(177,537)	(67,377)	1,482,292	9.22%	139,834
110		2030	177,537	0.000%	-	(177,537)	(67,377)	1,414,915	9.22%	133,619
111		2031	177,537	0.000%	-	(177,537)	(67,377)	1,347,538	9.22%	127,404
112		2032	177,537	0.000%	-	(177,537)	(67,377)	1,280,161	9.22%	121,189
113		2033	177,537	0.000%	-	(177,537)	(67,377)	1,212,784	9.22%	114,975
114		2034	177,537	0.000%	-	(177,537)	(67,377)	1,145,407	9.22%	108,760
115		2035	177,537	0.000%	-	(177,537)	(67,377)	1,078,030	9.22%	102,545
116		2036	177,537	0.000%	-	(177,537)	(67,377)	1,010,653	9.22%	96,330
117		2037	177,537	0.000%	-	(177,537)	(67,377)	943,277	9.22%	90,115
118		2038	177,537	0.000%	-	(177,537)	(67,377)	875,900	9.22%	83,900
119		2039	177,537	0.000%	-	(177,537)	(67,377)	808,523	9.22%	77,686
120		2040	177,537	0.000%	-	(177,537)	(67,377)	741,146	9.22%	71,471
121		2041	177,537	0.000%	-	(177,537)	(67,377)	673,769	9.22%	65,256
122		2042	177,537	0.000%	-	(177,537)	(67,377)	606,392	9.22%	59,041
123		2043	177,537	0.000%	-	(177,537)	(67,377)	539,015	9.22%	52,826
124		2044	177,537	0.000%	-	(177,537)	(67,377)	471,638	9.22%	46,611
125		2045	177,537	0.000%	-	(177,537)	(67,377)	404,261	9.22%	40,396
126		2046	177,537	0.000%	-	(177,537)	(67,377)	336,884	9.22%	34,182
127		2047	177,537	0.000%	-	(177,537)	(67,377)	269,508	9.22%	27,967
128		2048	177,537	0.000%	-	(177,537)	(67,377)	202,131	9.22%	21,752
129		2049	177,537	0.000%	-	(177,537)	(67,377)	134,754	9.22%	15,537
130		2050	177,537	0.000%	-	(177,537)	(67,377)	67,377	9.22%	9,322
131		2051	177,537	0.000%	-	(177,537)	(67,377)	0	9.22%	3,107
132			$ 17,753,655		100% $ 17,753,655	$ 0	$ 0			$ 28,477,640

Facility Name Prospect **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	2,121,187
2	RP Capability Allocator	RP and BOP Allocators	36.00%
3	**RP - Generator/Exciter**	(Line 1 * 2)	763,627
4			
5	GSU Transformer	Summary Investment	738,122
6	RP Capability Allocator	RP and BOP Allocators	36.00%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	265,724
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	8,677,601
10	Real and Reactive Power Portion	Summary Investment	764,114
11	RP Capability Allocator	RP and BOP Allocators	36.00%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	275,081
13	Total Plant Investment	Summary Investment	65,311,870
14	Balance of Plant	(Line 13 - 10 - 5 - 1)	61,688,447
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	16,535
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	1,320,967
18	RP Fixed Charge Percent	(Line 11(h))	13.2500%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 175,028**

	Depreciation			
20	Annual Depreciation Expense (D)	$	2,208,323	
21	Gross Plant Investment (F)		65,311,870	(Line 13)
22	SLDP=DE/F		3.3812%	(Line 20 / 21)
23	Depreciable years (n)=1/SLDP		30	
24	Book Life (n)		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
	Income Tax Factor to Include in Fixed Charge		
27	Factor	1.4525%	Based Upon Book Life
	[(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]		CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment						
			Amount	Investment	FCR %	
O&M	O&M by Facility	$	2,376,941	$ 65,311,870	3.6394%	(f)/(g)
A&G	Fixed Charge Items				0.4475%	
Cash Working Capital	#REF!				0.0460%	
Prepayments	Fixed Charge Items				0.0203%	
Materials and Supplies	Fixed Charge Items				0.1029%	
General and Intangible Plant	Fixed Charge Items				1.1057%	
Other Taxes	Fixed Charge Items				0.5233%	
Depreciation	(Line 26)				0.0056%	
Return	Fixed Charge Items				7.5512%	
Income Taxes	Line 27				1.4525%	
ADIT	Line 31(i)		(1,073,972)	65,311,870	-1.6444%	
Total RP Fixed Charge Percent					13.2500%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 65,311,870	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$14,212,754
31	In Service Year	1928				Levelized Revenue Requirement			1,073,972
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1928	$ 653,119	3.750%	$ 2,449,195	$ 1,796,076	$ 681,629	$ 681,629	10.69%	$ 36,431
33	1929	653,119	7.219%	4,714,864	4,061,745	1,541,473	2,223,102	10.69%	155,250
34	1930	653,119	6.677%	4,360,874	3,707,755	1,407,130	3,630,232	10.69%	312,844
35	1931	653,119	6.177%	4,034,314	3,381,196	1,283,198	4,913,429	10.69%	456,634
36	1932	653,119	5.713%	3,731,267	3,078,148	1,168,188	6,081,618	10.69%	587,654
37	1933	653,119	5.285%	3,451,732	2,798,614	1,062,102	7,143,719	10.69%	706,856
38	1934	653,119	4.888%	3,192,444	2,539,326	963,699	8,107,419	10.69%	815,129
39	1935	653,119	4.522%	2,953,403	2,300,284	872,981	8,980,400	10.69%	913,295
40	1936	653,119	4.462%	2,914,216	2,261,097	858,109	9,838,509	10.69%	1,005,816
41	1937	653,119	4.461%	2,913,563	2,260,444	857,861	10,696,370	10.69%	1,097,530
42	1938	653,119	4.462%	2,914,216	2,261,097	858,109	11,554,478	10.69%	1,189,244
43	1939	653,119	4.461%	2,913,563	2,260,444	857,861	12,412,340	10.69%	1,280,957
44	1940	653,119	4.462%	2,914,216	2,261,097	858,109	13,270,448	10.69%	1,372,671
45	1941	653,119	4.461%	2,913,563	2,260,444	857,861	14,128,309	10.69%	1,464,385
46	1942	653,119	4.462%	2,914,216	2,261,097	858,109	14,986,418	10.69%	1,556,098
47	1943	653,119	4.461%	2,913,563	2,260,444	857,861	15,844,279	10.69%	1,647,812
48	1944	653,119	4.462%	2,914,216	2,261,097	858,109	16,702,388	10.69%	1,739,526
49	1945	653,119	4.461%	2,913,563	2,260,444	857,861	17,560,249	10.69%	1,831,239
50	1946	653,119	4.462%	2,914,216	2,261,097	858,109	18,418,358	10.69%	1,922,953
51	1947	653,119	4.461%	2,913,563	2,260,444	857,861	19,276,219	10.69%	2,014,667
52	1948	653,119	2.231%	1,457,108	803,989	305,122	19,581,341	10.69%	2,076,825
53	1949	653,119	0.000%	-	(653,119)	(247,865)	19,333,476	10.69%	2,079,885
54	1950	653,119	0.000%	-	(653,119)	(247,865)	19,085,611	10.69%	2,053,390
55	1951	653,119	0.000%	-	(653,119)	(247,865)	18,837,746	10.69%	2,026,894
56	1952	653,119	0.000%	-	(653,119)	(247,865)	18,589,881	10.69%	2,000,399
57	1953	653,119	0.000%	-	(653,119)	(247,865)	18,342,016	10.69%	1,973,904
58	1954	653,119	0.000%	-	(653,119)	(247,865)	18,094,151	10.69%	1,947,408
59	1955	653,119	0.000%	-	(653,119)	(247,865)	17,846,286	10.69%	1,920,913
60	1956	653,119	0.000%	-	(653,119)	(247,865)	17,598,421	10.69%	1,894,417
61	1957	653,119	0.000%	-	(653,119)	(247,865)	17,350,555	10.69%	1,867,922
62	1958	653,119	0.000%	-	(653,119)	(247,865)	17,102,690	10.69%	1,841,427
63	1959	653,119	0.000%	-	(653,119)	(247,865)	16,854,825	10.69%	1,814,931
64	1960	653,119	0.000%	-	(653,119)	(247,865)	16,606,960	10.69%	1,788,436
65	1961	653,119	0.000%	-	(653,119)	(247,865)	16,359,095	10.69%	1,761,941
66	1962	653,119	0.000%	-	(653,119)	(247,865)	16,111,230	10.69%	1,735,445
67	1963	653,119	0.000%	-	(653,119)	(247,865)	15,863,365	10.69%	1,708,950
68	1964	653,119	0.000%	-	(653,119)	(247,865)	15,615,500	10.69%	1,682,455
69	1965	653,119	0.000%	-	(653,119)	(247,865)	15,367,635	10.69%	1,655,959
70	1966	653,119	0.000%	-	(653,119)	(247,865)	15,119,770	10.69%	1,629,464
71	1967	653,119	0.000%	-	(653,119)	(247,865)	14,871,905	10.69%	1,602,969
72	1968	653,119	0.000%	-	(653,119)	(247,865)	14,624,040	10.69%	1,576,473
73	1969	653,119	0.000%	-	(653,119)	(247,865)	14,376,175	10.69%	1,549,978
74	1970	653,119	0.000%	-	(653,119)	(247,865)	14,128,309	10.69%	1,523,483
75	1971	653,119	0.000%	-	(653,119)	(247,865)	13,880,444	10.69%	1,496,987
76	1972	653,119	0.000%	-	(653,119)	(247,865)	13,632,579	10.69%	1,470,492
77	1973	653,119	0.000%	-	(653,119)	(247,865)	13,384,714	10.69%	1,443,997
78	1974	653,119	0.000%	-	(653,119)	(247,865)	13,136,849	10.69%	1,417,501
79	1975	653,119	0.000%	-	(653,119)	(247,865)	12,888,984	10.69%	1,391,006
80	1976	653,119	0.000%	-	(653,119)	(247,865)	12,641,119	10.69%	1,364,511
81	1977	653,119	0.000%	-	(653,119)	(247,865)	12,393,254	10.69%	1,338,015
82	1978	653,119	0.000%	-	(653,119)	(247,865)	12,145,389	10.69%	1,311,520
83	1979	653,119	0.000%	-	(653,119)	(247,865)	11,897,524	10.69%	1,285,024
84	1980	653,119	0.000%	-	(653,119)	(247,865)	11,649,659	10.69%	1,258,529

85	1981	653,119	0.000%	-	(653,119)	(247,865)	11,401,794	10.69%	1,232,034	
86	1982	653,119	0.000%	-	(653,119)	(247,865)	11,153,929	10.69%	1,205,538	
87	1983	653,119	0.000%	-	(653,119)	(247,865)	10,906,063	10.69%	1,179,043	
88	1984	653,119	0.000%	-	(653,119)	(247,865)	10,658,198	10.69%	1,152,548	
89	1985	653,119	0.000%	-	(653,119)	(247,865)	10,410,333	10.69%	1,126,052	
90	1986	653,119	0.000%	-	(653,119)	(247,865)	10,162,468	10.69%	1,099,557	
91	1987	653,119	0.000%	-	(653,119)	(247,865)	9,914,603	10.69%	1,073,062	
92	1988	653,119	0.000%	-	(653,119)	(247,865)	9,666,738	10.69%	1,046,566	
93	1989	653,119	0.000%	-	(653,119)	(247,865)	9,418,873	10.69%	1,020,071	
94	1990	653,119	0.000%	-	(653,119)	(247,865)	9,171,008	10.69%	993,576	
95	1991	653,119	0.000%	-	(653,119)	(247,865)	8,923,143	10.69%	967,080	
96	1992	653,119	0.000%	-	(653,119)	(247,865)	8,675,278	10.69%	940,585	
97	1993	653,119	0.000%	-	(653,119)	(247,865)	8,427,413	10.69%	914,090	
98	1994	653,119	0.000%	-	(653,119)	(247,865)	8,179,548	10.69%	887,594	
99	1995	653,119	0.000%	-	(653,119)	(247,865)	7,931,682	10.69%	861,099	
100	1996	653,119	0.000%	-	(653,119)	(247,865)	7,683,817	10.69%	834,604	
101	1997	653,119	0.000%	-	(653,119)	(247,865)	7,435,952	10.69%	808,108	
102	1998	653,119	0.000%	-	(653,119)	(247,865)	7,188,087	10.69%	781,613	
103	1999	653,119	0.000%	-	(653,119)	(247,865)	6,940,222	10.69%	755,117	
104	2000	653,119	0.000%	-	(653,119)	(247,865)	6,692,357	10.69%	728,622	
105	2001	653,119	0.000%	-	(653,119)	(247,865)	6,444,492	10.69%	702,127	
106	2002	653,119	0.000%	-	(653,119)	(247,865)	6,196,627	10.69%	675,631	
107	2003	653,119	0.000%	-	(653,119)	(247,865)	5,948,762	10.69%	649,136	
108	2004	653,119	0.000%	-	(653,119)	(247,865)	5,700,897	10.69%	622,641	
109	2005	653,119	0.000%	-	(653,119)	(247,865)	5,453,032	10.69%	596,145	
110	2006	653,119	0.000%	-	(653,119)	(247,865)	5,205,167	10.69%	569,650	
111	2007	653,119	0.000%	-	(653,119)	(247,865)	4,957,302	10.69%	543,155	
112	2008	653,119	0.000%	-	(653,119)	(247,865)	4,709,436	10.69%	516,659	
113	2009	653,119	0.000%	-	(653,119)	(247,865)	4,461,571	10.69%	490,164	
114	2010	653,119	0.000%	-	(653,119)	(247,865)	4,213,706	10.69%	463,669	
115	2011	653,119	0.000%	-	(653,119)	(247,865)	3,965,841	10.69%	437,173	
116	2012	653,119	0.000%	-	(653,119)	(247,865)	3,717,976	10.69%	410,678	
117	2013	653,119	0.000%	-	(653,119)	(247,865)	3,470,111	10.69%	384,183	
118	2014	653,119	0.000%	-	(653,119)	(247,865)	3,222,246	10.69%	357,687	
119	2015	653,119	0.000%	-	(653,119)	(247,865)	2,974,381	10.69%	331,192	
120	2016	653,119	0.000%	-	(653,119)	(247,865)	2,726,516	10.69%	304,697	
121	2017	653,119	0.000%	-	(653,119)	(247,865)	2,478,651	10.69%	278,201	
122	2018	653,119	0.000%	-	(653,119)	(247,865)	2,230,786	9.22%	217,199	
123	2019	653,119	0.000%	-	(653,119)	(247,865)	1,982,921	9.22%	194,336	
124	2020	653,119	0.000%	-	(653,119)	(247,865)	1,735,056	9.22%	171,473	
125	2021	653,119	0.000%	-	(653,119)	(247,865)	1,487,190	9.22%	148,610	
126	2022	653,119	0.000%	-	(653,119)	(247,865)	1,239,325	9.22%	125,747	
127	2023	653,119	0.000%	-	(653,119)	(247,865)	991,460	9.22%	102,884	
128	2024	653,119	0.000%	-	(653,119)	(247,865)	743,595	9.22%	80,021	
129	2025	653,119	0.000%	-	(653,119)	(247,865)	495,730	9.22%	57,158	
130	2026	653,119	0.000%	-	(653,119)	(247,865)	247,865	9.22%	34,295	
131	2027	653,119	0.000%	-	(653,119)	(247,865)	-	9.22%	11,432	
132		$ 65,311,870	100%	$ 65,311,870	$ 0	$ -			$ 106,680,941	

Facility Name Copco **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	1,742,876
2	RP Capability Allocator	RP and BOP Allocators	26.06%
3	**RP - Generator/Exciter**	(Line 1 * 2)	454,185
4			
5	GSU Transformer	Summary Investment	3,471,263
6	RP Capability Allocator	RP and BOP Allocators	26.06%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	904,595
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	8,857,966
10	Real and Reactive Power Portion	Summary Investment	5,770,972
11	RP Capability Allocator	RP and BOP Allocators	26.06%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	1,503,888
13	Total Plant Investment	Summary Investment	28,249,298
14	Balance of Plant	(Line 13 - 10 - 5 - 1)	17,264,188
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	4,627
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	2,867,296
18	RP Fixed Charge Percent	(Line 11(h))	19.2795%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 552,800**

	Depreciation			
20	Annual Depreciation Expense (D)	$	3,609,681	
21	Gross Plant Investment (F)		28,249,298	(Line 13)
22	SLDP=DE/F		12.7779%	(Line 20 / 21)
23	Depreciable years =1/SLDP		8	
24	Book Life (n)		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.4525%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment						
			Amount	Investment	FCR %	
O&M	O&M by Facility	$	2,712,437	$ 28,249,298	9.6018%	(f)/(g)
A&G	Fixed Charge Items				0.4475%	
Cash Working Capital	#REF!				0.1131%	
Prepayments	Fixed Charge Items				0.0203%	
Materials and Supplies	Fixed Charge Items				0.1029%	
General and Intangible Plant	Fixed Charge Items				1.1057%	
Other Taxes	Fixed Charge Items				0.5233%	
Depreciation	(Line 26)				0.0056%	
Return	Fixed Charge Items				7.5512%	
Income Taxes	Line 27				1.4525%	
ADIT	Line 31(i)		(464,530)	28,249,298	-1.6444%	
Total RP Fixed Charge Percent					19.2795%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 28,249,298	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%		37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$6,147,508
31	In Service Year	1922	1918-1925			Levelized Revenue Requirement			464,530
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1922	$ 282,493	3.750%	$ 1,059,349	$ 776,856	$ 294,825	$ 294,825	10.69%	$ 15,758
33	1923	282,493	7.219%	2,039,317	1,756,824	666,732	961,557	10.69%	67,150
34	1924	282,493	6.677%	1,886,206	1,603,713	608,625	1,570,182	10.69%	135,314
35	1925	282,493	6.177%	1,744,959	1,462,466	555,021	2,125,202	10.69%	197,508
36	1926	282,493	5.713%	1,613,882	1,331,389	505,276	2,630,478	10.69%	254,177
37	1927	282,493	5.285%	1,492,975	1,210,482	459,390	3,089,868	10.69%	305,736
38	1928	282,493	4.888%	1,380,826	1,098,333	416,828	3,506,696	10.69%	352,567
39	1929	282,493	4.522%	1,277,433	994,940	377,590	3,884,286	10.69%	395,027
40	1930	282,493	4.462%	1,260,484	977,991	371,157	4,255,443	10.69%	435,045
41	1931	282,493	4.461%	1,260,201	977,708	371,050	4,626,493	10.69%	474,714
42	1932	282,493	4.462%	1,260,484	977,991	371,157	4,997,651	10.69%	514,383
43	1933	282,493	4.461%	1,260,201	977,708	371,050	5,368,701	10.69%	554,052
44	1934	282,493	4.462%	1,260,484	977,991	371,157	5,739,858	10.69%	593,720
45	1935	282,493	4.461%	1,260,201	977,708	371,050	6,110,908	10.69%	633,389
46	1936	282,493	4.462%	1,260,484	977,991	371,157	6,482,065	10.69%	673,058
47	1937	282,493	4.461%	1,260,201	977,708	371,050	6,853,115	10.69%	712,727
48	1938	282,493	4.462%	1,260,484	977,991	371,157	7,224,273	10.69%	752,396
49	1939	282,493	4.461%	1,260,201	977,708	371,050	7,595,323	10.69%	792,065
50	1940	282,493	4.462%	1,260,484	977,991	371,157	7,966,480	10.69%	831,734
51	1941	282,493	4.461%	1,260,201	977,708	371,050	8,337,530	10.69%	871,402
52	1942	282,493	2.231%	630,242	347,749	131,974	8,469,504	10.69%	898,288
53	1943	282,493	0.000%	-	(282,493)	(107,209)	8,362,295	10.69%	899,611
54	1944	282,493	0.000%	-	(282,493)	(107,209)	8,255,086	10.69%	888,151
55	1945	282,493	0.000%	-	(282,493)	(107,209)	8,147,877	10.69%	876,691
56	1946	282,493	0.000%	-	(282,493)	(107,209)	8,040,668	10.69%	865,231
57	1947	282,493	0.000%	-	(282,493)	(107,209)	7,933,460	10.69%	853,771
58	1948	282,493	0.000%	-	(282,493)	(107,209)	7,826,251	10.69%	842,311
59	1949	282,493	0.000%	-	(282,493)	(107,209)	7,719,042	10.69%	830,851
60	1950	282,493	0.000%	-	(282,493)	(107,209)	7,611,833	10.69%	819,391
61	1951	282,493	0.000%	-	(282,493)	(107,209)	7,504,624	10.69%	807,931
62	1952	282,493	0.000%	-	(282,493)	(107,209)	7,397,415	10.69%	796,471
63	1953	282,493	0.000%	-	(282,493)	(107,209)	7,290,206	10.69%	785,011
64	1954	282,493	0.000%	-	(282,493)	(107,209)	7,182,997	10.69%	773,551
65	1955	282,493	0.000%	-	(282,493)	(107,209)	7,075,788	10.69%	762,091
66	1956	282,493	0.000%	-	(282,493)	(107,209)	6,968,579	10.69%	750,631
67	1957	282,493	0.000%	-	(282,493)	(107,209)	6,861,370	10.69%	739,171
68	1958	282,493	0.000%	-	(282,493)	(107,209)	6,754,161	10.69%	727,711
69	1959	282,493	0.000%	-	(282,493)	(107,209)	6,646,953	10.69%	716,251
70	1960	282,493	0.000%	-	(282,493)	(107,209)	6,539,744	10.69%	704,791
71	1961	282,493	0.000%	-	(282,493)	(107,209)	6,432,535	10.69%	693,331
72	1962	282,493	0.000%	-	(282,493)	(107,209)	6,325,326	10.69%	681,871
73	1963	282,493	0.000%	-	(282,493)	(107,209)	6,218,117	10.69%	670,411
74	1964	282,493	0.000%	-	(282,493)	(107,209)	6,110,908	10.69%	658,951
75	1965	282,493	0.000%	-	(282,493)	(107,209)	6,003,699	10.69%	647,491
76	1966	282,493	0.000%	-	(282,493)	(107,209)	5,896,490	10.69%	636,031
77	1967	282,493	0.000%	-	(282,493)	(107,209)	5,789,281	10.69%	624,571
78	1968	282,493	0.000%	-	(282,493)	(107,209)	5,682,072	10.69%	613,111
79	1969	282,493	0.000%	-	(282,493)	(107,209)	5,574,863	10.69%	601,651
80	1970	282,493	0.000%	-	(282,493)	(107,209)	5,467,655	10.69%	590,191
81	1971	282,493	0.000%	-	(282,493)	(107,209)	5,360,446	10.69%	578,731
82	1972	282,493	0.000%	-	(282,493)	(107,209)	5,253,237	10.69%	567,271
83	1973	282,493	0.000%	-	(282,493)	(107,209)	5,146,028	10.69%	555,811
84	1974	282,493	0.000%	-	(282,493)	(107,209)	5,038,819	10.69%	544,351

85	1975	282,493	0.000%	-	(282,493)	(107,209)	4,931,610	10.69%	532,891	
86	1976	282,493	0.000%	-	(282,493)	(107,209)	4,824,401	10.69%	521,431	
87	1977	282,493	0.000%	-	(282,493)	(107,209)	4,717,192	10.69%	509,971	
88	1978	282,493	0.000%	-	(282,493)	(107,209)	4,609,983	10.69%	498,511	
89	1979	282,493	0.000%	-	(282,493)	(107,209)	4,502,774	10.69%	487,051	
90	1980	282,493	0.000%	-	(282,493)	(107,209)	4,395,565	10.69%	475,591	
91	1981	282,493	0.000%	-	(282,493)	(107,209)	4,288,356	10.69%	464,131	
92	1982	282,493	0.000%	-	(282,493)	(107,209)	4,181,148	10.69%	452,671	
93	1983	282,493	0.000%	-	(282,493)	(107,209)	4,073,939	10.69%	441,211	
94	1984	282,493	0.000%	-	(282,493)	(107,209)	3,966,730	10.69%	429,751	
95	1985	282,493	0.000%	-	(282,493)	(107,209)	3,859,521	10.69%	418,291	
96	1986	282,493	0.000%	-	(282,493)	(107,209)	3,752,312	10.69%	406,831	
97	1987	282,493	0.000%	-	(282,493)	(107,209)	3,645,103	10.69%	395,371	
98	1988	282,493	0.000%	-	(282,493)	(107,209)	3,537,894	10.69%	383,911	
99	1989	282,493	0.000%	-	(282,493)	(107,209)	3,430,685	10.69%	372,451	
100	1990	282,493	0.000%	-	(282,493)	(107,209)	3,323,476	10.69%	360,990	
101	1991	282,493	0.000%	-	(282,493)	(107,209)	3,216,267	10.69%	349,530	
102	1992	282,493	0.000%	-	(282,493)	(107,209)	3,109,058	10.69%	338,070	
103	1993	282,493	0.000%	-	(282,493)	(107,209)	3,001,850	10.69%	326,610	
104	1994	282,493	0.000%	-	(282,493)	(107,209)	2,894,641	10.69%	315,150	
105	1995	282,493	0.000%	-	(282,493)	(107,209)	2,787,432	10.69%	303,690	
106	1996	282,493	0.000%	-	(282,493)	(107,209)	2,680,223	10.69%	292,230	
107	1997	282,493	0.000%	-	(282,493)	(107,209)	2,573,014	10.69%	280,770	
108	1998	282,493	0.000%	-	(282,493)	(107,209)	2,465,805	10.69%	269,310	
109	1999	282,493	0.000%	-	(282,493)	(107,209)	2,358,596	10.69%	257,850	
110	2000	282,493	0.000%	-	(282,493)	(107,209)	2,251,387	10.69%	246,390	
111	2001	282,493	0.000%	-	(282,493)	(107,209)	2,144,178	10.69%	234,930	
112	2002	282,493	0.000%	-	(282,493)	(107,209)	2,036,969	10.69%	223,470	
113	2003	282,493	0.000%	-	(282,493)	(107,209)	1,929,760	10.69%	212,010	
114	2004	282,493	0.000%	-	(282,493)	(107,209)	1,822,552	10.69%	200,550	
115	2005	282,493	0.000%	-	(282,493)	(107,209)	1,715,343	10.69%	189,090	
116	2006	282,493	0.000%	-	(282,493)	(107,209)	1,608,134	10.69%	177,630	
117	2007	282,493	0.000%	-	(282,493)	(107,209)	1,500,925	10.69%	166,170	
118	2008	282,493	0.000%	-	(282,493)	(107,209)	1,393,716	10.69%	154,710	
119	2009	282,493	0.000%	-	(282,493)	(107,209)	1,286,507	10.69%	143,250	
120	2010	282,493	0.000%	-	(282,493)	(107,209)	1,179,298	10.69%	131,790	
121	2011	282,493	0.000%	-	(282,493)	(107,209)	1,072,089	10.69%	120,330	
122	2012	282,493	0.000%	-	(282,493)	(107,209)	964,880	10.69%	108,870	
123	2013	282,493	0.000%	-	(282,493)	(107,209)	857,671	10.69%	97,410	
124	2014	282,493	0.000%	-	(282,493)	(107,209)	750,462	10.69%	85,950	
125	2015	282,493	0.000%	-	(282,493)	(107,209)	643,253	10.69%	74,490	
126	2016	282,493	0.000%	-	(282,493)	(107,209)	536,045	10.69%	63,030	
127	2017	282,493	0.000%	-	(282,493)	(107,209)	428,836	10.69%	51,570	
128	2018	282,493	0.000%	-	(282,493)	(107,209)	321,627	9.22%	34,611	
129	2019	282,493	0.000%	-	(282,493)	(107,209)	214,418	9.22%	24,722	
130	2020	282,493	0.000%	-	(282,493)	(107,209)	107,209	9.22%	14,833	
131	2021	282,493	0.000%	-	(282,493)	(107,209)	-	9.22%	4,944	
132		$ 28,249,298		100% $ 28,249,298	$ (0)	$ -			$ 46,208,619	

Facility Name JC Boyle **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	3,807,076
2	RP Capability Allocator	RP and BOP Allocators	9.75%
3	**RP - Generator/Exciter**	(Line 1 * 2)	371,190
4			
5	GSU Transformer	Summary Investment	1,509,023
6	RP Capability Allocator	RP and BOP Allocators	9.75%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	147,130
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	6,860,818
10	Real and Reactive Power Portion	Summary Investment	3,294,206
11	RP Capability Allocator	RP and BOP Allocators	9.75%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	321,185
13	Total Plant Investment	Summary Investment	36,338,324
14	Balance of Plant	(Line 13 - 10 - 5 - 1)	27,728,019
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	7,432
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	846,937
18	RP Fixed Charge Percent	(Line 11(h))	13.5804%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 115,017**

	Depreciation			
20	Annual Depreciation Expense (D)	$	4,658,875	
21	Gross Plant Investment (F)		36,338,324	(Line 13)
22	SLDP=DE/F		12.8208%	(Line 20 / 21)
23	Depreciable years =1/SLDP		8	
24	Book Life (n)		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.4525%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment						
			Amount	Investment	FCR %	
O&M	O&M by Facility	$	1,440,537	$ 36,338,324	3.9642%	(f)/(g)
A&G	Fixed Charge Items				0.4475%	
Cash Working Capital	#REF!				0.0497%	
Prepayments	Fixed Charge Items				0.0203%	
Materials and Supplies	Fixed Charge Items				0.1029%	
General and Intangible Plant	Fixed Charge Items				1.1057%	
Other Taxes	Fixed Charge Items				0.5233%	
Depreciation	(Line 26)				0.0056%	
Return	Fixed Charge Items				7.5512%	
Income Taxes	Line 27				1.4525%	
ADIT	Line 31(i)		(596,854)	36,338,324	-1.6425%	
Total RP Fixed Charge Percent					13.5804%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 36,338,324	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$7,898,662
31	In Service Year	1958				Levelized Revenue Requirement			596,854
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1958	$ 363,383	3.750%	$ 1,362,687	$ 999,304	$ 379,246	$ 379,246	10.69%	$ 20,270
33	1959	363,383	7.219%	2,623,264	2,259,880	857,647	1,236,893	10.69%	86,378
34	1960	363,383	6.677%	2,426,310	2,062,927	782,901	2,019,794	10.69%	174,061
35	1961	363,383	6.177%	2,244,618	1,881,235	713,948	2,733,742	10.69%	254,063
36	1962	363,383	5.713%	2,076,008	1,712,625	649,958	3,383,700	10.69%	326,960
37	1963	363,383	5.285%	1,920,480	1,557,097	590,934	3,974,634	10.69%	393,282
38	1964	363,383	4.888%	1,776,217	1,412,834	536,185	4,510,819	10.69%	453,523
39	1965	363,383	4.522%	1,643,219	1,279,836	485,710	4,996,529	10.69%	508,140
40	1966	363,383	4.462%	1,621,416	1,258,033	477,436	5,473,965	10.69%	559,618
41	1967	363,383	4.461%	1,621,053	1,257,669	477,298	5,951,263	10.69%	610,646
42	1968	363,383	4.462%	1,621,416	1,258,033	477,436	6,428,699	10.69%	661,673
43	1969	363,383	4.461%	1,621,053	1,257,669	477,298	6,905,997	10.69%	712,701
44	1970	363,383	4.462%	1,621,416	1,258,033	477,436	7,383,434	10.69%	763,729
45	1971	363,383	4.461%	1,621,053	1,257,669	477,298	7,860,732	10.69%	814,757
46	1972	363,383	4.462%	1,621,416	1,258,033	477,436	8,338,168	10.69%	865,785
47	1973	363,383	4.461%	1,621,053	1,257,669	477,298	8,815,466	10.69%	916,812
48	1974	363,383	4.462%	1,621,416	1,258,033	477,436	9,292,902	10.69%	967,840
49	1975	363,383	4.461%	1,621,053	1,257,669	477,298	9,770,200	10.69%	1,018,868
50	1976	363,383	4.462%	1,621,416	1,258,033	477,436	10,247,636	10.69%	1,069,896
51	1977	363,383	4.461%	1,621,053	1,257,669	477,298	10,724,934	10.69%	1,120,923
52	1978	363,383	2.231%	810,708	447,325	169,764	10,894,698	10.69%	1,155,507
53	1979	363,383	0.000%	-	(363,383)	(137,908)	10,756,791	10.69%	1,157,210
54	1980	363,383	0.000%	-	(363,383)	(137,908)	10,618,883	10.69%	1,142,468
55	1981	363,383	0.000%	-	(363,383)	(137,908)	10,480,975	10.69%	1,127,727
56	1982	363,383	0.000%	-	(363,383)	(137,908)	10,343,068	10.69%	1,112,985
57	1983	363,383	0.000%	-	(363,383)	(137,908)	10,205,160	10.69%	1,098,244
58	1984	363,383	0.000%	-	(363,383)	(137,908)	10,067,253	10.69%	1,083,502
59	1985	363,383	0.000%	-	(363,383)	(137,908)	9,929,345	10.69%	1,068,761
60	1986	363,383	0.000%	-	(363,383)	(137,908)	9,791,438	10.69%	1,054,019
61	1987	363,383	0.000%	-	(363,383)	(137,908)	9,653,530	10.69%	1,039,278
62	1988	363,383	0.000%	-	(363,383)	(137,908)	9,515,622	10.69%	1,024,536
63	1989	363,383	0.000%	-	(363,383)	(137,908)	9,377,715	10.69%	1,009,794
64	1990	363,383	0.000%	-	(363,383)	(137,908)	9,239,807	10.69%	995,053
65	1991	363,383	0.000%	-	(363,383)	(137,908)	9,101,900	10.69%	980,311
66	1992	363,383	0.000%	-	(363,383)	(137,908)	8,963,992	10.69%	965,570
67	1993	363,383	0.000%	-	(363,383)	(137,908)	8,826,085	10.69%	950,828
68	1994	363,383	0.000%	-	(363,383)	(137,908)	8,688,177	10.69%	936,087
69	1995	363,383	0.000%	-	(363,383)	(137,908)	8,550,269	10.69%	921,345
70	1996	363,383	0.000%	-	(363,383)	(137,908)	8,412,362	10.69%	906,604
71	1997	363,383	0.000%	-	(363,383)	(137,908)	8,274,454	10.69%	891,862
72	1998	363,383	0.000%	-	(363,383)	(137,908)	8,136,547	10.69%	877,121
73	1999	363,383	0.000%	-	(363,383)	(137,908)	7,998,639	10.69%	862,379
74	2000	363,383	0.000%	-	(363,383)	(137,908)	7,860,732	10.69%	847,638
75	2001	363,383	0.000%	-	(363,383)	(137,908)	7,722,824	10.69%	832,896
76	2002	363,383	0.000%	-	(363,383)	(137,908)	7,584,916	10.69%	818,155
77	2003	363,383	0.000%	-	(363,383)	(137,908)	7,447,009	10.69%	803,413
78	2004	363,383	0.000%	-	(363,383)	(137,908)	7,309,101	10.69%	788,672
79	2005	363,383	0.000%	-	(363,383)	(137,908)	7,171,194	10.69%	773,930
80	2006	363,383	0.000%	-	(363,383)	(137,908)	7,033,286	10.69%	759,189
81	2007	363,383	0.000%	-	(363,383)	(137,908)	6,895,379	10.69%	744,447
82	2008	363,383	0.000%	-	(363,383)	(137,908)	6,757,471	10.69%	729,706
83	2009	363,383	0.000%	-	(363,383)	(137,908)	6,619,563	10.69%	714,964
84	2010	363,383	0.000%	-	(363,383)	(137,908)	6,481,656	10.69%	700,222

85		2011	363,383	0.000%	-	(363,383)	(137,908)	6,343,748	10.69%	685,481
86		2012	363,383	0.000%	-	(363,383)	(137,908)	6,205,841	10.69%	670,739
87		2013	363,383	0.000%	-	(363,383)	(137,908)	6,067,933	10.69%	655,998
88		2014	363,383	0.000%	-	(363,383)	(137,908)	5,930,026	10.69%	641,256
89		2015	363,383	0.000%	-	(363,383)	(137,908)	5,792,118	10.69%	626,515
90		2016	363,383	0.000%	-	(363,383)	(137,908)	5,654,210	10.69%	611,773
91		2017	363,383	0.000%	-	(363,383)	(137,908)	5,516,303	10.69%	597,032
92		2018	363,383	0.000%	-	(363,383)	(137,908)	5,378,395	9.22%	502,463
93		2019	363,383	0.000%	-	(363,383)	(137,908)	5,240,488	9.22%	489,743
94		2020	363,383	0.000%	-	(363,383)	(137,908)	5,102,580	9.22%	477,022
95		2021	363,383	0.000%	-	(363,383)	(137,908)	4,964,673	9.22%	464,302
96		2022	363,383	0.000%	-	(363,383)	(137,908)	4,826,765	9.22%	451,581
97		2023	363,383	0.000%	-	(363,383)	(137,908)	4,688,857	9.22%	438,860
98		2024	363,383	0.000%	-	(363,383)	(137,908)	4,550,950	9.22%	426,140
99		2025	363,383	0.000%	-	(363,383)	(137,908)	4,413,042	9.22%	413,419
100		2026	363,383	0.000%	-	(363,383)	(137,908)	4,275,135	9.22%	400,699
101		2027	363,383	0.000%	-	(363,383)	(137,908)	4,137,227	9.22%	387,978
102		2028	363,383	0.000%	-	(363,383)	(137,908)	3,999,320	9.22%	375,257
103		2029	363,383	0.000%	-	(363,383)	(137,908)	3,861,412	9.22%	362,537
104		2030	363,383	0.000%	-	(363,383)	(137,908)	3,723,504	9.22%	349,816
105		2031	363,383	0.000%	-	(363,383)	(137,908)	3,585,597	9.22%	337,096
106		2032	363,383	0.000%	-	(363,383)	(137,908)	3,447,689	9.22%	324,375
107		2033	363,383	0.000%	-	(363,383)	(137,908)	3,309,782	9.22%	311,655
108		2034	363,383	0.000%	-	(363,383)	(137,908)	3,171,874	9.22%	298,934
109		2035	363,383	0.000%	-	(363,383)	(137,908)	3,033,967	9.22%	286,213
110		2036	363,383	0.000%	-	(363,383)	(137,908)	2,896,059	9.22%	273,493
111		2037	363,383	0.000%	-	(363,383)	(137,908)	2,758,151	9.22%	260,772
112		2038	363,383	0.000%	-	(363,383)	(137,908)	2,620,244	9.22%	248,052
113		2039	363,383	0.000%	-	(363,383)	(137,908)	2,482,336	9.22%	235,331
114		2040	363,383	0.000%	-	(363,383)	(137,908)	2,344,429	9.22%	222,610
115		2041	363,383	0.000%	-	(363,383)	(137,908)	2,206,521	9.22%	209,890
116		2042	363,383	0.000%	-	(363,383)	(137,908)	2,068,614	9.22%	197,169
117		2043	363,383	0.000%	-	(363,383)	(137,908)	1,930,706	9.22%	184,449
118		2044	363,383	0.000%	-	(363,383)	(137,908)	1,792,798	9.22%	171,728
119		2045	363,383	0.000%	-	(363,383)	(137,908)	1,654,891	9.22%	159,007
120		2046	363,383	0.000%	-	(363,383)	(137,908)	1,516,983	9.22%	146,287
121		2047	363,383	0.000%	-	(363,383)	(137,908)	1,379,076	9.22%	133,566
122		2048	363,383	0.000%	-	(363,383)	(137,908)	1,241,168	9.22%	120,846
123		2049	363,383	0.000%	-	(363,383)	(137,908)	1,103,261	9.22%	108,125
124		2050	363,383	0.000%	-	(363,383)	(137,908)	965,353	9.22%	95,404
125		2051	363,383	0.000%	-	(363,383)	(137,908)	827,445	9.22%	82,684
126		2052	363,383	0.000%	-	(363,383)	(137,908)	689,538	9.22%	69,963
127		2053	363,383	0.000%	-	(363,383)	(137,908)	551,630	9.22%	57,243
128		2054	363,383	0.000%	-	(363,383)	(137,908)	413,723	9.22%	44,522
129		2055	363,383	0.000%	-	(363,383)	(137,908)	275,815	9.22%	31,801
130		2056	363,383	0.000%	-	(363,383)	(137,908)	137,908	9.22%	19,081
131		2057	363,383	0.000%	-	(363,383)	(137,908)	0	9.22%	6,360
132			$ 36,338,324	100%	$ 36,338,324	$ (0)	$ 0			$ 57,839,615

Facility Name Irongate **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	848,257
2	RP Capability Allocator	RP and BOP Allocators	9.75%
3	**RP - Generator/Exciter**	(Line 1 * 2)	82,705
4			
5	GSU Transformer	Summary Investment	134,801
6	RP Capability Allocator	RP and BOP Allocators	9.75%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	13,143
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	911,415
10	Real and Reactive Power Portion	Summary Investment	184,798
11	RP Capability Allocator	RP and BOP Allocators	9.75%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	18,018
13	Total Plant Investment	Summary Investment	30,376,361
14	Balance of Plant	(Line 13 - 10 - 5 - 1)	29,208,505
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	7,829
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	121,695
18	RP Fixed Charge Percent	(Line 11(h))	17.9559%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 21,851**

	Depreciation			
20	Annual Depreciation Expense (D)	$	3,816,575	
21	Gross Plant Investment (F)		30,376,361	(Line 13)
22	SLDP=DE/F		12.5643%	(Line 20 / 21)
23	Depreciable years (n)=1/SLDP		8	
24	Book Life (n)		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.4525%	Based Upon Book Life CTR=Composite Tax Rate

(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment					
		Amount	Investment	FCR %	
O&M	O&M by Facility	$ 2,518,217	$ 30,376,361	8.2901%	(f)/(g)
A&G	Fixed Charge Items			0.4475%	
Cash Working Capital	#REF!			0.0983%	
Prepayments	Fixed Charge Items			0.0203%	
Materials and Supplies	Fixed Charge Items			0.1029%	
General and Intangible Plant	Fixed Charge Items			1.1057%	
Other Taxes	Fixed Charge Items			0.5233%	
Depreciation	(Line 26)			0.0056%	
Return	Fixed Charge Items			7.5512%	
Income Taxes	Line 27			1.4525%	
ADIT	Line 31(i)	(498,624)	30,376,361	-1.6415%	
Total RP Fixed Charge Percent				17.9559%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 30,376,361	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$6,598,707
31	In Service Year	1962				Levelized Revenue Requirement			498,624
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1962	$ 303,764	3.750%	$ 1,139,114	$ 835,350	$ 317,024	$ 317,024	10.69%	$ 16,944
33	1963	303,764	7.219%	2,192,869	1,889,106	716,935	1,033,958	10.69%	72,206
34	1964	303,764	6.677%	2,028,230	1,724,466	654,452	1,688,410	10.69%	145,503
35	1965	303,764	6.177%	1,876,348	1,572,584	596,811	2,285,222	10.69%	212,379
36	1966	303,764	5.713%	1,735,401	1,431,638	543,321	2,828,543	10.69%	273,316
37	1967	303,764	5.285%	1,605,391	1,301,627	493,980	3,322,523	10.69%	328,757
38	1968	303,764	4.888%	1,484,797	1,181,033	448,214	3,770,737	10.69%	379,114
39	1969	303,764	4.522%	1,373,619	1,069,855	406,021	4,176,758	10.69%	424,771
40	1970	303,764	4.462%	1,355,393	1,051,630	399,104	4,575,862	10.69%	467,802
41	1971	303,764	4.461%	1,355,089	1,051,326	398,989	4,974,850	10.69%	510,458
42	1972	303,764	4.462%	1,355,393	1,051,630	399,104	5,373,954	10.69%	553,114
43	1973	303,764	4.461%	1,355,089	1,051,326	398,989	5,772,943	10.69%	595,770
44	1974	303,764	4.462%	1,355,393	1,051,630	399,104	6,172,047	10.69%	638,425
45	1975	303,764	4.461%	1,355,089	1,051,326	398,989	6,571,036	10.69%	681,081
46	1976	303,764	4.462%	1,355,393	1,051,630	399,104	6,970,140	10.69%	723,737
47	1977	303,764	4.461%	1,355,089	1,051,326	398,989	7,369,128	10.69%	766,393
48	1978	303,764	4.462%	1,355,393	1,051,630	399,104	7,768,232	10.69%	809,048
49	1979	303,764	4.461%	1,355,089	1,051,326	398,989	8,167,221	10.69%	851,704
50	1980	303,764	4.462%	1,355,393	1,051,630	399,104	8,566,325	10.69%	894,360
51	1981	303,764	4.461%	1,355,089	1,051,326	398,989	8,965,313	10.69%	937,016
52	1982	303,764	2.231%	677,697	373,933	141,911	9,107,225	10.69%	965,925
53	1983	303,764	0.000%	-	(303,764)	(115,281)	8,991,943	10.69%	967,348
54	1984	303,764	0.000%	-	(303,764)	(115,281)	8,876,662	10.69%	955,026
55	1985	303,764	0.000%	-	(303,764)	(115,281)	8,761,381	10.69%	942,703
56	1986	303,764	0.000%	-	(303,764)	(115,281)	8,646,099	10.69%	930,380
57	1987	303,764	0.000%	-	(303,764)	(115,281)	8,530,818	10.69%	918,057
58	1988	303,764	0.000%	-	(303,764)	(115,281)	8,415,537	10.69%	905,734
59	1989	303,764	0.000%	-	(303,764)	(115,281)	8,300,256	10.69%	893,411
60	1990	303,764	0.000%	-	(303,764)	(115,281)	8,184,974	10.69%	881,088
61	1991	303,764	0.000%	-	(303,764)	(115,281)	8,069,693	10.69%	868,765
62	1992	303,764	0.000%	-	(303,764)	(115,281)	7,954,412	10.69%	856,442
63	1993	303,764	0.000%	-	(303,764)	(115,281)	7,839,130	10.69%	844,119
64	1994	303,764	0.000%	-	(303,764)	(115,281)	7,723,849	10.69%	831,796
65	1995	303,764	0.000%	-	(303,764)	(115,281)	7,608,568	10.69%	819,474
66	1996	303,764	0.000%	-	(303,764)	(115,281)	7,493,286	10.69%	807,151
67	1997	303,764	0.000%	-	(303,764)	(115,281)	7,378,005	10.69%	794,828
68	1998	303,764	0.000%	-	(303,764)	(115,281)	7,262,724	10.69%	782,505
69	1999	303,764	0.000%	-	(303,764)	(115,281)	7,147,442	10.69%	770,182
70	2000	303,764	0.000%	-	(303,764)	(115,281)	7,032,161	10.69%	757,859
71	2001	303,764	0.000%	-	(303,764)	(115,281)	6,916,880	10.69%	745,536
72	2002	303,764	0.000%	-	(303,764)	(115,281)	6,801,598	10.69%	733,213
73	2003	303,764	0.000%	-	(303,764)	(115,281)	6,686,317	10.69%	720,890
74	2004	303,764	0.000%	-	(303,764)	(115,281)	6,571,036	10.69%	708,567
75	2005	303,764	0.000%	-	(303,764)	(115,281)	6,455,754	10.69%	696,244
76	2006	303,764	0.000%	-	(303,764)	(115,281)	6,340,473	10.69%	683,922
77	2007	303,764	0.000%	-	(303,764)	(115,281)	6,225,192	10.69%	671,599
78	2008	303,764	0.000%	-	(303,764)	(115,281)	6,109,910	10.69%	659,276
79	2009	303,764	0.000%	-	(303,764)	(115,281)	5,994,629	10.69%	646,953
80	2010	303,764	0.000%	-	(303,764)	(115,281)	5,879,348	10.69%	634,630
81	2011	303,764	0.000%	-	(303,764)	(115,281)	5,764,066	10.69%	622,307
82	2012	303,764	0.000%	-	(303,764)	(115,281)	5,648,785	10.69%	609,984
83	2013	303,764	0.000%	-	(303,764)	(115,281)	5,533,504	10.69%	597,661
84	2014	303,764	0.000%	-	(303,764)	(115,281)	5,418,222	10.69%	585,338

85	2015	303,764	0.000%		-	(303,764)	(115,281)	5,302,941	10.69%	573,015
86	2016	303,764	0.000%		-	(303,764)	(115,281)	5,187,660	10.69%	560,692
87	2017	303,764	0.000%		-	(303,764)	(115,281)	5,072,378	10.69%	548,369
88	2018	303,764	0.000%		-	(303,764)	(115,281)	4,957,097	9.22%	462,559
89	2019	303,764	0.000%		-	(303,764)	(115,281)	4,841,816	9.22%	451,926
90	2020	303,764	0.000%		-	(303,764)	(115,281)	4,726,534	9.22%	441,292
91	2021	303,764	0.000%		-	(303,764)	(115,281)	4,611,253	9.22%	430,659
92	2022	303,764	0.000%		-	(303,764)	(115,281)	4,495,972	9.22%	420,025
93	2023	303,764	0.000%		-	(303,764)	(115,281)	4,380,690	9.22%	409,392
94	2024	303,764	0.000%		-	(303,764)	(115,281)	4,265,409	9.22%	398,758
95	2025	303,764	0.000%		-	(303,764)	(115,281)	4,150,128	9.22%	388,125
96	2026	303,764	0.000%		-	(303,764)	(115,281)	4,034,846	9.22%	377,491
97	2027	303,764	0.000%		-	(303,764)	(115,281)	3,919,565	9.22%	366,857
98	2028	303,764	0.000%		-	(303,764)	(115,281)	3,804,284	9.22%	356,224
99	2029	303,764	0.000%		-	(303,764)	(115,281)	3,689,002	9.22%	345,590
100	2030	303,764	0.000%		-	(303,764)	(115,281)	3,573,721	9.22%	334,957
101	2031	303,764	0.000%		-	(303,764)	(115,281)	3,458,440	9.22%	324,323
102	2032	303,764	0.000%		-	(303,764)	(115,281)	3,343,158	9.22%	313,690
103	2033	303,764	0.000%		-	(303,764)	(115,281)	3,227,877	9.22%	303,056
104	2034	303,764	0.000%		-	(303,764)	(115,281)	3,112,596	9.22%	292,423
105	2035	303,764	0.000%		-	(303,764)	(115,281)	2,997,314	9.22%	281,789
106	2036	303,764	0.000%		-	(303,764)	(115,281)	2,882,033	9.22%	271,155
107	2037	303,764	0.000%		-	(303,764)	(115,281)	2,766,752	9.22%	260,522
108	2038	303,764	0.000%		-	(303,764)	(115,281)	2,651,471	9.22%	249,888
109	2039	303,764	0.000%		-	(303,764)	(115,281)	2,536,189	9.22%	239,255
110	2040	303,764	0.000%		-	(303,764)	(115,281)	2,420,908	9.22%	228,621
111	2041	303,764	0.000%		-	(303,764)	(115,281)	2,305,627	9.22%	217,988
112	2042	303,764	0.000%		-	(303,764)	(115,281)	2,190,345	9.22%	207,354
113	2043	303,764	0.000%		-	(303,764)	(115,281)	2,075,064	9.22%	196,721
114	2044	303,764	0.000%		-	(303,764)	(115,281)	1,959,783	9.22%	186,087
115	2045	303,764	0.000%		-	(303,764)	(115,281)	1,844,501	9.22%	175,454
116	2046	303,764	0.000%		-	(303,764)	(115,281)	1,729,220	9.22%	164,820
117	2047	303,764	0.000%		-	(303,764)	(115,281)	1,613,939	9.22%	154,186
118	2048	303,764	0.000%		-	(303,764)	(115,281)	1,498,657	9.22%	143,553
119	2049	303,764	0.000%		-	(303,764)	(115,281)	1,383,376	9.22%	132,919
120	2050	303,764	0.000%		-	(303,764)	(115,281)	1,268,095	9.22%	122,286
121	2051	303,764	0.000%		-	(303,764)	(115,281)	1,152,813	9.22%	111,652
122	2052	303,764	0.000%		-	(303,764)	(115,281)	1,037,532	9.22%	101,019
123	2053	303,764	0.000%		-	(303,764)	(115,281)	922,251	9.22%	90,385
124	2054	303,764	0.000%		-	(303,764)	(115,281)	806,969	9.22%	79,752
125	2055	303,764	0.000%		-	(303,764)	(115,281)	691,688	9.22%	69,118
126	2056	303,764	0.000%		-	(303,764)	(115,281)	576,407	9.22%	58,485
127	2057	303,764	0.000%		-	(303,764)	(115,281)	461,125	9.22%	47,851
128	2058	303,764	0.000%		-	(303,764)	(115,281)	345,844	9.22%	37,217
129	2059	303,764	0.000%		-	(303,764)	(115,281)	230,563	9.22%	26,584
130	2060	303,764	0.000%		-	(303,764)	(115,281)	115,281	9.22%	15,950
131	2061	303,764	0.000%		-	(303,764)	(115,281)	(0)	9.22%	5,317
132		$ 30,376,361		100%	$ 30,376,361	$ (0)	$ (0)			$ 48,066,161

Facility Name Ashton **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	922,501
2	RP Capability Allocator	RP and BOP Allocators	28.99%
3	**RP - Generator/Exciter**	(Line 1 * 2)	267,468
4			
5	GSU Transformer	Summary Investment	314,892
6	RP Capability Allocator	RP and BOP Allocators	28.99%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	91,299
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	1,330,021
10	Real and Reactive Power Portion	Summary Investment	351,281
11	RP Capability Allocator	RP and BOP Allocators	28.99%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	101,850
13	Total Plant Investment	Summary Investment	34,226,837
14	Balance of Plant	(Line 13 - 10 - 5 - 1)	32,638,163
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	8,748
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	469,365
18	RP Fixed Charge Percent	(Line 11(h))	10.9115%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 51,215**

	Depreciation			
20	Annual Depreciation Expense (D)	$	1,940,435	
21	Gross Plant Investment (F)		34,226,837	(Line 13)
22	SLDP=DE/F		5.6693%	(Line 20 / 21)
23	Depreciable years =1/SLDP		18	
24	Book Life (n)		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
	Income Tax Factor to Include in Fixed Charge		
27	Factor	1.4525%	Based Upon Book Life
	[(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]		CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 454,176	$ 34,226,837	1.3270%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	#REF!			0.0200%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.0056%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.4525%	
	ADIT	Line 31(i)	(562,825)	34,226,837	-1.6444%	
	Total RP Fixed Charge Percent				10.9115%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 34,226,837	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$7,448,331
31	In Service Year	1917				Levelized Revenue Requirement			562,825
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1917	$ 342,268	3.750%	$ 1,283,506	$ 941,238	$ 357,209	$ 357,209	10.69%	$ 19,092
33	1918	342,268	7.219%	2,470,835	2,128,567	807,812	1,165,022	10.69%	81,359
34	1919	342,268	6.677%	2,285,326	1,943,058	737,410	1,902,431	10.69%	163,947
35	1920	342,268	6.177%	2,114,192	1,771,923	672,463	2,574,894	10.69%	239,300
36	1921	342,268	5.713%	1,955,379	1,613,111	612,192	3,187,086	10.69%	307,961
37	1922	342,268	5.285%	1,808,888	1,466,620	556,597	3,743,683	10.69%	370,430
38	1923	342,268	4.888%	1,673,008	1,330,739	505,029	4,248,712	10.69%	427,170
39	1924	342,268	4.522%	1,547,738	1,205,469	457,488	4,706,199	10.69%	478,614
40	1925	342,268	4.462%	1,527,201	1,184,933	449,694	5,155,893	10.69%	527,100
41	1926	342,268	4.461%	1,526,859	1,184,591	449,564	5,605,457	10.69%	575,163
42	1927	342,268	4.462%	1,527,201	1,184,933	449,694	6,055,151	10.69%	623,226
43	1928	342,268	4.461%	1,526,859	1,184,591	449,564	6,504,715	10.69%	671,289
44	1929	342,268	4.462%	1,527,201	1,184,933	449,694	6,954,409	10.69%	719,351
45	1930	342,268	4.461%	1,526,859	1,184,591	449,564	7,403,973	10.69%	767,414
46	1931	342,268	4.462%	1,527,201	1,184,933	449,694	7,853,667	10.69%	815,477
47	1932	342,268	4.461%	1,526,859	1,184,591	449,564	8,303,231	10.69%	863,540
48	1933	342,268	4.462%	1,527,201	1,184,933	449,694	8,752,925	10.69%	911,602
49	1934	342,268	4.461%	1,526,859	1,184,591	449,564	9,202,489	10.69%	959,665
50	1935	342,268	4.462%	1,527,201	1,184,933	449,694	9,652,183	10.69%	1,007,728
51	1936	342,268	4.461%	1,526,859	1,184,591	449,564	10,101,747	10.69%	1,055,791
52	1937	342,268	2.231%	763,601	421,332	159,900	10,261,647	10.69%	1,088,365
53	1938	342,268	0.000%	-	(342,268)	(129,894)	10,131,753	10.69%	1,089,969
54	1939	342,268	0.000%	-	(342,268)	(129,894)	10,001,859	10.69%	1,076,084
55	1940	342,268	0.000%	-	(342,268)	(129,894)	9,871,964	10.69%	1,062,199
56	1941	342,268	0.000%	-	(342,268)	(129,894)	9,742,070	10.69%	1,048,314
57	1942	342,268	0.000%	-	(342,268)	(129,894)	9,612,176	10.69%	1,034,429
58	1943	342,268	0.000%	-	(342,268)	(129,894)	9,482,282	10.69%	1,020,544
59	1944	342,268	0.000%	-	(342,268)	(129,894)	9,352,387	10.69%	1,006,659
60	1945	342,268	0.000%	-	(342,268)	(129,894)	9,222,493	10.69%	992,774
61	1946	342,268	0.000%	-	(342,268)	(129,894)	9,092,599	10.69%	978,889
62	1947	342,268	0.000%	-	(342,268)	(129,894)	8,962,704	10.69%	965,004
63	1948	342,268	0.000%	-	(342,268)	(129,894)	8,832,810	10.69%	951,119
64	1949	342,268	0.000%	-	(342,268)	(129,894)	8,702,916	10.69%	937,234
65	1950	342,268	0.000%	-	(342,268)	(129,894)	8,573,022	10.69%	923,349
66	1951	342,268	0.000%	-	(342,268)	(129,894)	8,443,127	10.69%	909,464
67	1952	342,268	0.000%	-	(342,268)	(129,894)	8,313,233	10.69%	895,579
68	1953	342,268	0.000%	-	(342,268)	(129,894)	8,183,339	10.69%	881,694
69	1954	342,268	0.000%	-	(342,268)	(129,894)	8,053,445	10.69%	867,809
70	1955	342,268	0.000%	-	(342,268)	(129,894)	7,923,550	10.69%	853,924
71	1956	342,268	0.000%	-	(342,268)	(129,894)	7,793,656	10.69%	840,039
72	1957	342,268	0.000%	-	(342,268)	(129,894)	7,663,762	10.69%	826,154
73	1958	342,268	0.000%	-	(342,268)	(129,894)	7,533,868	10.69%	812,270
74	1959	342,268	0.000%	-	(342,268)	(129,894)	7,403,973	10.69%	798,385
75	1960	342,268	0.000%	-	(342,268)	(129,894)	7,274,079	10.69%	784,500
76	1961	342,268	0.000%	-	(342,268)	(129,894)	7,144,185	10.69%	770,615
77	1962	342,268	0.000%	-	(342,268)	(129,894)	7,014,290	10.69%	756,730
78	1963	342,268	0.000%	-	(342,268)	(129,894)	6,884,396	10.69%	742,845
79	1964	342,268	0.000%	-	(342,268)	(129,894)	6,754,502	10.69%	728,960
80	1965	342,268	0.000%	-	(342,268)	(129,894)	6,624,608	10.69%	715,075
81	1966	342,268	0.000%	-	(342,268)	(129,894)	6,494,713	10.69%	701,190
82	1967	342,268	0.000%	-	(342,268)	(129,894)	6,364,819	10.69%	687,305
83	1968	342,268	0.000%	-	(342,268)	(129,894)	6,234,925	10.69%	673,420
84	1969	342,268	0.000%	-	(342,268)	(129,894)	6,105,031	10.69%	659,535

85		1970	342,268	0.000%	-	(342,268)	(129,894)	5,975,136	10.69%	645,650
86		1971	342,268	0.000%	-	(342,268)	(129,894)	5,845,242	10.69%	631,765
87		1972	342,268	0.000%	-	(342,268)	(129,894)	5,715,348	10.69%	617,880
88		1973	342,268	0.000%	-	(342,268)	(129,894)	5,585,454	10.69%	603,995
89		1974	342,268	0.000%	-	(342,268)	(129,894)	5,455,559	10.69%	590,110
90		1975	342,268	0.000%	-	(342,268)	(129,894)	5,325,665	10.69%	576,225
91		1976	342,268	0.000%	-	(342,268)	(129,894)	5,195,771	10.69%	562,340
92		1977	342,268	0.000%	-	(342,268)	(129,894)	5,065,876	10.69%	548,455
93		1978	342,268	0.000%	-	(342,268)	(129,894)	4,935,982	10.69%	534,571
94		1979	342,268	0.000%	-	(342,268)	(129,894)	4,806,088	10.69%	520,686
95		1980	342,268	0.000%	-	(342,268)	(129,894)	4,676,194	10.69%	506,801
96		1981	342,268	0.000%	-	(342,268)	(129,894)	4,546,299	10.69%	492,916
97		1982	342,268	0.000%	-	(342,268)	(129,894)	4,416,405	10.69%	479,031
98		1983	342,268	0.000%	-	(342,268)	(129,894)	4,286,511	10.69%	465,146
99		1984	342,268	0.000%	-	(342,268)	(129,894)	4,156,617	10.69%	451,261
100		1985	342,268	0.000%	-	(342,268)	(129,894)	4,026,722	10.69%	437,376
101		1986	342,268	0.000%	-	(342,268)	(129,894)	3,896,828	10.69%	423,491
102		1987	342,268	0.000%	-	(342,268)	(129,894)	3,766,934	10.69%	409,606
103		1988	342,268	0.000%	-	(342,268)	(129,894)	3,637,040	10.69%	395,721
104		1989	342,268	0.000%	-	(342,268)	(129,894)	3,507,145	10.69%	381,836
105		1990	342,268	0.000%	-	(342,268)	(129,894)	3,377,251	10.69%	367,951
106		1991	342,268	0.000%	-	(342,268)	(129,894)	3,247,357	10.69%	354,066
107		1992	342,268	0.000%	-	(342,268)	(129,894)	3,117,462	10.69%	340,181
108		1993	342,268	0.000%	-	(342,268)	(129,894)	2,987,568	10.69%	326,296
109		1994	342,268	0.000%	-	(342,268)	(129,894)	2,857,674	10.69%	312,411
110		1995	342,268	0.000%	-	(342,268)	(129,894)	2,727,780	10.69%	298,526
111		1996	342,268	0.000%	-	(342,268)	(129,894)	2,597,885	10.69%	284,641
112		1997	342,268	0.000%	-	(342,268)	(129,894)	2,467,991	10.69%	270,757
113		1998	342,268	0.000%	-	(342,268)	(129,894)	2,338,097	10.69%	256,872
114		1999	342,268	0.000%	-	(342,268)	(129,894)	2,208,203	10.69%	242,987
115		2000	342,268	0.000%	-	(342,268)	(129,894)	2,078,308	10.69%	229,102
116		2001	342,268	0.000%	-	(342,268)	(129,894)	1,948,414	10.69%	215,217
117		2002	342,268	0.000%	-	(342,268)	(129,894)	1,818,520	10.69%	201,332
118		2003	342,268	0.000%	-	(342,268)	(129,894)	1,688,625	10.69%	187,447
119		2004	342,268	0.000%	-	(342,268)	(129,894)	1,558,731	10.69%	173,562
120		2005	342,268	0.000%	-	(342,268)	(129,894)	1,428,837	10.69%	159,677
121		2006	342,268	0.000%	-	(342,268)	(129,894)	1,298,943	10.69%	145,792
122		2007	342,268	0.000%	-	(342,268)	(129,894)	1,169,048	10.69%	131,907
123		2008	342,268	0.000%	-	(342,268)	(129,894)	1,039,154	10.69%	118,022
124		2009	342,268	0.000%	-	(342,268)	(129,894)	909,260	10.69%	104,137
125		2010	342,268	0.000%	-	(342,268)	(129,894)	779,366	10.69%	90,252
126		2011	342,268	0.000%	-	(342,268)	(129,894)	649,471	10.69%	76,367
127		2012	342,268	0.000%	-	(342,268)	(129,894)	519,577	10.69%	62,482
128		2013	342,268	0.000%	-	(342,268)	(129,894)	389,683	10.69%	48,597
129		2014	342,268	0.000%	-	(342,268)	(129,894)	259,789	10.69%	34,712
130		2015	342,268	0.000%	-	(342,268)	(129,894)	129,894	10.69%	20,827
131		2016	342,268	0.000%	-	(342,268)	(129,894)	0	10.69%	6,942
132			$ 34,226,837		100% $ 34,226,837	$ 0	$ 0			$ 56,001,569

Facility Name Soda **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	2,341,420
2	RP Capability Allocator	RP and BOP Allocators	26.90%
3	**RP - Generator/Exciter**	(Line 1 * 2)	629,783
4			
5	GSU Transformer	Summary Investment	241,895
6	RP Capability Allocator	RP and BOP Allocators	26.90%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	65,064
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	795,944
10	Real and Reactive Power Portion	Summary Investment	334,292
11	RP Capability Allocator	RP and BOP Allocators	26.90%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	89,916
13	Total Plant Investment	Summary Investment	18,696,873
14	Balance of Plant	(Line 13 - 10 - 5 - 1)	15,779,266
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	4,229
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	788,993
18	RP Fixed Charge Percent	(Line 11(h))	12.6022%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 99,430**

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 560,682	$ 18,696,873	2.9988%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	#REF!			0.0388%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.0056%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.4525%	
	ADIT	Line 31(i)	(307,450)	18,696,873	-1.6444%	
	Total RP Fixed Charge Percent				12.6022%	

	Depreciation			
20	Annual Depreciation Expense (D)	$ 602,131		
21	Gross Plant Investment (F)	18,696,873	(Line 13)	
22	SLDP=DE/F	3.2205%	(Line 20 / 21)	
23	Depreciable years =1/SLDP	31		
24	Book Life (n)	100	Book Lives	
25	SLDP for Book Life = 1/n	1.00%		
26	SFDP=(R/((1+R)^n-1)	0.01%	R=Return	

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.4525%	Based Upon Book Life CTR=Composite Tax Rate

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 18,696,873	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$4,068,735
31	In Service Year	1924				Levelized Revenue Requirement			307,450
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1924	$ 186,969	3.750%	$ 701,133	$ 514,164	$ 195,130	$ 195,130	10.69%	$ 10,429
33	1925	186,969	7.219%	1,349,727	1,162,759	441,278	636,409	10.69%	44,443
34	1926	186,969	6.677%	1,248,390	1,061,421	402,820	1,039,229	10.69%	89,558
35	1927	186,969	6.177%	1,154,906	967,937	367,342	1,406,571	10.69%	130,721
36	1928	186,969	5.713%	1,068,152	881,184	334,418	1,740,989	10.69%	168,228
37	1929	186,969	5.285%	988,130	801,161	304,049	2,045,037	10.69%	202,352
38	1930	186,969	4.888%	913,903	726,934	275,879	2,320,916	10.69%	233,348
39	1931	186,969	4.522%	845,473	658,504	249,909	2,570,825	10.69%	261,449
40	1932	186,969	4.462%	834,254	647,286	245,651	2,816,476	10.69%	287,936
41	1933	186,969	4.461%	834,068	647,099	245,580	3,062,057	10.69%	314,191
42	1934	186,969	4.462%	834,254	647,286	245,651	3,307,708	10.69%	340,446
43	1935	186,969	4.461%	834,068	647,099	245,580	3,553,289	10.69%	366,701
44	1936	186,969	4.462%	834,254	647,286	245,651	3,798,940	10.69%	392,955
45	1937	186,969	4.461%	834,068	647,099	245,580	4,044,521	10.69%	419,210
46	1938	186,969	4.462%	834,254	647,286	245,651	4,290,172	10.69%	445,465
47	1939	186,969	4.461%	834,068	647,099	245,580	4,535,753	10.69%	471,720
48	1940	186,969	4.462%	834,254	647,286	245,651	4,781,404	10.69%	497,975
49	1941	186,969	4.461%	834,068	647,099	245,580	5,026,984	10.69%	524,230
50	1942	186,969	4.462%	834,254	647,286	245,651	5,272,636	10.69%	550,485
51	1943	186,969	4.461%	834,068	647,099	245,580	5,518,216	10.69%	576,740
52	1944	186,969	2.231%	417,127	230,159	87,347	5,605,564	10.69%	594,534
53	1945	186,969	0.000%	-	(186,969)	(70,957)	5,534,607	10.69%	595,410
54	1946	186,969	0.000%	-	(186,969)	(70,957)	5,463,651	10.69%	587,825
55	1947	186,969	0.000%	-	(186,969)	(70,957)	5,392,694	10.69%	580,240
56	1948	186,969	0.000%	-	(186,969)	(70,957)	5,321,738	10.69%	572,656
57	1949	186,969	0.000%	-	(186,969)	(70,957)	5,250,781	10.69%	565,071
58	1950	186,969	0.000%	-	(186,969)	(70,957)	5,179,825	10.69%	557,486
59	1951	186,969	0.000%	-	(186,969)	(70,957)	5,108,868	10.69%	549,901
60	1952	186,969	0.000%	-	(186,969)	(70,957)	5,037,912	10.69%	542,316
61	1953	186,969	0.000%	-	(186,969)	(70,957)	4,966,955	10.69%	534,731
62	1954	186,969	0.000%	-	(186,969)	(70,957)	4,895,999	10.69%	527,146
63	1955	186,969	0.000%	-	(186,969)	(70,957)	4,825,042	10.69%	519,562
64	1956	186,969	0.000%	-	(186,969)	(70,957)	4,754,086	10.69%	511,977
65	1957	186,969	0.000%	-	(186,969)	(70,957)	4,683,129	10.69%	504,392
66	1958	186,969	0.000%	-	(186,969)	(70,957)	4,612,173	10.69%	496,807
67	1959	186,969	0.000%	-	(186,969)	(70,957)	4,541,216	10.69%	489,222
68	1960	186,969	0.000%	-	(186,969)	(70,957)	4,470,260	10.69%	481,637
69	1961	186,969	0.000%	-	(186,969)	(70,957)	4,399,303	10.69%	474,053
70	1962	186,969	0.000%	-	(186,969)	(70,957)	4,328,347	10.69%	466,468
71	1963	186,969	0.000%	-	(186,969)	(70,957)	4,257,390	10.69%	458,883
72	1964	186,969	0.000%	-	(186,969)	(70,957)	4,186,434	10.69%	451,298
73	1965	186,969	0.000%	-	(186,969)	(70,957)	4,115,477	10.69%	443,713
74	1966	186,969	0.000%	-	(186,969)	(70,957)	4,044,521	10.69%	436,128
75	1967	186,969	0.000%	-	(186,969)	(70,957)	3,973,564	10.69%	428,544
76	1968	186,969	0.000%	-	(186,969)	(70,957)	3,902,608	10.69%	420,959
77	1969	186,969	0.000%	-	(186,969)	(70,957)	3,831,651	10.69%	413,374
78	1970	186,969	0.000%	-	(186,969)	(70,957)	3,760,695	10.69%	405,789
79	1971	186,969	0.000%	-	(186,969)	(70,957)	3,689,738	10.69%	398,204
80	1972	186,969	0.000%	-	(186,969)	(70,957)	3,618,782	10.69%	390,619
81	1973	186,969	0.000%	-	(186,969)	(70,957)	3,547,825	10.69%	383,035
82	1974	186,969	0.000%	-	(186,969)	(70,957)	3,476,869	10.69%	375,450
83	1975	186,969	0.000%	-	(186,969)	(70,957)	3,405,912	10.69%	367,865
84	1976	186,969	0.000%	-	(186,969)	(70,957)	3,334,956	10.69%	360,280

85	1977	186,969	0.000%	-	(186,969)	(70,957)	3,263,999	10.69%	352,695
86	1978	186,969	0.000%	-	(186,969)	(70,957)	3,193,043	10.69%	345,110
87	1979	186,969	0.000%	-	(186,969)	(70,957)	3,122,086	10.69%	337,525
88	1980	186,969	0.000%	-	(186,969)	(70,957)	3,051,130	10.69%	329,941
89	1981	186,969	0.000%	-	(186,969)	(70,957)	2,980,173	10.69%	322,356
90	1982	186,969	0.000%	-	(186,969)	(70,957)	2,909,217	10.69%	314,771
91	1983	186,969	0.000%	-	(186,969)	(70,957)	2,838,260	10.69%	307,186
92	1984	186,969	0.000%	-	(186,969)	(70,957)	2,767,304	10.69%	299,601
93	1985	186,969	0.000%	-	(186,969)	(70,957)	2,696,347	10.69%	292,016
94	1986	186,969	0.000%	-	(186,969)	(70,957)	2,625,391	10.69%	284,432
95	1987	186,969	0.000%	-	(186,969)	(70,957)	2,554,434	10.69%	276,847
96	1988	186,969	0.000%	-	(186,969)	(70,957)	2,483,478	10.69%	269,262
97	1989	186,969	0.000%	-	(186,969)	(70,957)	2,412,521	10.69%	261,677
98	1990	186,969	0.000%	-	(186,969)	(70,957)	2,341,565	10.69%	254,092
99	1991	186,969	0.000%	-	(186,969)	(70,957)	2,270,608	10.69%	246,507
100	1992	186,969	0.000%	-	(186,969)	(70,957)	2,199,652	10.69%	238,923
101	1993	186,969	0.000%	-	(186,969)	(70,957)	2,128,695	10.69%	231,338
102	1994	186,969	0.000%	-	(186,969)	(70,957)	2,057,739	10.69%	223,753
103	1995	186,969	0.000%	-	(186,969)	(70,957)	1,986,782	10.69%	216,168
104	1996	186,969	0.000%	-	(186,969)	(70,957)	1,915,826	10.69%	208,583
105	1997	186,969	0.000%	-	(186,969)	(70,957)	1,844,869	10.69%	200,998
106	1998	186,969	0.000%	-	(186,969)	(70,957)	1,773,913	10.69%	193,413
107	1999	186,969	0.000%	-	(186,969)	(70,957)	1,702,956	10.69%	185,829
108	2000	186,969	0.000%	-	(186,969)	(70,957)	1,632,000	10.69%	178,244
109	2001	186,969	0.000%	-	(186,969)	(70,957)	1,561,043	10.69%	170,659
110	2002	186,969	0.000%	-	(186,969)	(70,957)	1,490,087	10.69%	163,074
111	2003	186,969	0.000%	-	(186,969)	(70,957)	1,419,130	10.69%	155,489
112	2004	186,969	0.000%	-	(186,969)	(70,957)	1,348,174	10.69%	147,904
113	2005	186,969	0.000%	-	(186,969)	(70,957)	1,277,217	10.69%	140,320
114	2006	186,969	0.000%	-	(186,969)	(70,957)	1,206,261	10.69%	132,735
115	2007	186,969	0.000%	-	(186,969)	(70,957)	1,135,304	10.69%	125,150
116	2008	186,969	0.000%	-	(186,969)	(70,957)	1,064,348	10.69%	117,565
117	2009	186,969	0.000%	-	(186,969)	(70,957)	993,391	10.69%	109,980
118	2010	186,969	0.000%	-	(186,969)	(70,957)	922,435	10.69%	102,395
119	2011	186,969	0.000%	-	(186,969)	(70,957)	851,478	10.69%	94,811
120	2012	186,969	0.000%	-	(186,969)	(70,957)	780,522	10.69%	87,226
121	2013	186,969	0.000%	-	(186,969)	(70,957)	709,565	10.69%	79,641
122	2014	186,969	0.000%	-	(186,969)	(70,957)	638,609	10.69%	72,056
123	2015	186,969	0.000%	-	(186,969)	(70,957)	567,652	10.69%	64,471
124	2016	186,969	0.000%	-	(186,969)	(70,957)	496,696	10.69%	56,886
125	2017	186,969	0.000%	-	(186,969)	(70,957)	425,739	10.69%	49,301
126	2018	186,969	0.000%	-	(186,969)	(70,957)	354,783	9.22%	35,998
127	2019	186,969	0.000%	-	(186,969)	(70,957)	283,826	9.22%	29,453
128	2020	186,969	0.000%	-	(186,969)	(70,957)	212,870	9.22%	22,908
129	2021	186,969	0.000%	-	(186,969)	(70,957)	141,913	9.22%	16,363
130	2022	186,969	0.000%	-	(186,969)	(70,957)	70,957	9.22%	9,818
131	2023	186,969	0.000%	-	(186,969)	(70,957)	-	9.22%	3,273
132		$ 18,696,873	100%	$ 18,696,873	$ 0	$ -			$ 30,572,899

Facility Name Grace **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	1,402,987
2	RP Capability Allocator	RP and BOP Allocators	19.00%
3	**RP - Generator/Exciter**	(Line 1 * 2)	266,567
4			
5	GSU Transformer	Summary Investment	1,375,865
6	RP Capability Allocator	RP and BOP Allocators	19.00%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	261,414
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	3,098,769
10	Real and Reactive Power Portion	Summary Investment	511,336
11	RP Capability Allocator	RP and BOP Allocators	19.00%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	97,154
13	Total Plant Investment	Summary Investment	24,489,558
14	Balance of Plant	(Line 13 - 10 - 5 - 1)	21,199,370
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	5,682
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	630,818
18	RP Fixed Charge Percent	(Line 11(h))	17.5764%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 110,875**

	Depreciation			
20	Annual Depreciation Expense (D)	$	748,426	
21	Gross Plant Investment (F)		24,489,558	(Line 13)
22	SLDP=DE/F		3.0561%	(Line 20 / 21)
23	Depreciable years =1/SLDP		33	
24	Book Life (n)		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.4525%	Based Upon Book Life CTR=Composite Tax Rate

(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment					
		Amount	Investment	FCR %	
O&M	O&M by Facility	$ 1,938,988	$ 24,489,558	7.9176%	(f)/(g)
A&G	Fixed Charge Items			0.4475%	
Cash Working Capital	#REF!			0.0941%	
Prepayments	Fixed Charge Items			0.0203%	
Materials and Supplies	Fixed Charge Items			0.1029%	
General and Intangible Plant	Fixed Charge Items			1.1057%	
Other Taxes	Fixed Charge Items			0.5233%	
Depreciation	(Line 26)			0.0056%	
Return	Fixed Charge Items			7.5512%	
Income Taxes	Line 27			1.4525%	
ADIT	Line 31(i)	(402,706)	24,489,558	-1.6444%	
Total RP Fixed Charge Percent				17.5764%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 24,489,558	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%		37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$5,329,336
31	In Service Year	1916	1908-1923			Levelized Revenue Requirement			402,706
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1916	$ 244,896	3.750%	$ 918,358	$ 673,463	$ 255,586	$ 255,586	10.69%	$ 13,660
33	1917	244,896	7.219%	1,767,901	1,523,006	577,996	833,582	10.69%	58,213
34	1918	244,896	6.677%	1,635,168	1,390,272	527,622	1,361,204	10.69%	117,305
35	1919	244,896	6.177%	1,512,720	1,267,824	481,152	1,842,356	10.69%	171,221
36	1920	244,896	5.713%	1,399,088	1,154,193	438,028	2,280,384	10.69%	220,349
37	1921	244,896	5.285%	1,294,273	1,049,378	398,249	2,678,633	10.69%	265,045
38	1922	244,896	4.888%	1,197,050	952,154	361,352	3,039,985	10.69%	305,644
39	1923	244,896	4.522%	1,107,418	862,522	327,336	3,367,321	10.69%	342,452
40	1924	244,896	4.462%	1,092,724	847,828	321,759	3,689,080	10.69%	377,144
41	1925	244,896	4.461%	1,092,479	847,584	321,666	4,010,747	10.69%	411,534
42	1926	244,896	4.462%	1,092,724	847,828	321,759	4,332,506	10.69%	445,923
43	1927	244,896	4.461%	1,092,479	847,584	321,666	4,654,172	10.69%	480,312
44	1928	244,896	4.462%	1,092,724	847,828	321,759	4,975,932	10.69%	514,701
45	1929	244,896	4.461%	1,092,479	847,584	321,666	5,297,598	10.69%	549,091
46	1930	244,896	4.462%	1,092,724	847,828	321,759	5,619,358	10.69%	583,480
47	1931	244,896	4.461%	1,092,479	847,584	321,666	5,941,024	10.69%	617,869
48	1932	244,896	4.462%	1,092,724	847,828	321,759	6,262,783	10.69%	652,258
49	1933	244,896	4.461%	1,092,479	847,584	321,666	6,584,450	10.69%	686,648
50	1934	244,896	4.462%	1,092,724	847,828	321,759	6,906,209	10.69%	721,037
51	1935	244,896	4.461%	1,092,479	847,584	321,666	7,227,876	10.69%	755,426
52	1936	244,896	2.231%	546,362	301,466	114,410	7,342,285	10.69%	778,733
53	1937	244,896	0.000%	-	(244,896)	(92,940)	7,249,345	10.69%	779,881
54	1938	244,896	0.000%	-	(244,896)	(92,940)	7,156,405	10.69%	769,946
55	1939	244,896	0.000%	-	(244,896)	(92,940)	7,063,464	10.69%	760,011
56	1940	244,896	0.000%	-	(244,896)	(92,940)	6,970,524	10.69%	750,076
57	1941	244,896	0.000%	-	(244,896)	(92,940)	6,877,584	10.69%	740,141
58	1942	244,896	0.000%	-	(244,896)	(92,940)	6,784,643	10.69%	730,207
59	1943	244,896	0.000%	-	(244,896)	(92,940)	6,691,703	10.69%	720,272
60	1944	244,896	0.000%	-	(244,896)	(92,940)	6,598,763	10.69%	710,337
61	1945	244,896	0.000%	-	(244,896)	(92,940)	6,505,822	10.69%	700,402
62	1946	244,896	0.000%	-	(244,896)	(92,940)	6,412,882	10.69%	690,468
63	1947	244,896	0.000%	-	(244,896)	(92,940)	6,319,942	10.69%	680,533
64	1948	244,896	0.000%	-	(244,896)	(92,940)	6,227,001	10.69%	670,598
65	1949	244,896	0.000%	-	(244,896)	(92,940)	6,134,061	10.69%	660,663
66	1950	244,896	0.000%	-	(244,896)	(92,940)	6,041,121	10.69%	650,728
67	1951	244,896	0.000%	-	(244,896)	(92,940)	5,948,181	10.69%	640,794
68	1952	244,896	0.000%	-	(244,896)	(92,940)	5,855,240	10.69%	630,859
69	1953	244,896	0.000%	-	(244,896)	(92,940)	5,762,300	10.69%	620,924
70	1954	244,896	0.000%	-	(244,896)	(92,940)	5,669,360	10.69%	610,989
71	1955	244,896	0.000%	-	(244,896)	(92,940)	5,576,419	10.69%	601,054
72	1956	244,896	0.000%	-	(244,896)	(92,940)	5,483,479	10.69%	591,120
73	1957	244,896	0.000%	-	(244,896)	(92,940)	5,390,539	10.69%	581,185
74	1958	244,896	0.000%	-	(244,896)	(92,940)	5,297,598	10.69%	571,250
75	1959	244,896	0.000%	-	(244,896)	(92,940)	5,204,658	10.69%	561,315
76	1960	244,896	0.000%	-	(244,896)	(92,940)	5,111,718	10.69%	551,381
77	1961	244,896	0.000%	-	(244,896)	(92,940)	5,018,777	10.69%	541,446
78	1962	244,896	0.000%	-	(244,896)	(92,940)	4,925,837	10.69%	531,511
79	1963	244,896	0.000%	-	(244,896)	(92,940)	4,832,897	10.69%	521,576
80	1964	244,896	0.000%	-	(244,896)	(92,940)	4,739,956	10.69%	511,641
81	1965	244,896	0.000%	-	(244,896)	(92,940)	4,647,016	10.69%	501,707
82	1966	244,896	0.000%	-	(244,896)	(92,940)	4,554,076	10.69%	491,772
83	1967	244,896	0.000%	-	(244,896)	(92,940)	4,461,135	10.69%	481,837
84	1968	244,896	0.000%	-	(244,896)	(92,940)	4,368,195	10.69%	471,902

85		1969	244,896	0.000%	-	(244,896)	(92,940)	4,275,255	10.69%	461,968
86		1970	244,896	0.000%	-	(244,896)	(92,940)	4,182,314	10.69%	452,033
87		1971	244,896	0.000%	-	(244,896)	(92,940)	4,089,374	10.69%	442,098
88		1972	244,896	0.000%	-	(244,896)	(92,940)	3,996,434	10.69%	432,163
89		1973	244,896	0.000%	-	(244,896)	(92,940)	3,903,493	10.69%	422,228
90		1974	244,896	0.000%	-	(244,896)	(92,940)	3,810,553	10.69%	412,294
91		1975	244,896	0.000%	-	(244,896)	(92,940)	3,717,613	10.69%	402,359
92		1976	244,896	0.000%	-	(244,896)	(92,940)	3,624,673	10.69%	392,424
93		1977	244,896	0.000%	-	(244,896)	(92,940)	3,531,732	10.69%	382,489
94		1978	244,896	0.000%	-	(244,896)	(92,940)	3,438,792	10.69%	372,554
95		1979	244,896	0.000%	-	(244,896)	(92,940)	3,345,852	10.69%	362,620
96		1980	244,896	0.000%	-	(244,896)	(92,940)	3,252,911	10.69%	352,685
97		1981	244,896	0.000%	-	(244,896)	(92,940)	3,159,971	10.69%	342,750
98		1982	244,896	0.000%	-	(244,896)	(92,940)	3,067,031	10.69%	332,815
99		1983	244,896	0.000%	-	(244,896)	(92,940)	2,974,090	10.69%	322,881
100		1984	244,896	0.000%	-	(244,896)	(92,940)	2,881,150	10.69%	312,946
101		1985	244,896	0.000%	-	(244,896)	(92,940)	2,788,210	10.69%	303,011
102		1986	244,896	0.000%	-	(244,896)	(92,940)	2,695,269	10.69%	293,076
103		1987	244,896	0.000%	-	(244,896)	(92,940)	2,602,329	10.69%	283,141
104		1988	244,896	0.000%	-	(244,896)	(92,940)	2,509,389	10.69%	273,207
105		1989	244,896	0.000%	-	(244,896)	(92,940)	2,416,448	10.69%	263,272
106		1990	244,896	0.000%	-	(244,896)	(92,940)	2,323,508	10.69%	253,337
107		1991	244,896	0.000%	-	(244,896)	(92,940)	2,230,568	10.69%	243,402
108		1992	244,896	0.000%	-	(244,896)	(92,940)	2,137,627	10.69%	233,467
109		1993	244,896	0.000%	-	(244,896)	(92,940)	2,044,687	10.69%	223,533
110		1994	244,896	0.000%	-	(244,896)	(92,940)	1,951,747	10.69%	213,598
111		1995	244,896	0.000%	-	(244,896)	(92,940)	1,858,806	10.69%	203,663
112		1996	244,896	0.000%	-	(244,896)	(92,940)	1,765,866	10.69%	193,728
113		1997	244,896	0.000%	-	(244,896)	(92,940)	1,672,926	10.69%	183,794
114		1998	244,896	0.000%	-	(244,896)	(92,940)	1,579,985	10.69%	173,859
115		1999	244,896	0.000%	-	(244,896)	(92,940)	1,487,045	10.69%	163,924
116		2000	244,896	0.000%	-	(244,896)	(92,940)	1,394,105	10.69%	153,989
117		2001	244,896	0.000%	-	(244,896)	(92,940)	1,301,164	10.69%	144,054
118		2002	244,896	0.000%	-	(244,896)	(92,940)	1,208,224	10.69%	134,120
119		2003	244,896	0.000%	-	(244,896)	(92,940)	1,115,284	10.69%	124,185
120		2004	244,896	0.000%	-	(244,896)	(92,940)	1,022,344	10.69%	114,250
121		2005	244,896	0.000%	-	(244,896)	(92,940)	929,403	10.69%	104,315
122		2006	244,896	0.000%	-	(244,896)	(92,940)	836,463	10.69%	94,380
123		2007	244,896	0.000%	-	(244,896)	(92,940)	743,523	10.69%	84,446
124		2008	244,896	0.000%	-	(244,896)	(92,940)	650,582	10.69%	74,511
125		2009	244,896	0.000%	-	(244,896)	(92,940)	557,642	10.69%	64,576
126		2010	244,896	0.000%	-	(244,896)	(92,940)	464,702	10.69%	54,641
127		2011	244,896	0.000%	-	(244,896)	(92,940)	371,761	10.69%	44,707
128		2012	244,896	0.000%	-	(244,896)	(92,940)	278,821	10.69%	34,772
129		2013	244,896	0.000%	-	(244,896)	(92,940)	185,881	10.69%	24,837
130		2014	244,896	0.000%	-	(244,896)	(92,940)	92,940	10.69%	14,902
131		2015	244,896	0.000%	-	(244,896)	(92,940)	0	10.69%	4,967
132			$ 24,489,558	100%	$ 24,489,558	$ (0)	$ 0			$ 40,069,542

Facility Name Oneida **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	4,776,191
2	RP Capability Allocator	RP and BOP Allocators	19.00%
3	**RP - Generator/Exciter**	(Line 1 * 2)	907,476
4			
5	GSU Transformer	Summary Investment	996,947
6	RP Capability Allocator	RP and BOP Allocators	19.00%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	189,420
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	2,369,988
10	Real and Reactive Power Portion	Summary Investment	829,066
11	RP Capability Allocator	RP and BOP Allocators	19.00%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	157,523
13	Total Plant Investment	Summary Investment	28,844,998
14	Balance of Plant	(Line 13 - 10 - 5 - 1)	22,242,794
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	5,962
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	1,260,381
18	RP Fixed Charge Percent	(Line 11(h))	13.2512%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 167,015**

	Depreciation			
20	Annual Depreciation Expense (D)	$	875,845	
21	Gross Plant Investment (F)		28,844,998	(Line 13)
22	SLDP=DE/F		3.0364%	(Line 20 / 21)
23	Depreciable years (n)=1/SLDP		33	
24	Book Life		100	Book Lives
25	SLDP for Book Life = 1/n		1.00%	
26	SFDP=(R/((1+R)^n-1)		0.01%	R=Return

	Income Taxes		
	Income Tax Factor to Include in Fixed Charge		
27	Factor	1.4525%	Based Upon Book Life
	[(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]		CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 1,050,116	$ 28,844,998	3.6405%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	#REF!			0.0460%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.0056%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.4525%	
	ADIT	Line 31(i)	(474,326)	28,844,998	-1.6444%	
	Total RP Fixed Charge Percent				13.2512%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 28,844,998	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$6,277,153
31	In Service Year	1918	1915-1920			Levelized Revenue Requirement			474,326
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1918	$ 288,450	3.750%	$ 1,081,687	$ 793,237	$ 301,042	$ 301,042	10.69%	$ 16,090
33	1919	288,450	7.219%	2,082,320	1,793,870	680,792	981,833	10.69%	68,566
34	1920	288,450	6.677%	1,925,981	1,637,531	621,459	1,603,293	10.69%	138,168
35	1921	288,450	6.177%	1,781,756	1,493,306	566,724	2,170,017	10.69%	201,673
36	1922	288,450	5.713%	1,647,915	1,359,465	515,930	2,685,947	10.69%	259,537
37	1923	288,450	5.285%	1,524,458	1,236,008	469,077	3,155,025	10.69%	312,183
38	1924	288,450	4.888%	1,409,944	1,121,494	425,618	3,580,643	10.69%	360,002
39	1925	288,450	4.522%	1,304,371	1,015,921	385,552	3,966,195	10.69%	403,357
40	1926	288,450	4.462%	1,287,064	998,614	378,984	4,345,179	10.69%	444,219
41	1927	288,450	4.461%	1,286,775	998,325	378,874	4,724,053	10.69%	484,724
42	1928	288,450	4.462%	1,287,064	998,614	378,984	5,103,037	10.69%	525,230
43	1929	288,450	4.461%	1,286,775	998,325	378,874	5,481,912	10.69%	565,735
44	1930	288,450	4.462%	1,287,064	998,614	378,984	5,860,896	10.69%	606,240
45	1931	288,450	4.461%	1,286,775	998,325	378,874	6,239,770	10.69%	646,746
46	1932	288,450	4.462%	1,287,064	998,614	378,984	6,618,754	10.69%	687,251
47	1933	288,450	4.461%	1,286,775	998,325	378,874	6,997,629	10.69%	727,756
48	1934	288,450	4.462%	1,287,064	998,614	378,984	7,376,613	10.69%	768,262
49	1935	288,450	4.461%	1,286,775	998,325	378,874	7,755,487	10.69%	808,767
50	1936	288,450	4.462%	1,287,064	998,614	378,984	8,134,471	10.69%	849,273
51	1937	288,450	4.461%	1,286,775	998,325	378,874	8,513,345	10.69%	889,778
52	1938	288,450	2.231%	643,532	355,082	134,757	8,648,103	10.69%	917,230
53	1939	288,450	0.000%	-	(288,450)	(109,470)	8,538,633	10.69%	918,582
54	1940	288,450	0.000%	-	(288,450)	(109,470)	8,429,163	10.69%	906,880
55	1941	288,450	0.000%	-	(288,450)	(109,470)	8,319,694	10.69%	895,178
56	1942	288,450	0.000%	-	(288,450)	(109,470)	8,210,224	10.69%	883,477
57	1943	288,450	0.000%	-	(288,450)	(109,470)	8,100,754	10.69%	871,775
58	1944	288,450	0.000%	-	(288,450)	(109,470)	7,991,285	10.69%	860,073
59	1945	288,450	0.000%	-	(288,450)	(109,470)	7,881,815	10.69%	848,371
60	1946	288,450	0.000%	-	(288,450)	(109,470)	7,772,345	10.69%	836,670
61	1947	288,450	0.000%	-	(288,450)	(109,470)	7,662,876	10.69%	824,968
62	1948	288,450	0.000%	-	(288,450)	(109,470)	7,553,406	10.69%	813,266
63	1949	288,450	0.000%	-	(288,450)	(109,470)	7,443,936	10.69%	801,565
64	1950	288,450	0.000%	-	(288,450)	(109,470)	7,334,467	10.69%	789,863
65	1951	288,450	0.000%	-	(288,450)	(109,470)	7,224,997	10.69%	778,161
66	1952	288,450	0.000%	-	(288,450)	(109,470)	7,115,527	10.69%	766,460
67	1953	288,450	0.000%	-	(288,450)	(109,470)	7,006,058	10.69%	754,758
68	1954	288,450	0.000%	-	(288,450)	(109,470)	6,896,588	10.69%	743,056
69	1955	288,450	0.000%	-	(288,450)	(109,470)	6,787,118	10.69%	731,355
70	1956	288,450	0.000%	-	(288,450)	(109,470)	6,677,649	10.69%	719,653
71	1957	288,450	0.000%	-	(288,450)	(109,470)	6,568,179	10.69%	707,951
72	1958	288,450	0.000%	-	(288,450)	(109,470)	6,458,709	10.69%	696,250
73	1959	288,450	0.000%	-	(288,450)	(109,470)	6,349,240	10.69%	684,548
74	1960	288,450	0.000%	-	(288,450)	(109,470)	6,239,770	10.69%	672,846
75	1961	288,450	0.000%	-	(288,450)	(109,470)	6,130,301	10.69%	661,145
76	1962	288,450	0.000%	-	(288,450)	(109,470)	6,020,831	10.69%	649,443
77	1963	288,450	0.000%	-	(288,450)	(109,470)	5,911,361	10.69%	637,741
78	1964	288,450	0.000%	-	(288,450)	(109,470)	5,801,892	10.69%	626,040
79	1965	288,450	0.000%	-	(288,450)	(109,470)	5,692,422	10.69%	614,338
80	1966	288,450	0.000%	-	(288,450)	(109,470)	5,582,952	10.69%	602,636
81	1967	288,450	0.000%	-	(288,450)	(109,470)	5,473,483	10.69%	590,935
82	1968	288,450	0.000%	-	(288,450)	(109,470)	5,364,013	10.69%	579,233
83	1969	288,450	0.000%	-	(288,450)	(109,470)	5,254,543	10.69%	567,531
84	1970	288,450	0.000%	-	(288,450)	(109,470)	5,145,074	10.69%	555,830

85		1971	288,450	0.000%	-	(288,450)	(109,470)	5,035,604	10.69%	544,128
86		1972	288,450	0.000%	-	(288,450)	(109,470)	4,926,134	10.69%	532,426
87		1973	288,450	0.000%	-	(288,450)	(109,470)	4,816,665	10.69%	520,725
88		1974	288,450	0.000%	-	(288,450)	(109,470)	4,707,195	10.69%	509,023
89		1975	288,450	0.000%	-	(288,450)	(109,470)	4,597,725	10.69%	497,321
90		1976	288,450	0.000%	-	(288,450)	(109,470)	4,488,256	10.69%	485,620
91		1977	288,450	0.000%	-	(288,450)	(109,470)	4,378,786	10.69%	473,918
92		1978	288,450	0.000%	-	(288,450)	(109,470)	4,269,316	10.69%	462,216
93		1979	288,450	0.000%	-	(288,450)	(109,470)	4,159,847	10.69%	450,515
94		1980	288,450	0.000%	-	(288,450)	(109,470)	4,050,377	10.69%	438,813
95		1981	288,450	0.000%	-	(288,450)	(109,470)	3,940,907	10.69%	427,111
96		1982	288,450	0.000%	-	(288,450)	(109,470)	3,831,438	10.69%	415,409
97		1983	288,450	0.000%	-	(288,450)	(109,470)	3,721,968	10.69%	403,708
98		1984	288,450	0.000%	-	(288,450)	(109,470)	3,612,499	10.69%	392,006
99		1985	288,450	0.000%	-	(288,450)	(109,470)	3,503,029	10.69%	380,304
100		1986	288,450	0.000%	-	(288,450)	(109,470)	3,393,559	10.69%	368,603
101		1987	288,450	0.000%	-	(288,450)	(109,470)	3,284,090	10.69%	356,901
102		1988	288,450	0.000%	-	(288,450)	(109,470)	3,174,620	10.69%	345,199
103		1989	288,450	0.000%	-	(288,450)	(109,470)	3,065,150	10.69%	333,498
104		1990	288,450	0.000%	-	(288,450)	(109,470)	2,955,681	10.69%	321,796
105		1991	288,450	0.000%	-	(288,450)	(109,470)	2,846,211	10.69%	310,094
106		1992	288,450	0.000%	-	(288,450)	(109,470)	2,736,741	10.69%	298,393
107		1993	288,450	0.000%	-	(288,450)	(109,470)	2,627,272	10.69%	286,691
108		1994	288,450	0.000%	-	(288,450)	(109,470)	2,517,802	10.69%	274,989
109		1995	288,450	0.000%	-	(288,450)	(109,470)	2,408,332	10.69%	263,288
110		1996	288,450	0.000%	-	(288,450)	(109,470)	2,298,863	10.69%	251,586
111		1997	288,450	0.000%	-	(288,450)	(109,470)	2,189,393	10.69%	239,884
112		1998	288,450	0.000%	-	(288,450)	(109,470)	2,079,923	10.69%	228,183
113		1999	288,450	0.000%	-	(288,450)	(109,470)	1,970,454	10.69%	216,481
114		2000	288,450	0.000%	-	(288,450)	(109,470)	1,860,984	10.69%	204,779
115		2001	288,450	0.000%	-	(288,450)	(109,470)	1,751,514	10.69%	193,078
116		2002	288,450	0.000%	-	(288,450)	(109,470)	1,642,045	10.69%	181,376
117		2003	288,450	0.000%	-	(288,450)	(109,470)	1,532,575	10.69%	169,674
118		2004	288,450	0.000%	-	(288,450)	(109,470)	1,423,105	10.69%	157,973
119		2005	288,450	0.000%	-	(288,450)	(109,470)	1,313,636	10.69%	146,271
120		2006	288,450	0.000%	-	(288,450)	(109,470)	1,204,166	10.69%	134,569
121		2007	288,450	0.000%	-	(288,450)	(109,470)	1,094,697	10.69%	122,868
122		2008	288,450	0.000%	-	(288,450)	(109,470)	985,227	10.69%	111,166
123		2009	288,450	0.000%	-	(288,450)	(109,470)	875,757	10.69%	99,464
124		2010	288,450	0.000%	-	(288,450)	(109,470)	766,288	10.69%	87,763
125		2011	288,450	0.000%	-	(288,450)	(109,470)	656,818	10.69%	76,061
126		2012	288,450	0.000%	-	(288,450)	(109,470)	547,348	10.69%	64,359
127		2013	288,450	0.000%	-	(288,450)	(109,470)	437,879	10.69%	52,658
128		2014	288,450	0.000%	-	(288,450)	(109,470)	328,409	10.69%	40,956
129		2015	288,450	0.000%	-	(288,450)	(109,470)	218,939	10.69%	29,254
130		2016	288,450	0.000%	-	(288,450)	(109,470)	109,470	10.69%	17,553
131		2017	288,450	0.000%	-	(288,450)	(109,470)	0	10.69%	5,851
132			$ 28,844,998	100%	$ 28,844,998	$ (0)	$ 0			$ 47,195,865

Facility Name Cutler **Cost Year:** 2019
Plant Type: Hydro

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	3,802,180
2	RP Capability Allocator	RP and BOP Allocators	36.00%
3	**RP - Generator/Exciter**	(Line 1 * 2)	1,368,785
4			
5	GSU Transformer	Summary Investment	550,286
6	RP Capability Allocator	RP and BOP Allocators	36.00%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	198,103
8			
9	Accessory Electric Equipment	Sum AEE Data - Hydro	2,953,535
10	Real and Reactive Power Portion	Summary Investment	2,090,384
11	RP Capability Allocator	RP and BOP Allocators	36.00%
12	**RP - Accesory Electric Equipment**	(Line 10 * 11)	752,538
13	Total Plant Investment	Summary Investment	34,621,486
14	Balance of Plant	(Line 13 - 10 - 5 - 1)	28,178,637
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	7,553
17	Total RP Investment	(Line 3 + 7 + 12 + 16)	2,326,979
18	RP Fixed Charge Percent	(Line 11(h))	15.5004%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 360,690**

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 2,030,447	$ 34,621,486	5.8647%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	#REF!			0.0710%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.0056%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.4525%	
	ADIT	Line 31(i)	(569,309)	34,621,486	-1.6444%	
	Total RP Fixed Charge Percent				15.5004%	

	Depreciation			
20	Annual Depreciation Expense (D)	$ 1,830,905		
21	Gross Plant Investment (F)	34,621,486	(Line 13)	
22	SLDP=DE/F	5.2883%	(Line 20 / 21)	
23	Depreciable years (n)=1/SLDP	19		
24	Book Life (n)	100	Book Lives	
25	SLDP for Book Life = 1/n	1.00%		
26	SFDP=(R/((1+R)^n-1)	0.01%	R=Return	

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.4525%	Based Upon Book Life CTR=Composite Tax Rate

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 34,621,486	Summary Investment						
29	Straight-line Tax Life	100	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$7,534,132
31	In Service Year	1927				Levelized Revenue Requirement			569,309
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	1927	$ 346,215	3.750%	$ 1,298,306	$ 952,091	$ 361,328	$ 361,328	10.69%	$ 19,312
33	1928	346,215	7.219%	2,499,325	2,153,110	817,127	1,178,455	10.69%	82,297
34	1929	346,215	6.677%	2,311,677	1,965,462	745,912	1,924,367	10.69%	165,837
35	1930	346,215	6.177%	2,138,569	1,792,354	680,216	2,604,584	10.69%	242,059
36	1931	346,215	5.713%	1,977,926	1,631,711	619,251	3,223,834	10.69%	311,512
37	1932	346,215	5.285%	1,829,746	1,483,531	563,015	3,786,849	10.69%	374,701
38	1933	346,215	4.888%	1,692,298	1,346,083	510,852	4,297,701	10.69%	432,096
39	1934	346,215	4.522%	1,565,584	1,219,369	462,763	4,760,464	10.69%	484,133
40	1935	346,215	4.462%	1,544,811	1,198,596	454,879	5,215,343	10.69%	533,178
41	1936	346,215	4.461%	1,544,465	1,198,250	454,748	5,670,090	10.69%	581,795
42	1937	346,215	4.462%	1,544,811	1,198,596	454,879	6,124,970	10.69%	630,412
43	1938	346,215	4.461%	1,544,465	1,198,250	454,748	6,579,717	10.69%	679,029
44	1939	346,215	4.462%	1,544,811	1,198,596	454,879	7,034,596	10.69%	727,646
45	1940	346,215	4.461%	1,544,465	1,198,250	454,748	7,489,344	10.69%	776,263
46	1941	346,215	4.462%	1,544,811	1,198,596	454,879	7,944,223	10.69%	824,880
47	1942	346,215	4.461%	1,544,465	1,198,250	454,748	8,398,971	10.69%	873,497
48	1943	346,215	4.462%	1,544,811	1,198,596	454,879	8,853,850	10.69%	922,114
49	1944	346,215	4.461%	1,544,465	1,198,250	454,748	9,308,598	10.69%	970,731
50	1945	346,215	4.462%	1,544,811	1,198,596	454,879	9,763,477	10.69%	1,019,347
51	1946	346,215	4.461%	1,544,465	1,198,250	454,748	10,218,225	10.69%	1,067,964
52	1947	346,215	2.231%	772,405	426,190	161,744	10,379,968	10.69%	1,100,914
53	1948	346,215	0.000%	-	(346,215)	(131,392)	10,248,576	10.69%	1,102,536
54	1949	346,215	0.000%	-	(346,215)	(131,392)	10,117,184	10.69%	1,088,491
55	1950	346,215	0.000%	-	(346,215)	(131,392)	9,985,792	10.69%	1,074,446
56	1951	346,215	0.000%	-	(346,215)	(131,392)	9,854,400	10.69%	1,060,401
57	1952	346,215	0.000%	-	(346,215)	(131,392)	9,723,008	10.69%	1,046,356
58	1953	346,215	0.000%	-	(346,215)	(131,392)	9,591,616	10.69%	1,032,311
59	1954	346,215	0.000%	-	(346,215)	(131,392)	9,460,224	10.69%	1,018,266
60	1955	346,215	0.000%	-	(346,215)	(131,392)	9,328,832	10.69%	1,004,221
61	1956	346,215	0.000%	-	(346,215)	(131,392)	9,197,440	10.69%	990,176
62	1957	346,215	0.000%	-	(346,215)	(131,392)	9,066,048	10.69%	976,131
63	1958	346,215	0.000%	-	(346,215)	(131,392)	8,934,656	10.69%	962,086
64	1959	346,215	0.000%	-	(346,215)	(131,392)	8,803,264	10.69%	948,041
65	1960	346,215	0.000%	-	(346,215)	(131,392)	8,671,872	10.69%	933,996
66	1961	346,215	0.000%	-	(346,215)	(131,392)	8,540,480	10.69%	919,951
67	1962	346,215	0.000%	-	(346,215)	(131,392)	8,409,088	10.69%	905,906
68	1963	346,215	0.000%	-	(346,215)	(131,392)	8,277,696	10.69%	891,861
69	1964	346,215	0.000%	-	(346,215)	(131,392)	8,146,304	10.69%	877,816
70	1965	346,215	0.000%	-	(346,215)	(131,392)	8,014,912	10.69%	863,770
71	1966	346,215	0.000%	-	(346,215)	(131,392)	7,883,520	10.69%	849,725
72	1967	346,215	0.000%	-	(346,215)	(131,392)	7,752,128	10.69%	835,680
73	1968	346,215	0.000%	-	(346,215)	(131,392)	7,620,736	10.69%	821,635
74	1969	346,215	0.000%	-	(346,215)	(131,392)	7,489,344	10.69%	807,590
75	1970	346,215	0.000%	-	(346,215)	(131,392)	7,357,952	10.69%	793,545
76	1971	346,215	0.000%	-	(346,215)	(131,392)	7,226,560	10.69%	779,500
77	1972	346,215	0.000%	-	(346,215)	(131,392)	7,095,168	10.69%	765,455
78	1973	346,215	0.000%	-	(346,215)	(131,392)	6,963,776	10.69%	751,410
79	1974	346,215	0.000%	-	(346,215)	(131,392)	6,832,384	10.69%	737,365
80	1975	346,215	0.000%	-	(346,215)	(131,392)	6,700,992	10.69%	723,320
81	1976	346,215	0.000%	-	(346,215)	(131,392)	6,569,600	10.69%	709,275
82	1977	346,215	0.000%	-	(346,215)	(131,392)	6,438,208	10.69%	695,230
83	1978	346,215	0.000%	-	(346,215)	(131,392)	6,306,816	10.69%	681,185
84	1979	346,215	0.000%	-	(346,215)	(131,392)	6,175,424	10.69%	667,140

85		1980	346,215	0.000%	-	(346,215)	(131,392)	6,044,032	10.69%	653,095
86		1981	346,215	0.000%	-	(346,215)	(131,392)	5,912,640	10.69%	639,050
87		1982	346,215	0.000%	-	(346,215)	(131,392)	5,781,248	10.69%	625,005
88		1983	346,215	0.000%	-	(346,215)	(131,392)	5,649,856	10.69%	610,960
89		1984	346,215	0.000%	-	(346,215)	(131,392)	5,518,464	10.69%	596,915
90		1985	346,215	0.000%	-	(346,215)	(131,392)	5,387,072	10.69%	582,870
91		1986	346,215	0.000%	-	(346,215)	(131,392)	5,255,680	10.69%	568,824
92		1987	346,215	0.000%	-	(346,215)	(131,392)	5,124,288	10.69%	554,779
93		1988	346,215	0.000%	-	(346,215)	(131,392)	4,992,896	10.69%	540,734
94		1989	346,215	0.000%	-	(346,215)	(131,392)	4,861,504	10.69%	526,689
95		1990	346,215	0.000%	-	(346,215)	(131,392)	4,730,112	10.69%	512,644
96		1991	346,215	0.000%	-	(346,215)	(131,392)	4,598,720	10.69%	498,599
97		1992	346,215	0.000%	-	(346,215)	(131,392)	4,467,328	10.69%	484,554
98		1993	346,215	0.000%	-	(346,215)	(131,392)	4,335,936	10.69%	470,509
99		1994	346,215	0.000%	-	(346,215)	(131,392)	4,204,544	10.69%	456,464
100		1995	346,215	0.000%	-	(346,215)	(131,392)	4,073,152	10.69%	442,419
101		1996	346,215	0.000%	-	(346,215)	(131,392)	3,941,760	10.69%	428,374
102		1997	346,215	0.000%	-	(346,215)	(131,392)	3,810,368	10.69%	414,329
103		1998	346,215	0.000%	-	(346,215)	(131,392)	3,678,976	10.69%	400,284
104		1999	346,215	0.000%	-	(346,215)	(131,392)	3,547,584	10.69%	386,239
105		2000	346,215	0.000%	-	(346,215)	(131,392)	3,416,192	10.69%	372,194
106		2001	346,215	0.000%	-	(346,215)	(131,392)	3,284,800	10.69%	358,149
107		2002	346,215	0.000%	-	(346,215)	(131,392)	3,153,408	10.69%	344,104
108		2003	346,215	0.000%	-	(346,215)	(131,392)	3,022,016	10.69%	330,059
109		2004	346,215	0.000%	-	(346,215)	(131,392)	2,890,624	10.69%	316,014
110		2005	346,215	0.000%	-	(346,215)	(131,392)	2,759,232	10.69%	301,969
111		2006	346,215	0.000%	-	(346,215)	(131,392)	2,627,840	10.69%	287,923
112		2007	346,215	0.000%	-	(346,215)	(131,392)	2,496,448	10.69%	273,878
113		2008	346,215	0.000%	-	(346,215)	(131,392)	2,365,056	10.69%	259,833
114		2009	346,215	0.000%	-	(346,215)	(131,392)	2,233,664	10.69%	245,788
115		2010	346,215	0.000%	-	(346,215)	(131,392)	2,102,272	10.69%	231,743
116		2011	346,215	0.000%	-	(346,215)	(131,392)	1,970,880	10.69%	217,698
117		2012	346,215	0.000%	-	(346,215)	(131,392)	1,839,488	10.69%	203,653
118		2013	346,215	0.000%	-	(346,215)	(131,392)	1,708,096	10.69%	189,608
119		2014	346,215	0.000%	-	(346,215)	(131,392)	1,576,704	10.69%	175,563
120		2015	346,215	0.000%	-	(346,215)	(131,392)	1,445,312	10.69%	161,518
121		2016	346,215	0.000%	-	(346,215)	(131,392)	1,313,920	10.69%	147,473
122		2017	346,215	0.000%	-	(346,215)	(131,392)	1,182,528	10.69%	133,428
123		2018	346,215	0.000%	-	(346,215)	(131,392)	1,051,136	9.22%	103,017
124		2019	346,215	0.000%	-	(346,215)	(131,392)	919,744	9.22%	90,897
125		2020	346,215	0.000%	-	(346,215)	(131,392)	788,352	9.22%	78,777
126		2021	346,215	0.000%	-	(346,215)	(131,392)	656,960	9.22%	66,658
127		2022	346,215	0.000%	-	(346,215)	(131,392)	525,568	9.22%	54,538
128		2023	346,215	0.000%	-	(346,215)	(131,392)	394,176	9.22%	42,419
129		2024	346,215	0.000%	-	(346,215)	(131,392)	262,784	9.22%	30,299
130		2025	346,215	0.000%	-	(346,215)	(131,392)	131,392	9.22%	18,179
131		2026	346,215	0.000%	-	(346,215)	(131,392)	-	9.22%	6,060
132			$ 34,621,486	100%	$ 34,621,486	$ 0	$ -			$ 56,569,310

	Name of Facility	In Service Year	Number of Turbines	MVA Rating	Annual Revenue Requirement		
1	**Glenrock I and III**	**2008-2009**	**92**	**135.3**	**$ 748,573**		
2	**Rolling Hills**	**2009**	**66**	**131.0**	**433,652**		
3	**Seven Mile Hill 1 and 2**	**2008**	**79**	**155.1**	**567,520**		
4	**High Plains/McFadden Ridge**	**2009**	**85**	**166.9**	**631,125**		
5	**Goodnoe Hills**	**2008**	**47**	**104.5**	**In BPA BAA - pseudo-tied to PAC**	$ 86,710	
6	**Leaning Juniper**	**2006**	**67**	**120.7**	**In BPA BAA - pseudo-tied to PAC**	376,212	
7	**Marengo I and II**	**2007-2008**	**117**	**245.3**	**430,396**		
8	**Dunlap**	**2010**	**74**	**145.3**	**671,878**	Repowered in 2020. In service 10/15/2020	
9	**Foote Creek**	**1999**	**13**	**52.1**	**237,694**	Repowered in 2020. In service 11/1/2020	
10	**Cedar Springs II**	**2020**	**72**	**221.6**	**1,178,985**	In-service 11/5/2020	
11	**Ekola Flats**	**2020**	**63**	**274.2**	**1,171,858**	In-service 11/1/2020	
12	**TB Flats I**	**2020**	**79**	**331.1**	**884,567**	In-service 11/1/2020	
13	**TB Flatts II**	**2021**	**53**	**209.5**	**In service after rates effective**	In service early 2021	538,770
14	**Pryor Mountain**	**2020**	**114**	**244.0**	**In service after rates effective**	In-service 12/17/2020	406,920
15	**Total**			**2,537**	**$ 6,956,246**		

Facility Name **Glenrock I and III** **Cost Year:** 2019
Plant Type: Wind

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	11,668,665
2	RP Capability Allocator	RP and BOP Allocators	20.32%
3	**RP - Generator/Exciter**	(Line 1 * 2)	2,371,478
4			
5	GSU Transformer	Summary Investment	5,994,041
6	RP Capability Allocator	RP and BOP Allocators	20.32%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	1,218,197
8			
9	Accessory Electrical Equipment Related to the Production of Real and Reactive Power	Summary Investment	17,474,014
10	RP Capability Allocator	RP and BOP Allocators	20.32%
11	**RP - Accesory Electric Equipment**	(Line 9 * 10)	3,551,326
12	Total Plant Investment	Summary Investment	280,537,039
13	Balance of Plant	(Line 12 - 9 - 5 - 1)	245,400,320
14	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
15	**RP - Balance of Plant**	(Line 13 * 14)	65,775
16	Total RP Investment	(Line 3 + 7 + 11 + 15)	7,206,776
17	RP Fixed Charge Percent	(Line 11(h))	10.3871%
18	**Reactive Power Revenue Requirement**	(Line 16 * 17)	**$ 748,573**

	Depreciation			
19	Annual Depreciation Expense (D)	$ 9,854,128		
20	Gross Plant Investment (F)	280,537,039		(Line 14)
21	SLDP=DE/F	3.5126%		(Line 19 / 20)
22	Depreciable years =1/SLDP	28		
23	Book Life (n)	30		Book Lives
24	SLDP for Book Life = 1/n	3.33%		
25	SFDP=(R/((1+R)^n-1)	0.91%		R=Return

	Income Taxes		
26	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.1370%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 1,393,248	$ 280,537,039	0.4966%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0103%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 25)			0.9145%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 26			1.1370%	
	ADIT	Line 30(i)	(5,392,297)	280,537,039	-1.9221%	
	Total RP Fixed Charge Percent				10.3871%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
27	Investment	$ 280,537,039	Summary Investment						
28	Straight-line Tax Life	30	(Line 23)						
29	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$63,369,073
30	In Service Year	2009	2008-2009			Levelized Revenue Requirement			5,392,297
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 27 / 28	(Tax Depreciation Rates)	(Line 27 * Line 31c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
31	2009	$ 9,351,235	20.000%	$ 56,107,408	$ 46,756,173	$ 17,744,435	$ 17,744,435	10.69%	$ 948,389
32	2010	9,351,235	32.000%	89,771,853	80,420,618	30,520,429	48,264,864	10.69%	3,528,007
33	2011	9,351,235	19.200%	53,863,112	44,511,877	16,892,702	65,157,566	10.69%	6,062,102
34	2012	9,351,235	11.520%	32,317,867	22,966,632	8,716,067	73,873,633	10.69%	7,430,817
35	2013	9,351,235	11.520%	32,317,867	22,966,632	8,716,067	82,589,700	10.69%	8,362,515
36	2014	9,351,235	5.760%	16,158,933	6,807,699	2,583,590	85,173,289	10.69%	8,966,449
37	2015	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	81,624,402	10.69%	8,914,856
38	2016	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	78,075,515	10.69%	8,535,501
39	2017	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	74,526,628	10.69%	8,156,145
40	2018	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	70,977,741	9.22%	6,710,661
41	2019	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	67,428,854	9.22%	6,383,311
42	2020	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	63,879,967	9.22%	6,055,962
43	2021	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	60,331,080	9.22%	5,728,613
44	2022	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	56,782,193	9.22%	5,401,264
45	2023	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	53,233,306	9.22%	5,073,914
46	2024	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	49,684,419	9.22%	4,746,565
47	2025	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	46,135,532	9.22%	4,419,216
48	2026	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	42,586,645	9.22%	4,091,866
49	2027	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	39,037,758	9.22%	3,764,517
50	2028	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	35,488,871	9.22%	3,437,168
51	2029	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	31,939,984	9.22%	3,109,818
52	2030	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	28,391,096	9.22%	2,782,469
53	2031	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	24,842,209	9.22%	2,455,120
54	2032	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	21,293,322	9.22%	2,127,770
55	2033	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	17,744,435	9.22%	1,800,421
56	2034	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	14,195,548	9.22%	1,473,072
57	2035	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	10,646,661	9.22%	1,145,723
58	2036	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	7,097,774	9.22%	818,373
59	2037	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	3,548,887	9.22%	491,024
60	2038	9,351,235	0.000%	-	(9,351,235)	(3,548,887)	(0)	9.22%	163,675
61		$ 280,537,039	100%	$ 280,537,039	$ 0	$ (0)			$ 133,085,304

Facility Name Rolling Hills **Cost Year:** 2019
Plant Type: Wind

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	7,850,217
2	RP Capability Allocator	RP and BOP Allocators	19.87%
3	**RP - Generator/Exciter**	(Line 1 * 2)	1,559,877
4			
5	GSU Transformer	Summary Investment	-
6	RP Capability Allocator	RP and BOP Allocators	19.87%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	0
8			
9	Accessory Electrical Equipment Related to the Production of Real and Reactive Power	Summary Investment	12,436,383
10	RP Capability Allocator	RP and BOP Allocators	19.87%
11	**RP - Accesory Electric Equipment**	(Line 9 * 10)	2,471,171
12	Total Plant Investment	Summary Investment	194,100,992
13	Balance of Plant	(Line 12 - 9 - 5 - 1)	173,814,392
14	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
15	**RP - Balance of Plant**	(Line 13 * 14)	46,588
16	Total RP Investment	(Line 3 + 7 + 11 + 15)	4,077,637
17	RP Fixed Charge Percent	(Line 11(h))	10.6349%
18	**Reactive Power Revenue Requirement**	(Line 16 * 17)	**$ 433,652**

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 1,439,813	$ 194,100,992	0.7418%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0129%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 25)			0.9145%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 26			1.1370%	
	ADIT	Line 30(i)	(3,730,880)	194,100,992	-1.9221%	
	Total RP Fixed Charge Percent				10.6349%	

	Depreciation		
19	Annual Depreciation Expense (D)	$ 6,748,149	
20	Gross Plant Investment (F)	194,100,992	(Line 14)
21	SLDP=DE/F	3.4766%	(Line 19 / 20)
22	Depreciable years =1/SLDP	29	
23	Book Life (n)	30	Book Lives
24	SLDP for Book Life = 1/n	3.33%	
25	SFDP=(R/((1+R)^n-1)	0.91%	R=Return

	Income Taxes		
26	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.1370%	Based Upon Book Life CTR=Composite Tax Rate

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
27	Investment	$ 194,100,992	Summary Investment						
28	Straight-line Tax Life	30	(Line 23)						
29	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$43,844,478
30	In Service Year	2009				Levelized Revenue Requirement			3,730,880
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 27 / 28	(Tax Depreciation Rates)	(Line 27 * Line 31c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
31	2009	$ 6,470,033	20.000%	$ 38,820,198	$ 32,350,165	$ 12,277,211	$ 12,277,211	10.69%	$ 656,182
32	2010	6,470,033	32.000%	62,112,317	55,642,284	21,116,803	33,394,015	10.69%	2,440,996
33	2011	6,470,033	19.200%	37,267,390	30,797,357	11,687,905	45,081,920	10.69%	4,194,313
34	2012	6,470,033	11.520%	22,360,434	15,890,401	6,030,566	51,112,486	10.69%	5,141,314
35	2013	6,470,033	11.520%	22,360,434	15,890,401	6,030,566	57,143,052	10.69%	5,785,947
36	2014	6,470,033	5.760%	11,180,217	4,710,184	1,787,562	58,930,614	10.69%	6,203,803
37	2015	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	56,475,172	10.69%	6,168,107
38	2016	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	54,019,729	10.69%	5,905,634
39	2017	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	51,564,287	10.69%	5,643,162
40	2018	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	49,108,845	9.22%	4,643,044
41	2019	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	46,653,403	9.22%	4,416,554
42	2020	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	44,197,960	9.22%	4,190,064
43	2021	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	41,742,518	9.22%	3,963,574
44	2022	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	39,287,076	9.22%	3,737,084
45	2023	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	36,831,634	9.22%	3,510,595
46	2024	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	34,376,191	9.22%	3,284,105
47	2025	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	31,920,749	9.22%	3,057,615
48	2026	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	29,465,307	9.22%	2,831,125
49	2027	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	27,009,865	9.22%	2,604,635
50	2028	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	24,554,422	9.22%	2,378,145
51	2029	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	22,098,980	9.22%	2,151,655
52	2030	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	19,643,538	9.22%	1,925,165
53	2031	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	17,188,096	9.22%	1,698,675
54	2032	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	14,732,653	9.22%	1,472,185
55	2033	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	12,277,211	9.22%	1,245,695
56	2034	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	9,821,769	9.22%	1,019,205
57	2035	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	7,366,327	9.22%	792,715
58	2036	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	4,910,884	9.22%	566,225
59	2037	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	2,455,442	9.22%	339,735
60	2038	6,470,033	0.000%	-	(6,470,033)	(2,455,442)	0	9.22%	113,245
61		$ 194,100,992	100%	$ 194,100,992	$ (0)	$ 0			$ 92,080,495

Facility Name Seven Mile Hill 1 and 2 **Cost Year:** 2019
Plant Type: Wind

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	10,726,471
2	RP Capability Allocator	RP and BOP Allocators	20.55%
3	**RP - Generator/Exciter**	(Line 1 * 2)	2,204,233
4			
5	GSU Transformer	Summary Investment	2,097,471
6	RP Capability Allocator	RP and BOP Allocators	20.55%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	431,019
8			
9	Accessory Electrical Equipment Related to the Production of Real and Reactive Power	Summary Investment	13,034,646
10	RP Capability Allocator	RP and BOP Allocators	20.55%
11	**RP - Accesory Electric Equipment**	(Line 9 * 10)	2,678,551
12			
13	Total Plant Investment	Summary Investment	225,985,934
14	Balance of Plant	(Line 13 - 9 - 5 - 1)	200,127,346
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	53,641
17			
18	Total RP Investment	(Line 3 + 7 + 11 + 16)	5,367,444
19	RP Fixed Charge Percent	(Line 12(h))	10.5734%
20	**Reactive Power Revenue Requirement**	(Line 18 * 19)	**$ 567,520**

	Depreciation		
21	Annual Depreciation Expense (D)	$ 7,875,974	
22	Gross Plant Investment (F)	225,985,934	(Line 15)
23	SLDP=DE/F	3.4852%	(Line 21 / 22)
24	Depreciable years =1/SLDP	29	
25	Book Life (n)	30	Book Lives
26	SLDP for Book Life = 1/n	3.33%	
27	SFDP=(R/((1+R)^n-1)	0.91%	R=Return

	Income Taxes		
28	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.1370%	Based Upon Book Life CTR=Composite Tax Rate

(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment					
		Amount	Investment	FCR %	
O&M	O&M by Facility	$ 1,503,799	$ 225,985,934	0.6654%	(f)/(g)
A&G	Fixed Charge Items			0.4475%	
Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0121%	
Prepayments	Fixed Charge Items			0.0203%	
Maintenance Prepayments	(Line 18 g)	70,710	225,985,934	0.0313%	
Materials and Supplies	Fixed Charge Items			0.1029%	
General and Intangible Plant	Fixed Charge Items			1.1057%	
Other Taxes	Fixed Charge Items			0.5233%	
Depreciation	(Line 27)			0.9145%	
Return	Fixed Charge Items			7.5512%	
Income Taxes	Line 28			1.1370%	
ADIT	Line 32(i)	(4,379,041)	225,985,934	-1.9377%	
Total RP Fixed Charge Percent				10.5734%	

Maintenance Prepayment Amount	FF1, page 233.15f + 16f	$ 813,862
Return and Income Taxes	(Line 9 h + Line 10 h)	8.69%
Annual Revenue Requirement	(Line 16 h * Line 17 h)	$ 70,710

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes									
29	Investment		$ 225,985,934	Summary Investment						
30	Straight-line Tax Life		30	(Line 25)						
31	Composite Tax Rate (CTR)		24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$51,461,518
32	In Service Year		2008				Levelized Revenue Requirement			4,379,041
	Year		SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
			Line 29 / 30	(Tax Depreciation Rates)	(Line 29 * Line 33c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
33		2008	$ 7,532,864	20.000%	$ 45,197,187	$ 37,664,322	$ 14,293,987	$ 14,293,987	10.69%	$ 763,972
34		2009	7,532,864	32.000%	72,315,499	64,782,634	24,585,658	38,879,645	10.69%	2,841,978
35		2010	7,532,864	19.200%	43,389,299	35,856,435	13,607,876	52,487,520	10.69%	4,883,312
36		2011	7,532,864	11.520%	26,033,580	18,500,715	7,021,206	59,508,726	10.69%	5,985,877
37		2012	7,532,864	11.520%	26,033,580	18,500,715	7,021,206	66,529,933	10.69%	6,736,403
38		2013	7,532,864	5.760%	13,016,790	5,483,925	2,081,205	68,611,137	10.69%	7,222,901
39		2014	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	65,752,340	10.69%	7,181,341
40		2015	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	62,893,543	10.69%	6,875,752
41		2016	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	60,034,745	10.69%	6,570,163
42		2017	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	57,175,948	10.69%	6,264,574
43		2018	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	54,317,150	9.22%	5,142,061
44		2019	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	51,458,353	9.22%	4,878,366
45		2020	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	48,599,556	9.22%	4,614,670
46		2021	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	45,740,758	9.22%	4,350,975
47		2022	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	42,881,961	9.22%	4,087,279
48		2023	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	40,023,163	9.22%	3,823,584
49		2024	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	37,164,366	9.22%	3,559,888
50		2025	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	34,305,569	9.22%	3,296,193
51		2026	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	31,446,771	9.22%	3,032,498
52		2027	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	28,587,974	9.22%	2,768,802
53		2028	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	25,729,177	9.22%	2,505,107
54		2029	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	22,870,379	9.22%	2,241,411
55		2030	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	20,011,582	9.22%	1,977,716
56		2031	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	17,152,784	9.22%	1,714,020
57		2032	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	14,293,987	9.22%	1,450,325
58		2033	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	11,435,190	9.22%	1,186,629
59		2034	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	8,576,392	9.22%	922,934
60		2035	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	5,717,595	9.22%	659,239
61		2036	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	2,858,797	9.22%	395,543
62		2037	7,532,864	0.000%	-	(7,532,864)	(2,858,797)	(0)	9.22%	131,848
63			$ 225,985,934	100%	$ 225,985,934	$ (0)	$ (0)			$ 108,065,362

Facility Name High Plains/McFadden Ridge **Cost Year:** 2019
Plant Type: Wind

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	11,333,570
2	RP Capability Allocator	RP and BOP Allocators	20.55%
3	**RP - Generator/Exciter**	(Line 1 * 2)	2,328,989
4			
5	GSU Transformer	Summary Investment	1,757,299
6	RP Capability Allocator	RP and BOP Allocators	20.55%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	361,116
8			
9	Accessory Electrical Equipment Related to the Production of Real and Reactive Power	Summary Investment	14,763,312
10	RP Capability Allocator	RP and BOP Allocators	20.55%
11	**RP - Accesory Electric Equipment**	(Line 9 * 10)	3,033,783
12	**Capacitors**	Capacitor Data	32,634
13	Total Plant Investment	Summary Investment	241,553,702
14	Balance of Plant	(Line 13 - 9 - 5 - 1)	213,699,520
15	Balance of Plant Allocator	RP and BOP Allocators	0.0186%
16	**RP - Balance of Plant**	(Line 14 * 15)	39,774
17	Total RP Investment	(Line 3 + 7 + 11 + 12 + 16)	5,796,296
18	RP Fixed Charge Percent	(Line 11(h))	10.8884%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 631,125**

Capacitor investment not included in Total Plant Investment

	Depreciation			
20	Annual Depreciation Expense (D)	$ 9,144,710		
21	Gross Plant Investment (F)	241,553,702		(Line 15)
22	SLDP=DE/F	3.7858%		(Line 20 / 21)
23	Depreciable years =1/SLDP	26		
24	Book Life (n)	30		Book Lives
25	SLDP for Book Life = 1/n	3.33%		
26	SFDP=(R/((1+R)^n-1)	0.91%		R=Return

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.1370%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 2,408,336	$ 241,553,702	0.9970%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0157%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.9145%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.1370%	
	ADIT	Line 31(i)	(4,653,788)	241,553,702	-1.9266%	
	Total RP Fixed Charge Percent				10.8884%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 241,553,702	Summary Investment						
29	Straight-line Tax Life	30	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$54,690,279
31	In Service Year	2009				Levelized Revenue Requirement			4,653,788
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	2009	$ 8,051,790	20.000%	$ 48,310,740	$ 40,258,950	$ 15,278,674	$ 15,278,674	10.69%	$ 816,601
33	2010	8,051,790	32.000%	77,297,185	69,245,395	26,279,320	41,557,994	10.69%	3,037,756
34	2011	8,051,790	19.200%	46,378,311	38,326,521	14,545,298	56,103,292	10.69%	5,219,715
35	2012	8,051,790	11.520%	27,826,986	19,775,196	7,504,885	63,608,177	10.69%	6,398,233
36	2013	8,051,790	11.520%	27,826,986	19,775,196	7,504,885	71,113,061	10.69%	7,200,462
37	2014	8,051,790	5.760%	13,913,493	5,861,703	2,224,575	73,337,636	10.69%	7,720,474
38	2015	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	70,281,901	10.69%	7,676,051
39	2016	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	67,226,167	10.69%	7,349,410
40	2017	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	64,170,432	10.69%	7,022,770
41	2018	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	61,114,697	9.22%	5,778,150
42	2019	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	58,058,962	9.22%	5,496,289
43	2020	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	55,003,227	9.22%	5,214,428
44	2021	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	51,947,492	9.22%	4,932,567
45	2022	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	48,891,758	9.22%	4,650,706
46	2023	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	45,836,023	9.22%	4,368,845
47	2024	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	42,780,288	9.22%	4,086,984
48	2025	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	39,724,553	9.22%	3,805,123
49	2026	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	36,668,818	9.22%	3,523,262
50	2027	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	33,613,083	9.22%	3,241,401
51	2028	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	30,557,348	9.22%	2,959,540
52	2029	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	27,501,614	9.22%	2,677,679
53	2030	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	24,445,879	9.22%	2,395,818
54	2031	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	21,390,144	9.22%	2,113,957
55	2032	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	18,334,409	9.22%	1,832,096
56	2033	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	15,278,674	9.22%	1,550,235
57	2034	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	12,222,939	9.22%	1,268,374
58	2035	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	9,167,205	9.22%	986,513
59	2036	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	6,111,470	9.22%	704,652
60	2037	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	3,055,735	9.22%	422,791
61	2038	8,051,790	0.000%	-	(8,051,790)	(3,055,735)	12,222,939	9.22%	1,268,374
62		$ 241,553,702	100%	$ 241,553,702	$ 0	$ (0)			$ 115,719,256

Facility Name Goodnoe Hills **Cost Year:** 2019
Plant Type: Wind

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	7,173,099
2	RP Capability Allocator	RP and BOP Allocators	2.16%
3	**RP - Generator/Exciter**	(Line 1 * 2)	155,072
4			
5	GSU Transformer	Summary Investment	3,357,435
6	RP Capability Allocator	RP and BOP Allocators	2.16%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	72,583
8			
9	Accessory Electrical Equipment Related to the Production of Real and Reactive Power	Summary Investment	7,434,456
10	RP Capability Allocator	RP and BOP Allocators	2.16%
11	**RP - Accesory Electric Equipment**	(Line 9 * 10)	160,722
12	**Capacitors**	Capacitor Data	389,918
13	Total Plant Investment	Summary Investment	158,979,266
14	Balance of Plant	(Line 13 - 9 - 5 - 1)	141,014,276
15	Balance of Plant Allocator	RP and BOP Allocators	0.0186%
16	**RP - Balance of Plant**	(Line 14 * 15)	26,245
17	Total RP Investment	(Line 3 + 7 + 11 + 12 + 16)	804,539
18	RP Fixed Charge Percent	(Line 11(h))	10.7775%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 86,710**

Capacitor investment not included in Total Plant Investment

	Depreciation			
20	Annual Depreciation Expense (D)	$	6,134,166	
21	Gross Plant Investment (F)		158,979,266	(Line 15)
22	SLDP=DE/F		3.8585%	(Line 20 / 21)
23	Depreciable years =1/SLDP		26	
24	Book Life (n)		30	Book Lives
25	SLDP for Book Life = 1/n		3.33%	
26	SFDP=(R/((1+R)^n-1)		0.91%	R=Return

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.1370%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 1,442,812	$ 158,979,266	0.9075%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0147%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.9145%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.1370%	
	ADIT	Line 31(i)	(3,095,376)	158,979,266	-1.9470%	
	Total RP Fixed Charge Percent				10.7775%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 158,979,266	Summary Investment						
29	Straight-line Tax Life	30	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$36,376,176
31	In Service Year	2008				Levelized Revenue Requirement			3,095,376
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	2008	$ 5,299,309	20.000%	$ 31,795,853	$ 26,496,544	$ 10,055,704	$ 10,055,704	10.69%	$ 537,448
33	2009	5,299,309	32.000%	50,873,365	45,574,056	17,295,810	27,351,514	10.69%	1,999,308
34	2010	5,299,309	19.200%	30,524,019	25,224,710	9,573,030	36,924,543	10.69%	3,435,370
35	2011	5,299,309	11.520%	18,314,411	13,015,103	4,939,362	41,863,905	10.69%	4,211,016
36	2012	5,299,309	11.520%	18,314,411	13,015,103	4,939,362	46,803,266	10.69%	4,739,005
37	2013	5,299,309	5.760%	9,157,206	3,857,897	1,464,110	48,267,377	10.69%	5,081,252
38	2014	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	46,256,236	10.69%	5,052,015
39	2015	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	44,245,095	10.69%	4,837,036
40	2016	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	42,233,955	10.69%	4,622,056
41	2017	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	40,222,814	10.69%	4,407,077
42	2018	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	38,211,673	9.22%	3,617,398
43	2019	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	36,200,533	9.22%	3,431,891
44	2020	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	34,189,392	9.22%	3,246,383
45	2021	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	32,178,251	9.22%	3,060,875
46	2022	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	30,167,111	9.22%	2,875,368
47	2023	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	28,155,970	9.22%	2,689,860
48	2024	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	26,144,829	9.22%	2,504,353
49	2025	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	24,133,688	9.22%	2,318,845
50	2026	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	22,122,548	9.22%	2,133,337
51	2027	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	20,111,407	9.22%	1,947,830
52	2028	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	18,100,266	9.22%	1,762,322
53	2029	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	16,089,126	9.22%	1,576,815
54	2030	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	14,077,985	9.22%	1,391,307
55	2031	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	12,066,844	9.22%	1,205,799
	2032	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	10,055,704	9.22%	1,020,292
	2033	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	8,044,563	9.22%	834,784
	2034	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	6,033,422	9.22%	649,277
	2035	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	4,022,281	9.22%	463,769
56	2036	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	10,055,704	9.22%	1,020,292
57	2037	5,299,309	0.000%	-	(5,299,309)	(2,011,141)	8,044,563	9.22%	834,784
58		$ 158,979,266	100%	$ 158,979,266	$ 0	$ -			$ 77,507,164

Facility Name Leaning Juniper **Cost Year:** 2019
Plant Type: Wind

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	8,506,173
2	RP Capability Allocator	RP and BOP Allocators	16.44%
3	**RP - Generator/Exciter**	(Line 1 * 2)	1,398,038
4			
5	GSU Transformer	Summary Investment	3,233,153
6	RP Capability Allocator	RP and BOP Allocators	16.44%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	531,387
8			
9	Accessory Electrical Equipment Related to the Production of Real and Reactive Power	Summary Investment	9,512,344
10	RP Capability Allocator	RP and BOP Allocators	16.44%
11	**RP - Accesory Electric Equipment**	(Line 9 * 10)	1,563,408
12	Total Plant Investment	Summary Investment	177,706,380
13	Balance of Plant	(Line 12 - 9 - 5 - 1)	156,454,710
14	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
15	**RP - Balance of Plant**	(Line 12 * 13)	41,935
16	Total RP Investment	(Line 3 + 7 + 11 + 15)	3,534,767
17	RP Fixed Charge Percent	(Line 11(h))	10.6432%
18	**Reactive Power Revenue Requirement**	(Line 16 * 17)	**$ 376,212**

	Depreciation		
19	Annual Depreciation Expense (D)	$ 5,810,865	
20	Gross Plant Investment (F)	177,706,380	(Line 14)
21	SLDP=DE/F	3.2699%	(Line 19 / 20)
22	Depreciable years =1/SLDP	31	
23	Book Life (n)	30	Book Lives
24	SLDP for Book Life = 1/n	3.33%	
25	SFDP=(R/((1+R)^n-1)	0.91%	R=Return

	Income Taxes		
26	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.1370%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 1,405,963	$ 177,706,380	0.7912%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0135%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 25)			0.9145%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 26			1.1370%	
	ADIT	Line 30(i)	(3,489,697)	177,706,380	-1.9637%	
	Total RP Fixed Charge Percent				10.6432%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
27	Investment	$ 177,706,380	Summary Investment						
28	Straight-line Tax Life	30	(Line 23)						
29	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$41,010,149
30	In Service Year	2006				Levelized Revenue Requirement			3,489,697

	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 27 / 28	(Tax Depreciation Rates)	(Line 27 * Line 31c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
31	2006	$ 5,923,546	20.000%	$ 35,541,276	$ 29,617,730	$ 11,240,225	$ 11,240,225	10.69%	$ 600,758
32	2007	5,923,546	32.000%	56,866,042	50,942,496	19,333,186	30,573,411	10.69%	2,234,818
33	2008	5,923,546	19.200%	34,119,625	28,196,079	10,700,694	41,274,105	10.69%	3,840,043
34	2009	5,923,546	11.520%	20,471,775	14,548,229	5,521,198	46,795,304	10.69%	4,707,056
35	2010	5,923,546	11.520%	20,471,775	14,548,229	5,521,198	52,316,502	10.69%	5,297,241
36	2011	5,923,546	5.760%	10,235,887	4,312,341	1,636,577	53,953,079	10.69%	5,679,803
37	2012	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	51,705,034	10.69%	5,647,122
38	2013	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	49,456,989	10.69%	5,406,819
39	2014	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	47,208,944	10.69%	5,166,516
40	2015	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	44,960,899	10.69%	4,926,213
41	2016	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	42,712,854	10.69%	4,685,910
42	2017	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	40,464,809	10.69%	4,445,607
43	2018	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	38,216,764	9.22%	3,628,794
44	2019	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	35,968,719	9.22%	3,421,434
45	2020	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	33,720,674	9.22%	3,214,074
46	2021	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	31,472,629	9.22%	3,006,715
47	2022	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	29,224,584	9.22%	2,799,355
48	2023	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	26,976,539	9.22%	2,591,996
49	2024	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	24,728,494	9.22%	2,384,636
50	2025	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	22,480,449	9.22%	2,177,276
51	2026	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	20,232,404	9.22%	1,969,917
52	2027	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	17,984,360	9.22%	1,762,557
53	2028	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	15,736,315	9.22%	1,555,197
54	2029	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	13,488,270	9.22%	1,347,838
55	2030	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	11,240,225	9.22%	1,140,478
56	2031	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	8,992,180	9.22%	933,118
57	2032	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	6,744,135	9.22%	725,759
58	2033	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	4,496,090	9.22%	518,399
59	2034	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	2,248,045	9.22%	311,039
60	2035	5,923,546	0.000%	-	(5,923,546)	(2,248,045)	(0)	9.22%	103,680
61		$ 177,706,380	100%	$ 177,706,380	$ (0)	$ (0)			$ 86,230,167

Facility Name Marengo I and II **Cost Year:** 2019
Plant Type: Wind

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	13,536,139
2	RP Capability Allocator	RP and BOP Allocators	9.03%
3	**RP - Generator/Exciter**	(Line 1 * 2)	1,222,273
4			
5	GSU Transformer	Summary Investment	4,232,780
6	RP Capability Allocator	RP and BOP Allocators	9.03%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	382,207
8			
9	Accessory Electrical Equipment Related to the Production of Real and Reactive Power	Summary Investment	20,187,305
10	RP Capability Allocator	RP and BOP Allocators	9.03%
11	**RP - Accesory Electric Equipment**	(Line 9 * 10)	1,822,853
12	**Capacitors**	Capacitor Data	560,070
13	Total Plant Investment	Summary Investment	375,047,769
14	Balance of Plant	(Line 13 - 9 - 5 - 1)	337,091,545
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 13 * 14)	90,352
17			
18	Total RP Investment	(Line 3 + 7 + 11 + 12 + 16)	4,077,754
19	RP Fixed Charge Percent	(Line 11(h))	10.5547%
20	**Reactive Power Revenue Requirement**	(Line 18 * 19)	**$ 430,396**

Capacitor investment not included in Total Plant Investment

	Depreciation			
21	Annual Depreciation Expense (D)	$	12,449,276	
22	Gross Plant Investment (F)		375,047,769	(Line 15)
23	SLDP=DE/F		3.3194%	(Line 21 / 22)
24	Depreciable years (n)=1/SLDP		30	
25	Book Life (n)		30	Book Lives
26	SLDP for Book Life = 1/n		3.33%	
27	SFDP=(R/((1+R)^n-1)		0.91%	R=Return

	Income Taxes		
28	Income Tax Factor to Include in Fixed Charge Factor	1.1370%	Based Upon Book Life
	[(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]		CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 2,542,571	$ 375,047,769	0.6779%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0122%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 27)			0.9145%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 28			1.1370%	
	ADIT	Line 32(i)	(7,267,486)	375,047,769	-1.9377%	
	Total RP Fixed Charge Percent				10.5547%	

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes									
29	Investment		$ 375,047,769	Summary Investment						
30	Straight-line Tax Life		30	(Line 25)						
31	Composite Tax Rate (CTR)		24.59%		37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$85,405,880
32	In Service Year		2008	2007-2008			Levelized Revenue Requirement			7,267,486
	Year		SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
			Line 29 / 30	(Tax Depreciation Rates)	(Line 29 * Line 33c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
33		2008	$ 12,501,592	20.000%	$ 75,009,554	$ 62,507,961	$ 23,722,396	$ 23,722,396	10.69%	$ 1,267,894
34		2009	12,501,592	32.000%	120,015,286	107,513,694	40,802,522	64,524,918	10.69%	4,716,565
35		2010	12,501,592	19.200%	72,009,172	59,507,579	22,583,721	87,108,640	10.69%	8,104,377
36		2011	12,501,592	11.520%	43,205,503	30,703,911	11,652,441	98,761,081	10.69%	9,934,201
37		2012	12,501,592	11.520%	43,205,503	30,703,911	11,652,441	110,413,522	10.69%	11,179,780
38		2013	12,501,592	5.760%	21,602,751	9,101,159	3,453,981	113,867,503	10.69%	11,987,175
39		2014	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	109,123,024	10.69%	11,918,202
40		2015	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	104,378,544	10.69%	11,411,044
41		2016	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	99,634,065	10.69%	10,903,887
42		2017	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	94,889,586	10.69%	10,396,729
43		2018	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	90,145,107	9.22%	8,533,799
44		2019	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	85,400,627	9.22%	8,096,168
45		2020	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	80,656,148	9.22%	7,658,538
46		2021	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	75,911,669	9.22%	7,220,907
47		2022	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	71,167,189	9.22%	6,783,276
48		2023	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	66,422,710	9.22%	6,345,645
49		2024	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	61,678,231	9.22%	5,908,015
50		2025	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	56,933,752	9.22%	5,470,384
51		2026	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	52,189,272	9.22%	5,032,753
52		2027	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	47,444,793	9.22%	4,595,123
53		2028	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	42,700,314	9.22%	4,157,492
54		2029	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	37,955,834	9.22%	3,719,861
55		2030	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	33,211,355	9.22%	3,282,230
56		2031	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	28,466,876	9.22%	2,844,600
57		2032	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	23,722,396	9.22%	2,406,969
58		2033	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	18,977,917	9.22%	1,969,338
59		2034	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	14,233,438	9.22%	1,531,708
60		2035	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	9,488,959	9.22%	1,094,077
61		2036	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	4,744,479	9.22%	656,446
62		2037	12,501,592	0.000%	-	(12,501,592)	(4,744,479)	0	9.22%	218,815
63			$ 375,047,769	100%	$ 375,047,769	$ (0)	$ 0			$ 179,345,999

Facility Name **Dunlap** **Cost Year:** 2019/2021
Plant Type: Wind

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	16,707,566
2	RP Capability Allocator	RP and BOP Allocators	20.55%
3	**RP - Generator/Exciter**	(Line 1 * 2)	3,433,317
4			
5	GSU Transformer	Summary Investment	1,704,005
6	RP Capability Allocator	RP and BOP Allocators	20.55%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	350,164
8			
9	Accessory Electrical Equipment Related to the Production of Real and Reactive Power	Summary Investment	12,327,565
10	RP Capability Allocator	RP and BOP Allocators	20.55%
11	**RP - Accesory Electric Equipment**	(Line 9 * 10)	2,533,250
12	**Capacitors**	Capacitor Data	89,698
13	Total Plant Investment	Summary Investment	372,526,200
14	Balance of Plant	(Line 13 - 11 - 5 - 1)	341,787,064
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 13 * 14)	91,610
17			
18	Total RP Investment	(Line 3 + 7 + 11 + 12 + 16)	6,498,039
19	RP Fixed Charge Percent	(Line 11(h))	10.3397%
20	**Reactive Power Revenue Requirement**	(Line 18 * 19)	**$ 671,878**

Capacitor investment not included in Total Plant Investment

	Depreciation			
20	Annual Depreciation Expense (D)	$	12,192,466	
21	Gross Plant Investment (F)		372,526,200	(Line 15)
22	SLDP=DE/F		3.2729%	(Line 20 / 21)
23	Depreciable years =1/SLDP		31	
24	Book Life (n)		30	Book Lives
25	SLDP for Book Life = 1/n		3.33%	
26	SFDP=(R/((1+R)^n-1)		0.91%	R=Return

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.1370%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 1,610,606	$ 372,526,200	0.4323%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0096%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.9145%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.1370%	
	ADIT	Line 31(i)	(7,094,834)	372,526,200	-1.9045%	
	Total RP Fixed Charge Percent				10.3397%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 372,526,200	Summary Investment						
29	Straight-line Tax Life	30	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$83,376,909
31	In Service Year	2010				Levelized Revenue Requirement			7,094,834
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	2010	$ 12,417,540	20.000%	$ 74,505,240	$ 62,087,700	$ 23,562,903	$ 23,562,903	10.69%	$ 1,259,369
33	2011	12,417,540	32.000%	119,208,384	106,790,844	40,528,193	64,091,096	10.69%	4,684,854
34	2012	12,417,540	19.200%	71,525,030	59,107,490	22,431,884	86,522,980	10.69%	8,049,889
35	2013	12,417,540	11.520%	42,915,018	30,497,478	11,574,098	98,097,078	10.69%	9,867,411
36	2014	12,417,540	11.520%	42,915,018	30,497,478	11,574,098	109,671,176	10.69%	11,104,615
37	2015	12,417,540	5.760%	21,457,509	9,039,969	3,430,759	113,101,934	10.69%	11,906,581
38	2016	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	108,389,354	10.69%	11,838,072
39	2017	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	103,676,773	10.69%	11,334,324
40	2018	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	98,964,193	9.22%	9,345,800
41	2019	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	94,251,612	9.22%	8,911,112
42	2020	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	89,539,031	9.22%	8,476,424
43	2021	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	84,826,451	9.22%	8,041,735
44	2022	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	80,113,870	9.22%	7,607,047
45	2023	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	75,401,290	9.22%	7,172,358
46	2024	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	70,688,709	9.22%	6,737,670
47	2025	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	65,976,128	9.22%	6,302,982
48	2026	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	61,263,548	9.22%	5,868,293
49	2027	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	56,550,967	9.22%	5,433,605
50	2028	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	51,838,387	9.22%	4,998,916
51	2029	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	47,125,806	9.22%	4,564,228
52	2030	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	42,413,225	9.22%	4,129,540
53	2031	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	37,700,645	9.22%	3,694,851
54	2032	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	32,988,064	9.22%	3,260,163
55	2033	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	28,275,484	9.22%	2,825,475
56	2034	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	23,562,903	9.22%	2,390,786
57	2035	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	18,850,322	9.22%	1,956,098
58	2036	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	14,137,742	9.22%	1,521,409
59	2037	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	9,425,161	9.22%	1,086,721
60	2038	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	4,712,581	9.22%	652,033
61	2039	12,417,540	0.000%	-	(12,417,540)	(4,712,581)	(0)	9.22%	217,344
62		$ 372,526,200	100%	$ 372,526,200	$ (0)	$ (0)			$ 175,239,704

Facility Name Foote Creek **Cost Year:** 2019/2021
Plant Type: Wind

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	7,384,382
2	RP Capability Allocator	RP and BOP Allocators	15.21%
3	**RP - Generator/Exciter**	(Line 1 * 2)	1,123,464
4			
5	GSU Transformer	Summary Investment	-
6	RP Capability Allocator	RP and BOP Allocators	15.21%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	0
8			
9	Accessory Electrical Equipment Related to the Production of Real and Reactive Power	Summary Investment	7,392,658
10	RP Capability Allocator	RP and BOP Allocators	15.21%
11	**RP - Accesory Electric Equipment**	(Line 9 * 10)	1,124,723
12	Total Plant Investment	Summary Investment	123,797,900
13	Balance of Plant	(Line 12 - 9 - 5 - 1)	109,020,859
14	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
15	**RP - Balance of Plant**	(Line 13 * 14)	29,221
16	Total RP Investment	(Line 3 + 7 + 11 + 15)	2,277,407
17	RP Fixed Charge Percent	(Line 11(h))	10.4370%
18	**Reactive Power Revenue Requirement**	(Line 16 * 17) **$**	**237,694**

	Depreciation			
19	Annual Depreciation Expense (D)	$	3,763,382	
20	Gross Plant Investment (F)		123,797,900	(Line 14)
21	SLDP=DE/F		3.0399%	(Line 19 / 20)
22	Depreciable years (n)=1/SLDP		33	
23	Book Life (n)		30	Book Lives
24	SLDP for Book Life = 1/n		3.33%	
25	SFDP=(R/((1+R)^n-1)		0.91%	R=Return

	Income Taxes		
26	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.1370%	Based Upon Book Life CTR=Composite Tax Rate

(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment					
		Amount	Investment	FCR %	
O&M	O&M by Facility	$ 790,038	$ 123,797,900	0.6382%	(f)/(g)
A&G	Fixed Charge Items			0.4475%	
Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0118%	
Prepayments	Fixed Charge Items			0.0203%	
Materials and Supplies	Fixed Charge Items			0.1029%	
General and Intangible Plant	Fixed Charge Items			1.1057%	
Other Taxes	Fixed Charge Items			0.5233%	
Depreciation	(Line 25)			0.9145%	
Return	Fixed Charge Items			7.5512%	
Income Taxes	Line 26			1.1370%	
ADIT	Line 30(i)	(2,494,824)	123,797,900	-2.0152%	
Total RP Fixed Charge Percent				10.4370%	

	(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes									
27	Investment		$ 123,797,900	Summary Investment						
28	Straight-line Tax Life		30	(Line 23)						
29	Composite Tax Rate (CTR)		24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$29,318,622
30	In Service Year		1999				Levelized Revenue Requirement			2,494,824
	Year		SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
			Line 27 / 28	(Tax Depreciation Rates)	(Line 27 * Line 31c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
31		1999	$ 4,126,597	20.000%	$ 24,759,580	$ 20,632,983	$ 7,830,423	$ 7,830,423	10.69%	$ 418,514
32		2000	4,126,597	32.000%	39,615,328	35,488,731	13,468,328	21,298,752	10.69%	1,556,871
33		2001	4,126,597	19.200%	23,769,197	19,642,600	7,454,563	28,753,315	10.69%	2,675,139
34		2002	4,126,597	11.520%	14,261,518	10,134,921	3,846,304	32,599,619	10.69%	3,279,138
35		2003	4,126,597	11.520%	14,261,518	10,134,921	3,846,304	36,445,923	10.69%	3,690,285
36		2004	4,126,597	5.760%	7,130,759	3,004,162	1,140,110	37,586,033	10.69%	3,956,795
37		2005	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	36,019,948	10.69%	3,934,028
38		2006	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	34,453,863	10.69%	3,766,622
39		2007	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	32,887,779	10.69%	3,599,217
40		2008	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	31,321,694	10.69%	3,431,811
41		2009	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	29,755,609	10.69%	3,264,406
42		2010	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	28,189,525	10.69%	3,097,001
43		2011	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	26,623,440	10.69%	2,929,595
44		2012	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	25,057,355	10.69%	2,762,190
45		2013	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	23,491,270	10.69%	2,594,784
46		2014	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	21,925,186	10.69%	2,427,379
47		2015	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	20,359,101	10.69%	2,259,973
48		2016	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	18,793,016	10.69%	2,092,568
49		2017	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	17,226,932	10.69%	1,925,163
50		2018	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	15,660,847	9.22%	1,516,784
51		2019	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	14,094,762	9.22%	1,372,329
52		2020	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	12,528,678	9.22%	1,227,873
53		2021	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	10,962,593	9.22%	1,083,417
54		2022	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	9,396,508	9.22%	938,962
55		2023	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	7,830,423	9.22%	794,506
56		2024	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	6,264,339	9.22%	650,050
57		2025	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	4,698,254	9.22%	505,595
58		2026	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	3,132,169	9.22%	361,139
59		2027	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	1,566,085	9.22%	216,683
60		2028	4,126,597	0.000%	-	(4,126,597)	(1,566,085)	0	9.22%	72,228
61			$ 123,797,900	100%	$ 123,797,900	$ 0	$ 0			$ 62,401,044

Facility Name Cedar Springs II **Cost Year:** 2021
Plant Type: Wind

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	18,631,876
2	RP Capability Allocator	RP and BOP Allocators	20.46%
3	**RP - Generator/Exciter**	(Line 1 * 2)	3,812,058
4			
5	GSU Transformer	Summary Investment	2,793,553
6	RP Capability Allocator	RP and BOP Allocators	20.46%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	571,557
8			
	Accessory Electrical Equipment Related to the		
9	Production of Real and Reactive Power	Summary Investment	25,806,123
10	RP Capability Allocator	RP and BOP Allocators	20.46%
11	**RP - Accesory Electric Equipment**	(Line 9 * 10)	5,279,899
0			
12	Total Plant Investment	Summary Investment	270,400,000
13	Balance of Plant	(Line 12 - 9 - 5 - 1)	223,168,448
14	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
15	**RP - Balance of Plant**	(Line 13 * 14)	59,817
16	Total RP Investment	(Line 3 + 7 + 11 + 15)	9,723,331
17	RP Fixed Charge Percent	(Line 11(h))	12.1253%
18	**Reactive Power Revenue Requirement**	(Line 16 * 17) **$**	**1,178,985**

	Depreciation			
19	Annual Depreciation Expense (D)	$	9,013,333	
20	Gross Plant Investment (F)		270,400,000	(Line 14)
21	SLDP=DE/F		3.3333%	(Line 19 / 20)
22	Depreciable years =1/SLDP		30	
23	Book Life (n)		30	Book Lives
24	SLDP for Book Life = 1/n		3.33%	
25	SFDP=(R/((1+R)^n-1)		0.91%	R=Return

	Income Taxes		
	Income Tax Factor to Include in Fixed Charge		
26	Factor	1.1370%	Based Upon Book Life
	[(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]		CTR=Composite Tax Rate

(d)	(e)	(f)	(g)	(h)	
Fixed Charge Rate for Reactive Investment					
		Amount	Investment	FCR %	
O&M	O&M by Facility	$ 3,891,443	$ 270,400,000	1.4391%	(f)/(g)
A&G	Fixed Charge Items			0.4475%	
Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0205%	
Prepayments	Fixed Charge Items			0.0203%	
Materials and Supplies	Fixed Charge Items			0.1029%	
General and Intangible Plant	Fixed Charge Items			1.1057%	
Other Taxes	Fixed Charge Items			0.5233%	
Depreciation	(Line 25)			0.9145%	
Return	Fixed Charge Items			7.5512%	
Income Taxes	Line 26			1.1370%	
ADIT	Line 30(i)	(3,073,450)	270,400,000	-1.1366%	
Total RP Fixed Charge Percent				12.1253%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
27	Investment	$ 270,400,000	Summary Investment						
28	Straight-line Tax Life	30	(Line 23)						
29	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$36,118,506
30	In Service Year	2020				Levelized Revenue Requirement			3,073,450
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 27 / 28	(Tax Depreciation Rates)	(Line 27 * Line 31c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
31	2020	$ 9,013,333	20.000%	$ 54,080,000	$ 45,066,667	$ 11,080,361	$ 11,080,361	9.22%	$ 511,026
32	2021	9,013,333	32.000%	86,528,000	77,514,667	19,058,221	30,138,582	9.22%	1,901,017
33	2022	9,013,333	19.200%	51,916,800	42,903,467	10,548,504	40,687,086	9.22%	3,266,479
34	2023	9,013,333	11.520%	31,150,080	22,136,747	5,442,673	46,129,759	9.22%	4,003,992
35	2024	9,013,333	11.520%	31,150,080	22,136,747	5,442,673	51,572,433	9.22%	4,506,025
36	2025	9,013,333	5.760%	15,575,040	6,561,707	1,613,301	53,185,733	9.22%	4,831,446
37	2026	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	50,969,661	9.22%	4,803,646
38	2027	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	48,753,589	9.22%	4,599,236
39	2028	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	46,537,516	9.22%	4,394,825
40	2029	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	44,321,444	9.22%	4,190,415
41	2030	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	42,105,372	9.22%	3,986,004
42	2031	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	39,889,300	9.22%	3,781,594
43	2032	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	37,673,228	9.22%	3,577,183
44	2033	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	35,457,155	9.22%	3,372,773
45	2034	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	33,241,083	9.22%	3,168,362
46	2035	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	31,025,011	9.22%	2,963,952
47	2036	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	28,808,939	9.22%	2,759,541
48	2037	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	26,592,867	9.22%	2,555,131
49	2038	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	24,376,794	9.22%	2,350,721
50	2039	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	22,160,722	9.22%	2,146,310
51	2040	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	19,944,650	9.22%	1,941,900
52	2041	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	17,728,578	9.22%	1,737,489
53	2042	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	15,512,505	9.22%	1,533,079
54	2043	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	13,296,433	9.22%	1,328,668
55	2044	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	11,080,361	9.22%	1,124,258
56	2045	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	8,864,289	9.22%	919,847
57	2046	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	6,648,217	9.22%	715,437
58	2047	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	4,432,144	9.22%	511,026
59	2048	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	2,216,072	9.22%	306,616
60	2049	9,013,333	0.000%	-	(9,013,333)	(2,216,072)	0	9.22%	102,205
61		$ 270,400,000	100%	$ 270,400,000	$ (0)	$ 0			$ 77,890,204

Facility Name Ekola Flats **Cost Year:** 2021
Plant Type: Wind

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	21,944,223
2	RP Capability Allocator	RP and BOP Allocators	16.28%
3	**RP - Generator/Exciter**	(Line 1 * 2)	3,572,542
4			
5	GSU Transformer	Summary Investment	2,930,546
6	RP Capability Allocator	RP and BOP Allocators	16.28%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	477,096
8			
9	Accessory Electrical Equipment Related to the Production of Real and Reactive Power	Summary Investment	37,203,627
10	RP Capability Allocator	RP and BOP Allocators	16.28%
11	**RP - Accesory Electric Equipment**	(Line 9 * 10)	6,056,789
12			
13	Total Plant Investment	Summary Investment	323,999,710
14	Balance of Plant	(Line 13 - 9 - 5 - 1)	261,921,314
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	70,204
17			
18	Total RP Investment	(Line 3 + 7 + 11 + 16)	10,176,630
19	RP Fixed Charge Percent	(Line 11(h))	11.5152%
20	**Reactive Power Revenue Requirement**	(Line 18 * 19)	**$ 1,171,858**

	Depreciation			
21	Annual Depreciation Expense (D)	$	10,799,990	
22	Gross Plant Investment (F)		323,999,710	(Line 15)
23	SLDP=DE/F		3.3333%	(Line 21 / 22)
24	Depreciable years =1/SLDP		30	
25	Book Life (n)		30	Book Lives
26	SLDP for Book Life = 1/n		3.33%	
27	SFDP=(R/((1+R)^n-1)		0.91%	R=Return

	Income Taxes		
28	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.1370%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 2,707,237	$ 323,999,710	0.8356%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0139%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 27)			0.9145%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 28			1.1370%	
	ADIT	Line 32(i)	(3,682,681)	323,999,710	-1.1366%	
	Total RP Fixed Charge Percent				11.5152%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
29	Investment	$ 323,999,710	Summary Investment						
30	Straight-line Tax Life	30	(Line 25)						
31	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$43,278,053
32	In Service Year	2020				Levelized Revenue Requirement			3,682,681

	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 29 / 30	(Tax Depreciation Rates)	(Line 29 * Line 33c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
33	2020	$ 10,799,990	20.000%	$ 64,799,942	$ 53,999,952	$ 13,276,752	$ 13,276,752	9.22%	$ 612,324
34	2021	10,799,990	32.000%	103,679,907	92,879,917	22,836,014	36,112,766	9.22%	2,277,844
35	2022	10,799,990	19.200%	62,207,944	51,407,954	12,639,468	48,752,234	9.22%	3,913,973
36	2023	10,799,990	11.520%	37,324,767	26,524,776	6,521,541	55,273,774	9.22%	4,797,679
37	2024	10,799,990	11.520%	37,324,767	26,524,776	6,521,541	61,795,315	9.22%	5,399,226
38	2025	10,799,990	5.760%	18,662,383	7,862,393	1,933,095	63,728,410	9.22%	5,789,154
39	2026	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	61,073,060	9.22%	5,755,843
40	2027	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	58,417,709	9.22%	5,510,914
41	2028	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	55,762,359	9.22%	5,265,984
42	2029	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	53,107,008	9.22%	5,021,055
43	2030	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	50,451,658	9.22%	4,776,125
44	2031	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	47,796,308	9.22%	4,531,196
45	2032	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	45,140,957	9.22%	4,286,266
46	2033	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	42,485,607	9.22%	4,041,337
47	2034	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	39,830,256	9.22%	3,796,407
48	2035	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	37,174,906	9.22%	3,551,478
49	2036	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	34,519,556	9.22%	3,306,548
50	2037	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	31,864,205	9.22%	3,061,619
51	2038	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	29,208,855	9.22%	2,816,689
52	2039	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	26,553,504	9.22%	2,571,760
53	2040	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	23,898,154	9.22%	2,326,830
54	2041	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	21,242,803	9.22%	2,081,901
55	2042	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	18,587,453	9.22%	1,836,971
56	2043	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	15,932,103	9.22%	1,592,042
57	2044	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	13,276,752	9.22%	1,347,112
58	2045	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	10,621,402	9.22%	1,102,183
59	2046	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	7,966,051	9.22%	857,253
60	2047	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	5,310,701	9.22%	612,324
61	2048	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	2,655,350	9.22%	367,394
62	2049	10,799,990	0.000%	-	(10,799,990)	(2,655,350)	(0)	9.22%	122,465
63		$ 323,999,710	100%	$ 323,999,710	$ (0)	$ (0)			$ 93,329,895

Facility Name **TB Flats I** **Cost Year:** 2021
Plant Type: Wind

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	39,528,469
2	RP Capability Allocator	RP and BOP Allocators	13.33%
3	**RP - Generator/Exciter**	(Line 1 * 2)	5,269,624
4			
5	GSU Transformer	Summary Investment	7,286,972
6	RP Capability Allocator	RP and BOP Allocators	13.33%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	971,442
8			
9	Accessory Electrical Equipment Related to the Production of Real and Reactive Power	Summary Investment	42,625,403
10	RP Capability Allocator	RP and BOP Allocators	13.33%
11	**RP - Accesory Electric Equipment**	(Line 9 * 10)	5,682,483
12	Total Plant Investment	Summary Investment	555,380,727
13	Balance of Plant	(Line 12 - 9 - 5 - 1)	465,939,883
14	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
15	**RP - Balance of Plant**	(Line 13 * 14)	124,887
16			
17	Total RP Investment	(Line 3 + 7 + 11 + 15)	12,048,437
18	RP Fixed Charge Percent	(Line 11(h))	11.8135%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 1,423,337**

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 6,279,326	$ 555,380,727	1.1306%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0171%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.9145%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.1370%	
	ADIT	Line 31(i)	(6,312,630)	555,380,727	-1.1366%	
	Total RP Fixed Charge Percent				11.8135%	

	Depreciation		
20	Annual Depreciation Expense (D)	$ 18,512,691	
21	Gross Plant Investment (F)	555,380,727	(Line 14)
22	SLDP=DE/F	3.3333%	(Line 20 / 21)
23	Depreciable years =1/SLDP	30	
24	Book Life (n)	30	Book Lives
25	SLDP for Book Life = 1/n	3.33%	
26	SFDP=(R/((1+R)^n-1)	0.91%	R=Return

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.1370%	Based Upon Book Life CTR=Composite Tax Rate

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 555,380,727	Summary Investment						
29	Straight-line Tax Life	30	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$74,184,624
31	In Service Year	2020				Levelized Revenue Requirement			6,312,630
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	2020	$ 18,512,691	20.000%	$ 111,076,145	$ 92,563,454	$ 22,758,206	$ 22,758,206	9.22%	$ 1,049,608
33	2021	18,512,691	32.000%	177,721,833	159,209,142	39,144,115	61,902,321	9.22%	3,904,543
34	2022	18,512,691	19.200%	106,633,100	88,120,409	21,665,812	83,568,133	9.22%	6,709,097
35	2023	18,512,691	11.520%	63,979,860	45,467,169	11,178,831	94,746,964	9.22%	8,223,891
36	2024	18,512,691	11.520%	63,979,860	45,467,169	11,178,831	105,925,795	9.22%	9,255,027
37	2025	18,512,691	5.760%	31,989,930	13,477,239	3,313,595	109,239,390	9.22%	9,923,417
38	2026	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	104,687,749	9.22%	9,866,319
39	2027	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	100,136,108	9.22%	9,446,475
40	2028	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	95,584,466	9.22%	9,026,632
41	2029	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	91,032,825	9.22%	8,606,789
42	2030	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	86,481,184	9.22%	8,186,945
43	2031	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	81,929,543	9.22%	7,767,102
44	2032	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	77,377,901	9.22%	7,347,259
45	2033	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	72,826,260	9.22%	6,927,415
46	2034	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	68,274,619	9.22%	6,507,572
47	2035	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	63,722,978	9.22%	6,087,728
48	2036	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	59,171,336	9.22%	5,667,885
49	2037	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	54,619,695	9.22%	5,248,042
50	2038	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	50,068,054	9.22%	4,828,198
51	2039	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	45,516,413	9.22%	4,408,355
52	2040	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	40,964,771	9.22%	3,988,512
53	2041	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	36,413,130	9.22%	3,568,668
54	2042	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	31,861,489	9.22%	3,148,825
55	2043	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	27,309,848	9.22%	2,728,982
56	2044	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	22,758,206	9.22%	2,309,138
57	2045	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	18,206,565	9.22%	1,889,295
58	2046	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	13,654,924	9.22%	1,469,452
59	2047	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	9,103,283	9.22%	1,049,608
60	2048	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	4,551,641	9.22%	629,765
61	2049	18,512,691	0.000%	-	(18,512,691)	(4,551,641)	0	9.22%	209,922
62		$ 555,380,727	100%	$ 555,380,727	$ (0)	$ 0			$ 159,980,467

Facility Name Pryor Mountain **Cost Year:** 2021
Plant Type: Wind

	(a)	(b)	(c)
	Annual Revenue Requirement	**Reference**	
	Investment		
1	Generator & Exciter	Summary Investment	26,682,847
2	RP Capability Allocator	RP and BOP Allocators	3.39%
3	**RP - Generator/Exciter**	(Line 1 * 2)	904,128
4			
5	GSU Transformer	Summary Investment	3,000,000
6	RP Capability Allocator	RP and BOP Allocators	3.39%
7	**RP Cost - GSU Transformers**	(Line 5 * 6)	101,653
8			
	Accessory Electrical Equipment Related to the		
9	Production of Real and Reactive Power	Summary Investment	42,271,004
10	RP Capability Allocator	RP and BOP Allocators	3.39%
11	**RP - Accesory Electric Equipment**	(Line 9 * 10)	1,432,321
12	**Capacitors**	Pryor Mountain	1,000,000
13	Total Plant Investment	Summary Investment	400,000,000
14	Balance of Plant	(Line 13 - 9 - 5 - 1)	328,046,149
15	Balance of Plant Allocator	RP and BOP Allocators	0.0268%
16	**RP - Balance of Plant**	(Line 14 * 15)	87,927
17	Total RP Investment	(Line 3 + 7 + 11 + 12 + 16)	3,526,029
18	RP Fixed Charge Percent	(Line 11(h))	11.5405%
19	**Reactive Power Revenue Requirement**	(Line 17 * 18)	**$ 406,920**

	Depreciation			
20	Annual Depreciation Expense (D)	$	13,333,333	
21	Gross Plant Investment (F)		400,000,000	(Line 15)
22	SLDP=DE/F		3.3333%	(Line 20 / 21)
23	Depreciable years =1/SLDP		30	
24	Book Life (n)		30	Book Lives
25	SLDP for Book Life = 1/n		3.33%	
26	SFDP=(R/((1+R)^n-1)		0.91%	R=Return

	Income Taxes		
27	Income Tax Factor to Include in Fixed Charge Factor [(CTR/(1-CTR))*(R- SLDP + SFDP)*(1-WLTD/R)]	1.1370%	Based Upon Book Life CTR=Composite Tax Rate

	(d)	(e)	(f)	(g)	(h)	
	Fixed Charge Rate for Reactive Investment					
			Amount	Investment	FCR %	
	O&M	O&M by Facility	$ 3,442,324	$ 400,000,000	0.8606%	(f)/(g)
	A&G	Fixed Charge Items			0.4475%	
	Cash Working Capital	(Lines 1 + 2)/8 * (Lines 9 + 10)			0.0142%	
	Prepayments	Fixed Charge Items			0.0203%	
	Materials and Supplies	Fixed Charge Items			0.1029%	
	General and Intangible Plant	Fixed Charge Items			1.1057%	
	Other Taxes	Fixed Charge Items			0.5233%	
	Depreciation	(Line 26)			0.9145%	
	Return	Fixed Charge Items			7.5512%	
	Income Taxes	Line 27			1.1370%	
	ADIT	Line 31(i)	(4,546,524)	400,000,000	-1.1366%	
	Total RP Fixed Charge Percent				11.5405%	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Accumulated Deferred Income Taxes								
28	Investment	$ 400,000,000	Summary Investment						
29	Straight-line Tax Life	30	(Line 24)						
30	Composite Tax Rate (CTR)	24.59%	Fixed Charge Items	37.951%	(prior to 1/1/18)	Net Present Value of Revenue Requirement			$53,429,743
31	In Service Year	2020				Levelized Revenue Requirement			4,546,524
	Year	SL Tax Depreciation	MACRS Depreciation Rate	Tax Depreciation	Accelerated Less Straight-line Tax Depreciation	Annual Deferred Income Taxes	Accumulated Deferred Income Taxes	ROR Including Income Taxes	Return and Income Taxes
		Line 28 / 29	(Tax Depreciation Rates)	(Line 28 * Line 32c)	(d-b)	(e*CTR)	Accum. (f)	(ROE + IT)	((g1+g2)/2 * h)
32	2020	$ 13,333,333	20.000%	$ 80,000,000	$ 66,666,667	$ 16,391,067	$ 16,391,067	9.22%	$ 755,956
33	2021	13,333,333	32.000%	128,000,000	114,666,667	28,192,635	44,583,701	9.22%	2,812,156
34	2022	13,333,333	19.200%	76,800,000	63,466,667	15,604,295	60,187,997	9.22%	4,832,070
35	2023	13,333,333	11.520%	46,080,000	32,746,667	8,051,292	68,239,289	9.22%	5,923,066
36	2024	13,333,333	11.520%	46,080,000	32,746,667	8,051,292	76,290,581	9.22%	6,665,717
37	2025	13,333,333	5.760%	23,040,000	9,706,667	2,386,539	78,677,120	9.22%	7,147,110
38	2026	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	75,398,907	9.22%	7,105,986
39	2027	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	72,120,693	9.22%	6,803,603
40	2028	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	68,842,480	9.22%	6,501,221
41	2029	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	65,564,267	9.22%	6,198,838
42	2030	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	62,286,053	9.22%	5,896,456
43	2031	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	59,007,840	9.22%	5,594,074
44	2032	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	55,729,627	9.22%	5,291,691
45	2033	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	52,451,413	9.22%	4,989,309
46	2034	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	49,173,200	9.22%	4,686,927
47	2035	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	45,894,987	9.22%	4,384,544
48	2036	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	42,616,773	9.22%	4,082,162
49	2037	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	39,338,560	9.22%	3,779,780
50	2038	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	36,060,347	9.22%	3,477,397
51	2039	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	32,782,133	9.22%	3,175,015
52	2040	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	29,503,920	9.22%	2,872,632
53	2041	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	26,225,707	9.22%	2,570,250
54	2042	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	22,947,493	9.22%	2,267,868
55	2043	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	19,669,280	9.22%	1,965,485
56	2044	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	16,391,067	9.22%	1,663,103
57	2045	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	13,112,853	9.22%	1,360,721
58	2046	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	9,834,640	9.22%	1,058,338
59	2047	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	6,556,427	9.22%	755,956
60	2048	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	3,278,213	9.22%	453,574
61	2049	13,333,333	0.000%	-	(13,333,333)	(3,278,213)	-	9.22%	151,191
62		$ 400,000,000	100%	$ 400,000,000	$ -	$ -			$ 115,222,196

	Name of PPA	MW	LGIA Power Factor	MVA	Mvar	Comparable PAC Facility	Cost per MVAR	RP Revenue Requirement	
	Wind								
1	**Cedar Springs I and III**	**322.4**	**0.90**	**358.2**	**156.1**	**Cedar Springs II**	**$ 11,764**	**$ 1,836,928**	Comparable turbines
2	**Pioneer Wind Park**	**80.0**	**0.90**	**88.9**	**38.7**	**Seven Mile Hill 1 and 2**	**8,072**	**312,744**	Comparable turbines
3	**Total**	**402.4**		**447.1**	**194.9**			**$ 2,149,672**	

PacifiCorp
Reactive Power
Reactive Power Capability Allocator and Balance of Plant Allocator
2019

	Generating Facility	PC Ownership of Output	Unit No.	MVA Capability (100%)	Power Factor	MW Capability (100%) (reflects any interconnection limits)	MVAR Capability (100%)	Reactive Power Capability Allocation Factor	MVAR (PAC Ownership) at CP	Field Exciter Losses MWs (PAC Ownership)	Balance of Plant Allocator	
1	Blundell	100.00%	1	30.7	0.850	26.1	16.2	27.75%	2.6	0.080		
2		100.00%	2	14.1	0.850	12.0	7.4	27.75%	0.1	0.030		
3	Total			44.8		38.1	23.6	27.75%	2.7	0.110	0.0268%	
4	Chehalis	100.00%	1	234.0	0.850	198.9	123.3	27.75%	16.9	0.410		Max. MVAr as not included in PC BA
5		100.00%	2	234.0	0.850	198.9	123.3	27.75%	15.3	0.410		Max. MVAr as not included in PC BA
6		100.00%	3	230.0	0.850	195.5	121.2	27.75%	16.0	0.940		Max. MVAr as not included in PC BA
7	Total			698.0		593.3	367.7	27.75%	48.2	1.760	0.0186%	
8	Cholla	100.00%	4	460.0	0.900	414.0	200.5	19.00%	24.6	-	0.0000%	Max. MVAr as not included in PC BA - retiring 12/2020
9	Colstrip	10.00%	3	819.0	0.950	778.1	255.7	9.75%	5.0	-		Max. MVAr as not included in PC BA
10		10.00%	4	819.0	0.950	778.1	255.7	9.75%	19.9	-		Max. MVAr as not included in PC BA
11	Total			1,638.0		1,556.1	511.5	9.75%	24.9	-	0.0000%	
12	Currant Creek	100.00%	1	172.0	0.850	146.2	90.6	27.75%	14.1	0.470		
13		100.00%	2	172.0	0.850	146.2	90.6	27.75%	11.8	0.470		
14		100.00%	3	305.0	0.900	274.5	132.9	19.00%	17.8	0.730		
15	Total			649.0		566.9	314.2	23.43%	43.7	1.670	0.0268%	
16	Dave Johnston	100.00%	1	133.7	0.850	113.6	70.4	27.75%	15.1	0.210		
17		100.00%	2	133.7	0.850	113.6	70.4	27.75%	18.7	0.210		
18		100.00%	3	255.0	0.900	229.5	111.2	19.00%	28.3	0.470		
19		100.00%	4	400.0	0.900	360.0	174.4	19.00%	25.2	0.940		
20	Total			922.4		816.8	426.4	21.37%	87.3	1.830	0.0268%	
21	Gadsby	100.00%	1	81.8	0.850	69.5	43.1	27.75%	4.3	0.130		
22		100.00%	2	86.3	0.800	69.0	51.8	36.00%	1.3	0.150		
23		100.00%	3	133.7	0.850	113.6	70.4	27.75%	7.3	0.140		
24		100.00%	4	71.0	0.850	60.4	37.4	27.75%	-	0.180		
25		100.00%	5	71.0	0.850	60.4	37.4	27.75%	-	0.180		
26		100.00%	6	71.0	0.850	60.4	37.4	27.75%	-	0.180		
27	Total			514.8		433.3	277.5	29.06%	12.9	0.960	0.0268%	
28	Hermiston	50.00%	1	204.5	0.900	184.1	89.1	19.00%	5.7	-		Max. MVAr as not included in PC BA
29		50.00%	2	106.2	0.900	95.6	46.3	19.00%	2.8	-		Max. MVAr as not included in PC BA
30		50.00%	3	204.5	0.900	184.1	89.1	19.00%	2.8	-		Max. MVAr as not included in PC BA
31		50.00%	4	106.2	0.900	95.6	46.3	19.00%	2.8	-		Max. MVAr as not included in PC BA
32	Total			621.4		559.3	270.9	19.00%	13.9	-	0.0000%	
33	Hunter	93.75%	1	525.0	0.930	488.3	193.0	13.51%	22.6	0.844		
34		60.31%	2	525.0	0.930	488.3	193.0	13.51%	0.3	0.543		
35		100.00%	3	527.2	0.940	495.6	179.9	11.64%	44.7	0.780		
36	Total			1,577.2		1,472.1	565.8	12.76%	67.6	2.167	0.0268%	
37	Huntington	100.00%	1	541.3	0.920	498.0	212.1	15.36%	13.8	1.160		
38		100.00%	2	575.0	0.900	517.5	250.6	19.00%	17.2	1.650		
39	Total			1,116.3		1,015.5	462.8	17.19%	31.0	2.810	0.0268%	
40	Jim Bridger	66.67%	1	608.3	0.950	577.9	189.9	9.75%	49.7	0.613		
41		66.67%	2	617.0	0.950	586.2	192.7	9.75%	49.7	0.613		
42		66.67%	3	608.3	0.950	577.9	189.9	9.75%	49.7	0.613		
43		66.67%	4	608.3	0.960	584.0	170.3	7.84%	49.7	0.573		
44	Total			2,441.9		2,325.9	742.9	9.25%	198.7	2.413	0.0268%	

PacifiCorp
Reactive Power
Reactive Power Capability Allocator and Balance of Plant Allocator
2019

	Generating Facility	PC Ownership	Unit No.	MVA Capability	Power Factor	MW Capability (reflects any interconnection limits)	MVAR Capability	Reactive Power Capability Allocation Factor	MVAR at CP	Field Exciter Losses MWs	Balance of Plant Allocator	
45	Lake Side	100.00%	1	203.0	0.900	182.7	88.5	19.00%	7.4	0.310		
46		100.00%	2	203.0	0.900	182.7	88.5	19.00%	10.7	0.310		
47		100.00%	3	251.0	0.900	225.9	109.4	19.00%	0.8	0.250		
48		100.00%	4	206.0	0.900	185.4	89.8	19.00%	20.1	0.250		
49		100.00%	5	206.0	0.900	185.4	89.8	19.00%	19.7	0.250		
50		100.00%	6	316.0	0.900	284.4	137.7	19.00%	1.7	0.490		
51	Total			1,385.0		1,246.5	603.7	19.00%	60.4	1.860	0.0268%	
52	Naughton	100.00%	1	192.0	0.850	163.2	101.1	27.75%	2.6	0.520		
53		100.00%	2	256.0	0.850	217.6	134.9	27.75%	11.2	0.780		
54		100.00%	3	384.0	0.850	326.4	202.3	27.75%	-	0.930		
55	Total			832.0		707.2	438.3	27.75%	13.8	2.230	0.0268%	
												Max. MVAr as not included in PC BA
56	Craig	19.28%	1	496.0	0.950	471.2	154.9	9.75%	7.4	-		Max. MVAr as not included in PC BA
57		19.28%	2	496.0	0.950	471.2	154.9	9.75%	15.2	-		
58	Total			992.0		942.4	309.8	9.75%	22.6	-	0.0000%	
												Max. MVAr as not included in PC BA
59	Hayden	24.50%	1	202.7	0.940	190.5	69.2	11.64%	2.5	-		Max. MVAr as not included in PC BA
60		12.60%	2	306.0	0.900	275.4	133.4	19.00%	0.5	-		
61	Total Hayden			508.7		465.9	202.5	14.64%	3.1	-	0.0000%	
62	Wyodak	80.00%	1	402.3	0.900	362.1	175.4	19.00%	25.2	0.976	0.0268%	
63	Merwin	100.00%	1-3	170.0	0.800	136.0	102.0	36.00%	10.8	0.090	0.0268%	
64	Yale	100.00%	1-2	137.4	0.975	134.0	30.5	4.94%	3.4	0.060	0.0268%	
65	Swift 1	100.00%	1-3	266.7	0.900	240.0	116.2	19.00%	1.9	0.114	0.0268%	
66	Lemolo	100.00%	1-2	74.2	0.950	70.5	23.2	9.75%	3.5	0.017	0.0268%	
67	Toketee	100.00%	1-3	50.0	0.850	42.5	26.3	27.75%	1.3	0.023	0.0268%	
68	Slide Creek	100.00%	1	21.2	0.850	18.0	11.2	27.75%	1.3	0.012	0.0268%	
69	Soda Springs	100.00%	1	12.9	0.850	11.0	6.8	27.75%	0.7	0.011	0.0268%	
70	Clearwater	100.00%	1-2	48.2	0.850	41.0	25.4	27.75%	1.0	0.004	0.0268%	
71	Fish Creek	100.00%	1	12.9	0.850	11.0	6.8	27.75%	0.3	0.001	0.0268%	
72	Prospect	100.00%	1-4	55.0	0.800	44.0	33.0	36.00%	0.5	0.023	0.0268%	
73	Copco	100.00%	11-12	25.0	0.800	20.0	15.0					
74	Copco	100.00%	21-22	30.0	0.900	27.0	13.1					
75	Total Copco			55.0		47.0	28.1	26.06%	-	0.044	0.0268%	
76	JC Boyle	100.00%	1-2	103.2	0.950	98.0	32.2	9.75%	6.6	0.042	0.0268%	
77	Irongate	100.00%	1	18.9	0.950	18.0	5.9	9.75%	0.1	0.002	0.0268%	

PacifiCorp
Reactive Power
Reactive Power Capability Allocator and Balance of Plant Allocator
2019

	Generating Facility	PC Ownership	Unit No.	MVA Capability	Power Factor	MW Capability (reflects any interconnection limits)	MVAR Capability	Reactive Power Capability Allocation Factor	MVAR at CP	Field Exciter Losses MWs	Balance of Plant Allocator	
78	Ashton	100.00%	1	3.0	0.900	2.7	1.3					
79	Ashton	100.00%	2-3	5.0	0.800	4.0	3.0					
80	Total Ashton			8.0		6.7	4.3	28.99%	0.8	0.017	0.0268%	
81	Soda	100.00%	1-2	16.4	0.855	14.0	8.5	26.90%	0.6	0.018	0.0268%	
82	Grace	100.00%	3-5	36.7	0.900	33.0	16.0	19.00%	0.9	0.168	0.0268%	
83	Oneida	100.00%	1-3	33.3	0.900	30.0	14.5	19.00%	1.2	0.023	0.0268%	
84	Cutler	100.00%	1-2	37.5	0.800	30.0	22.5	36.00%	3.8	0.038	0.0268%	
85	Glenrock I and III	100.00%		135.3	0.893	120.8	61.0	20.32%	0.9	2.500	0.0268%	
86	Rolling Hills	100.00%		131.0	0.895	117.2	58.4	19.87%	0.9	2.700	0.0268%	
87	Seven Mile Hill 1 and 2	100.00%		155.1	0.891	138.3	70.3	20.55%	1.5	1.500	0.0268%	
88	High Plains/McFadden Ridge	100.00%		166.9	0.891	148.8	75.7	20.55%	11.4	-	0.0186%	Not included in PAC BAA
89	Goodnoe Hills	100.00%		104.5	0.989	103.4	15.4	2.16%	3.2	0.002	0.0186%	Not included in PAC BAA
90	Leaning Juniper	100.00%		120.7	0.914	110.4	49.0	16.44%	5.0	0.008	0.0268%	
91	Marengo I and II	100.00%		245.3	0.954	234.0	73.7	9.03%	16.3	2.300	0.0268%	
92	Dunlap	100.00%		145.3	0.891	129.5	65.9	20.55%	8.1	1.300	0.0268%	
93	Foote Creek	100.00%		52.1	0.921	48.0	20.3	15.21%	7.7	0.020	0.0268%	
94	Cedar Springs II	100.00%		221.6	0.892	197.6	100.2	20.46%	-	-	0.0268%	
95	Ekola Flats	100.00%		274.2	0.915	250.9	110.6	16.28%	-	-	0.0268%	
96	TB Flats I	100.00%		331.1	0.929	307.5	122.7	13.73%	-	-	0.0268%	
97	TB Flats II	100.00%		209.5	0.934	195.7	74.7	12.72%	-	-	0.0268%	
98	Total TB Flats	100.00%		540.5	0.931	503.2	197.4	13.33%	-	-	0.0268%	
99	Pryor Mountain	100.00%		244.0	0.983	239.8	44.9	3.39%	-	-	0.0268%	
	Total			18,497.9	-	16,881.7	7,349.5	15.79%	774.3	29.8	0.0186%	
	Without Facilities in Other BAAs			13,354.6		12,137.0	5,422.3	16.49%	628.8	28.1	0.0268%	

Note: For facilities where PacifiCorp does not have the same ownership of each each unit and the units have differening power factors, the reactive power allocation factor and the balance of plant allocator are weighted average based upon PacifiCorp ownership

	Plant	Turbine Type	# of Turbines	kW	kVAR	Turbine PF	Plant PF	MW Capability	Total
1	Leaning Juniper	GE 1.62 Non-ESS 575V	59	1,620	710	0.92	0.91	95,580	
2		GE 1.85 690 V	8	1,850	890	0.90		14,800	110,380
3	Goodnoe Hills	Vestas V110 Mk10C 2.2MW	7	2,200	-	1.00	0.99	15,400	
4		Vestas V110 Mk10D 2.2MW	40	2,200	355	0.99		88,000	103,400
5	Marengo 1	Vestas V100 Mk10C 2.0MW	11	2,000	406	0.98	0.95	22,000	
6		Vestas V100 Mk10D 2.0MW	67	2,000	660	0.95		134,000	156,000
7	Marengo 2	Vestas V100 Mk10C 2.0MW	5	2,000	406	0.98	0.95	10,000	
8		Vestas V100/V110 Mk10D 2.0MW	34	2,000	660	0.95		68,000	78,000
9	Marengo 1 and 2	Vestas V100 Mk10C 2.0MW	16	2,000	406	0.98	0.95	32,000	
10		Vestas V100/V110 Mk10D 2.0MW	101	2,000	660	0.95		202,000	234,000
11	Foote Creek	Vestas V110 MK10C 2.0MW	3	2,000	406	0.98	0.92	6,000	
12		Vestas V136 Mk3 4.2MW	10	4,200	1,998	0.90		42,000	48,000
13	Glenrock	GE 1.5 Non Repower	8	1,500	710	0.90	0.89	12,000	
14		GE 1.85	71	1,750	890	0.89		124,250	136,250
15	Rolling Hills	GE 1.5 Non Repower	24	1,500	710	0.90	0.90	36,000	
16		GE 1.85	55	1,750	890	0.89		96,250	132,250
17	Seven Mile	GE 1.85	79	1,750	890	0.89	0.89	138,250	138,250
18	Ekola	GE 2.3-116	10	2,300	1,114	0.90	0.91	23,000	
19		Vestas V136 4.3 MW	53	4,300	1,860	0.92		227,900	250,900
20	High Plains	GE 1.85	85	1,750	890	0.89	0.89	148,750	148,750
21	Dunlap	GE 1.85	74	1,750	890	0.89	0.89	129,500	129,500
22	TB Flats I	Vestas V110 MK10C 2.0MW	14	2,000	406	0.98	0.93	28,000	
23		Vestas V136 4.3 MW	65	4,300	1,860	0.92		279,500	307,500
	TB Flats II	Vestas V110 MK10C 2.0MW	14	2,000	406	0.98	0.93	28,000	
		Vestas V136 4.3 MW	39	4,300	1,860	0.92		167,700	195,700
24	Cedar Springs	GE 2.3-116	8	2,300	1,114	0.90	0.89	18,400	
25		GE 2.8-127	64	2,800	1,428	0.89		179,200	197,600
26	Pryor Mountain	Vestas V110 Mk10B 2.0 MW	57	2,000	406	0.98		114,000	
27		Vestas V110 Mk10C 2.2 MW	21	2,200	-	1.00	0.98	46,200	
28		Vestas V110 Mk10D 2.2 MW	32	2,200	355	0.99		70,400	
29		GE 2.3-116	4	2,300	1,114	0.90		9,200	239,800

	Ownership Share When less than 100%	Unit	Year of Test	Nameplate/ Test	MW	MVAR	MVA	PF
1	Blundell	1	Not required	Nameplate	26.1	16.2	30.7	0.850
2				Max Real, Max Reactive				
3	No testing required			Max Real, Min Reactive				
4				Min Real, Max Reactive				
5				Min Real, Min Reactive				
6		2	Not required	Nameplate	12.0	7.4	14.1	0.850
7				Max Real, Max Reactive				
8				Max Real, Min Reactive				
9				Min Real, Max Reactive				
10				Min Real, Min Reactive				
11	Chehalis	CT1	2016	Nameplate	198.9	123.3	198.9	0.850
12				Max Real, Max Reactive	154.0	70.0	169.2	0.910
13				Max Real, Min Reactive	154.0	(55.0)		
14				Min Real, Max Reactive	90.0	61.0		
15				Min Real, Min Reactive	93.0	(64.0)		
16		CT2	2016	Nameplate	198.9	123.3	234.0	0.850
17				Max Real, Max Reactive	156.0	72.0	171.8	0.908
18				Max Real, Min Reactive	156.0	(41.0)		
19				Min Real, Max Reactive	90.0	61.0		
20				Min Real, Min Reactive	93.0	(64.0)		
21		STG	2016	Nameplate	195.5	121.2	230.0	0.850
22				Max Real, Max Reactive	168.0	44.0	173.7	0.967
23				Max Real, Min Reactive	166.0	(42.0)		
24				Min Real, Max Reactive	136.0	37.0		
25				Min Real, Min Reactive	134.0	(50.0)		
26	Colstrip	3	2018	Nameplate	778.1	255.7	819.0	0.950
27				Max Real, Max Reactive	797.0	294.0	849.5	0.938
28				Max Real, Min Reactive	797.0	(184.0)		
29				Min Real, Max Reactive	249.0	203.0		
30				Min Real, Min Reactive	244.0	(233.0)		
31		4	2018	Nameplate	778.1	255.7	819.0	0.950
32				Max Real, Max Reactive	772.0	234.0	806.7	0.957
33				Max Real, Min Reactive	767.0	(216.0)		
34				Min Real, Max Reactive	255.0	217.0		
35				Min Real, Min Reactive	243.0	(225.0)		
36	Currant Creek	1	2016	Nameplate	146.2	90.6	172.0	0.850
37				Max Real, Max Reactive	144.0	59.0	155.6	0.925
38				Max Real, Min Reactive	144.0	(58.0)		
39				Min Real, Max Reactive	NA			
40				Min Real, Min Reactive	NA			
41		2	2016	Nameplate	146.2	90.6	172.0	0.850
42				Max Real, Max Reactive	141.0	58.0	152.5	0.925
43				Max Real, Min Reactive	142.0	(60.0)		
44				Min Real, Max Reactive	15.0	56.0		
45				Min Real, Min Reactive	17.0	(68.0)		
46		3	2016	Nameplate	274.5	132.9	305.0	0.900
47				Max Real, Max Reactive	247.0	82.0	260.3	0.949
48				Max Real, Min Reactive	244.0	(61.0)		
49				Min Real, Max Reactive	30.0	64.0		
50				Min Real, Min Reactive	31.0	(97.0)		

	Ownership Share When less than 100%	Unit	Year of Test	Nameplate/ Test	MW	MVAR	MVA	PF
51	Dave Johnston	1	2016	Nameplate	113.6	70.4	133.7	0.850
52				Max Real, Max Reactive	94.0	35.0	100.3	0.937
53				Max Real, Min Reactive	98.0	(36.0)		
54				Min Real, Max Reactive	55.0	25.0		
55				Min Real, Min Reactive	55.0	(37.0)		
56		2	2018	Nameplate	113.6	70.4	133.7	0.850
57				Max Real, Max Reactive	111.0	47.0	120.5	0.921
58				Max Real, Min Reactive	108.0	(30.0)		
59				Min Real, Max Reactive	6.0	33.0		
60				Min Real, Min Reactive	5.0	(37.0)		
61		3	2019	Nameplate	229.5	111.2	255.0	0.900
62				Max Real, Max Reactive	201.0	83.0	217.5	0.924
63				Max Real, Min Reactive	207.0	(63.0)		
64				Min Real, Max Reactive	138.0	78.0		
65				Min Real, Min Reactive	138.0	(73.0)		
66		4	2018	Nameplate	360.0	174.4	400.0	0.900
67				Max Real, Max Reactive	306.0	74.0	314.8	0.972
68				Max Real, Min Reactive	306.0	(122.0)		
69				Min Real, Max Reactive	173.0	67.0		
70				Min Real, Min Reactive	175.0	(153.0)		
71	Gadsby	1		Nameplate	69.5	43.1	81.8	0.850
72	No testing required			Max Real, Max Reactive				
73				Max Real, Min Reactive				
74				Min Real, Max Reactive				
75				Min Real, Min Reactive				
76	No testing required	2		Nameplate	69.0	51.8	86.3	0.800
77				Max Real, Max Reactive				
78				Max Real, Min Reactive				
79				Min Real, Max Reactive				
80				Min Real, Min Reactive				
81		3	2017	Nameplate	113.6	70.4	133.7	0.850
82				Max Real, Max Reactive	98.0	42.0	106.6	0.919
83				Max Real, Min Reactive	99.0	(54.0)		
84				Min Real, Max Reactive	26.0	47.0		
85				Min Real, Min Reactive	27.0	(57.0)		
86		4	2015	Nameplate	60.4	37.4	71.0	0.850
87				Max Real, Max Reactive	36.0	31.0	47.5	0.758
88				Max Real, Min Reactive	37.0	(12.0)		
89				Min Real, Max Reactive	10.0	33.0		
90				Min Real, Min Reactive	10.0	(15.0)		
91		5	2015	Nameplate	60.4	37.4	71.0	0.850
92				Max Real, Max Reactive	38.0	27.0	46.6	0.815
93				Max Real, Min Reactive	38.0	(12.0)		
94				Min Real, Max Reactive	10.0	7.0		
95				Min Real, Min Reactive	10.0	(14.0)		
96		6	2015	Nameplate	60.4	37.4	71.0	0.850
97				Max Real, Max Reactive	37.0	30.0	47.6	0.777
98				Max Real, Min Reactive	38.0	(9.0)		
99				Min Real, Max Reactive	10.0	34.0		
100				Min Real, Min Reactive	10.0	(10.0)		

	Ownership Share When less than 100%	Unit	Year of Test	Nameplate/ Test	MW	MVAR	MVA	PF
101	Hermiston	1	2017	Nameplate	184.1	89.1	204.5	0.900
102	50.00%			Max Real, Max Reactive	151.0	111.0	187.4	0.806
103				Max Real, Min Reactive	151.0	(38.0)		
104				Min Real, Max Reactive	86.0	132.0		
105				Min Real, Min Reactive	85.0	(40.0)		
106	50.00%	2	2017	Nameplate	95.6	46.3	106.2	0.900
107				Max Real, Max Reactive	74.0	29.0	79.5	0.931
108				Max Real, Min Reactive	75.0	(19.0)		
109				Min Real, Max Reactive	61.0	25.0		
110				Min Real, Min Reactive	61.0	(26.0)		
111		3	2017	Nameplate	184.1	89.1	204.5	0.900
112				Max Real, Max Reactive	144.0	109.0	180.6	0.797
113				Max Real, Min Reactive	145.0	(43.0)		
114				Min Real, Max Reactive	81.0	136.0		
115				Min Real, Min Reactive	80.0	(50.0)		
116		4	2017	Nameplate	95.6	46.3	106.2	0.900
117				Max Real, Max Reactive	73.0	38.0	82.3	0.887
118				Max Real, Min Reactive	73.0	(16.0)		
119				Min Real, Max Reactive	61.0	38.0		
120				Min Real, Min Reactive	61.0	(19.0)		
121	Hunter	1	2019	Nameplate	488.3	193.0	525.0	0.930
122	93.75%			Max Real, Max Reactive	479.0	119.0	493.6	0.970
123				Max Real, Min Reactive	480.0	(63.0)		
124				Min Real, Max Reactive	86.0	156.0		
125				Min Real, Min Reactive	84.0	(154.0)		
126	60.31%	2	2019	Nameplate	488.3	193.0	525.0	0.930
127				Max Real, Max Reactive	470.0	118.0	484.6	0.970
128				Max Real, Min Reactive	463.0	(113.0)		
129				Min Real, Max Reactive	80.0	150.0		
130				Min Real, Min Reactive	80.0	(181.0)		
131		3	2016	Nameplate	495.6	179.9	527.2	0.940
132				Max Real, Max Reactive	506.0	174.0	535.1	0.946
133				Max Real, Min Reactive	501.0	(60.0)		
134				Min Real, Max Reactive	148.0	215.0		
135				Min Real, Min Reactive	150.0	(160.0)		
136	Huntington	1	2019	Nameplate	498.0	212.1	541.3	0.920
137				Max Real, Max Reactive	480.0	154.0	504.1	0.952
138				Max Real, Min Reactive	477.0	(109.0)		
139				Min Real, Max Reactive	93.0	145.0		
140				Min Real, Min Reactive	96.0	(117.0)		
141		2	2016	Nameplate	517.5	250.6	575.0	0.900
142				Max Real, Max Reactive	473.0	180.0	506.1	0.935
143				Max Real, Min Reactive	473.0	(116.0)		
144				Min Real, Max Reactive	32.0	155.0		
145				Min Real, Min Reactive	31.0	(187.0)		

		Ownership Share When less than 100%	Unit	Year of Test	Nameplate/ Test	MW	MVAR	MVA	PF
146	Jim Bridger		1	2018	Nameplate	577.9	189.9	608.3	0.950
147		66.67%			Max Real, Max Reactive	540.0	228.0	586.2	0.921
148					Max Real, Min Reactive	543.0	(121.0)		
149					Min Real, Max Reactive	50.0	258.0		
150					Min Real, Min Reactive	54.0	(157.0)		
151		66.67%	2	2017	Nameplate	586.2	192.7	617.0	0.950
152					Max Real, Max Reactive	574.0	213.0	612.2	0.938
153					Max Real, Min Reactive	574.0	(77.0)		
154					Min Real, Max Reactive	41.0	274.0		
155					Min Real, Min Reactive	45.0	(149.0)		
156		66.67%	3	2019	Nameplate	577.9	189.9	608.3	0.950
157					Max Real, Max Reactive	548.0	203.0	584.4	0.938
158					Max Real, Min Reactive	547.0	(125.0)		
159					Min Real, Max Reactive	109.0	259.0		
160					Min Real, Min Reactive	128.0	(164.0)		
161		66.67%	4	2017	Nameplate	584.0	170.3	608.3	0.960
162					Max Real, Max Reactive	564.0	201.0	598.7	0.942
163					Max Real, Min Reactive	561.0	(105.0)		
164					Min Real, Max Reactive	55.0	216.0		
165					Min Real, Min Reactive	80.0	(162.0)		
166	Lake Side		1	2015	Nameplate	182.7	88.5	203.0	0.900
167			(U11)		Max Real, Max Reactive	163.0	78.0	180.7	0.902
168					Max Real, Min Reactive	155.0	(41.0)		
169					Min Real, Max Reactive	10.0	105.0		
170					Min Real, Min Reactive	10.0	(26.0)		
171			2	2016	Nameplate	182.7	88.5	203.0	0.900
172			(U12)		Max Real, Max Reactive	162.0	96.0	188.3	0.860
173					Max Real, Min Reactive	162.0	(27.0)		
174					Min Real, Max Reactive	10.0	120.0		
175					Min Real, Min Reactive	10.0	(33.0)		
176			3	2016	Nameplate	225.9	109.4	251.0	0.900
177			(U10)		Max Real, Max Reactive	174.0	101.0	201.2	0.865
178					Max Real, Min Reactive	174.0	(35.0)		
179					Min Real, Max Reactive	56.0	103.0		
180					Min Real, Min Reactive	56.0	(45.0)		
181			4	2019	Nameplate	185.4	89.8	206.0	0.900
182			(U21)		Max Real, Max Reactive	175.0	53.0	182.8	0.957
183					Max Real, Min Reactive	178.0	(77.0)		
184					Min Real, Max Reactive	110.0	58.0		
185					Min Real, Min Reactive	110.0	(99.0)		
186			5	2019	Nameplate	185.4	89.8	206.0	0.900
187			(U22)		Max Real, Max Reactive	176.0	57.0	185.0	0.951
188					Max Real, Min Reactive	176.0	(81.0)		
189					Min Real, Max Reactive	110.0	62.0		
190					Min Real, Min Reactive	110.0	(100.0)		
191			6	2019	Nameplate	284.4	137.7	316.0	0.900
192			(U20)		Max Real, Max Reactive	280.0	82.0	291.8	0.960
193					Max Real, Min Reactive	281.0	(58.0)		
194					Min Real, Max Reactive	57.0	74.0		
195					Min Real, Min Reactive	62.0	(112.0)		

		Ownership Share When less than 100%	Unit	Year of Test	Nameplate/ Test	MW	MVAR	MVA	PF
196	Naughton		1	2017	Nameplate	163.2	101.1	192.0	0.850
197					Max Real, Max Reactive	166.0	73.0	181.3	0.915
198					Max Real, Min Reactive	170.0	(28.0)		
199					Min Real, Max Reactive	8.0	97.0		
200					Min Real, Min Reactive	8.0	(43.0)		
201			2	2017	Nameplate	217.6	134.9	256.0	0.850
202					Max Real, Max Reactive	222.0	106.0	246.0	0.902
203					Max Real, Min Reactive	225.0	(37.0)		
204					Min Real, Max Reactive	44.0	100.0		
205					Min Real, Min Reactive	45.0	(16.0)		
206			3	2016	Nameplate	326.4	202.3	384.0	0.850
207					Max Real, Max Reactive	301.0	155.0	338.6	0.889
208					Max Real, Min Reactive	305.0	(38.0)		
209					Min Real, Max Reactive	75.0	152.0		
210					Min Real, Min Reactive	75.0	(36.0)		
211	Craig		1	2019	Nameplate	471.2	154.9	496.0	0.950
212		19.28%			Max Real, Max Reactive	428.0	228.0	484.9	0.883
213					Max Real, Min Reactive	430.0	(62.0)		
214					Min Real, Max Reactive	195.0	167.0		
215					Min Real, Min Reactive	192.0	(84.0)		
216		19.28%	2	2019	Nameplate	471.2	154.9	496.0	0.950
217					Max Real, Max Reactive	440.0	183.0	476.5	0.923
218					Max Real, Min Reactive	442.0	(21.0)		
219					Min Real, Max Reactive	153.0	266.0		
220					Min Real, Min Reactive	153.0	(70.0)		
221	Hayden		1	2017	Nameplate	190.5	69.2	202.7	0.940
222		24.50%			Max Real, Max Reactive	196.0	40.0	200.0	0.980
223					Max Real, Min Reactive	196.0	(35.0)		
224					Min Real, Max Reactive	121.0	58.0		
225					Min Real, Min Reactive	122.0	(59.0)		
226		12.60%	2	2017	Nameplate	275.4	133.4	306.0	0.900
227					Max Real, Max Reactive	286.0	102.0	303.6	0.942
228					Max Real, Min Reactive	288.0	(57.0)		
229					Min Real, Max Reactive	135.0	86.0		
230					Min Real, Min Reactive	134.0	(90.0)		
231	Wyodak		1		Nameplate	362.1	175.4	402.3	0.900
232		80.00%			Max Real, Max Reactive	354.0	111.0	371.0	0.954
233					Max Real, Min Reactive	360.0	(82.0)		
234					Min Real, Max Reactive	222.0	108.0		
235					Min Real, Min Reactive	220.0	(106.0)		
236	Merwin		1	2018	Nameplate	45.0	33.8	56.3	0.800
237					Max Real, Max Reactive	44.8	18.3	48.4	0.926
238					Max Real, Min Reactive	45.1	(8.7)		
239					Min Real, Max Reactive	-	20.0		
240					Min Real, Min Reactive	0.1	(7.7)		
241			2	2018	Nameplate	45.0	33.8	56.3	0.800
242					Max Real, Max Reactive	44.9	19.9	49.1	0.914
243					Max Real, Min Reactive	45.2	(8.0)		
244					Min Real, Max Reactive	0.2	21.9		
245					Min Real, Min Reactive	0.2	(6.6)		
246			3	2018	Nameplate	45.0	33.8	56.3	0.800
247					Max Real, Max Reactive	44.8	19.0	48.7	0.921
248					Max Real, Min Reactive	45.2	(3.8)		
249					Min Real, Max Reactive	(0.1)	20.5		
250					Min Real, Min Reactive	(0.1)	(1.5)		

	Ownership Share When less than 100%	Unit	Year of Test	Nameplate/ Test	MW	MVAR	MVA	PF
251	Yale	1	2018	Nameplate	81.4	18.6	83.5	0.975
252	(nameplate updated per MOD-25 Report)			Max Real, Max Reactive	80.9	17.8	82.8	0.977
253				Max Real, Min Reactive	80.9	(11.6)		
254				Min Real, Max Reactive	0.2	24.4		
255				Min Real, Min Reactive	(0.2)	(38.1)		
256		2	2018	Nameplate	81.4	18.6	83.5	0.975
257	(nameplate updated per MOD-25 Report)			Max Real, Max Reactive	81.2	18.4	83.3	0.975
258				Max Real, Min Reactive	81.1	(11.6)		
259				Min Real, Max Reactive	(0.2)	22.4		
260				Min Real, Min Reactive	(0.7)	(38.0)		
261	Swift 1	1	2017	Nameplate	80.0	38.7	88.9	0.900
262				Max Real, Max Reactive	80.5	33.5	87.2	0.923
263				Max Real, Min Reactive	79.9	(5.8)		
264				Min Real, Max Reactive	-	50.7		
265				Min Real, Min Reactive	0.2	(24.4)		
266		2	2017	Nameplate	80.0	38.7	88.9	0.900
267				Max Real, Max Reactive	80.5	31.3	86.4	0.932
268				Max Real, Min Reactive	80.9	(7.3)		
269				Min Real, Max Reactive	-	49.8		
270				Min Real, Min Reactive	0.4	(25.0)		
271		3	2017	Nameplate	80.0	38.7	88.9	0.900
272				Max Real, Max Reactive	78.0	43.4	89.3	0.874
273				Max Real, Min Reactive	80.2	(6.7)		
274				Min Real, Max Reactive	0.7	50.3		
275				Min Real, Min Reactive	(0.2)	(23.1)		
276	Lemolo	1	2018	Nameplate	32.0	10.5	33.7	0.950
277				Max Real, Max Reactive	31.1	3.8	31.3	0.993
278				Max Real, Min Reactive	31.2	(5.6)		
279				Min Real, Max Reactive	(0.6)	10.2		
280				Min Real, Min Reactive	(0.1)	(5.6)		
281		2	2018	Nameplate	38.5	12.7	40.5	0.950
282				Max Real, Max Reactive	35.4	12.0	37.4	0.947
283				Max Real, Min Reactive	35.4	(8.0)		
284				Min Real, Max Reactive	(0.3)	12.5		
285				Min Real, Min Reactive	(0.4)	(9.0)		
286	Toketee	1	2006	Nameplate	14.2	8.8	16.7	0.850
287				Max Real, Max Reactive	13.4	5.8	14.6	0.918
288				Max Real, Min Reactive	12.2	(7.3)		
289				Min Real, Max Reactive	NA			
290				Min Real, Min Reactive	NA			
291		2	2006	Nameplate	14.2	8.8	16.7	0.850
292				Max Real, Max Reactive	15.1	5.7	16.1	0.936
293				Max Real, Min Reactive	14.2	(3.3)		
294				Min Real, Max Reactive	NA			
295				Min Real, Min Reactive	NA			
296		3	2006	Nameplate	14.2	8.8	16.7	0.850
297				Max Real, Max Reactive	15.8	5.0	16.6	0.953
298				Max Real, Min Reactive	15.7	(3.0)		
299				Min Real, Max Reactive	NA			
300				Min Real, Min Reactive	NA			
301	Slide Creek	1	2018	Nameplate	18.0	11.2	21.2	0.850
302				Max Real, Max Reactive	14.0	11.0	17.8	0.786
303				Max Real, Min Reactive	18.0	(3.0)		
304				Min Real, Max Reactive	-	15.0		
305				Min Real, Min Reactive	-	(10.0)		

	Ownership Share When less than 100%		Unit		Year of Test	Nameplate/ Test	MW	MVAR	MVA	PF
306	Soda Springs		1		2006	Nameplate	11.0	6.8	12.9	0.850
307						Max Real, Max Reactive	11.0	6.0	12.5	0.878
308						Max Real, Min Reactive	11.0	(1.0)		
309						Min Real, Max Reactive	NA			
310						Min Real, Min Reactive	NA			
311	Clearwater		1		2013	Nameplate	15.0	9.3	17.6	0.850
312		V				Max Real, Max Reactive	14.6	5.5	15.6	0.936
313		D				Max Real, Min Reactive	14.6	(3.6)		
314						Min Real, Max Reactive	0.1	6.2		
315						Min Real, Min Reactive	0.1	(8.4)		
316			2		2017	Nameplate	26.0	16.1	30.6	0.850
317						Max Real, Max Reactive				
318						Max Real, Min Reactive				
319						Min Real, Max Reactive				
320						Min Real, Min Reactive				
321	Fish Creek		1		2006	Nameplate	11.0	6.8	12.9	0.850
322						Max Real, Max Reactive	11.0	4.0	11.7	0.940
323						Max Real, Min Reactive	10.0	(4.0)		
324						Min Real, Max Reactive	NA			
325						Min Real, Min Reactive	NA			
326	Prospect		21		??	Nameplate	16.0	12.0	20.0	0.800
327	Four units -					Max Real, Max Reactive	12.0	10.8	16.1	0.743
328	- test results for 21 and 22 only					Max Real, Min Reactive	12.0	(7.2)		
329		V				Min Real, Max Reactive	0.1	12.6		
330		D				Min Real, Min Reactive	0.1	(8.9)		
331			22			Nameplate	16.0	12.0	20.0	0.800
332		V				Max Real, Max Reactive	12.2	10.3	16.0	0.764
333		D				Max Real, Min Reactive	12.0	(7.2)		
334						Min Real, Max Reactive	0.2	12.1		
335						Min Real, Min Reactive	0.2	(8.9)		
336	Copco		11-12	each	2013	Nameplate	10.0	7.5	12.5	0.800
337		V				Max Real, Max Reactive	10.0	4.6	11.0	0.908
338		D				Max Real, Min Reactive	10.2	(0.8)		
339						Min Real, Max Reactive	0.2	6.2		
340						Min Real, Min Reactive	0.2	(3.7)		
341			21-22	each	2013	Nameplate	13.5	6.5	15.0	0.900
342		V				Max Real, Max Reactive	13.5	6.5	15.0	0.901
343		D				Max Real, Min Reactive	13.5	(5.0)		
344						Min Real, Max Reactive	-	8.2		
345						Min Real, Min Reactive	-	(8.0)		
346	JC Boyle		1		2017	Nameplate	50.4	16.6	53.1	0.950
347						Max Real, Max Reactive	50.5	4.6	50.7	0.996
348						Max Real, Min Reactive	50.5	(5.4)		
349						Min Real, Max Reactive	0.3	17.1		
350						Min Real, Min Reactive	0.4	(19.0)		
351			2		2017	Nameplate	48.5	15.9	51.1	0.950
352						Max Real, Max Reactive	48.2	4.7	48.4	0.995
353						Max Real, Min Reactive	48.2	(2.3)		
354						Min Real, Max Reactive	(0.2)	10.3		
355						Min Real, Min Reactive	(0.1)	(16.7)		
351	Irongate		1		2013	Nameplate	18.0	5.9	18.9	0.950
352		V				Max Real, Max Reactive	16.0	6.0	17.1	0.936
353		D				Max Real, Min Reactive	16.1	(4.3)		
354						Min Real, Max Reactive	0.1	6.5		
355						Min Real, Min Reactive	-	(6.9)		

	Ownership Share When less than 100%		Unit	Year of Test	Nameplate/ Test	MW	MVAR	MVA	PF
356	Ashton		1	?	Nameplate	6.7	4.3	8.0	0.838
357	No testing required		2-3						
358	Soda		1-2	?	Nameplate	14.0	8.5	16.4	0.855
359	No testing required				Max Real, Max Reactive				
360	Grace		3	?	Nameplate	11.0	5.3	12.2	0.900
361		V			Max Real, Max Reactive	11.1	5.3	12.3	0.902
362		D			Max Real, Min Reactive	11.0	(4.0)		
363					Min Real, Max Reactive	0.2	8.2		
364					Min Real, Min Reactive	0.1	(6.2)		
365			4		Nameplate	11.0	5.3	12.2	0.900
366		V			Max Real, Max Reactive	11.4	4.1	12.1	0.941
367		D			Max Real, Min Reactive	11.4	(3.5)		
368					Min Real, Max Reactive	0.2	5.0		
369					Min Real, Min Reactive	-	(7.1)		
370			5		Nameplate	11.0	5.3	12.2	0.900
371		V			Max Real, Max Reactive	11.2	2.2	11.4	0.981
372		D			Max Real, Min Reactive	11.2	(3.6)		
373					Min Real, Max Reactive	0.1	2.8		
374					Min Real, Min Reactive	0.1	(6.8)		
375	Oneida		1	?	Nameplate	10.0	4.8	11.1	0.900
376		V			Max Real, Max Reactive	10.0	4.0	10.8	0.928
377					Max Real, Min Reactive				
378					Min Real, Max Reactive				
379					Min Real, Min Reactive	-	(6.8)		
380			2		Nameplate	10.0	4.8	11.1	0.900
381		V			Max Real, Max Reactive	10.0	4.1	10.8	0.925
382					Max Real, Min Reactive				
383					Min Real, Max Reactive				
384					Min Real, Min Reactive	-	(8.4)		
385			3		Nameplate	10.0	4.8	11.1	0.900
386		V			Max Real, Max Reactive	9.6	3.9	10.4	0.926
387					Max Real, Min Reactive				
388					Min Real, Max Reactive				
389					Min Real, Min Reactive	-	(5.3)		
390	Cutler		1	2012	Nameplate	15.0	11.3	18.8	0.800
391		V			Max Real, Max Reactive	10.7	6.0	12.3	0.872
392		D			Max Real, Min Reactive	10.6	(6.1)		
393					Min Real, Max Reactive	0.3	7.3		
394					Min Real, Min Reactive	0.3	(8.5)		
395			2	2008	Nameplate	15.0	11.3	18.8	0.800
396		V			Max Real, Max Reactive	15.2	3.0	15.5	0.981
397		D			Max Real, Min Reactive	15.1	(6.0)		
398					Min Real, Max Reactive	-	4.5		
399					Min Real, Min Reactive	-	(5.0)		
400	Glenrock I and III			2017	Nameplate	120.8	61.0	135.3	0.893
401					Max Lagging	3.8	35.0	35.2	0.108
402					Max Leading	5.0	(30.5)		
403	Rolling Hills			2017	Nameplate	117.2	58.4	131.0	0.895
404					Max Lagging	2.6	24.0	24.1	0.108
405					Max Leading	2.6	(21.5)		
406	Seven Mile Hill 1 and 2			2020	Nameplate	138.3	58.4	155.1	0.891
407					Max Lagging	117.5	42.3	124.9	0.941
408	High Plains/McFadden Ridge			2017	Nameplate	148.8	75.7	166.9	0.891
409					Max Lagging	34.5	17.2	38.5	0.895
410					Max Leading	29.0	(24.3)		

	Ownership Share When less than 100%	Unit	Year of Test	Nameplate/ Test	MW	MVAR	MVA	PF
411	Goodnoe Hills		2020	Nameplate	103.4	15.4	104.5	0.989
412	Testing in 2020			Max Lagging				
413				Max Leading				
414	Leaning Juniper			Nameplate	110.4	49.0	120.7	0.914
415				Max Lagging	99.5	33.8	105.1	0.947
416	Marengo I and II		2020	Nameplate	234.0	73.7	245.3	0.954
417	Testing in 2020			Max Lagging				
418				Max Leading				
419	Dunlap		2021	Nameplate	129.5	65.9	145.3	0.891
420	Testing in 2021			Max Lagging				
421				Max Leading				
422	Foote Creek		2021	Nameplate	48.0	20.3	52.1	0.921
423	Testing in 2021			Max Lagging				
424				Max Leading				
425	Cedar Springs II		2021	Nameplate	197.6	100.2	221.6	0.892
426	Testing in 2021			Test Results	NA			
427	Ekola Flats		2021	Nameplate	250.9	110.6	274.2	0.915
428	Testing in 2021			Test Results	NA			
429	TB Flats I		2021	Nameplate	307.5	122.7	331.1	0.929
430	Testing in 2021			Test Results	NA			
431	Pryor Mountain		2021	Nameplate	239.8	44.9	244.0	0.983
432	Testing in 2021			Test Results	NA			

	Generating Facility	Unit No.	Generator Type	Turbogenerator	Generator/Exciter	Generator/Exciter Percentage	Accessory Electric Equipment	GSU	Total Facility	Book Depreciation Expense
1	Blundell	1	Steam - Geothermal	17,884,336	3,475,646	19.4%	5,045,404	-	43,617,417	1,305,382
2		2	Steam - Geothermal	16,569,227	4,671,295	28.2%	2,453,737	-	28,340,534	886,604
		Common		-	-		1,121,675	1,504,131	83,028,363	2,071,922
3	Total Blundell			34,453,563	8,146,941		8,620,816	1,504,131	154,986,314	4,263,907
4	Chehalis	CT1	GT	40,002,076	7,410,029	18.5%			45,787,069	1,382,176
5		CT2	GT	42,443,059	7,178,306	16.9%			48,191,184	1,456,614
6		ST	Combined Cycle	29,958,371	7,149,892	23.9%			177,077,856	5,327,474
		Common		630,027	-		38,588,536	12,401,911	99,261,722	2,480,406
7	Total Chehalis			113,033,534	21,738,227	19.2%	38,588,536	12,401,911	370,317,831	10,646,670
8	Cholla	4	Steam - Coal	68,539,074	12,254,447	17.9%	63,189,469	7,277,416	90,824,255	2,302,817
		Common		555,096	-		5,632,629	453,511	469,557,428	12,987,698
	Total Cholla			69,094,170	12,254,447		68,822,098	7,730,928	560,381,683	15,290,516
9	Colstrip	3	Steam - Coal							
10		4	Steam - Coal							
11	Total Colstrip			39,413,100	6,281,957	15.9%	9,471,996	1,969,943	245,036,407	5,166,314
12	Currant Creek	CT1	GT	32,616,143	6,694,710	20.5%			38,040,675	1,138,517
13		CT2	GT	31,880,217	6,700,494	21.0%			37,274,001	1,115,247
14		ST	Combined Cycle	26,432,848	13,198,941	49.9%			162,847,827	4,848,586
		Common		8,533,682	41,310		43,011,421	7,053,477	124,373,564	811,138
15	Total CC			99,462,890	26,635,454	26.8%	43,011,421	7,053,477	362,536,068	7,913,488
16	Dave Johnston	1	Steam - Coal	13,439,565	2,065,752	15.4%	2,876,383		72,977,246	3,980,960
17		2	Steam - Coal	16,932,299	1,984,763	11.7%	3,477,125		80,287,706	4,386,972
18		3	Steam - Coal	23,330,119	3,387,020	14.5%	14,838,244		289,148,271	16,040,246
19		4	Steam - Coal	42,129,766	4,543,391	10.8%	14,479,267		308,828,718	17,019,964
		Common		9,919,936	78,177		27,826,054	10,842,240	332,933,708	17,075,768
20	Total DJ			105,751,685	12,059,103	11.4%	63,497,074	10,842,240	1,084,175,649	58,503,910
21	Gadsby	1	Combustion Turbine and Steam-NG	3,330,495	338,423	10.2%	1,394,622		18,434,966	427,216
22		2	Combustion Turbine and Steam-NG	5,177,734	1,156,217	22.3%	1,424,532		23,069,793	529,664
23		3	Combustion Turbine and Steam-NG	5,055,303	658,751	13.0%	2,552,867		25,732,507	594,007
24		4	GT	19,381,212	5,758,864	29.7%	682,694		23,459,389	897,290
25		5	GT	20,373,511	5,818,211	28.6%	660,745		24,460,815	936,774
26		6	GT	18,583,015	6,128,495	33.0%	604,652		22,599,411	862,991
		Common		1,409,879	116,001		4,200,465	4,913,813	39,224,868	1,036,380
27	Total Gadsby			73,311,149	19,974,963	27.2%	11,520,577	4,913,813	176,981,749	5,284,323

PacifiCorp
Reactive Power
Investment Data by Generating Facility
2019

	Generating Facility	Unit No.	Generator Type	Turbogenerator	Generator/Exciter	Generator/Exciter Percentage	Accessory Electric Equipment	GSU	Total Facility	Book Depreciation Expense
28	Hermiston	1 CT	GT	-	-					
29		1 ST	Combined Cycle	-	-					
30		2 CT	GT	-	-					
31		2 ST	Combined Cycle	-	-					
		Common		42,343,523	18,964,806	44.8%	9,781,188	4,766,278	184,561,925	5,955,573
32	Total Hermiston			42,343,523	18,964,806	44.8%	9,781,188	4,766,278	184,561,925	5,955,573
33	Hunter	1	Steam - Coal	67,231,487	15,351,201	22.8%	34,624,801	4,232,581	398,936,573	10,831,157
34		2	Steam - Coal	46,644,338	8,871,304	19.0%	16,952,557	5,618,764	252,897,453	6,830,228
35		3	Steam - Coal	84,538,730	27,214,381	32.2%	54,675,655	7,440,261	502,881,649	13,289,101
			Common	5,042,060	186,014		1,853,269	-	198,880,071	3,680,801
36	Total Hunter			203,456,616	51,622,900	25.4%	108,106,282	17,291,605	1,353,595,746	34,631,286
37	Huntington	1	Steam - Coal	62,055,903	7,870,360	12.7%	20,953,063	-	398,807,334	13,835,869
38		2	Steam - Coal	59,130,185	14,432,120	24.4%	23,690,463	-	367,606,780	12,262,772
			Common	7,250,239	115,432		4,002,259	15,642,571	151,842,395	3,897,797
39	Total Huntington			128,436,327	22,417,911	17.5%	48,645,784	15,642,571	918,256,508	29,996,439
40	Jim Bridger	1	Steam - Coal	47,260,473	12,429,112	26.3%	10,883,656	-	250,917,275	7,134,287
41		2	Steam - Coal	59,922,944	12,978,683	21.7%	9,393,089	-	255,919,673	7,394,723
42		3	Steam - Coal	44,205,069	14,375,865	32.5%	8,108,958	-	336,174,840	9,439,621
43		4	Steam - Coal	45,637,965	11,743,531	25.7%	16,781,678	-	398,921,726	11,016,686
			Common	9,396,229	2,346,773		16,331,621	14,443,972	193,399,417	4,888,563
44	Total Jim Bridger			206,422,681	53,873,964	26.1%	61,499,002	14,443,972	1,435,332,930	39,873,880
45	Lake Side	CT11	GT	46,049,016	7,565,912	16.4%	111,165		51,966,854	1,609,539
46		CT12	GT	45,216,412	7,565,912	16.7%	11,873		50,988,632	1,583,245
47		ST1	Combined Cycle	28,705,916	7,246,384	25.2%	-		172,967,602	5,345,156
48		CT21	GT	59,667,577	18,766,359	31.5%	-		72,067,221	2,232,318
49		CT22	GT	59,699,312	18,766,359	31.4%	-		75,574,693	2,343,394
50		ST2	Combined Cycle	84,066,458	21,806,510	25.9%	-		322,623,599	9,964,009
		Common		23,269	23,269		120,262,960	10,669,330	287,176,751	7,307,364
51	Total Lake Side			323,427,959	81,740,705	25.3%	120,385,997	10,669,330	1,033,365,351	30,385,025
52	Naughton	1	Steam - Coal	20,591,180	1,490,768	7.2%	20,713,160	-	216,970,709	10,230,884
53		2	Steam - Coal	24,167,771	2,862,632	11.8%	30,169,722	-	265,887,175	12,571,019
54		3	Combustion Turbine and Steam-NG	39,074,797	10,450,485	26.7%	11,439,684	-	156,105,179	7,334,839
55		Common		7,912,246	-		3,661,962	4,112,697	116,897,740	4,904,579
56	Total Naughton			91,745,994	14,803,885	16.1%	65,984,527	4,112,697	755,860,804	35,041,322
57	Craig	1	Steam - Coal	12,874,514	2,981,969	23.2%	7,040,561	415,874	65,065,710	1,835,313
58		2	Steam - Coal	13,100,687	4,018,141	30.7%	7,366,693	131,992	107,850,154	3,113,770
59		Common		2,196,721	116,865		336,369	-	21,525,770	540,816
60	Total Craig			28,171,921	7,116,975	25.3%	14,743,623	547,866	194,441,633	5,489,900
61	Hayden	1	Steam - Coal	5,353,540	1,497,427	28.0%	1,032,901	264,221	55,140,562	1,751,301
62		2	Steam - Coal	4,514,141	802,462	17.8%	1,332,170	545,658	32,457,057	1,040,427
63		Common		251,780	52,425		209,312	34,222	28,747,569	1,096,894
64	Total Hayden			10,119,460	2,352,314	23.2%	2,574,383	844,101	116,345,189	3,888,622
65	Wyodak		Steam - Coal	66,820,413	10,337,764	15.5%	27,654,373	4,426,087	471,519,749	13,698,305

	Generating Facility	Unit No.	Generator Type	Turbogenerator	Generator/Exciter	Generator/Exciter Percentage	Accessory Electric Equipment	GSU	Total Facility	Book Depreciation Expense
66	Merwin	1-3	Hydro	7,978,506	4,328,371	54.3%	1,207,933	2,145,545	139,189,039	2,713,542
67	Yale	1-2	Hydro	13,699,711	6,607,404	48.2%	1,732,428	1,776,325	84,037,148	1,147,070
68	Swift 1	1-3	Hydro	16,798,780	10,425,852	62.1%	1,748,245	3,565,636	169,064,982	2,901,986
69	Lemolo	1-2	Hydro	11,678,117	4,320,547	37.0%	2,554,803	3,777,087	79,134,237	2,534,063
70	Toketee	1-3	Hydro	4,002,314	2,641,918	66.0%	1,036,967	354,719	24,132,441	758,952
71	Slide Creek	1	Hydro	5,726,529	552,027	9.6%	2,494,839	1,559,207	26,787,264	868,668
72	Soda Springs	1	Hydro	1,323,466	422,910	32.0%	184,981	109,437	99,631,721	2,934,226
73	Clearwater	1-2	Hydro	2,096,014	1,187,803	56.7%	146,590	1,386,748	28,629,870	895,732
74	Fish Creek	1	Hydro	1,141,887	293,192	25.7%	56,301	108,663	17,753,655	551,969
75	Prospect	1-4	Hydro	6,150,370	2,121,187	34.5%	764,114	738,122	65,311,870	2,208,323
76	Copco	11-12	Hydro	3,783,810	877,993	23.2%		627,922	11,435,363	1,438,349
77	Copco	21-22	Hydro	3,579,826	864,883	24.2%		2,843,340	16,813,935	2,171,332
78	Total Copco			7,363,636	1,742,876	23.7%	5,770,972	3,471,263	28,249,298	3,609,681
79	JC Boyle	1-2	Hydro	8,618,283	3,807,076	44.2%	3,294,206	1,509,023	36,338,324	4,658,875
80	Irongate	1	Hydro	2,271,909	848,257	37.3%	184,798	134,801	30,376,361	3,816,575
81	Ashton	1	Hydro	2,055,203	922,501	44.9%			34,226,837	1,940,435
82	Ashton	2-3	Hydro	-	-				-	-
83	Total Ashton			2,055,203	922,501	44.9%	351,281	314,892	34,226,837	1,940,435
84	Soda	1-2	Hydro	4,646,255	2,341,420	50.4%	334,292	241,895	18,696,873	602,131
85	Grace	3-5	Hydro	2,690,772	1,402,987	52.1%	511,336	1,375,865	24,489,558	748,426
86	Oneida	1-3	Hydro	13,149,124	4,776,191	36.3%	829,066	996,947	28,844,998	875,845
87	Cutler	1-2	Hydro	12,109,190	3,802,180	31.4%	2,090,384	550,286	34,621,486	1,830,905
88	Glenrock I		Wind	173,874,815	8,514,164	4.9%	11,633,617	-	189,264,397	6,635,116
89	Glenrock III		Wind	72,917,879	3,154,501	4.3%	5,683,918	-	79,962,802	2,913,451
90	Glenrock	Common	Wind	-	-		156,479	5,994,041	11,309,840	305,561
91	Total Glenrock			246,792,694	11,668,665	4.7%	17,474,014	5,994,041	280,537,039	9,854,128
92	Rolling Hills		Wind	177,526,860	7,850,217	4.4%	12,436,383	-	194,100,992	6,748,149
93	Seven Mile Hill 1		Wind	169,168,279	8,956,558	5.3%	10,395,205	-	183,408,598	6,401,393
94	Seven Mike Hill 2		Wind	34,337,243	1,769,912	5.2%	2,440,236	-	37,513,147	1,339,701
95	Seven Mile Hill	Common	Wind	-	-		199,204	2,097,471	5,064,189	134,880
96	Total Seven Mile Hill			203,505,522	10,726,471	5.3%	13,034,646	2,097,471	225,985,934	7,875,974

	Generating Facility	Unit No.	Generator Type	Turbogenerator	Generator/Exciter	Generator/Exciter Percentage	Accessory Electric Equipment	GSU	Total Facility	Book Depreciation Expense	
97	High Plains		Wind	169,853,045	8,817,599	5.2%	11,356,897	-	186,527,284	7,205,277	
98	McFadden Ridge		Wind	46,926,839	2,515,972	5.4%	3,406,416	-	51,448,522	1,852,464	
99	HP/MR	Common	Wind	-	-		-	1,757,299	3,577,896	86,969	
100	Total HP/MR			216,779,884	11,333,570	5.2%	14,763,312	1,757,299	241,553,702	9,144,710	
99	Goodnoe Hills		Wind	142,512,865	7,173,099	5.0%	7,434,456	3,357,435	158,979,266	6,134,166	Being repowered in 2020
100	Leaning Juniper		Wind	159,894,217	8,506,173	5.3%	9,512,344	3,233,153	177,706,380	5,810,865	Being repowered in 2020
101	Marengo I		Wind	223,941,289	8,328,703	3.7%	14,134,103	-	238,131,843	7,836,150	New in 2020
102	Marengo II		Wind	117,088,501	4,053,798	3.5%	5,797,966	-	127,024,887	4,204,221	
103	Marengo	Common		2,900,538	1,153,639	39.8%	255,236	4,232,780	9,891,039	408,906	New in 2020
104	Total Marengo			343,930,328	13,536,139	3.9%	20,187,305	4,232,780	375,047,769	12,449,276	
105	Dunlap		Wind	344,851,379	16,707,566	4.8%	12,327,565	1,704,005	372,526,200	12,192,466	New in 2020
106	Foote Creek		Wind	106,244,083	7,384,382	7.0%	7,392,658	-	123,797,900	3,763,382	New in 2020
107	Cedar Springs II		Wind	232,898,450	18,631,876	8.0%	25,806,123	2,793,553	270,400,000	9,013,333	
108	Ekola Flats		Wind	274,302,787	21,944,223	8.0%	37,203,627	2,930,546	323,999,710	10,799,990	
109	TB Flats I		Wind	494,105,856	39,528,469	8.0%	42,625,403	7,286,972	555,380,727	18,512,691	
110	Pryor Mountain		Wind	333,535,589	26,682,847	8.0%	42,271,004	3,000,000	400,000,000	13,333,333	

Grand Total	5,035,845,563	624,540,709	990,670,050	181,664,665	14,087,227,117	467,259,350

Production Plant Asset Values as of 12-31-2019 and the associated depreciation for 2019

					Values	
	Location	Location Description	Class	Class Description	Sum of Current APC	Sum of Dep. for year
1	000219	LAKE SIDE GAS PLANT PROVO WETLANDS	34010	Fee Land - Other	235,129.44	-
2	**000219 Total**				**235,129.44**	**-**
3	000220	LAKE SIDE GAS PLANT COMMON	34010	Fee Land - Other	3,030,329.21	-
4			34030	Water Rights - Other	28,061,442.32	-
5			34100	Structures & Improve	71,291,388.38	(1,969,661.24)
6			34200	Fuel Hldrs,Prdcr, Ac	8,506,486.62	(256,045.24)
7			34300	Prime Movers	1,716,431.80	(42,537.37)
8			34600	Misc. Pwr Plt Eqp	725,447.00	(19,949.80)
9	**000220 Total**				**113,331,525.33**	**(2,288,193.65)**
10	000221	LAKE SIDE BLOCK 2 COMMON & STEELMILL SUB	34100	Structures & Improve	15,018,534.67	(416,013.41)
11			34300	Prime Movers	14,890,478.97	(461,427.20)
12			34400	Generators	311,908.98	(9,513.22)
13			34500	Access Elec Equip	75,361,660.58	(2,087,517.99)
14			34600	Misc. Pwr Plt Eqp	2,944,945.25	(80,985.99)
15	**000221 Total**				**108,527,528.45**	**(3,055,457.81)**
16	000222	LAKE SIDE BLOCK 2 COMBUSTION TURBINE A	34300	Prime Movers	53,300,861.90	(1,659,944.25)
17			34400	Generators	18,766,359.00	(572,373.95)
18	**000222 Total**				**72,067,220.90**	**(2,232,318.20)**
19	000223	LAKE SIDE BLOCK 2 COMBUSTION TURBINE B	34300	Prime Movers	56,808,333.70	(1,771,020.18)
20			34400	Generators	18,766,359.00	(572,373.95)
21	**000223 Total**				**75,574,692.70**	**(2,343,394.13)**
22	000224	LAKE SIDE BLOCK 2 STEAM TURBINE	34300	Prime Movers	206,318,548.38	(6,416,704.68)
23			34400	Generators	116,305,050.33	(3,547,304.05)
24	**000224 Total**				**322,623,598.71**	**(9,964,008.73)**
25	000225	LAKE SIDE BLOCK 1 COMMON & DYNAMO SUB	34100	Structures & Improve	2,613,185.68	(70,317.30)
26			34300	Prime Movers	12,242,616.21	(356,178.25)
27			34400	Generators	85,714.59	(709.70)
28			34500	Access Elec Equip	44,901,299.58	(1,234,929.01)
29			34600	Misc. Pwr Plt Eqp	2,451,484.27	(67,415.82)
30			35340	GSU and Assoc Equip	2,788,266.97	(48,515.84)
31	**000225 Total**				**65,082,567.30**	**(1,778,065.92)**
32	000226	LAKE SIDE BLOCK 1 COMBUSTION TURBINE A	34300	Prime Movers	44,289,777.12	(1,378,447.43)
33			34400	Generators	7,565,911.85	(230,760.32)
34			34500	Access Elec Equip	111,164.68	(331.24)
35	**000226 Total**				**51,966,853.65**	**(1,609,538.99)**
36	000227	LAKE SIDE BLOCK 1 COMBUSTION TURBINE B	34300	Prime Movers	43,410,847.78	(1,352,156.05)
37			34400	Generators	7,565,911.85	(230,760.32)
38			34500	Access Elec Equip	11,872.60	(328.87)
39	**000227 Total**				**50,988,632.23**	**(1,583,245.24)**
40	000228	LAKE SIDE BLOCK 1 STEAM TURBINE	34300	Prime Movers	118,892,795.01	(3,695,874.50)
41			34400	Generators	54,074,807.41	(1,649,281.63)
42	**000228 Total**				**172,967,602.42**	**(5,345,156.13)**
43	000235	EAST SIDE MOBILE GENERATION EQUIPMENT	34400	Generators	839,680.12	(13,434.88)

44	**000235 Total**				**839,680.12**	**(13,434.88)**
45	000240	CHOLLA PLANT - COMMON	31000	Land - Steam	1,147,452.00	-
46			31010	Fee Land - Steam	119,399.31	-
47			31020	Land Rights - Steam	1,368,465.38	(39,548.65)
48			31100	Struct.&Improv. Th	43,809,872.16	(1,023,024.80)
49			31200	Boiler Plant Equipm.	36,491,923.95	(1,045,677.85)
50			31400	Turbogenerator Units	555,095.68	(15,820.24)
51			31500	Access. Electr. Equi	5,632,628.94	(129,615.10)
52			31600	Misc.PwPlnt Equipm.	1,245,906.31	(41,239.50)
53			35340	GSU and Assoc Equip	453,511.28	(7,891.10)
54	**000240 Total**				**90,824,255.01**	**(2,302,817.24)**
55	000244	CHOLLA PLANT - UNIT #4	31100	Struct.&Improv. Th	21,785,678.69	(509,784.87)
56			31200	Boiler Plant Equipm.	305,852,358.54	(8,836,572.96)
57			31400	Turbogenerator Units	68,539,074.06	(1,953,393.89)
58			31500	Access. Electr. Equi	63,176,480.04	(1,463,905.03)
59			31570	Access. Electr E-S&A	12,989.40	(301.35)
60			31600	Misc.PwPlnt Equipm.	2,913,431.18	(95,809.23)
61			35340	GSU and Assoc Equip	7,277,416.23	(127,930.96)
62	**000244 Total**				**469,557,428.14**	**(12,987,698.29)**
63	000250	CARBON PLANT COMMON FACILITIES AND SUBST	31010	Fee Land - Steam	94,334.51	-
64			31030	Water Rights - Steam	-	-
65			31200	Water Rights - Steam	-	
66	**000250 Total**				**94,334.51**	**-**
67	000251	CARBON PLANT - UNIT #1	31200	Water Rights - Steam	-	
68	**000251 Total**				**-**	
69	000252	CARBON PLANT - UNIT #2	31200	Water Rights - Steam	-	
70	**000252 Total**				**-**	
71	000260	GADSBY PLANT COMMON FACILITIES AND SUBST	31010	Fee Land - Steam	1,243,952.29	-
72			31030	Water Rights - Steam	8,138.01	-
73			31100	Struct.&Improv. Th	11,951,572.31	(240,350.83)
74			31200	Boiler Plant Equipm.	1,603,419.14	(30,753.42)
75			31400	Turbogenerator Units	475,708.66	(11,559.71)
76			31500	Access. Electr. Equi	3,196,436.11	(91,333.11)
77			31600	Misc.PwPlnt Equipm.	377,082.73	(11,953.52)
78			35340	GSU and Assoc Equip	2,553,551.60	(43,414.91)
79	**000260 Total**				**21,409,860.85**	**(429,365.50)**
80	000261	GADSBY NO 1 STEAM ELECTRIC STATION	31100	Struct.&Improv. Th	1,228,845.39	(24,328.36)
81			31200	Boiler Plant Equipm.	10,244,973.58	(227,438.43)
82			31400	Turbogenerator Units	5,545,263.48	(134,749.90)
83			31500	Access. Electr. Equi	1,394,621.84	(40,025.65)
84			31600	Misc.PwPlnt Equipm.	21,261.95	(674.00)
85	**000261 Total**				**18,434,966.24**	**(427,216.34)**
86	000262	GADSBY NO 2 STEAM ELECTRIC STATION	31100	Struct.&Improv. Th	1,108,222.29	(21,741.12)
87			31200	Boiler Plant Equipm.	14,155,174.19	(312,754.28)
88			31400	Turbogenerator Units	6,369,161.73	(154,770.66)
89			31500	Access. Electr. Equi	1,424,532.29	(39,995.63)
90			31600	Misc.PwPlnt Equipm.	12,702.95	(402.68)
91	**000262 Total**				**23,069,793.45**	**(529,664.37)**
92	000263	GADSBY NO 3 STEAM ELECTRIC STATION	31100	Struct.&Improv. Th	1,213,027.25	(23,342.47)
93			31200	Boiler Plant Equipm.	14,308,038.68	(312,654.41)
94			31400	Turbogenerator Units	7,611,642.65	(184,412.86)
95			31500	Access. Electr. Equi	2,552,866.95	(72,109.80)

96			31600	Misc.PwPlnt Equipm.	46,931.11	(1,487.72)
97	**000263 Total**				**25,732,506.64**	**(594,007.26)**
98	000264	GADSBY COMMON GAS PEAKERS & SUBSTATION	34100	Structures & Improve	4,273,000.07	(146,563.92)
99			34200	Fuel Hldrs,Prdcr, Ac	2,759,334.26	(99,611.97)
100			34300	Prime Movers	7,341,190.22	(283,137.03)
101			34400	Generators	77,192.72	(2,809.82)
102			34500	Access Elec Equip	1,004,029.04	(34,513.14)
103			35340	GSU and Assoc Equip	2,360,261.16	(40,378.71)
104	**000264 Total**				**17,815,007.47**	**(607,014.59)**
105	000265	GADSBY NO 4 GAS TURBINE PEAKER	34300	Prime Movers	17,017,830.46	(662,953.36)
106			34400	Generators	5,758,863.68	(209,622.64)
107			34500	Access Elec Equip	682,694.40	(24,713.54)
108	**000265 Total**				**23,459,388.54**	**(897,289.54)**
109	000266	GADSBY NO 5 GAS TURBINE PEAKER	34300	Prime Movers	17,981,859.21	(701,072.55)
110			34400	Generators	5,818,211.37	(211,782.89)
111			34500	Access Elec Equip	660,744.66	(23,918.96)
112	**000266 Total**				**24,460,815.24**	**(936,774.40)**
113	000267	GADSBY NO 6 GAS TURBINE PEAKER	34300	Prime Movers	15,866,263.85	(618,025.14)
114			34400	Generators	6,128,494.94	(223,077.22)
115			34500	Access Elec Equip	604,651.88	(21,888.40)
116	**000267 Total**				**22,599,410.67**	**(862,990.76)**
117	000270	NAUGHTON PLANT COMMON FACILITIES AND SUB	31010	Fee Land - Steam	1,305,323.66	-
118			31020	Land Rights - Steam	15,015.87	(217.73)
119			31030	Water Rights - Steam	690.97	-
120			31100	Struct.&Improv. Th	63,340,275.92	(2,708,129.47)
121			31200	Boiler Plant Equipm.	34,886,771.98	(1,559,618.72)
122			31400	Turbogenerator Units	7,912,246.27	(311,890.46)
123			31500	Access. Electr. Equi	3,661,961.71	(181,536.84)
124			31600	Misc.PwPlnt Equipm.	1,662,756.22	(85,487.59)
125			35340	GSU and Assoc Equip	4,112,697.46	(57,698.67)
126	**000270 Total**				**116,897,740.06**	**(4,904,579.48)**
127	000271	NAUGHTON NO 1 STEAM ELECTRIC STATION	31100	Struct.&Improv. Th	21,128,557.02	(917,893.95)
128			31200	Boiler Plant Equipm.	154,441,924.41	(7,389,523.35)
129			31400	Turbogenerator Units	20,591,179.75	(855,943.56)
130			31500	Access. Electr. Equi	20,713,159.62	(1,062,585.10)
131			31600	Misc.PwPlnt Equipm.	95,888.60	(4,938.26)
132	**000271 Total**				**216,970,709.40**	**(10,230,884.22)**
133	000272	NAUGHTON NO 2 STEAM ELECTRIC STATION	31100	Struct.&Improv. Th	29,216,582.88	(1,271,810.85)
134			31200	Boiler Plant Equipm.	181,944,228.36	(8,732,173.43)
135			31400	Turbogenerator Units	24,167,770.80	(1,000,755.35)
136			31500	Access. Electr. Equi	30,169,721.60	(1,546,252.68)
137			31600	Misc.PwPlnt Equipm.	388,871.65	(20,026.90)
138	**000272 Total**				**265,887,175.29**	**(12,571,019.21)**
139	000273	NAUGHTON NO 3 STEAM ELECTRIC STATION	31100	Struct.&Improv. Th	14,116,555.22	(611,366.57)
140			31200	Boiler Plant Equipm.	91,267,838.33	(4,497,484.22)
141			31400	Turbogenerator Units	39,074,797.09	(1,628,507.90)
142			31500	Access. Electr. Equi	11,439,683.73	(586,855.79)
143			31600	Misc.PwPlnt Equipm.	206,305.08	(10,624.71)
144	**000273 Total**				**156,105,179.45**	**(7,334,839.19)**
145	000280	HUNTINGTON PLANT COMMON FACILITIES AND S	31000	Land - Steam	158,988.61	-
146			31010	Fee Land - Steam	746,936.62	-
147			31030	Water Rights - Steam	1,471,639.00	-

148			31100	Struct.&Improv. Th	80,965,920.25	(1,915,831.77)
149			31200	Boiler Plant Equipm.	40,201,196.61	(1,335,113.19)
150			31400	Turbogenerator Units	7,250,238.95	(248,683.22)
151			31500	Access. Electr. Equi	4,002,258.70	(109,431.83)
152			31600	Misc.PwPlnt Equipm.	1,402,644.86	(40,129.02)
153			35340	GSU and Assoc Equip	15,642,570.93	(248,608.31)
154	**000280 Total**				**151,842,394.53**	**(3,897,797.34)**
155	000281	HUNTINGTON NO 1 STEAM ELECTRIC STATION	31100	Struct.&Improv. Th	19,939,527.63	(476,207.27)
156			31200	Boiler Plant Equipm.	294,830,606.94	(10,618,115.47)
157			31400	Turbogenerator Units	62,055,903.00	(2,124,926.34)
158			31500	Access. Electr. Equi	20,953,062.85	(571,544.93)
159			31600	Misc.PwPlnt Equipm.	1,028,233.16	(45,075.16)
160	**000281 Total**				**398,807,333.58**	**(13,835,869.17)**
161	000282	HUNTINGTON NO 2 STEAM ELECTRIC STATION	31100	Struct.&Improv. Th	26,711,343.61	(632,215.83)
162			31200	Boiler Plant Equipm.	257,103,527.49	(8,929,728.40)
163			31400	Turbogenerator Units	59,130,184.89	(2,001,910.93)
164			31500	Access. Electr. Equi	23,690,462.77	(660,455.34)
165			31600	Misc.PwPlnt Equipm.	971,260.90	(38,461.93)
166	**000282 Total**				**367,606,779.66**	**(12,262,772.43)**
167	000300	HUNTER PLANT COMMON FACILITIES	31010	Fee Land - Steam	4,546,613.34	-
168			31020	Land Rights - Steam	246,337.54	(3,966.04)
169			31030	Water Rights - Steam	24,271,831.30	-
170			31100	Struct.&Improv. Th	111,782,391.41	(2,152,903.79)
171			31200	Boiler Plant Equipm.	28,266,214.62	(781,960.33)
172			31400	Turbogenerator Units	1,210,000.76	(37,790.83)
173			31500	Access. Electr. Equi	1,751,455.41	(29,293.75)
174			31600	Misc.PwPlnt Equipm.	485,055.79	(14,939.73)
175	**000300 Total**				**172,559,900.17**	**(3,020,854.47)**
176	000301	HUNTER NO 1 STEAM ELECTRIC STATION	31100	Struct.&Improv. Th	23,135,839.18	(446,001.13)
177			31200	Boiler Plant Equipm.	268,909,340.94	(7,476,659.64)
178			31400	Turbogenerator Units	67,231,487.44	(2,128,747.29)
179			31500	Access. Electr. Equi	34,624,800.68	(681,383.78)
180			31600	Misc.PwPlnt Equipm.	802,524.57	(24,717.76)
181			35340	GSU and Assoc Equip	4,232,580.53	(73,646.90)
182	**000301 Total**				**398,936,573.34**	**(10,831,156.50)**
183	000302	HUNTER NO 2 STEAM ELECTRIC STATION	31100	Struct.&Improv. Th	12,593,258.95	(241,946.84)
184			31200	Boiler Plant Equipm.	171,088,535.76	(4,703,634.24)
185			31400	Turbogenerator Units	46,644,337.70	(1,469,752.05)
186			31500	Access. Electr. Equi	16,952,557.25	(331,962.52)
187			35340	GSU and Assoc Equip	5,618,763.59	(82,932.52)
188	**000302 Total**				**252,897,453.25**	**(6,830,228.17)**
189	000303	HUNTER NO 3 STEAM ELECTRIC STATION	31010	Fee Land - Steam	586,308.71	-
190			31100	Struct.&Improv. Th	55,964,750.32	(1,079,655.64)
191			31200	Boiler Plant Equipm.	298,042,358.12	(8,282,082.40)
192			31400	Turbogenerator Units	84,538,730.20	(2,679,203.74)
193			31500	Access. Electr. Equi	54,675,654.81	(1,075,958.69)
194			31600	Misc.PwPlnt Equipm.	1,633,585.53	(50,314.44)
195			35340	GSU and Assoc Equip	7,440,260.86	(121,885.64)
196	**000303 Total**				**502,881,648.55**	**(13,289,100.55)**
197	000305	HUNTER PLANT COMMON FACILTIES - UNITS 1	31100	Struct.&Improv. Th	9,528,120.97	(183,892.72)
198			31200	Boiler Plant Equipm.	12,034,275.06	(329,426.37)
199			31400	Turbogenerator Units	3,832,059.57	(120,224.79)

200			31500	Access. Electr. Equi	101,813.37	(1,026.37)
201			31600	Misc.PwPlnt Equipm.	823,901.93	(25,376.18)
202	**000305 Total**				**26,320,170.90**	**(659,946.43)**
203	000310	CURRANT CREEK TOTAL PLANT COMMON	34010	Fee Land - Other	512,130.54	-
204			34030	Water Rights - Other	2,891,146.49	-
205			34100	Structures & Improve	25,821,046.63	(666,279.98)
206			34200	Fuel Hldrs,Prdcr, Ac	3,299,735.22	(92,392.59)
207			34300	Prime Movers	1,112,471.24	(29,617.72)
208			34500	Access Elec Equip	235,752.76	(5,754.74)
209			34600	Misc. Pwr Plt Eqp	659,947.04	(17,092.63)
210	**000310 Total**				**34,532,229.92**	**(811,137.66)**
211	000311	CURRANT CREEK BLK 1 COMBUSTION TURBINE A	34300	Prime Movers	31,345,965.63	(943,701.13)
212			34400	Generators	6,694,709.69	(194,816.05)
213	**000311 Total**				**38,040,675.32**	**(1,138,517.18)**
214	000312	CURRANT CREEK BLK 1 COMBUSTION TURBINE B	34300	Prime Movers	30,573,507.82	(920,262.59)
215			34400	Generators	6,700,493.66	(194,984.35)
216	**000312 Total**				**37,274,001.48**	**(1,115,246.94)**
217	000313	CURRANT CREEK BLK 1 STEAM TURBINE	34300	Prime Movers	113,125,020.82	(3,402,848.28)
218			34400	Generators	49,722,806.31	(1,445,738.15)
219	**000313 Total**				**162,847,827.13**	**(4,848,586.43)**
220	000314	CURRANT CREEK BLK 1 COMMON & SUBSTATION	34100	Structures & Improve	18,532,177.48	(479,983.38)
221			34300	Prime Movers	19,115,304.73	(569,619.29)
222			34400	Generators	41,309.86	(1,202.12)
223			34500	Access Elec Equip	42,775,668.12	(1,129,277.66)
224			34600	Misc. Pwr Plt Eqp	2,323,397.15	(60,175.98)
225			35340	GSU and Assoc Equip	7,053,477.20	(122,730.48)
226	**000314 Total**				**89,841,334.54**	**(2,362,988.91)**
227	000380	BLUNDELL GEOTHERMAL PLANT COMMON & SUBST	31010	Fee Land - Steam	177,023.03	-
228			31026	Steam Rghts-Blundell	-	-
229			31080	Land - Leased	36,662.19	-
230			31100	Struct.&Improv. Th	904,648.38	(22,012.21)
231			31200	Boiler Plant Equipm.	270,620.15	(8,064.48)
232			31500	Access. Electr. Equi	42,332.23	(1,142.97)
233			31600	Misc.PwPlnt Equipm.	74,760.16	(2,810.98)
234			35340	GSU and Assoc Equip	1,504,130.52	(26,098.81)
235	**000380 Total**				**3,010,176.66**	**(60,129.45)**
236	000381	BLUNDELL GEOTHERMAL PLANT UNIT 1	31100	Struct.&Improv. Th	6,622,320.15	(165,425.34)
237			31200	Boiler Plant Equipm.	13,401,933.25	(392,616.41)
238			31400	Turbogenerator Units	17,884,335.74	(587,020.32)
239			31500	Access. Electr. Equi	5,045,404.31	(136,225.92)
240			31600	Misc.PwPlnt Equipm.	663,423.70	(24,093.74)
241	**000381 Total**				**43,617,417.15**	**(1,305,381.73)**
242	000382	BLUNDELL GEOTHERMAL PLANT UNIT 2	31100	Struct.&Improv. Th	689,372.12	(17,303.24)
243			31200	Boiler Plant Equipm.	8,082,922.40	(237,587.53)
244			31400	Turbogenerator Units	16,569,227.31	(544,959.71)
245			31500	Access. Electr. Equi	2,453,737.00	(66,250.91)
246			31600	Misc.PwPlnt Equipm.	545,275.12	(20,502.34)
247	**000382 Total**				**28,340,533.95**	**(886,603.73)**
248	000385	BLUNDELL GEOTHERMAL STEAM FIELD	31010	Fee Land - Steam	-	-
249			31020	Land Rights - Steam	40,981,910.43	(856,521.93)
250			31100	Struct.&Improv. Th	250,763.16	(6,294.16)
251			31200	Boiler Plant Equipm.	37,581,069.40	(1,115,130.14)

252			31500	Access. Electr. Equi	1,079,342.30	(29,142.26)
253			31600	Misc.PwPlnt Equipm.	125,101.43	(4,703.81)
254	**000385 Total**				**80,018,186.72**	**(2,011,792.30)**
255	000400	CRAIG PLANT - COMMON, UNITS 1, 2 & 3	31010	Fee Land - Steam	125,828.00	-
256			31100	Struct.&Improv. Th	12,143,331.76	(255,203.93)
257			31200	Boiler Plant Equipm.	5,864,179.21	(175,139.87)
258			31400	Turbogenerator Units	2,196,720.57	(76,885.24)
259			31500	Access. Electr. Equi	336,368.56	(6,861.91)
260			31600	Misc.PwPlnt Equipm.	859,341.74	(26,725.52)
261	**000400 Total**				**21,525,769.84**	**(540,816.47)**
262	000401	CRAIG PLANT UNIT 1	31100	Struct.&Improv. Th	11,672,605.41	(246,098.13)
263			31200	Boiler Plant Equipm.	32,809,376.96	(980,732.79)
264			31400	Turbogenerator Units	12,874,514.22	(450,699.97)
265			31500	Access. Electr. Equi	7,040,561.41	(142,684.94)
266			31600	Misc.PwPlnt Equipm.	252,778.01	(7,861.39)
267			35340	GSU and Assoc Equip	415,873.55	(7,236.20)
268	**000401 Total**				**65,065,709.56**	**(1,835,313.42)**
269	000402	CRAIG PLANT UNIT 2	31100	Struct.&Improv. Th	11,688,308.90	(246,623.32)
270			31200	Boiler Plant Equipm.	75,562,473.65	(2,256,045.15)
271			31400	Turbogenerator Units	13,100,686.52	(458,524.02)
272			31500	Access. Electr. Equi	7,366,692.60	(150,280.52)
273			31600	Misc.PwPlnt Equipm.	-	-
274			35340	GSU and Assoc Equip	131,992.14	(2,296.66)
275	**000402 Total**				**107,850,153.81**	**(3,113,769.67)**
276	000405	CRAIG PLANT - COMMON, UNITS 1 & 2	31010	Fee Land - Steam	11,258.00	-
277			31100	Struct.&Improv. Th	3,033,316.18	(63,282.63)
278			31200	Boiler Plant Equipm.	23,434,436.29	(702,755.99)
279			31400	Turbogenerator Units	1,347,271.32	(47,154.50)
280			31500	Access. Electr. Equi	2,578,979.66	(52,611.18)
281			31600	Misc.PwPlnt Equipm.	124,977.85	(3,886.81)
282			35340	GSU and Assoc Equip	423,928.84	(7,376.36)
283	**000405 Total**				**30,954,168.14**	**(877,067.47)**
284	000406	CRAIG PLANT-COMMON-RAIL COAL HANDLING FA	31100	Struct.&Improv. Th	156,377.94	(3,299.56)
285			31200	Boiler Plant Equipm.	173,803.47	(5,214.10)
286			31500	Access. Electr. Equi	52,666.01	(1,074.39)
287			31600	Misc.PwPlnt Equipm.	3,197.00	(99.43)
288	**000406 Total**				**386,044.42**	**(9,687.48)**
289	000410	HAYDEN PLANT - COMMON	31010	Fee Land - Steam	554,771.80	-
290			31100	Struct.&Improv. Th	14,946,303.29	(686,252.57)
291			31200	Boiler Plant Equipm.	12,589,008.52	(391,891.71)
292			31400	Turbogenerator Units	251,779.69	(9,290.67)
293			31500	Access. Electr. Equi	209,311.98	(3,642.02)
294			31600	Misc.PwPlnt Equipm.	162,172.05	(5,221.94)
295			35340	GSU and Assoc Equip	34,222.08	(595.46)
296	**000410 Total**				**28,747,569.41**	**(1,096,894.37)**
297	000411	HAYDEN PLANT UNIT 1	31010	Fee Land - Steam	125,575.00	-
298			31100	Struct.&Improv. Th	1,134,916.82	(52,433.16)
299			31200	Boiler Plant Equipm.	46,979,330.70	(1,473,357.30)
300			31400	Turbogenerator Units	5,353,539.79	(195,205.81)
301			31500	Access. Electr. Equi	1,032,901.48	(17,654.76)
302			31600	Misc.PwPlnt Equipm.	250,077.04	(8,052.49)
303			35340	GSU and Assoc Equip	264,221.35	(4,597.46)

304	**000411 Total**				**55,140,562.18**	**(1,751,300.98)**
305	000412	HAYDEN PLANT UNIT 2	31010	Fee Land - Steam	2,722.00	-
306			31100	Struct.&Improv. Th	1,827,762.87	(84,442.67)
307			31200	Boiler Plant Equipm.	24,009,544.89	(750,719.74)
308			31400	Turbogenerator Units	4,514,140.98	(166,248.49)
309			31500	Access. Electr. Equi	1,332,169.75	(23,167.44)
310			31600	Misc.PwPlnt Equipm.	225,059.01	(7,246.90)
311			35340	GSU and Assoc Equip	545,657.89	(8,601.39)
312	**000412 Total**				**32,457,057.39**	**(1,040,426.63)**
313	000444	CUTLER HYDROELECTRIC STATION - PROJECT	33010	Fee Land - Hydro	3,414,662.72	-
314			33020	Land Rights - Hydro	655.72	(54.69)
315			33030	Water Rights - Hydro	4,818.31	(149.85)
316			33040	Flood Rights - Hydro	90,968.42	(3,029.25)
317			33100	Struct/Improv Hydro	1,170,604.77	(59,543.58)
318			33110	Struc/Improv Prod.	1,788,297.43	(58,405.81)
319			33130	Struc/Improv Recreat	1,766,079.38	(89,211.19)
320			33200	Reserv,- Dams & Wway	3,685,528.43	(185,431.37)
321			33210	Resvors,Dams, Wway P	6,410,888.79	(314,556.12)
322			33230	Resvors,Dams,Wway Re	63,464.17	(3,179.55)
323			33300	Water Wheels- Turb &	12,109,189.85	(867,834.18)
324			33400	Access. Electr. Equi	2,964,686.31	(215,244.33)
325			33500	Misc Power Plant Equ	11,124.11	(502.81)
326			33600	Roads- Railroads & B	590,232.26	(26,555.89)
327			35340	GSU and Assoc Equip	550,285.72	(7,205.92)
328	**000444 Total**				**34,621,486.39**	**(1,830,904.54)**
329	000445	GRANITE HE PLANT AND SUBSTATION	33010	Fee Land - Hydro	180.40	-
330			33100	Struct/Improv Hydro	429,569.54	(18,986.98)
331			33110	Struc/Improv Prod.	118,599.60	(5,242.11)
332			33200	Reserv,- Dams & Wway	210,061.42	(7,607.93)
333			33210	Resvors,Dams, Wway P	3,566,281.67	(128,040.38)
334			33300	Water Wheels- Turb &	720,702.06	(22,053.48)
335			33400	Access. Electr. Equi	225,749.94	(8,133.71)
336			33500	Misc Power Plant Equ	1,409.81	(34.53)
337	**000445 Total**				**5,272,554.44**	**(190,099.12)**
338	000449	PIONEER HE PLANT,SUBSTATION & MAINT BLDG	33010	Fee Land - Hydro	2,059.72	-
339			33020	Land Rights - Hydro	9,247.48	(100.79)
340			33030	Water Rights - Hydro	110,805.67	(1,207.78)
341			33100	Struct/Improv Hydro	289,872.30	(10,235.85)
342			33110	Struc/Improv Prod.	373,659.45	(10,720.38)
343			33120	Struc/Imprpv/ Fish/W	10,074.12	(356.62)
344			33200	Reserv,- Dams & Wway	1,554,039.62	(46,926.29)
345			33210	Resvors,Dams, Wway P	6,711,239.69	(196,706.97)
346			33300	Water Wheels- Turb &	1,672,757.25	(69,645.14)
347			33400	Access. Electr. Equi	1,077,302.34	(38,124.70)
348			33500	Misc Power Plant Equ	9,601.69	(273.65)
349			33600	Roads- Railroads & B	61,394.46	(3,174.10)
350	**000449 Total**				**11,882,053.79**	**(377,472.27)**
351	000452	STAIRS HE PLANT AND SUBSTATION	33000	Land - Hydro	2,231.07	-
352			33100	Struct/Improv Hydro	101,697.57	(2,420.41)
353			33110	Struc/Improv Prod.	79,323.63	(1,887.92)
354			33200	Reserv,- Dams & Wway	715,226.30	(25,726.14)
355			33210	Resvors,Dams, Wway P	336,766.21	(11,632.22)

356			33300	Water Wheels- Turb &	524,923.71	(13,048.29)
357			33400	Access. Electr. Equi	225,590.01	(4,994.33)
358			33600	Roads- Railroads & B	33,032.82	(1,678.07)
359	**000452 Total**				**2,018,791.32**	**(61,387.38)**
360	000454	WEBER HYDROELECTRIC STATION - PROJECT	33000	Land - Hydro	10,725.01	-
361			33100	Struct/Improv Hydro	230,138.32	(7,797.45)
362			33110	Struc/Improv Prod.	23,775.23	(286.93)
363			33130	Struc/Improv Recreat	148,291.09	(5,264.33)
364			33200	Reserv,- Dams & Wway	1,803,478.10	(70,612.50)
365			33210	Resvors,Dams, Wway P	244,491.64	(7,359.30)
366			33300	Water Wheels- Turb &	1,120,605.50	(46,393.07)
367			33400	Access. Electr. Equi	321,794.76	(31,265.20)
368			33500	Misc Power Plant Equ	22,270.09	(884.12)
369			33600	Roads- Railroads & B	39,856.53	(1,737.75)
370			35340	GSU and Assoc Equip	146,484.07	(2,548.82)
371	**000454 Total**				**4,111,910.34**	**(174,149.47)**
372	000455	ASHTON HE PLANT, SUBSTATION AND OFFICE -	33000	Land - Hydro	118,274.28	-
373			33010	Fee Land - Hydro	9,921.55	-
374			33020	Land Rights - Hydro	328,066.33	(9,153.05)
375			33100	Struct/Improv Hydro	377,816.49	(12,581.29)
376			33110	Struc/Improv Prod.	1,424,112.88	(45,942.61)
377			33120	Struc/Imprpv/ Fish/W	353,572.07	(11,773.95)
378			33200	Reserv,- Dams & Wway	357,098.16	(21,518.31)
379			33210	Resvors,Dams, Wway P	27,826,149.03	(1,720,041.30)
380			33300	Water Wheels- Turb &	2,055,202.83	(63,482.07)
381			33400	Access. Electr. Equi	1,303,551.72	(47,904.15)
382			33470	Access. Elect EquiSA	59,354.29	(2,237.66)
383			33500	Misc Power Plant Equ	8,192.17	(231.01)
384			33600	Roads- Railroads & B	5,524.92	(90.60)
385	**000455 Total**				**34,226,836.72**	**(1,934,956.00)**
386	000456	COVE HE PLANT AND SUBSTATION - PROJECT	33100	Struct/Improv Hydro	136,206.80	(4,208.78)
387			33110	Struc/Improv Prod.	12,532.24	(387.25)
388	**000456 Total**				**148,739.04**	**(4,596.03)**
389	000457	GRACE HE PLANT,SUBSTATION AND BUILDINGS	33010	Fee Land - Hydro	62,168.99	-
390			33100	Struct/Improv Hydro	1,124,429.48	(33,906.50)
391			33110	Struc/Improv Prod.	1,871,128.46	(55,508.72)
392			33130	Struc/Improv Recreat	49,031.38	(1,515.07)
393			33200	Reserv,- Dams & Wway	9,827,326.09	(305,917.29)
394			33210	Resvors,Dams, Wway P	3,737,588.80	(99,607.16)
395			33300	Water Wheels- Turb &	2,690,771.77	(93,399.59)
396			33400	Access. Electr. Equi	3,109,611.41	(116,297.32)
397			33470	Access. Elect EquiSA	4,229.14	(160.28)
398			33500	Misc Power Plant Equ	69,764.51	(1,905.15)
399			33600	Roads- Railroads & B	567,642.62	(16,268.40)
400			35340	GSU and Assoc Equip	1,375,865.08	(23,940.05)
401	**000457 Total**				**24,489,557.73**	**(748,425.53)**
402	000458	LIFTON PUMPING STATION AND SUBSTATION	33010	Fee Land - Hydro	1,501,189.49	-
403			33020	Land Rights - Hydro	20,758.93	(388.19)
404			33030	Water Rights - Hydro	24,129.94	(465.71)
405			33100	Struct/Improv Hydro	795,932.54	(22,286.13)
406			33110	Struc/Improv Prod.	452,850.22	(12,230.70)
407			33130	Struc/Improv Recreat	3,786.73	(106.03)

408			33200	Reserv,- Dams & Wway	1,823,198.92	(58,029.23)
409			33210	Resvors,Dams, Wway P	6,045,898.69	(191,366.68)
410			33220	Resvors, Dams,Wway F	410,760.28	(13,021.10)
411			33300	Water Wheels- Turb &	7,882,121.26	(325,401.03)
412			33400	Access. Electr. Equi	440,499.26	(14,656.47)
413			33500	Misc Power Plant Equ	12,063.43	(358.28)
414			33600	Roads- Railroads & B	225,326.60	(7,160.45)
415	**000458 Total**				**19,638,516.29**	**(645,470.00)**
416	000459	ONEIDA HE PLANT AND SUBSTATION - PROJECT	33000	Land - Hydro	23,462.72	-
417			33010	Fee Land - Hydro	247,171.68	-
418			33100	Struct/Improv Hydro	893,823.22	(28,269.13)
419			33110	Struc/Improv Prod.	1,373,681.32	(40,156.95)
420			33130	Struc/Improv Recreat	63,880.02	(1,973.89)
421			33200	Reserv,- Dams & Wway	1,812,229.08	(60,147.26)
422			33210	Resvors,Dams, Wway P	7,069,408.35	(222,471.88)
423			33300	Water Wheels- Turb &	13,149,124.22	(397,939.83)
424			33400	Access. Electr. Equi	2,379,915.87	(89,822.56)
425			33500	Misc Power Plant Equ	4,676.90	(154.41)
426			33600	Roads- Railroads & B	662,757.24	(19,485.06)
427			35340	GSU and Assoc Equip	965,047.34	(9,035.15)
428	**000459 Total**				**28,645,177.96**	**(869,456.12)**
429	000460	PARIS HYDROELECTRIC STATION	33000	Land - Hydro	1,806.01	-
430			33100	Struct/Improv Hydro	92,170.43	(9,364.52)
431			33110	Struc/Improv Prod.	17,667.40	(1,795.00)
432			33200	Reserv,- Dams & Wway	103,588.54	-
433			33210	Resvors,Dams, Wway P	15,054.28	-
434			33300	Water Wheels- Turb &	73,253.33	-
435			33400	Access. Electr. Equi	162,281.25	(7,951.77)
436			33500	Misc Power Plant Equ	417.22	-
437	**000460 Total**				**466,238.46**	**(19,111.29)**
438	000461	SODA HE PLANT AND SUBSTATION - PROJECT	33010	Fee Land - Hydro	505,203.54	-
439			33020	Land Rights - Hydro	5,879.43	(81.13)
440			33100	Struct/Improv Hydro	752,110.97	(22,766.91)
441			33110	Struc/Improv Prod.	634,552.67	(15,100.23)
442			33200	Reserv,- Dams & Wway	2,070,060.75	(68,754.38)
443			33210	Resvors,Dams, Wway P	9,022,503.73	(298,533.89)
444			33300	Water Wheels- Turb &	4,646,254.52	(162,618.90)
445			33400	Access. Electr. Equi	804,583.22	(29,636.04)
446			33500	Misc Power Plant Equ	4,734.34	(129.25)
447			35340	GSU and Assoc Equip	241,895.31	(4,208.98)
448	**000461 Total**				**18,687,778.48**	**(601,829.71)**
449	000462	ST. ANTHONY HE PLANT AND SUBSTATION - PR	33000	Land - Hydro	2,098.02	-
450	**000462 Total**				**2,098.02**	**-**
451	000463	GUNLOCK HE PLANT AND SUBSTATION	33010	Fee Land - Hydro	1,643.97	-
452			33100	Struct/Improv Hydro	36,443.67	(1,840.40)
453			33200	Reserv,- Dams & Wway	194,578.08	(9,573.24)
454			33300	Water Wheels- Turb &	158,748.56	(7,048.44)
455			33400	Access. Electr. Equi	286,709.07	(15,654.32)
456			33500	Misc Power Plant Equ	4,550.48	(164.73)
457			33600	Roads- Railroads & B	371.17	(6.64)
458	**000463 Total**				**683,045.00**	**(34,287.77)**
459	000464	VEYO HE PLANT, SUBSTATION, OFFICE AND SH	33010	Fee Land - Hydro	2,715.59	-

460			33100	Struct/Improv Hydro	59,842.14	(3,022.02)
461			33110	Struc/Improv Prod.	29,120.28	(1,470.57)
462			33200	Reserv,- Dams & Wway	202,318.91	(10,165.30)
463			33210	Resvors,Dams, Wway P	301,679.91	(12,966.18)
464			33300	Water Wheels- Turb &	144,098.09	(6,397.95)
465			33400	Access. Electr. Equi	174,350.50	(9,519.56)
466			33500	Misc Power Plant Equ	3,402.00	(123.15)
467			33600	Roads- Railroads & B	19,076.23	(341.46)
468	**000464 Total**				**936,603.65**	**(44,006.19)**
469	000465	SAND COVE HE PLANT AND SUBSTATION	33010	Fee Land - Hydro	1,187.66	-
470			33100	Struct/Improv Hydro	21,989.79	(1,110.49)
471			33110	Struc/Improv Prod.	37,884.89	(1,652.03)
472			33200	Reserv,- Dams & Wway	480,327.62	(22,126.47)
473			33210	Resvors,Dams, Wway P	194,007.99	(9,545.18)
474			33300	Water Wheels- Turb &	161,508.12	(7,170.96)
475			33400	Access. Electr. Equi	254,766.62	(13,431.41)
476			33600	Roads- Railroads & B	2,058.71	(36.85)
477	**000465 Total**				**1,153,731.40**	**(55,073.39)**
478	000467	VIVA NAUGHTON H. E. PLANT	33100	Struct/Improv Hydro	367,978.75	(7,911.55)
479			33110	Struc/Improv Prod.	35,246.18	(757.79)
480			33200	Reserv,- Dams & Wway	91,817.07	(1,873.07)
481			33210	Resvors,Dams, Wway P	11,689.92	(238.47)
482			33300	Water Wheels- Turb &	497,437.95	(11,242.09)
483			33400	Access. Electr. Equi	207,350.74	(5,453.33)
484			33500	Misc Power Plant Equ	20,594.26	(471.61)
485	**000467 Total**				**1,232,114.87**	**(27,947.91)**
486	000468	LAST CHANCE CANAL H. E. PLANT	33000	Land - Hydro	79.13	-
487			33100	Struct/Improv Hydro	382,915.37	(13,519.57)
488			33110	Struc/Improv Prod.	109,452.91	(2,898.22)
489			33200	Reserv,- Dams & Wway	630,881.84	(25,424.54)
490			33210	Resvors,Dams, Wway P	326,798.29	(13,169.97)
491			33300	Water Wheels- Turb &	1,395,661.68	(46,754.66)
492			33400	Access. Electr. Equi	265,771.54	(13,369.93)
493			33600	Roads- Railroads & B	65,286.71	(2,004.30)
494	**000468 Total**				**3,176,847.47**	**(117,141.19)**
495	000559	ONEIDA HYDRO PLANT - NON-PROJECT	33000	Land - Hydro	13,235.41	-
496			33100	Struct/Improv Hydro	4,042.44	(124.91)
497			33400	Access. Electr. Equi	150,642.32	(5,709.34)
498			35340	GSU and Assoc Equip	31,900.00	(555.06)
499	**000559 Total**				**199,820.17**	**(6,389.31)**
500	000561	SODA HYDRO PLANT - NON-PROJECT	33200	Reserv,- Dams & Wway	9,094.58	(301.03)
501	**000561 Total**				**9,094.58**	**(301.03)**
502	001307	LAVA DEVELOPMENT	33010	Fee Land - Hydro	20,282.21	-
503	**001307 Total**				**20,282.21**	**-**
504	001312	MINK DEVELOPMENT	33010	Fee Land - Hydro	11,553.46	-
505	**001312 Total**				**11,553.46**	**-**
506	013000	FALL CREEK HYDRO PLANT - OR	33010	Fee Land - Hydro	580.58	-
507			33020	Land Rights - Hydro	600.00	(42.12)
508			33040	Flood Rights - Hydro	150.00	(7.91)
509			33100	Struct/Improv Hydro	2,841.83	(223.65)
510			33210	Resvors,Dams, Wway P	149,444.13	(8,652.82)
511			33400	Access. Electr. Equi	5,872.08	(488.56)

512	**013000 Total**				**159,488.62**	**(9,415.06)**
513	015000	KENO REGULATING DAM	33010	Fee Land - Hydro	104,360.98	-
514			33020	Land Rights - Hydro	14,002.12	(982.94)
515			33100	Struct/Improv Hydro	4,191.20	(329.85)
516			33120	Struc/Imprpv/ Fish/W	9,635.61	(758.32)
517			33130	Struc/Improv Recreat	297,020.41	(23,375.47)
518			33210	Resvors,Dams, Wway P	6,796,776.90	(393,533.38)
519			33220	Resvors, Dams,Wway F	254,974.11	(14,763.00)
520			33400	Access. Electr. Equi	17,509.74	(1,456.81)
521			33470	Access. Elect EquiSA	13,492.71	(1,122.59)
522			33600	Roads- Railroads & B	172,097.39	(12,752.42)
523	**015000 Total**				**7,684,061.17**	**(449,074.78)**
524	015058	CANYON LANDS DISTRICT SERVICE CENTER	34400	Generators	36,389.01	-
525	**015058 Total**				**36,389.01**	**-**
526	016000	EAST SIDE HYDRO PLANT	33010	Fee Land - Hydro	12,255.91	-
527			33110	Struc/Improv Prod.	179,048.41	(14,091.13)
528			33210	Resvors,Dams, Wway P	1,500,211.64	(86,862.24)
529			33300	Water Wheels- Turb &	103,157.52	(6,024.41)
530			33400	Access. Electr. Equi	101,063.75	(8,408.49)
531			33470	Access. Elect EquiSA	18,205.47	(1,514.70)
532			33510	Misc PPlt Equip Prod	11,212.42	(775.90)
533			33600	Roads- Railroads & B	66,539.46	(4,930.58)
534	**016000 Total**				**1,991,694.58**	**(122,607.45)**
535	017000	WEST SIDE HYDRO PLANT	33010	Fee Land - Hydro	38,838.93	-
536			33110	Struc/Improv Prod.	120,177.63	(9,458.00)
537			33130	Struc/Improv Recreat	7,863.15	(618.83)
538			33210	Resvors,Dams, Wway P	260,145.05	(10,312.60)
539			33300	Water Wheels- Turb &	46,708.72	(2,727.80)
540			33400	Access. Electr. Equi	35,249.22	(2,932.73)
541			33600	Roads- Railroads & B	62,401.59	(4,623.96)
542	**017000 Total**				**571,384.29**	**(30,673.92)**
543	018000	JC BOYLE HYDRO PLANT	33010	Fee Land - Hydro	25,845.33	-
544			33100	Struct/Improv Hydro	-	-
545			33110	Struc/Improv Prod.	3,072,202.42	(8,984.96)
546			33120	Struc/Imprpv/ Fish/W	682,116.50	(1,200,171.00)
547			33130	Struc/Improv Recreat	53,311.28	29,805.46
548			33210	Resvors,Dams, Wway P	13,785,137.66	(372,215.22)
549			33220	Resvors, Dams,Wway F	2,115,877.97	(2,812,111.45)
550			33300	Water Wheels- Turb &	8,618,283.35	(1,526,667.11)
551			33400	Access. Electr. Equi	5,954,363.12	1,559,169.27
552			33470	Access. Elect EquiSA	906,455.08	506,784.01
553			33510	Misc PPlt Equip Prod	152,370.83	49,692.04
554			33600	Roads- Railroads & B	972,360.15	(126,467.21)
555	**018000 Total**				**36,338,323.69**	**(3,901,166.17)**
556	019000	KLAMATH LAKE RESERVOIR	33010	Fee Land - Hydro	2,551.12	-
557			33020	Land Rights - Hydro	624,390.84	(43,832.24)
558			33040	Flood Rights - Hydro	235,149.03	(12,392.35)
559			33110	Struc/Improv Prod.	22,113.17	(1,740.31)
560			33130	Struc/Improv Recreat	23,489.91	(1,848.65)
561			33210	Resvors,Dams, Wway P	2,372,473.15	(136,809.61)
562			33400	Access. Electr. Equi	532,530.64	(43,927.58)
563			33510	Misc PPlt Equip Prod	50,575.16	(3,499.80)

564			33600	Roads- Railroads & B	1,144.12	(84.78)
565	**019000 Total**				**3,864,417.14**	**(244,135.32)**
566	023000	BEND HYDRO PLANT	33010	Fee Land - Hydro	4,858.66	-
567			33110	Struc/Improv Prod.	52,126.83	(1,066.59)
568			33130	Struc/Improv Recreat	10,202.17	(213.23)
569			33210	Resvors,Dams, Wway P	1,926,718.08	(253,175.72)
570			33230	Resvors,Dams,Wway Re	1,906.62	(336.33)
571			33300	Water Wheels- Turb &	402,616.43	(27,248.88)
572			33400	Access. Electr. Equi	101,824.27	(3,263.79)
573			33470	Access. Elect EquiSA	535,126.61	(18,889.97)
574			33510	Misc PPlt Equip Prod	15,383.82	(519.97)
575			33600	Roads- Railroads & B	174.40	-
576	**023000 Total**				**3,050,937.89**	**(304,714.48)**
577	029000	WALLOWA FALLS HYDRO PLANT	33010	Fee Land - Hydro	2,111.53	-
578			33110	Struc/Improv Prod.	104,573.22	(4,611.69)
579			33130	Struc/Improv Recreat	63,873.72	(2,816.83)
580			33210	Resvors,Dams, Wway P	1,420,288.85	(45,459.48)
581			33300	Water Wheels- Turb &	806,659.87	(73,406.03)
582			33400	Access. Electr. Equi	789,932.02	(37,266.59)
583			33470	Access. Elect EquiSA	443.61	(22.13)
584			33600	Roads- Railroads & B	649,143.03	(30,899.21)
585			35340	GSU and Assoc Equip	17,149.81	(298.41)
586	**029000 Total**				**3,854,175.66**	**(194,780.37)**
587	031000	PROSPECT #1 HYDRO PLANT	33010	Fee Land - Hydro	3,022.48	-
588			33110	Struc/Improv Prod.	2,045,507.87	(56,660.54)
589			33120	Struc/Imprpv/ Fish/W	16,254.48	(450.25)
590			33130	Struc/Improv Recreat	-	-
591			33210	Resvors,Dams, Wway P	1,807,772.12	(59,114.14)
592			33300	Water Wheels- Turb &	508,870.26	(16,182.08)
593			33400	Access. Electr. Equi	911,858.19	(30,456.08)
594			33600	Roads- Railroads & B	50,178.59	(1,425.06)
595	**031000 Total**				**5,343,463.99**	**(164,288.15)**
596	031100	PROSPECT #1 HYDRO NON-PROJECT	33010	Fee Land - Hydro	988.19	-
597	**031100 Total**				**988.19**	**-**
598	032000	PROSPECT #2 HYDRO PLANT	33010	Fee Land - Hydro	93,276.18	-
599			33020	Land Rights - Hydro	3,711.84	(74.98)
600			33040	Flood Rights - Hydro	3,166.96	(43.07)
601			33110	Struc/Improv Prod.	3,832,079.77	(99,684.11)
602			33120	Struc/Imprpv/ Fish/W	498,829.08	(13,817.57)
603			33130	Struc/Improv Recreat	69,385.31	(1,921.96)
604			33210	Resvors,Dams, Wway P	35,468,749.03	(1,150,323.74)
605			33220	Resvors, Dams,Wway F	191,496.57	(6,261.92)
606			33300	Water Wheels- Turb &	2,332,189.48	(74,130.43)
607			33400	Access. Electr. Equi	4,954,852.16	(165,492.07)
608			33470	Access. Elect EquiSA	80,176.09	(2,677.88)
609			33510	Misc PPlt Equip Prod	19,027.06	(580.33)
610			33600	Roads- Railroads & B	538,436.29	(14,396.96)
611	**032000 Total**				**48,085,375.82**	**(1,529,405.02)**
612	032100	PROSPECT #2 HYDRO NON-PROJECT	33010	Fee Land - Hydro	5,013.08	-
613	**032100 Total**				**5,013.08**	**-**
614	033000	PROSPECT #3 HYDRO PLANT	33010	Fee Land - Hydro	37,958.68	-
615			33110	Struc/Improv Prod.	629,968.95	(34,251.71)

616			33120	Struc/Imprpv/ Fish/W	4,433.04	(242.04)	
617			33130	Struc/Improv Recreat	1,637.56	(89.41)	
618			33210	Resvors,Dams, Wway P	2,580,237.12	(103,782.37)	
619			33220	Resvors, Dams,Wway F	2,087,334.37	(86,511.92)	
620			33300	Water Wheels- Turb &	1,927,911.61	(90,672.00)	
621			33400	Access. Electr. Equi	1,886,802.78	(99,057.18)	
622			33510	Misc PPlt Equip Prod	62,714.94	(2,646.57)	
623			33600	Roads- Railroads & B	125,995.54	(3,805.50)	
624	**033000 Total**				**9,344,994.59**	**(421,058.70)**	
625	033100	PROSPECT #3 HYDRO NON-PROJECT	33010	Fee Land - Hydro	3,389.87	-	
626			33120	Struc/Imprpv/ Fish/W	10,517.23	(574.24)	
627	**033100 Total**				**13,907.10**	**(574.24)**	
628	034000	PROSPECT #4 HYDRO PLANT	33110	Struc/Improv Prod.	63,558.55	(1,760.56)	
629			33130	Struc/Improv Recreat	9,312.00	(257.94)	8,677,601.33
630			33210	Resvors,Dams, Wway P	111,611.27	(3,649.69)	
631			33300	Water Wheels- Turb &	1,381,398.45	(43,928.47)	
632			33400	Access. Electr. Equi	843,912.11	(28,186.66)	
633			33600	Roads- Railroads & B	108,334.86	(2,369.91)	
634	**034000 Total**				**2,518,127.24**	**(80,153.23)**	
635	036000	EAGLE POINT HYDRO PLANT	33010	Fee Land - Hydro	291.76	-	
636			33020	Land Rights - Hydro	12,122.48	-	
637			33110	Struc/Improv Prod.	179,421.91	(1,960.12)	
638			33210	Resvors,Dams, Wway P	1,258,263.46	(15,770.24)	
639			33220	Resvors, Dams,Wway F	25,994.53	(324.93)	
640			33300	Water Wheels- Turb &	251,541.42	(779.77)	
641			33400	Access. Electr. Equi	135,492.79	(3,631.21)	
642			33600	Roads- Railroads & B	178,281.91	(5,277.14)	
643	**036000 Total**				**2,041,410.26**	**(27,743.41)**	
644	040000	LEMOLO #1 HYDRO PLANT	33110	Struc/Improv Prod.	1,262,501.41	(47,852.32)	
645			33120	Struc/Imprpv/ Fish/W	1,504,988.83	(57,490.58)	
646			33130	Struc/Improv Recreat	183,829.77	(7,022.30)	
647			33210	Resvors,Dams, Wway P	16,070,193.08	(458,638.46)	
648			33220	Resvors, Dams,Wway F	-	-	
649			33300	Water Wheels- Turb &	4,030,572.91	(131,799.73)	
650			33400	Access. Electr. Equi	2,667,261.11	(100,022.30)	
651			33470	Access. Elect EquiSA	-	-	
652			33510	Misc PPlt Equip Prod	28,956.51	(883.17)	
653			33600	Roads- Railroads & B	531,800.86	(13,346.34)	
654	**040000 Total**				**26,280,104.48**	**(817,055.20)**	
655	041000	LEMOLO #2 HYDRO PLANT	33110	Struc/Improv Prod.	1,726,401.46	(65,948.53)	
656			33120	Struc/Imprpv/ Fish/W	4,567,453.33	(174,476.71)	
657			33130	Struc/Improv Recreat	2,462.10	(94.05)	
658			33200	Reserv,- Dams & Wway	80,528.69	(2,365.67)	
659			33210	Resvors,Dams, Wway P	32,748,244.09	(949,670.32)	
660			33220	Resvors, Dams,Wway F	50,493.07	(1,464.30)	
661			33300	Water Wheels- Turb &	7,647,544.21	(250,074.70)	
662			33400	Access. Electr. Equi	4,203,073.27	(157,266.60)	
663			33470	Access. Elect EquiSA	-	-	
664			33510	Misc PPlt Equip Prod	7,352.71	(224.26)	
665			33600	Roads- Railroads & B	1,820,579.61	(49,701.82)	
666	**041000 Total**				**52,854,132.54**	**(1,651,286.96)**	
667	042000	CLEARWATER #1 HYDRO PLANT	33110	Struc/Improv Prod.	694,896.25	(26,370.54)	

668			33120	Struc/Imprpv/ Fish/W	812,288.87	(31,029.42)
669			33210	Resvors,Dams, Wway P	5,185,179.30	(150,383.98)
670			33220	Resvors, Dams,Wway F	-	-
671			33300	Water Wheels- Turb &	887,852.63	(29,032.79)
672			33400	Access. Electr. Equi	512,122.10	(18,556.58)
673			33470	Access. Elect EquiSA	21,509.64	(806.61)
674			33510	Misc PPlt Equip Prod	3,559.89	(108.58)
675			33600	Roads- Railroads & B	50,817.36	(1,387.32)
676	**042000 Total**				**8,168,226.04**	**(257,675.82)**
677	043000	CLEARWATER #2 HYDRO PLANT	33110	Struc/Improv Prod.	1,582,040.31	(60,442.22)
678			33120	Struc/Imprpv/ Fish/W	860,346.27	(32,865.22)
679			33130	Struc/Improv Recreat	6,924.89	(264.53)
680			33210	Resvors,Dams, Wway P	14,809,834.94	(429,799.74)
681			33220	Resvors, Dams,Wway F	-	-
682			33300	Water Wheels- Turb &	1,208,161.42	(39,506.88)
683			33400	Access. Electr. Equi	968,050.63	(35,863.86)
684			33470	Access. Elect EquiSA	33,515.50	(1,256.84)
685			33510	Misc PPlt Equip Prod	4,719.80	(143.95)
686			33600	Roads- Railroads & B	250,151.07	(6,829.13)
687			35340	GSU and Assoc Equip	737,899.10	(6,954.50)
688	**043000 Total**				**20,461,643.93**	**(613,926.87)**
689	044000	TOKETEE HYDRO PLANT	33110	Struc/Improv Prod.	3,999,104.83	(148,146.94)
690			33130	Struc/Improv Recreat	519,357.33	(19,839.45)
691			33210	Resvors,Dams, Wway P	12,765,379.81	(370,824.45)
692			33220	Resvors, Dams,Wway F	60,347.47	(1,750.08)
693			33300	Water Wheels- Turb &	4,002,313.61	(127,548.87)
694			33400	Access. Electr. Equi	2,184,224.49	(73,758.44)
695			33470	Access. Elect EquiSA	48,647.43	(1,824.28)
696			33510	Misc PPlt Equip Prod	50,114.19	(1,528.48)
697			33600	Roads- Railroads & B	502,951.97	(13,730.59)
698	**044000 Total**				**24,132,441.13**	**(758,951.58)**
699	045000	FISH CREEK HYDRO PLANT	33110	Struc/Improv Prod.	936,563.45	(35,776.72)
700			33120	Struc/Imprpv/ Fish/W	828,371.50	(31,643.79)
701			33210	Resvors,Dams, Wway P	8,316,805.60	(241,175.14)
702			33220	Resvors, Dams,Wway F	4,145,556.62	(120,213.39)
703			33300	Water Wheels- Turb &	1,141,886.87	(37,339.69)
704			33400	Access. Electr. Equi	1,844,125.89	(69,154.73)
705			33510	Misc PPlt Equip Prod	7,330.72	(223.59)
706			33600	Roads- Railroads & B	533,014.64	(14,551.30)
707	**045000 Total**				**17,753,655.29**	**(550,078.35)**
708	046000	SODA SPRINGS HYDRO PLANT	33110	Struc/Improv Prod.	1,273,731.39	(44,694.82)
709			33120	Struc/Imprpv/ Fish/W	2,895,052.00	(110,483.86)
710			33130	Struc/Improv Recreat	261,918.08	(10,005.27)
711			33210	Resvors,Dams, Wway P	90,417,551.08	(2,617,685.56)
712			33300	Water Wheels- Turb &	1,323,465.83	(43,277.31)
713			33400	Access. Electr. Equi	1,316,136.71	(47,228.82)
714			33470	Access. Elect EquiSA	34,721.68	(1,302.06)
715			33510	Misc PPlt Equip Prod	20,132.96	(614.06)
716			33600	Roads- Railroads & B	2,089,011.67	(57,030.01)
717	**046000 Total**				**99,631,721.40**	**(2,932,321.77)**
718	047000	SLIDE CREEK HYDRO PLANT	33110	Struc/Improv Prod.	1,252,787.31	(45,561.44)
719			33120	Struc/Imprpv/ Fish/W	1,020,583.43	(38,986.29)

720			33210	Resvors,Dams, Wway P	14,933,839.54	(431,824.02)
721			33300	Water Wheels- Turb &	5,726,528.59	(187,008.25)
722			33400	Access. Electr. Equi	3,200,843.27	(119,652.05)
723			33470	Access. Elect EquiSA	66,243.91	(2,484.15)
724			33510	Misc PPlt Equip Prod	3,784.98	(115.44)
725			33600	Roads- Railroads & B	582,652.89	(15,906.43)
726	**047000 Total**				**26,787,263.92**	**(841,538.07)**
727	048000	NORTH UMPQUA HYDRO-GENL	33110	Struc/Improv Prod.	7,998,698.17	(295,869.20)
728			33120	Struc/Imprpv/ Fish/W	656,568.27	(25,080.91)
729			33130	Struc/Improv Recreat	182,575.27	(6,974.38)
730			33210	Resvors,Dams, Wway P	1,259,605.12	(35,995.87)
731			33300	Water Wheels- Turb &	61,993.99	-
732			33400	Access. Electr. Equi	2,732,826.30	(101,920.11)
733			33470	Access. Elect EquiSA	229,132.26	(8,608.38)
734			33500	Misc Power Plant Equ	-	-
735			33510	Misc PPlt Equip Prod	595,805.46	(18,172.07)
736			33600	Roads- Railroads & B	3,697,909.18	(100,958.57)
737	**048000 Total**				**17,415,114.02**	**(593,579.49)**
738	119850	OREGON HIGH DESERT SOLAR GENERATING	34400	Generators	56,321.97	-
739	**119850 Total**				**56,321.97**	**-**
740	122350	WEST SIDE MOBILE GENERATION EQUIPMENT	34400	Generators	849,226.01	(15,286.07)
741	**122350 Total**				**849,226.01**	**(15,286.07)**
742	129500	HERMISTON U.S. GENERATING PROJECT	34010	Fee Land - Other	796,928.90	-
743			34100	Structures & Improve	12,865,750.93	(372,504.87)
744			34200	Fuel Hldrs,Prdcr, Ac	25,321.62	(779.91)
745			34300	Prime Movers	113,770,313.53	(3,875,460.01)
746			34400	Generators	42,343,523.14	(1,336,544.03)
747			34500	Access Elec Equip	9,781,187.95	(281,312.55)
748			34600	Misc. Pwr Plt Eqp	212,621.54	(6,038.46)
749			35340	GSU and Assoc Equip	4,766,277.59	(82,933.24)
750	**129500 Total**				**184,561,925.20**	**(5,955,573.07)**
751	129600	LEANING JUNIPER 1 WIND PLANT	34100	Structures & Improve	4,985,629.87	(168,859.82)
752			34300	Prime Movers	151,388,043.96	(5,088,724.01)
753			34400	Generators	8,506,173.04	(208,144.90)
754			34500	Access Elec Equip	9,512,344.25	(301,565.26)
755			34600	Misc. Pwr Plt Eqp	81,035.73	(2,560.73)
756			35340	GSU and Assoc Equip	3,233,153.07	(41,010.38)
757	**129600 Total**				**177,706,379.92**	**(5,810,865.10)**
758	137500	BLACK CAP SOLAR FACILITY	34010	Fee Land - Other	74,985.87	-
759	**137500 Total**				**74,985.87**	**-**
760	203300	CHEHALIS PLANT COMMON & SUBSTATION	34010	Fee Land - Other	1,973,790.62	-
761			34030	Water Rights - Other	1,756,736.02	-
762			34100	Structures & Improve	24,526,599.99	(648,788.02)
763			34200	Fuel Hldrs,Prdcr, Ac	1,597,345.52	(45,843.82)
764			34300	Prime Movers	15,147,972.13	(446,512.26)
765			34500	Access Elec Equip	38,588,536.43	(1,036,517.84)
766			34600	Misc. Pwr Plt Eqp	3,268,830.29	(86,950.88)
767			35340	GSU and Assoc Equip	12,401,910.76	(215,793.26)
768	**203300 Total**				**99,261,721.76**	**(2,480,406.08)**
769	203301	CHEHALIS COMBUSTION TURBINE A	34300	Prime Movers	38,377,039.79	(1,164,321.34)
770			34400	Generators	7,410,029.25	(217,854.85)
771	**203301 Total**				**45,787,069.04**	**(1,382,176.19)**

772	203302	CHEHALIS COMBUSTION TURBINE B	34300	Prime Movers	41,012,878.38	(1,245,571.57)
773			34400	Generators	7,178,305.78	(211,042.19)
774	**203302 Total**				**48,191,184.16**	**(1,456,613.76)**
775	203303	CHEHALIS STEAM TURBINE	34300	Prime Movers	121,482,554.80	(3,694,409.13)
776			34400	Generators	55,595,301.16	(1,633,064.66)
777	**203303 Total**				**177,077,855.96**	**(5,327,473.79)**
778	205100	GOODNOE HILLS WIND PLANT COMMON	34100	Structures & Improve	5,502,586.61	(188,723.83)
779	**205100 Total**				**5,502,586.61**	**(188,723.83)**
780	205200	GOODNOE HILLS WIND PLANT UNIT 1	34300	Prime Movers	135,339,766.31	(5,367,526.48)
781			34400	Generators	7,173,098.82	(150,716.12)
782			34500	Access Elec Equip	7,434,455.97	(363,261.63)
783			34600	Misc. Pwr Plt Eqp	171,923.00	(5,518.73)
784			35340	GSU and Assoc Equip	3,357,434.87	(58,419.37)
785	**205200 Total**				**153,476,678.97**	**(5,945,442.33)**
786	206100	MARENGO WIND PLANT COMMON	34100	Structures & Improve	6,557,256.78	(227,029.34)
787			34300	Prime Movers	1,746,899.47	(56,514.21)
788			34400	Generators	1,153,638.73	(38,300.81)
789			34500	Access Elec Equip	255,235.57	(7,625.59)
790			34600	Misc. Pwr Plt Eqp	178,008.87	(5,785.29)
791	**206100 Total**				**9,891,039.42**	**(335,255.24)**
792	206110	MARENGO WIND PLANT UNIT 1	34100	Structures & Improve	56,451.13	(1,066.53)
793			34300	Prime Movers	215,612,586.17	(7,131,618.90)
794			34400	Generators	8,328,702.54	(244,664.59)
795			34500	Access Elec Equip	14,134,102.87	(458,799.53)
796	**206110 Total**				**238,131,842.71**	**(7,836,149.55)**
797	206120	MARENGO WIND PLANT UNIT 2	34100	Structures & Improve	3,964,143.38	(137,329.34)
798			34300	Prime Movers	113,034,703.13	(3,752,855.68)
799			34400	Generators	4,053,798.22	(120,755.71)
800			34500	Access Elec Equip	5,797,966.08	(187,616.59)
801			34600	Misc. Pwr Plt Eqp	174,276.00	(5,663.97)
802	**206120 Total**				**127,024,886.81**	**(4,204,221.29)**
803	215000	MERWIN HYDRO PLANT	33010	Fee Land - Hydro	475,824.59	-
804			33020	Land Rights - Hydro	300,510.01	(1,502.55)
805			33030	Water Rights - Hydro	20,872.12	(423.70)
806			33050	Land Rights - Fish/W	212,279.74	(1,018.94)
807			33100	Struct/Improv Hydro	-	(7.26)
808			33110	Struc/Improv Prod.	9,880,156.08	(193,629.11)
809			33120	Struc/Imprpv/ Fish/W	71,548,797.62	(1,509,135.12)
810			33130	Struc/Improv Recreat	4,138,510.80	(86,973.30)
811			33210	Resvors,Dams, Wway P	20,642,286.85	(338,446.66)
812			33220	Resvors, Dams,Wway F	12,179,359.00	(222,881.05)
813			33230	Resvors,Dams,Wway Re	34,975.04	(554.12)
814			33300	Water Wheels- Turb &	7,978,505.81	(113,390.01)
815			33400	Access. Electr. Equi	7,225,672.90	(168,977.67)
816			33470	Access. Elect EquiSA	97,836.17	(2,289.37)
817			33510	Misc PPlt Equip Prod	120,063.83	(2,485.32)
818			33520	Misc PPlt Equippm FW	-	-
819			33600	Roads- Railroads & B	2,187,843.43	(34,719.18)
820			35340	GSU and Assoc Equip	2,145,545.45	(37,108.85)
821	**215000 Total**				**139,189,039.44**	**(2,713,542.21)**
822	215100	CRESAP BAY PARK - LEWIS RIVER	33130	Struc/Improv Recreat	5,447,424.11	(114,907.24)
823			33230	Resvors,Dams,Wway Re	60,965.44	(1,179.99)

824			33600	Roads- Railroads & B	1,441,160.49	(23,346.80)
825	**215100 Total**				**6,949,550.04**	**(139,434.03)**
826	215300	LEWIS RIVER GENERAL	33010	Fee Land - Hydro	725,567.38	-
827			33110	Struc/Improv Prod.	1,229,901.98	(25,950.94)
828			33120	Struc/Imprpv/ Fish/W	4,159,504.74	(87,765.55)
829			33130	Struc/Improv Recreat	438,560.89	(9,253.63)
830			33160	Struct. - Lease Impr	14,658,988.95	(311,695.72)
831			33200	Reserv,- Dams & Wway	(20,235.39)	(477.06)
832			33300	Water Wheels- Turb &	463,788.26	(6,678.55)
833			33400	Access. Electr. Equi	3,138,887.90	(73,235.75)
834			33510	Misc PPlt Equip Prod	48,468.70	(1,003.30)
835			33600	Roads- Railroads & B	563,723.93	(9,132.33)
836	**215300 Total**				**25,407,157.34**	**(525,192.83)**
837	218000	SWIFT HYDRO #1 PLANT	33010	Fee Land - Hydro	11,537,429.74	-
838			33020	Land Rights - Hydro	6,277,412.59	(53,985.75)
839			33050	Land Rights - Fish/W	97,228.11	(855.61)
840			33100	Struct/Improv Hydro	-	-
841			33110	Struc/Improv Prod.	6,268,837.36	(140,396.91)
842			33120	Struc/Imprpv/ Fish/W	63,306,686.52	(1,452,061.76)
843			33130	Struc/Improv Recreat	1,961,004.03	(35,060.61)
844			33200	Reserv,- Dams & Wway	3,664,838.06	(51,666.68)
845			33210	Resvors,Dams, Wway P	45,631,513.22	(614,847.18)
846			33230	Resvors,Dams,Wway Re	110,283.47	(1,543.97)
847			33300	Water Wheels- Turb &	16,798,780.08	(273,044.77)
848			33400	Access. Electr. Equi	7,787,688.29	(177,175.80)
849			33470	Access. Elect EquiSA	328,073.83	(7,512.90)
850			33510	Misc PPlt Equip Prod	409,705.28	(5,981.70)
851			33530	Misc PPlt Equippm RC	-	-
852			33600	Roads- Railroads & B	1,319,864.78	(26,133.33)
853			35340	GSU and Assoc Equip	3,565,636.19	(61,719.02)
854	**218000 Total**				**169,064,981.55**	**(2,901,985.99)**
855	219000	YALE HYDRO PLANT	33010	Fee Land - Hydro	7,418,449.94	-
856			33020	Land Rights - Hydro	761,579.86	(6,244.96)
857			33110	Struc/Improv Prod.	11,020,410.13	(175,465.96)
858			33120	Struc/Imprpv/ Fish/W	3,710.40	(59.37)
859			33130	Struc/Improv Recreat	6,738,590.25	(107,674.20)
860			33210	Resvors,Dams, Wway P	35,640,545.29	(475,220.32)
861			33220	Resvors, Dams,Wway F	43,164.08	(604.30)
862			33300	Water Wheels- Turb &	13,699,710.95	(223,174.35)
863			33400	Access. Electr. Equi	3,852,080.77	(80,095.28)
864			33470	Access. Elect EquiSA	110,528.44	(2,365.31)
865			33510	Misc PPlt Equip Prod	743,438.56	(9,255.20)
866			33600	Roads- Railroads & B	2,045,630.90	(36,003.13)
867			35340	GSU and Assoc Equip	1,776,324.67	(30,908.05)
868	**219000 Total**				**83,854,164.24**	**(1,147,070.43)**
869	219100	NONPROJECT LANDS - YALE	33010	Fee Land - Hydro	182,983.32	-
870	**219100 Total**				**182,983.32**	**-**
871	401000	COLSTRIP STEAM PLT	31010	Fee Land - Steam	1,788,644.22	-
872			31100	Struct.&Improv. Th	68,684,662.79	(1,190,492.30)
873			31200	Boiler Plant Equipm.	123,226,692.45	(2,743,378.23)
874			31400	Turbogenerator Units	39,413,100.31	(1,016,561.90)
875			31500	Access. Electr. Equi	9,471,995.82	(171,335.75)

876			31600	Misc.PwPlnt Equipm.	481,368.31	(12,607.28)
877			35340	GSU and Assoc Equip	1,969,943.43	(31,938.63)
878	**401000 Total**				**245,036,407.33**	**(5,166,314.09)**
879	410000	BIG FORK HYDRO PLANT	33010	Fee Land - Hydro	6,044.31	-
880			33110	Struc/Improv Prod.	400,673.16	(5,649.46)
881			33130	Struc/Improv Recreat	356,908.60	(5,032.40)
882			33200	Reserv,- Dams & Wway	2,502,005.91	(32,286.59)
883			33210	Resvors,Dams, Wway P	3,374,385.47	(42,781.81)
884			33220	Resvors, Dams,Wway F	87,666.66	(1,130.90)
885			33230	Resvors,Dams,Wway Re	2,431.29	(31.36)
886			33300	Water Wheels- Turb &	1,577,420.30	(22,922.50)
887			33400	Access. Electr. Equi	931,051.20	(14,151.98)
888			33600	Roads- Railroads & B	504,453.23	(10,744.85)
889	**410000 Total**				**9,743,040.13**	**(134,731.85)**
890	502001	ATLANTIC CITY REMOTE SOLAR PANEL	34400	Generators	5,545.93	(227.94)
891	**502001 Total**				**5,545.93**	**(227.94)**
892	505100	GLENROCK WIND PLANT COMMON	34010	Fee Land - Other	704,284.76	-
893			34100	Structures & Improve	2,637,372.43	(91,178.60)
894			34300	Prime Movers	1,309,056.28	(85,887.57)
895			34400	Generators	-	(2,744.15)
896			34500	Access Elec Equip	156,479.31	(5,199.16)
897			34600	Misc. Pwr Plt Eqp	508,606.88	(16,682.30)
898			35340	GSU and Assoc Equip	5,994,040.61	(103,869.53)
899	**505100 Total**				**11,309,840.27**	**(305,561.31)**
900	505110	GLENROCK WIND PLANT UNIT 1	34100	Structures & Improve	3,258,302.40	(115,018.07)
901			34300	Prime Movers	165,360,650.65	(5,912,879.03)
902			34400	Generators	8,514,164.06	(210,036.63)
903			34500	Access Elec Equip	11,633,616.76	(380,858.71)
904			34600	Misc. Pwr Plt Eqp	497,663.00	(16,323.35)
905	**505110 Total**				**189,264,396.87**	**(6,635,115.79)**
906	505120	ROLLING HILLS WIND PLANT	34100	Structures & Improve	3,478,252.15	(122,782.31)
907			34300	Prime Movers	169,676,643.16	(5,985,151.29)
908			34400	Generators	7,850,216.85	(211,332.75)
909			34500	Access Elec Equip	12,436,382.67	(407,251.57)
910			34600	Misc. Pwr Plt Eqp	659,497.00	(21,631.50)
911	**505120 Total**				**194,100,991.83**	**(6,748,149.42)**
912	505130	GLENROCK WIND PLANT UNIT 3	34100	Structures & Improve	1,361,005.58	(48,043.50)
913			34300	Prime Movers	69,763,377.86	(2,593,758.85)
914			34400	Generators	3,154,501.00	(84,884.63)
915			34500	Access Elec Equip	5,683,917.68	(186,764.34)
916	**505130 Total**				**79,962,802.12**	**(2,913,451.32)**
917	506100	SEVEN MILE HILL WIND PLANT COMMON	34100	Structures & Improve	1,932,284.06	(66,390.27)
918			34300	Prime Movers	31,407.90	-
919			34500	Access Elec Equip	199,204.09	(6,447.32)
920			34600	Misc. Pwr Plt Eqp	803,821.77	(25,963.45)
921			35340	GSU and Assoc Equip	2,097,471.35	(36,078.61)
922	**506100 Total**				**5,064,189.17**	**(134,879.65)**
923	506110	SEVEN MILE HILL WIND PLANT UNIT 1	34100	Structures & Improve	3,845,113.82	(132,623.17)
924			34300	Prime Movers	160,211,720.62	(5,718,461.35)
925			34400	Generators	8,956,558.45	(208,952.61)
926			34500	Access Elec Equip	10,395,205.11	(341,355.92)
927	**506110 Total**				**183,408,598.00**	**(6,401,393.05)**

928	506120	SEVEN MILE HILL WIND PLANT UNIT 2	34100	Structures & Improve	735,667.69	(25,380.54)
929			34300	Prime Movers	32,567,330.35	(1,187,376.71)
930			34400	Generators	1,769,912.15	(47,745.73)
931			34500	Access Elec Equip	2,440,236.39	(79,197.82)
932	**506120 Total**				**37,513,146.58**	**(1,339,700.80)**
933	509100	DUNLAP WIND PLANT COMMON	34010	Fee Land - Other	5,366,044.69	-
934			34100	Structures & Improve	8,125,767.12	(273,033.21)
935			34500	Access Elec Equip	5,746.78	(70.25)
936			34600	Misc. Pwr Plt Eqp	149,099.80	(4,845.74)
937			35340	GSU and Assoc Equip	1,704,004.65	(29,225.22)
938	**509100 Total**				**15,350,663.04**	**(307,174.42)**
939	509110	DUNLAP WIND PLANT COMMON	34100	Structures & Improve	2,339.53	(81.65)
940			34300	Prime Movers	208,522,477.97	(6,941,270.16)
941			34400	Generators	6,665,901.19	(220,468.07)
942			34500	Access Elec Equip	12,321,817.96	(401,371.87)
943	**509110 Total**				**227,512,536.65**	**(7,563,191.75)**
944	510100	HIGH PLAINS - MCFADDEN WIND PLANT COMMON	34010	Fee Land - Other	29,940.00	-
945			34100	Structures & Improve	1,676,939.85	(48,597.76)
946			34400	Generators	-	(4,121.60)
947			34600	Misc. Pwr Plt Eqp	113,716.50	(3,673.04)
948			35340	GSU and Assoc Equip	1,757,299.34	(30,577.01)
949	**510100 Total**				**3,577,895.69**	**(86,969.41)**
950	510110	HIGH PLAINS WIND PLANT	34100	Structures & Improve	5,317,342.44	(184,511.78)
951			34300	Prime Movers	161,035,446.21	(6,471,824.01)
952			34400	Generators	8,817,598.55	(182,285.53)
953			34500	Access Elec Equip	11,356,896.70	(366,656.04)
954	**510110 Total**				**186,527,283.90**	**(7,205,277.36)**
955	510120	MCFADDEN RIDGE WIND PLANT	34100	Structures & Improve	1,115,267.21	(38,699.77)
956			34300	Prime Movers	44,410,867.60	(1,648,492.13)
957			34400	Generators	2,515,971.89	(55,257.33)
958			34500	Access Elec Equip	3,406,415.61	(110,014.33)
959	**510120 Total**				**51,448,522.31**	**(1,852,463.56)**
960	514000	DAVE JOHNSTON STEAM PLANT	31010	Fee Land - Steam	647,631.44	-
961			31020	Land Rights - Steam	99,970.26	(2,299.32)
962			31030	Water Rights - Steam	9,700,996.61	-
963			31100	Struct.&Improv. Th	131,689,800.80	(6,971,911.34)
964			31200	Boiler Plant Equipm.	133,687,202.29	(7,363,575.49)
965			31400	Turbogenerator Units	9,919,936.45	(472,330.55)
966			31500	Access. Electr. Equi	27,826,053.98	(1,570,764.77)
967			31600	Misc.PwPlnt Equipm.	8,519,876.05	(506,231.43)
968			35340	GSU and Assoc Equip	10,842,239.69	(188,654.97)
969	**514000 Total**				**332,933,707.57**	**(17,075,767.87)**
970	514001	DAVE JOHNSTON UNIT 1	31100	Struct.&Improv. Th	1,108,743.90	(58,091.24)
971			31200	Boiler Plant Equipm.	55,549,879.07	(3,115,744.94)
972			31400	Turbogenerator Units	13,439,564.93	(645,691.29)
973			31500	Access. Electr. Equi	2,876,383.33	(161,271.55)
974			31600	Misc.PwPlnt Equipm.	2,674.50	(161.27)
975	**514001 Total**				**72,977,245.73**	**(3,980,960.29)**
976	514002	DAVE JOHNSTON UNIT 2	31100	Struct.&Improv. Th	566,770.57	(31,512.44)
977			31200	Boiler Plant Equipm.	59,311,511.93	(3,338,568.32)
978			31400	Turbogenerator Units	16,932,298.77	(820,244.89)
979			31500	Access. Electr. Equi	3,477,124.97	(196,646.76)

980	**514002 Total**				**80,287,706.24**	**(4,386,972.41)**
981	514003	DAVE JOHNSTON UNIT 3	31100	Struct.&Improv. Th	18,998,017.01	(1,055,809.81)
982			31200	Boiler Plant Equipm.	231,741,687.34	(13,025,846.11)
983			31400	Turbogenerator Units	23,330,118.79	(1,104,719.93)
984			31500	Access. Electr. Equi	14,838,244.12	(839,385.96)
985			31600	Misc.PwPlnt Equipm.	240,204.09	(14,484.31)
986	**514003 Total**				**289,148,271.35**	**(16,040,246.12)**
987	514004	DAVE JOHNSTON UNIT 4	31100	Struct.&Improv. Th	15,137,308.69	(841,018.22)
988			31200	Boiler Plant Equipm.	236,483,048.77	(13,313,608.38)
989			31400	Turbogenerator Units	42,129,766.41	(2,011,714.41)
990			31500	Access. Electr. Equi	14,479,267.29	(817,748.98)
991			31600	Misc.PwPlnt Equipm.	599,327.00	(35,873.57)
992	**514004 Total**				**308,828,718.16**	**(17,019,963.56)**
993	517000	JIM BRIDGER PLANT	31010	Fee Land - Steam	741,379.68	-
994			31020	Land Rights - Steam	281,111.10	(3,823.10)
995			31030	Water Rights - Steam	171,270.00	-
996			31100	Struct.&Improv. Th	68,147,402.70	(1,262,784.43)
997			31200	Boiler Plant Equipm.	95,090,410.16	(2,648,146.19)
998			31400	Turbogenerator Units	9,396,228.84	(309,456.02)
999			31500	Access. Electr. Equi	16,282,482.82	(311,679.83)
1000			31570	Access. Electr E-S&A	49,138.00	(948.36)
1001			31600	Misc.PwPlnt Equipm.	3,239,993.28	(100,399.99)
1002	**517000 Total**				**193,399,416.58**	**(4,637,237.92)**
1003	517001	JIM BRIDGER UNIT 1	31100	Struct.&Improv. Th	15,431,386.45	(288,566.93)
1004			31200	Boiler Plant Equipm.	177,028,032.13	(5,042,980.84)
1005			31400	Turbogenerator Units	47,260,472.93	(1,585,043.10)
1006			31500	Access. Electr. Equi	10,883,656.25	(207,907.92)
1007			31600	Misc.PwPlnt Equipm.	313,727.10	(9,788.29)
1008	**517001 Total**				**250,917,274.86**	**(7,134,287.08)**
1009	517002	JIM BRIDGER UNIT 2	31100	Struct.&Improv. Th	12,844,744.79	(239,622.30)
1010			31200	Boiler Plant Equipm.	173,560,412.51	(4,956,300.25)
1011			31400	Turbogenerator Units	59,922,944.17	(2,012,569.31)
1012			31500	Access. Electr. Equi	9,393,089.29	(180,038.15)
1013			31600	Misc.PwPlnt Equipm.	198,482.09	(6,192.64)
1014	**517002 Total**				**255,919,672.85**	**(7,394,722.65)**
1015	517003	JIM BRIDGER UNIT 3	31100	Struct.&Improv. Th	12,969,362.02	(242,090.29)
1016			31200	Boiler Plant Equipm.	270,698,965.14	(7,555,456.81)
1017			31400	Turbogenerator Units	44,205,069.21	(1,482,438.34)
1018			31500	Access. Electr. Equi	8,108,958.27	(153,630.26)
1019			31600	Misc.PwPlnt Equipm.	192,485.09	(6,005.54)
1020	**517003 Total**				**336,174,839.73**	**(9,439,621.24)**
1021	517004	JIM BRIDGER UNIT 4	31100	Struct.&Improv. Th	40,402,319.06	(753,820.38)
1022			31200	Boiler Plant Equipm.	294,851,213.85	(8,366,588.97)
1023			31400	Turbogenerator Units	45,637,965.49	(1,533,435.62)
1024			31500	Access. Electr. Equi	16,781,677.77	(323,886.38)
1025			31600	Misc.PwPlnt Equipm.	1,248,549.58	(38,954.75)
1026	**517004 Total**				**398,921,725.75**	**(11,016,686.10)**
1027	519000	WYODAK PLANT	31010	Fee Land - Steam	32,232.80	-
1028			31020	Land Rights - Steam	164,796.80	(2,719.15)
1029			31030	Water Rights - Steam	13,496.80	-
1030			31100	Struct.&Improv. Th	52,251,117.04	(1,041,090.77)
1031			31200	Boiler Plant Equipm.	303,282,507.00	(9,317,314.43)

1032			31400	Turbogenerator Units	66,820,412.54	(2,084,043.31)
1033			31500	Access. Electr. Equi	27,654,372.86	(670,987.37)
1034			31600	Misc.PwPlnt Equipm.	1,553,303.70	(55,457.56)
1035			35340	GSU and Assoc Equip	4,426,086.78	(77,013.91)
1036	**519000 Total**				**456,198,326.32**	**(13,248,626.50)**
1037	519005	WYODAK COAL FACILITIES	31100	Struct.&Improv. Th	576,305.63	(10,511.46)
1038			31200	Boiler Plant Equipm.	13,864,788.80	(414,402.39)
1039	**519005 Total**				**14,441,094.43**	**(424,913.85)**
1040	519006	WYODAK BACK-UP COAL SYSTEM	31100	Struct.&Improv. Th	225,653.48	(4,535.63)
1041			31200	Boiler Plant Equipm.	384,220.69	(11,872.41)
1042	**519006 Total**				**609,874.17**	**(16,408.04)**
1043	519007	WYODAK "O" CONVEYOR EXTENSION-PACIFICORP	31200	Boiler Plant Equipm.	270,454.02	(8,357.03)
1044	**519007 Total**				**270,454.02**	**(8,357.03)**
1045	525000	GREEN RIVER SOLAR	34400	Generators	55,086.78	-
1046	**525000 Total**				**55,086.78**	**-**
1047	576500	FOOTE CREEK WIND PLANT	34020	Land Rights - Other	5,525,955.68	(51,551.13)
1048			34100	Structures & Improve	630,080.62	(9,403.31)
1049			34300	Prime Movers	33,498,585.29	(929,798.37)
1050			34400	Generators	2,092,046.44	(55,158.04)
1051			34500	Access Elec Equip	2,988,455.66	(82,045.06)
1052	**576500 Total**				**44,735,123.69**	**(1,127,955.91)**
1053	610000	IRON GATE HYDRO PLANT	33010	Fee Land - Hydro	337,015.79	-
1054			33020	Land Rights - Hydro	4,601.29	(2,973.20)
1055			33110	Struc/Improv Prod.	1,997,017.08	557,108.16
1056			33120	Struc/Imprpv/ Fish/W	5,787,033.49	(4,601,424.15)
1057			33130	Struc/Improv Recreat	735,539.55	(9,511.52)
1058			33210	Resvors,Dams, Wway P	14,697,350.84	(6,685,563.52)
1059			33220	Resvors, Dams,Wway F	2,515,654.67	(3,608,469.30)
1060			33300	Water Wheels- Turb &	2,271,908.50	247,336.86
1061			33400	Access. Electr. Equi	858,403.82	(785,434.21)
1062			33470	Access. Elect EquiSA	53,010.71	46,409.93
1063			33510	Misc PPlt Equip Prod	23,082.96	(4,345.02)
1064			33520	Misc PPlt Equippm FW	-	-
1065			33600	Roads- Railroads & B	1,095,742.02	254,849.75
1066	**610000 Total**				**30,376,360.72**	**(14,592,016.22)**
1067	611000	COPCO #1 HYDRO PLANT	33010	Fee Land - Hydro	69,649.06	-
1068			33020	Land Rights - Hydro	36,340.01	31,815.03
1069			33040	Flood Rights - Hydro	1,029.50	899.87
1070			33110	Struc/Improv Prod.	1,943,450.04	(17,422.05)
1071			33130	Struc/Improv Recreat	163,508.08	(47,782.01)
1072			33210	Resvors,Dams, Wway P	3,374,970.83	(130,589.19)
1073			33300	Water Wheels- Turb &	3,783,810.23	1,520,433.20
1074			33400	Access. Electr. Equi	1,863,432.49	32,855.54
1075			33470	Access. Elect EquiSA	59,035.87	51,684.83
1076			33510	Misc PPlt Equip Prod	6,788.88	(8,637.60)
1077			33600	Roads- Railroads & B	133,348.39	31,941.84
1078	**611000 Total**				**11,435,363.38**	**1,465,199.46**
1079	612000	COPCO #2 HYDRO PLANT	33010	Fee Land - Hydro	20,913.63	-
1080			33110	Struc/Improv Prod.	2,556,191.61	185,358.17
1081			33210	Resvors,Dams, Wway P	3,169,819.29	1,971,610.33
1082			33300	Water Wheels- Turb &	3,579,826.11	2,377,759.78
1083			33400	Access. Electr. Equi	6,676,077.52	669,583.46

1084			33470	Access. Elect EquiSA	259,419.72	227,117.34
1085			33510	Misc PPlt Equip Prod	-	-
1086			33600	Roads- Railroads & B	551,687.09	(399,574.96)
1087	**612000 Total**				**16,813,934.97**	**5,031,854.12**
1088	613000	FALL CREEK HYDRO PLANT - CA	33010	Fee Land - Hydro	41,342.98	-
1089			33040	Flood Rights - Hydro	17,210.72	(907.00)
1090			33110	Struc/Improv Prod.	376,358.29	(26,902.04)
1091			33130	Struc/Improv Recreat	3,100.66	(244.02)
1092			33210	Resvors,Dams, Wway P	901,371.81	(41,941.42)
1093			33300	Water Wheels- Turb &	743,428.35	(40,765.10)
1094			33400	Access. Electr. Equi	183,037.31	(15,228.70)
1095	**613000 Total**				**2,265,850.12**	**(125,988.28)**
1096	**Grand Total**				**12,497,826,048.25**	**(415,835,259.61)**

PacifiCorp
Reactive Power
Turbogenerator Investment
2019

		Asset	SNo	Cap.date	Asset description	Acquis.val.	Generator/Exciter
1		314033000240	0	2/18/2003	CW-CHOLLA U0 CIRCULATING WATER EQUIPMENT	26,507.63	
2		314050000240	0	6/7/2006	GN-CHOLLA U0 GENERATOR EQUIPMENT	99,103.91	
3		314062000240	0	7/19/2004	LO-CHOLLA U0 LUBE OIL EQUIPMENT	43,846.18	
4		314062000240	1	7/18/2007	LO-CHOLLA U0 LUBE OIL EQUIPMENT	23,567.00	
5		314084000240	0	12/31/1998	TB-CHOLLA U0 TURBINE EQUIPMENT	-	
6		314084000240	1	12/31/1978	TB-CHOLLA U0 TURBINE EQUIPMENT	138,103.00	
7		314084000240	2	12/31/1981	TB-CHOLLA U0 TURBINE EQUIPMENT	205,794.00	
8		314084000240	3	10/11/1999	TB-CHOLLA U0 TURBINE EQUIPMENT	18,173.96	
9	*	Location	000240		CHOLLA PLANT - COMMON	555,095.68	
10		314022000244	0	12/31/1998	CD-CHOLLA U4 CONDENSER EQUIPMENT	-	
11		314022000244	1	12/31/1981	CD-CHOLLA U4 CONDENSER EQUIPMENT	7,357.73	
12		314028000244	0	12/31/1998	CN-CHOLLA U4 CONDENSER EQUIPMENT	-	
13		314028000244	1	12/31/1981	CN-CHOLLA U4 CONDENSER EQUIPMENT	1,253,109.64	
14		314028000244	2	12/31/1987	CN-CHOLLA U4 CONDENSER EQUIPMENT	2,418,574.00	
15		314028000244	3	12/31/1988	CN-CHOLLA U4 CONDENSER EQUIPMENT	7,823.00	
16		314028000244	4	12/31/1985	CN-CHOLLA U4 CONDENSER EQUIPMENT	55,373.87	
17		314028000244	5	12/31/1986	CN-CHOLLA U4 CONDENSER EQUIPMENT	1,873.56	
18		314028000244	6	12/31/1981	CN-CHOLLA U4 CONDENSER EQUIPMENT	297,459.53	
19		314028000244	8	7/19/2004	CN-CHOLLA U4 CONDENSER EQUIPMENT	41,457.06	
20		314028000244	9	7/19/2004	CN-CHOLLA U4 CONDENSER EQUIPMENT	177,101.26	
21		314028000244	10	8/18/2004	CN-CHOLLA U4 CONDENSER EQUIPMENT	30,032.22	
22		314028000244	12	5/21/2008	CN-CHOLLA U4 CONDENSER EQUIPMENT	1,391,655.92	
23		314028000244	13	6/9/2009	CN-CHOLLA U4 CONDENSER EQUIPMENT	66,777.41	
24		314028000244	14	12/13/2012	CN-CHOLLA U4 CONDENSER EQUIPMENT	98,170.45	
25		314028000244	15	4/27/2018	CN-CHOLLA U4 CONDENSER EQUIPMENT	199,403.74	
26		314032000244	0	12/31/1998	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	-	
27		314032000244	2	12/31/1994	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	83,888.70	
28		314032000244	5	12/9/1999	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	69,929.24	
29		314032000244	6	4/10/2002	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	485,053.95	
30		314032000244	7	7/19/2004	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	710,902.76	
31		314032000244	8	7/19/2004	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	77,557.79	
32		314032000244	9	2/23/2007	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	493,015.46	
33		314032000244	10	6/8/2006	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	236,940.43	
34		314032000244	11	6/8/2006	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	103,408.63	
35		314032000244	12	6/8/2006	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	103,408.65	
36		314032000244	13	1/24/2007	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	179,305.88	
37		314032000244	14	7/18/2007	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	573,187.15	
38		314032000244	15	7/18/2007	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	930,733.51	
39		314032000244	16	5/22/2008	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	327,659.25	
40		314032000244	17	5/22/2008	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	603,902.42	
41		314032000244	18	5/22/2008	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	566,002.02	
42		314032000244	19	11/28/2011	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	1,898,201.39	
43		314032000244	20	11/28/2011	CT-CHOLLA U4 COOLING TOWER STRUCTURES & EQUIP	2,669,966.93	
44		314033000244	0	12/31/1998	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	-	
45		314033000244	1	12/31/1981	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	47,144.79	
46		314033000244	2	12/31/1987	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	335,110.00	
47		314033000244	3	12/31/1981	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	42,306.94	
48		314033000244	5	12/31/1981	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	243,221.88	
49		314033000244	6	12/31/1981	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	75,757.93	
50		314033000244	7	12/31/1984	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	10,906.29	
51		314033000244	8	12/31/1981	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	654,904.61	
52		314033000244	10	2/13/2002	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	25,772.41	
53		314033000244	11	7/19/2004	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	335,042.13	
54		314033000244	12	8/18/2004	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	21,451.58	
55		314033000244	13	2/27/2007	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	148,362.80	
56		314033000244	14	2/27/2007	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	90,932.03	
57		314033000244	15	11/13/2007	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	604,461.41	
58		314033000244	16	4/22/2008	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	174,894.91	
59		314033000244	17	5/22/2008	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	231,924.37	
60		314033000244	18	5/22/2008	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	773,096.65	
61		314033000244	19	5/22/2008	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	345,520.28	
62		314033000244	20	5/22/2008	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	129,500.90	
63		314033000244	21	5/22/2008	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	129,500.86	
64		314033000244	22	4/12/2013	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	1,995,747.17	
65		314033000244	23	5/30/2014	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	82,872.50	
66		314033000244	24	4/27/2018	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	435,213.08	
67		314033000244	25	5/9/2018	CW-CHOLLA U4 CIRCULATING WATER EQUIPMENT	1,424,033.27	

68	314050000244	0	12/31/1998	GN-CHOLLA U4 GENERATOR EQUIPMENT	-	
69	314050000244	2	12/31/1994	GN-CHOLLA U4 GENERATOR EQUIPMENT	44,186.23	
70	314050000244	3	12/31/1981	GN-CHOLLA U4 GENERATOR EQUIPMENT	3,640,996.12	
71	314050000244	4	12/31/1981	GN-CHOLLA U4 GENERATOR EQUIPMENT	490,200.68	
72	314050000244	5	12/31/1994	GN-CHOLLA U4 GENERATOR EQUIPMENT	13,150.98	
73	314050000244	6	12/31/1981	GN-CHOLLA U4 GENERATOR EQUIPMENT	75,800.39	
74	314050000244	7	12/31/1981	GN-CHOLLA U4 GENERATOR EQUIPMENT	862,341.64	
75	314050000244	8	12/31/1981	GN-CHOLLA U4 GENERATOR EQUIPMENT	256,458.68	
76	314050000244	9	10/8/1999	GN-CHOLLA U4 GENERATOR EQUIPMENT	21,791.67	
77	314050000244	10	12/31/1996	GN-CHOLLA U4 GENERATOR EQUIPMENT	51,956.64	
78	314050000244	11	10/8/1999	GN-CHOLLA U4 GENERATOR EQUIPMENT	95,784.33	
79	314050000244	12	12/31/1997	GN-CHOLLA U4 GENERATOR EQUIPMENT	1,131,439.47	
80	314050000244	13	12/20/2004	GN-CHOLLA U4 GENERATOR EQUIPMENT	118,468.60	
81	314050000244	14	6/29/2004	GN-CHOLLA U4 GENERATOR EQUIPMENT	861,226.53	
82	314050000244	15	6/29/2004	GN-CHOLLA U4 GENERATOR EQUIPMENT	446,415.55	
83	314050000244	16	10/14/2005	GN-CHOLLA U4 GENERATOR EQUIPMENT	58,395.70	
84	314050000244	17	6/8/2006	GN-CHOLLA U4 GENERATOR EQUIPMENT	14,618.59	
85	314050000244	18	5/22/2008	GN-CHOLLA U4 GENERATOR EQUIPMENT	141,337.13	
86	314050000244	19	5/22/2008	GN-CHOLLA U4 GENERATOR EQUIPMENT	1,731,146.13	
87	314050000244	21	5/22/2008	GN-CHOLLA U4 GENERATOR EQUIPMENT	2,198,731.87	12,254,446.93
88	314062000244	0	12/31/1998	LO-CHOLLA U4 LUBE OIL EQUIPMENT	-	
89	314062000244	1	12/31/1981	LO-CHOLLA U4 LUBE OIL EQUIPMENT	274,330.57	
90	314062000244	2	12/31/1988	LO-CHOLLA U4 LUBE OIL EQUIPMENT	235,453.00	
91	314062000244	3	12/31/1989	LO-CHOLLA U4 LUBE OIL EQUIPMENT	7,442.87	
92	314062000244	4	7/24/2002	LO-CHOLLA U4 LUBE OIL EQUIPMENT	38,616.73	
93	314082000244	0	10/30/2008	SP-CHOLLA U4 FERC 314 CAPITALIZED SPARE PARTS	236,317.18	
94	314084000244	0	12/31/1998	TB-CHOLLA U4 TURBINE EQUIPMENT	-	
95	314084000244	1	12/31/1987	TB-CHOLLA U4 TURBINE EQUIPMENT	42,179.00	
96	314084000244	2	12/31/1981	TB-CHOLLA U4 TURBINE EQUIPMENT	2,697,946.10	
97	314084000244	3	12/31/1981	TB-CHOLLA U4 TURBINE EQUIPMENT	897,277.70	
98	314084000244	4	12/31/1981	TB-CHOLLA U4 TURBINE EQUIPMENT	1,326,668.24	
99	314084000244	5	12/31/1981	TB-CHOLLA U4 TURBINE EQUIPMENT	3,585,434.74	
100	314084000244	6	12/31/1996	TB-CHOLLA U4 TURBINE EQUIPMENT	146,077.11	
101	314084000244	7	12/31/1981	TB-CHOLLA U4 TURBINE EQUIPMENT	3,824,688.80	
102	314084000244	8	12/31/1981	TB-CHOLLA U4 TURBINE EQUIPMENT	992,528.70	
103	314084000244	9	12/31/1981	TB-CHOLLA U4 TURBINE EQUIPMENT	1,013,439.89	
104	314084000244	10	12/31/1981	TB-CHOLLA U4 TURBINE EQUIPMENT	4,881,089.01	
105	314084000244	11	12/31/1985	TB-CHOLLA U4 TURBINE EQUIPMENT	144,749.00	
106	314084000244	12	12/31/1981	TB-CHOLLA U4 TURBINE EQUIPMENT	1,306,306.43	
107	314084000244	13	12/31/1981	TB-CHOLLA U4 TURBINE EQUIPMENT	118,710.32	
108	314084000244	14	12/31/1981	TB-CHOLLA U4 TURBINE EQUIPMENT	690,453.31	
109	314084000244	15	12/31/1981	TB-CHOLLA U4 TURBINE EQUIPMENT	2,451,003.40	
110	314084000244	16	12/31/1997	TB-CHOLLA U4 TURBINE EQUIPMENT	352,560.34	
111	314084000244	17	5/23/2002	TB-CHOLLA U4 TURBINE EQUIPMENT	54,851.22	
112	314084000244	18	8/18/2004	TB-CHOLLA U4 TURBINE EQUIPMENT	25,741.90	
113	314084000244	19	2/23/2007	TB-CHOLLA U4 TURBINE EQUIPMENT	176,091.04	
114	314084000244	20	7/18/2007	TB-CHOLLA U4 TURBINE EQUIPMENT	231,417.10	
115	314084000244	21	5/22/2008	TB-CHOLLA U4 TURBINE EQUIPMENT	528,725.87	
116	314084000244	22	5/22/2008	TB-CHOLLA U4 TURBINE EQUIPMENT	2,022,866.45	
117	314084000244	23	5/22/2008	TB-CHOLLA U4 TURBINE EQUIPMENT	505,716.59	
118	314084000244	24	5/22/2008	TB-CHOLLA U4 TURBINE EQUIPMENT	2,528,583.04	
119	314084000244	25	10/27/2011	TB-CHOLLA U4 TURBINE EQUIPMENT	72,745.30	
120	314084000244	26	11/28/2011	TB-CHOLLA U4 TURBINE EQUIPMENT	311,769.49	
121	314084000244	27	5/15/2013	TB-CHOLLA U4 TURBINE EQUIPMENT	45,934.35	
122	314099000244	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
123	* Location	000244		CHOLLA PLANT - UNIT #4	68,539,074.06	17.88%
124	314018000260	0	12/31/1998	BU-MAIN BUILDING	-	
125	314018000260	1	12/31/1985	BU-MAIN BUILDING	1,614.91	
126	314032000260	0	12/31/1998	CT-COOLING TOWER PIPING	-	
127	314033000260	0	12/31/1998	CW-PUMPS	-	
128	314033000260	1	12/31/1992	CW-PUMPS	65,321.11	
129	314033000260	2	12/31/1996	CW-PUMPS	16,279.25	
130	314033000260	3	5/3/2000	CW-PUMPS	22,640.43	
131	314033000260	4	3/8/2001	CW-PUMPS	16,110.46	
132	314050000260	1	4/17/2009	GN-GADSBY U0 GENERATOR EQUIPMENT	49,448.29	
133	314062000260	0	12/31/1998	LO-GADSBY U0 LUBE OIL EQUIPMENT	-	
134	314062000260	1	12/31/1992	LO-GADSBY U0 LUBE OIL EQUIPMENT	5,741.63	
135	314062000260	2	12/31/1994	LO-GADSBY U0 LUBE OIL EQUIPMENT	38,812.11	
136	314062000260	3	12/31/1994	LO-GADSBY U0 LUBE OIL EQUIPMENT	65,932.82	
137	314062000260	4	12/12/2001	LO-GADSBY U0 LUBE OIL EQUIPMENT	85,511.33	
138	314062000260	5	3/29/2005	LO-GADSBY U0 LUBE OIL EQUIPMENT	2,636.98	
139	314062000260	6	1/27/2000	LO-GADSBY U0 LUBE OIL EQUIPMENT	57,789.00	
140	314062000260	7	6/24/1999	LO-GADSBY U0 LUBE OIL EQUIPMENT	31,412.84	

141		314093000260	0	12/31/1998	WP-GROUND & SURFACE WATER MONITORING SYSTEM	-	
142		314093000260	1	12/31/1982	WP-GROUND & SURFACE WATER MONITORING SYSTEM	16,457.50	
143	*	Location	000260		GADSBY PLANT COMMON FACILITIES AND	475,708.66	
144		314028000261	0	12/31/1998	CN-CONDENSER SYSTEM TUBES	-	
145		314028000261	1	12/31/1951	CN-CONDENSER SYSTEM TUBES	211,685.80	
146		314032000261	0	12/31/1998	CT-COOLING TOWER PIPING	-	
147		314032000261	3	12/31/1972	CT-COOLING TOWER PIPING	1,640.97	
148		314032000261	4	12/31/1994	CT-COOLING TOWER PIPING	239,406.27	
149		314032000261	5	12/31/1994	CT-COOLING TOWER PIPING	730,627.06	
150		314032000261	6	12/31/1994	CT-COOLING TOWER PIPING	74,139.38	
151		314032000261	7	12/31/1994	CT-COOLING TOWER PIPING	149,424.55	
152		314032000261	8	12/31/1994	CT-COOLING TOWER PIPING	3,883.05	
153		314032000261	9	12/31/1994	CT-COOLING TOWER PIPING	161,028.60	
154		314032000261	10	12/31/1994	CT-COOLING TOWER PIPING	166,716.19	
155		314033000261	0	12/31/1998	CW-PUMPS	-	
156		314033000261	1	12/31/1951	CW-PUMPS	203,599.32	
157		314033000261	2	12/31/1994	CW-PUMPS	18,446.69	
158		314033000261	3	12/31/1994	CW-PUMPS	176,061.29	
159		314033000261	4	1/10/2008	CW-PUMPS	12,880.58	
160		314033000261	5	7/10/2008	CW-PUMPS	118,580.39	
161		314050000261	0	12/31/1998	GN-GADSBY U1 GENERATOR EQUIPMENT	-	
162		314050000261	1	12/31/1951	GN-GADSBY U1 GENERATOR EQUIPMENT	73,075.00	
163		314050000261	2	12/31/1994	GN-GADSBY U1 GENERATOR EQUIPMENT	181,538.51	
164		314050000261	3	10/8/1999	GN-GADSBY U1 GENERATOR EQUIPMENT	10,400.45	
165		314050000261	4	5/21/2003	GN-GADSBY U1 GENERATOR EQUIPMENT	36,765.39	
166		314050000261	5	3/10/2003	GN-GADSBY U1 GENERATOR EQUIPMENT	36,643.97	
167		314050000261	6	2/10/2004	GN-GADSBY U1 GENERATOR EQUIPMENT	-	338,423.32
168		314051000261	0	12/31/1998	GR-GROUNDS	-	
169		314051000261	1	12/31/1951	GR-GROUNDS	107,564.23	
170		314062000261	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
171		314062000261	1	12/31/1994	LO-LUBE OIL PUMPS & PUMP MOTORS	25,979.35	
172		314062000261	2	12/31/1994	LO-LUBE OIL PUMPS & PUMP MOTORS	71,664.35	
173		314084000261	0	12/31/1998	TB-GADSBY U1 TURBINE EQUIPMENT	-	
174		314084000261	1	12/31/1951	TB-GADSBY U1 TURBINE EQUIPMENT	2,264,262.84	
175		314084000261	2	12/31/1979	TB-GADSBY U1 TURBINE EQUIPMENT	10,386.54	
176		314084000261	3	12/31/1980	TB-GADSBY U1 TURBINE EQUIPMENT	45,592.67	
177		314084000261	4	12/31/1982	TB-GADSBY U1 TURBINE EQUIPMENT	802.85	
178		314084000261	5	12/31/1988	TB-GADSBY U1 TURBINE EQUIPMENT	5,839.88	
179		314084000261	6	12/31/1994	TB-GADSBY U1 TURBINE EQUIPMENT	24,382.40	
180		314084000261	7	3/14/2003	TB-GADSBY U1 TURBINE EQUIPMENT	40,548.90	
181		314084000261	8	3/14/2003	TB-GADSBY U1 TURBINE EQUIPMENT	233,006.88	
182		314084000261	9	3/10/2003	TB-GADSBY U1 TURBINE EQUIPMENT	48,519.30	
183		314084000261	10	1/19/2017	TB-GADSBY U1 TURBINE EQUIPMENT	60,169.83	
184	*	Location	000261		GADSBY NO 1 STEAM ELECTRIC STATION	5,545,263.48	
185		314018000262	0	12/31/1998	BU-MAIN BUILDING	-	
186		314018000262	1	12/31/1952	BU-MAIN BUILDING	19,169.25	
187		314028000262	0	12/31/1998	CN-CONDENSER SYSTEM TUBES	-	
188		314028000262	1	12/31/1952	CN-CONDENSER SYSTEM TUBES	231,564.57	
189		314032000262	0	12/31/1998	CT-GADSBY U2 COOLING TOWER STRUCTURES & EQUIP	-	
190		314032000262	6	5/12/2005	CT-GADSBY U2 COOLING TOWER STRUCTURES & EQUIP	181,501.46	
191		314032000262	7	5/12/2005	CT-GADSBY U2 COOLING TOWER STRUCTURES & EQUIP	86,054.74	
192		314032000262	8	3/25/2008	CT-GADSBY U2 COOLING TOWER STRUCTURES & EQUIP	93,948.14	
193		314032000262	9	12/29/2011	CT-GADSBY U2 COOLING TOWER STRUCTURES & EQUIP	66,483.19	
194		314032000262	10	4/8/2014	CT-GADSBY U2 COOLING TOWER STRUCTURES & EQUIP	42,124.48	
195		314032000262	11	9/25/2014	CT-GADSBY U2 COOLING TOWER STRUCTURES & EQUIP	35,085.88	
196		314033000262	0	12/31/1998	CW-PUMPS	-	
197		314033000262	1	12/31/1952	CW-PUMPS	55,284.20	
198		314033000262	2	12/31/1994	CW-PUMPS	38,308.58	
199		314033000262	4	12/31/1994	CW-PUMPS	6,372.41	
200		314033000262	5	12/31/1994	CW-PUMPS	32,675.97	
201		314033000262	6	3/22/2004	CW-PUMPS	56,726.66	
202		314033000262	8	6/23/2009	CW-PUMPS	83,588.28	
203		314033000262	9	12/19/2012	CW-PUMPS	68,176.62	
204		314033000262	10	12/30/2013	CW-PUMPS	33,970.79	
205		314050000262	0	12/31/1998	GN-GADSBY U2 GENERATOR EQUIPMENT	-	
206		314050000262	1	12/31/1984	GN-GADSBY U2 GENERATOR EQUIPMENT	121,290.00	
207		314050000262	2	12/31/1994	GN-GADSBY U2 GENERATOR EQUIPMENT	64,832.61	
208		314050000262	3	10/8/1999	GN-GADSBY U2 GENERATOR EQUIPMENT	10,400.48	
209		314050000262	5	3/28/2001	GN-GADSBY U2 GENERATOR EQUIPMENT	20,136.01	
210		314050000262	6	2/25/2002	GN-GADSBY U2 GENERATOR EQUIPMENT	21,740.13	
211		314050000262	7	3/22/2004	GN-GADSBY U2 GENERATOR EQUIPMENT	17,858.06	
212		314050000262	8	3/22/2004	GN-GADSBY U2 GENERATOR EQUIPMENT	10,486.03	
213		314050000262	9	3/22/2004	GN-GADSBY U2 GENERATOR EQUIPMENT	50,872.30	

214	314050000262	10	12/31/2008	GN-GADSBY U2 GENERATOR EQUIPMENT	58,747.09	
215	314050000262	11	3/28/2012	GN-GADSBY U2 GENERATOR EQUIPMENT	73,722.78	
216	314050000262	12	6/20/2012	GN-GADSBY U2 GENERATOR EQUIPMENT	651,754.52	
217	314050000262	13	6/20/2012	GN-GADSBY U2 GENERATOR EQUIPMENT	54,377.11	1,156,217.12
218	314062000262	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
219	314062000262	1	12/31/1952	LO-LUBE OIL PUMPS & PUMP MOTORS	9,867.55	
220	314062000262	2	12/31/1957	LO-LUBE OIL PUMPS & PUMP MOTORS	1,201.95	
221	314062000262	3	12/31/1994	LO-LUBE OIL PUMPS & PUMP MOTORS	2,623.91	
222	314076000262	0	12/31/1998	RS-REHEAT STEAM	-	
223	314076000262	1	12/31/1957	RS-REHEAT STEAM	46,738.56	
224	314082000262	0	12/31/1998	SP-CAPITALIZED SPARE PARTS	-	
225	314082000262	1	12/31/1983	SP-CAPITALIZED SPARE PARTS	14,501.45	
226	314082000262	2	12/31/1985	SP-CAPITALIZED SPARE PARTS	34,223.44	
227	314082000262	3	12/31/1986	SP-CAPITALIZED SPARE PARTS	17,112.94	
228	314084000262	0	12/31/1998	TB-GADSBY U2 STEAM TURBINE EQUIPMENT	-	
229	314084000262	1	12/31/1952	TB-GADSBY U2 STEAM TURBINE EQUIPMENT	3,312,729.79	
230	314084000262	7	12/31/1986	TB-GADSBY U2 STEAM TURBINE EQUIPMENT	43,679.85	
231	314084000262	8	12/31/1987	TB-GADSBY U2 STEAM TURBINE EQUIPMENT	89,465.23	
232	314084000262	9	12/31/1994	TB-GADSBY U2 STEAM TURBINE EQUIPMENT	32,247.59	
233	314084000262	10	5/3/2000	TB-GADSBY U2 STEAM TURBINE EQUIPMENT	56,816.69	
234	314084000262	11	5/4/2000	TB-GADSBY U2 STEAM TURBINE EQUIPMENT	17,052.08	
235	314084000262	12	5/4/2000	TB-GADSBY U2 STEAM TURBINE EQUIPMENT	81,327.54	
236	314084000262	13	5/4/2000	TB-GADSBY U2 STEAM TURBINE EQUIPMENT	146,735.06	
237	314084000262	14	3/22/2004	TB-GADSBY U2 STEAM TURBINE EQUIPMENT	67,988.80	
238	314084000262	15	3/28/2012	TB-GADSBY U2 STEAM TURBINE EQUIPMENT	105,137.38	
239	314084000262	16	12/20/2013	TB-GADSBY U2 STEAM TURBINE EQUIPMENT	2,459.58	
240	* Location	000262		GADSBY NO 2 STEAM ELECTRIC STATION	6,369,161.73	
241	314028000263	0	12/31/1998	CN-CONDENSER SYSTEM TUBES	-	
242	314028000263	1	12/31/1955	CN-CONDENSER SYSTEM TUBES	378,509.97	
243	314032000263	0	12/31/1998	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	-	
244	314032000263	1	12/31/1955	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	58,921.83	
245	314032000263	2	12/31/1961	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	1,961.77	
246	314032000263	4	12/31/1991	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	122,685.77	
247	314032000263	5	12/31/1992	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	3,277.40	
248	314032000263	7	5/22/2000	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	5,000.88	
249	314032000263	8	5/22/2000	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	82,514.38	
250	314032000263	10	6/28/1999	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	305,169.96	
251	314032000263	11	6/28/1999	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	4,690.81	
252	314032000263	13	2/25/2002	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	10,666.33	
253	314032000263	14	2/25/2002	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	127,995.94	
254	314032000263	16	6/19/2002	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	106,122.31	
255	314032000263	17	6/19/2002	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	101,851.84	
256	314032000263	18	12/19/2002	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	12,089.66	
257	314032000263	20	6/29/2005	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	34,571.64	
258	314032000263	21	3/31/2006	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	127,245.22	
259	314032000263	22	3/31/2006	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	29,020.76	
260	314032000263	23	3/31/2006	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	8,094.93	
261	314032000263	24	3/10/2014	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	144,178.06	
262	314032000263	25	3/30/2015	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	225,720.19	
263	314032000263	26	12/31/2014	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	54,562.53	
264	314032000263	27	12/23/2016	CT-GADSBY U3 COOLING TOWER STRUCTURES & EQUIX	11,294.55	
265	314033000263	0	12/31/1998	CW-PUMPS	-	
266	314033000263	1	12/31/1955	CW-PUMPS	316,244.92	
267	314033000263	2	12/31/1991	CW-PUMPS	48,186.35	
268	314033000263	4	5/21/2003	CW-PUMPS	16,044.41	
269	314033000263	5	5/21/2003	CW-PUMPS	16,044.40	
270	314033000263	6	12/26/2007	CW-PUMPS	61,454.48	
271	314033000263	7	11/15/2011	CW-PUMPS	94,057.77	
272	314033000263	8	4/30/2012	CW-PUMPS	65,454.86	
273	314048000263	0	12/31/1998	FZ-FREEZE PROTECTION	-	
274	314048000263	1	12/31/1965	FZ-FREEZE PROTECTION	7,754.33	
275	314050000263	0	12/31/1998	GN-GADSBY U3 GENERATOR EQUIPMENT	-	
276	314050000263	2	12/31/1992	GN-GADSBY U3 GENERATOR EQUIPMENT	1,978.51	
277	314050000263	3	12/31/1996	GN-GADSBY U3 GENERATOR EQUIPMENT	32,850.95	
278	314050000263	5	7/17/2000	GN-GADSBY U3 GENERATOR EQUIPMENT	25,568.34	
279	314050000263	6	2/25/2002	GN-GADSBY U3 GENERATOR EQUIPMENT	15,776.26	
280	314050000263	7	12/31/2007	GN-GADSBY U3 GENERATOR EQUIPMENT	19,843.79	
281	314050000263	8	2/25/2011	GN-GADSBY U3 GENERATOR EQUIPMENT	337,109.98	
282	314050000263	9	8/29/2011	GN-GADSBY U3 GENERATOR EQUIPMENT	225,623.47	658,751.30
283	314051000263	0	12/31/1998	GR-GROUNDS	-	
284	314051000263	1	12/31/1955	GR-GROUNDS	37,096.37	
285	314062000263	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
286	314062000263	1	12/31/1955	LO-LUBE OIL PUMPS & PUMP MOTORS	6,770.51	

287		314062000263	2	12/31/1992	LO-LUBE OIL PUMPS & PUMP MOTORS	7,256.01
288		314084000263	0	12/31/1998	TB-GADSBY U3 TURBINE EQUIPMENT	-
289		314084000263	1	12/31/1955	TB-GADSBY U3 TURBINE EQUIPMENT	3,168,683.18
290		314084000263	2	12/31/1970	TB-GADSBY U3 TURBINE EQUIPMENT	795.66
291		314084000263	5	12/31/1985	TB-GADSBY U3 TURBINE EQUIPMENT	5,862.02
292		314084000263	7	2/25/2002	TB-GADSBY U3 TURBINE EQUIPMENT	55,361.98
293		314084000263	8	2/25/2002	TB-GADSBY U3 TURBINE EQUIPMENT	51,239.54
294		314084000263	9	2/25/2002	TB-GADSBY U3 TURBINE EQUIPMENT	173,853.14
295		314084000263	10	2/25/2002	TB-GADSBY U3 TURBINE EQUIPMENT	78,945.85
296		314084000263	11	2/25/2002	TB-GADSBY U3 TURBINE EQUIPMENT	33,793.35
297		314084000263	12	5/13/2002	TB-GADSBY U3 TURBINE EQUIPMENT	72,243.46
298		314084000263	13	2/9/2007	TB-GADSBY U3 TURBINE EQUIPMENT	84,418.06
299		314084000263	14	4/13/2009	TB-GADSBY U3 TURBINE EQUIPMENT	269,115.01
300		314084000263	15	3/18/2014	TB-GADSBY U3 TURBINE EQUIPMENT	119,746.44
301		314084000263	16	7/16/2014	TB-GADSBY U3 TURBINE EQUIPMENT	183,687.63
302	*	Location	000263		GADSBY NO 3 STEAM ELECTRIC STATION	7,589,007.76
303		314032000270	0	12/31/1998	CT-NAU U0 COOLING TOWER STRUCTURES & EQUIP	-
304		314032000270	1	12/31/1988	CT-NAU U0 COOLING TOWER STRUCTURES & EQUIP	10,638.08
305		314032000270	2	3/31/2005	CT-NAU U0 COOLING TOWER STRUCTURES & EQUIP	16,103.18
306		314032000270	5	12/28/2017	CT-NAU U0 COOLING TOWER STRUCTURES & EQUIP	6,161,348.55
307		314033000270	0	12/31/1998	CW-NAU U0 CIRCULATING WATER EQUIPMENT	-
308		314033000270	2	3/29/2004	CW-NAU U0 CIRCULATING WATER EQUIPMENT	509,771.84
309		314033000270	3	12/30/2011	CW-NAU U0 CIRCULATING WATER EQUIPMENT	84,089.55
310		314050000270	1	12/27/2012	GN-NAU U0 GENERATOR EQUIPMENT	18,934.16
311		314062000270	0	12/31/1998	LO-NAU U0 LUBE OIL EQUIPMENT	-
312		314062000270	1	12/31/1963	LO-NAU U0 LUBE OIL EQUIPMENT	45,314.18
313		314062000270	2	3/12/2003	LO-NAU U0 LUBE OIL EQUIPMENT	46,688.25
314		314082000270	1	11/27/2013	SP-NAU U0 CAPITALIZED SPARE PARTS FERC 314	42,741.44
315		314082000270	2	12/31/2013	SP-NAU U0 CAPITALIZED SPARE PARTS FERC 314	29,689.91
316		314084000270	0	12/31/1998	TB-NAU U0 TURBINE EQUIPMENT	-
317		314084000270	1	12/31/1984	TB-NAU U0 TURBINE EQUIPMENT	3,522.69
318		314084000270	3	12/31/1994	TB-NAU U0 TURBINE EQUIPMENT	38,551.63
319		314084000270	4	11/26/2002	TB-NAU U0 TURBINE EQUIPMENT	21,045.05
320		314084000270	5	8/28/2003	TB-NAU U0 TURBINE EQUIPMENT	166,013.86
321		314084000270	9	12/31/2008	TB-NAU U0 TURBINE EQUIPMENT	266,115.36
322		314084000270	10	10/30/2019	TB-NAU U0 TURBINE EQUIPMENT	451,678.54
323	*	Location	000270		NAUGHTON PLANT COMMON FACILITIES AN	7,912,246.27
324		314022000271	0	12/31/1998	CD-CONDENSATE TANK FOUNDATIONS	-
325		314022000271	1	12/31/1997	CD-CONDENSATE TANK FOUNDATIONS	25,422.46
326		314028000271	0	12/31/1998	CN-NAUGHTON U1 CONDENSER SYSTEM EQUIPMENT	-
327		314028000271	1	12/31/1963	CN-NAUGHTON U1 CONDENSER SYSTEM EQUIPMENT	266,487.49
328		314028000271	2	5/23/2017	CN-NAUGHTON U1 CONDENSER SYSTEM EQUIPMENT	1,477,577.20
329		314032000271	0	12/31/1998	CT-NAUGHTON U1 COOLING TOWER STRUCTURES, EQUX	-
330		314032000271	1	12/31/1963	CT-NAUGHTON U1 COOLING TOWER STRUCTURES, EQUX	58,874.95
331		314032000271	2	12/31/1997	CT-NAUGHTON U1 COOLING TOWER STRUCTURES, EQUX	430,561.99
332		314032000271	3	12/31/1997	CT-NAUGHTON U1 COOLING TOWER STRUCTURES, EQUX	313,135.99
333		314032000271	6	12/31/1997	CT-NAUGHTON U1 COOLING TOWER STRUCTURES, EQUX	313,135.99
334		314032000271	7	12/31/1997	CT-NAUGHTON U1 COOLING TOWER STRUCTURES, EQUX	273,993.99
335		314032000271	8	12/31/1997	CT-NAUGHTON U1 COOLING TOWER STRUCTURES, EQUX	273,993.99
336		314032000271	9	2/20/2001	CT-NAUGHTON U1 COOLING TOWER STRUCTURES, EQUX	20,777.33
337		314032000271	10	10/30/2001	CT-NAUGHTON U1 COOLING TOWER STRUCTURES, EQUX	14,123.03
338		314032000271	11	10/17/2002	CT-NAUGHTON U1 COOLING TOWER STRUCTURES, EQUX	116,085.08
339		314032000271	12	2/19/2004	CT-NAUGHTON U1 COOLING TOWER STRUCTURES, EQUX	-
340		314032000271	13	5/27/2010	CT-NAUGHTON U1 COOLING TOWER STRUCTURES, EQUX	10,202.18
341		314032000271	14	5/27/2010	CT-NAUGHTON U1 COOLING TOWER STRUCTURES, EQUX	9,138.01
342		314032000271	15	5/23/2017	CT-NAUGHTON U1 COOLING TOWER STRUCTURES, EQUX	299,754.81
343		314032000271	16	12/28/2017	CT-NAUGHTON U1 COOLING TOWER STRUCTURES, EQUX	286,893.20
344		314033000271	0	12/31/1998	CW-NAUGHTON U1 CIRCULATING WATER EQUIPMENT	-
345		314033000271	1	12/31/1963	CW-NAUGHTON U1 CIRCULATING WATER EQUIPMENT	209,198.10
346		314033000271	3	12/31/1995	CW-NAUGHTON U1 CIRCULATING WATER EQUIPMENT	4,734.68
347		314033000271	4	12/31/1994	CW-NAUGHTON U1 CIRCULATING WATER EQUIPMENT	191,833.23
348		314033000271	5	12/21/2001	CW-NAUGHTON U1 CIRCULATING WATER EQUIPMENT	23,845.84
349		314033000271	6	3/28/2002	CW-NAUGHTON U1 CIRCULATING WATER EQUIPMENT	9,045.87
350		314033000271	7	3/12/2003	CW-NAUGHTON U1 CIRCULATING WATER EQUIPMENT	-
351		314033000271	8	4/15/2004	CW-NAUGHTON U1 CIRCULATING WATER EQUIPMENT	289,823.23
352		314033000271	9	8/10/2004	CW-NAUGHTON U1 CIRCULATING WATER EQUIPMENT	46,088.31
353		314033000271	10	8/31/2004	CW-NAUGHTON U1 CIRCULATING WATER EQUIPMENT	52,201.64
354		314033000271	11	2/28/2006	CW-NAUGHTON U1 CIRCULATING WATER EQUIPMENT	77,451.29
355		314033000271	12	9/28/2007	CW-NAUGHTON U1 CIRCULATING WATER EQUIPMENT	43,132.81
356		314033000271	13	3/31/2008	CW-NAUGHTON U1 CIRCULATING WATER EQUIPMENT	12,701.91
357		314033000271	14	6/14/2012	CW-NAUGHTON U1 CIRCULATING WATER EQUIPMENT	93,754.46
358		314050000271	0	12/31/1998	GN-NAUGHTON U1 GENERATOR EQUIPMENT	-
359		314050000271	2	12/31/1992	GN-NAUGHTON U1 GENERATOR EQUIPMENT	82,930.62

360	314050000271	3	12/31/1997	GN-NAUGHTON U1 GENERATOR EQUIPMENT	11,601.81	
361	314050000271	4	12/31/1997	GN-NAUGHTON U1 GENERATOR EQUIPMENT	116,584.82	
362	314050000271	5	12/21/2001	GN-NAUGHTON U1 GENERATOR EQUIPMENT	16,318.37	
363	314050000271	6	10/17/2002	GN-NAUGHTON U1 GENERATOR EQUIPMENT	13,369.26	
364	314050000271	7	10/17/2002	GN-NAUGHTON U1 GENERATOR EQUIPMENT	69,870.40	
365	314050000271	10	11/16/2004	GN-NAUGHTON U1 GENERATOR EQUIPMENT	433,905.52	
366	314050000271	11	3/29/2007	GN-NAUGHTON U1 GENERATOR EQUIPMENT	50,731.78	
367	314050000271	12	5/31/2007	GN-NAUGHTON U1 GENERATOR EQUIPMENT	308,328.22	
368	314050000271	13	5/31/2007	GN-NAUGHTON U1 GENERATOR EQUIPMENT	65,999.52	
369	314050000271	14	5/31/2007	GN-NAUGHTON U1 GENERATOR EQUIPMENT	35,351.91	
370	314050000271	15	5/23/2017	GN-NAUGHTON U1 GENERATOR EQUIPMENT	285,776.20	1,490,768.43
371	314062000271	0	12/31/1998	LO-NAUGHTON U1 LUBE OIL EQUIPMENT	-	
372	314062000271	1	12/31/1984	LO-NAUGHTON U1 LUBE OIL EQUIPMENT	28,019.15	
373	314062000271	2	7/6/2007	LO-NAUGHTON U1 LUBE OIL EQUIPMENT	9,249.43	
374	314062000271	3	7/6/2007	LO-NAUGHTON U1 LUBE OIL EQUIPMENT	4,465.25	
375	314062000271	4	7/6/2007	LO-NAUGHTON U1 LUBE OIL EQUIPMENT	14,671.51	
376	314062000271	5	7/6/2007	LO-NAUGHTON U1 LUBE OIL EQUIPMENT	3,508.40	
377	314082000271	0	12/31/1998	SP-CAPITALIZED SPARE PARTS	-	
378	314082000271	1	12/31/1983	SP-CAPITALIZED SPARE PARTS	112,720.54	
379	314082000271	3	12/31/1988	SP-CAPITALIZED SPARE PARTS	30,716.15	
380	314082000271	7	1/31/2005	SP-CAPITALIZED SPARE PARTS	14,965.86	
381	314082000271	8	8/29/2005	SP-CAPITALIZED SPARE PARTS	93,830.89	
382	314084000271	0	12/31/1998	TB-NAUGHTON U1 TURBINE EQUIPMENT	-	
383	314084000271	1	12/31/1963	TB-NAUGHTON U1 TURBINE EQUIPMENT	3,622,514.99	
384	314084000271	2	12/31/1973	TB-NAUGHTON U1 TURBINE EQUIPMENT	1,984.54	
385	314084000271	3	12/31/1980	TB-NAUGHTON U1 TURBINE EQUIPMENT	306,538.07	
386	314084000271	4	12/31/1982	TB-NAUGHTON U1 TURBINE EQUIPMENT	53,072.28	
387	314084000271	5	12/31/1983	TB-NAUGHTON U1 TURBINE EQUIPMENT	867.47	
388	314084000271	7	12/31/1992	TB-NAUGHTON U1 TURBINE EQUIPMENT	1,463.92	
389	314084000271	8	12/31/1994	TB-NAUGHTON U1 TURBINE EQUIPMENT	430,980.45	
390	314084000271	9	12/31/1997	TB-NAUGHTON U1 TURBINE EQUIPMENT	28,232.00	
391	314084000271	10	12/31/1994	TB-NAUGHTON U1 TURBINE EQUIPMENT	260,891.51	
392	314084000271	11	12/31/1994	TB-NAUGHTON U1 TURBINE EQUIPMENT	481,380.15	
393	314084000271	12	5/9/2000	TB-NAUGHTON U1 TURBINE EQUIPMENT	70,837.72	
394	314084000271	17	10/17/2002	TB-NAUGHTON U1 TURBINE EQUIPMENT	480,033.77	
395	314084000271	18	12/31/1979	TB-NAUGHTON U1 TURBINE EQUIPMENT	419,107.89	
396	314084000271	19	12/31/1985	TB-NAUGHTON U1 TURBINE EQUIPMENT	230,945.83	
397	314084000271	20	12/31/1990	TB-NAUGHTON U1 TURBINE EQUIPMENT	1,282.00	
398	314084000271	21	4/15/2004	TB-NAUGHTON U1 TURBINE EQUIPMENT	125,548.16	
399	314084000271	22	4/15/2004	TB-NAUGHTON U1 TURBINE EQUIPMENT	55,614.36	
400	314084000271	23	4/29/2005	TB-NAUGHTON U1 TURBINE EQUIPMENT	124,808.98	
401	314084000271	24	3/29/2007	TB-NAUGHTON U1 TURBINE EQUIPMENT	325,903.73	
402	314084000271	25	3/29/2007	TB-NAUGHTON U1 TURBINE EQUIPMENT	338,761.24	
403	314084000271	26	3/29/2007	TB-NAUGHTON U1 TURBINE EQUIPMENT	1,778,757.54	
404	314084000271	27	3/29/2007	TB-NAUGHTON U1 TURBINE EQUIPMENT	37,700.01	
405	314084000271	28	4/30/2007	TB-NAUGHTON U1 TURBINE EQUIPMENT	288,137.72	
406	314084000271	29	3/29/2007	TB-NAUGHTON U1 TURBINE EQUIPMENT	150,915.71	
407	314084000271	30	5/31/2007	TB-NAUGHTON U1 TURBINE EQUIPMENT	130,848.83	
408	314084000271	31	5/31/2007	TB-NAUGHTON U1 TURBINE EQUIPMENT	24,970.59	
409	314084000271	32	6/18/2012	TB-NAUGHTON U1 TURBINE EQUIPMENT	2,273,505.59	
410	314084000271	33	6/26/2012	TB-NAUGHTON U1 TURBINE EQUIPMENT	97,925.65	
411	314084000271	34	6/26/2012	TB-NAUGHTON U1 TURBINE EQUIPMENT	195,851.30	
412	314084000271	35	6/26/2012	TB-NAUGHTON U1 TURBINE EQUIPMENT	97,925.63	
413	314084000271	36	5/23/2017	TB-NAUGHTON U1 TURBINE EQUIPMENT	1,042,031.00	
414	* Location	000271		NAUGHTON NO 1 STEAM ELECTRIC STATIO	20,526,223.30	
415	314022000272	0	12/31/1998	CD-CONDENSATE TANK FOUNDATIONS	-	
416	314022000272	1	12/31/1996	CD-CONDENSATE TANK FOUNDATIONS	15,426.32	
417	314028000272	0	12/31/1998	CN-CONDENSER SYSTEM TUBES	-	
418	314028000272	1	12/31/1968	CN-CONDENSER SYSTEM TUBES	178,873.47	
419	314028000272	3	5/30/2006	CN-CONDENSER SYSTEM TUBES	2,157,832.39	
420	314028000272	4	5/31/2011	CN-CONDENSER SYSTEM TUBES	23,997.83	
421	314032000272	0	12/31/1998	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	-	
422	314032000272	1	12/31/1968	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	85,849.22	
423	314032000272	2	12/31/1979	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	24,298.53	
424	314032000272	3	12/31/1984	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	94,702.62	
425	314032000272	8	12/31/1996	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	103,816.36	
426	314032000272	10	12/31/1992	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	9,653.74	
427	314032000272	11	10/30/2001	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	9,534.50	
428	314032000272	12	5/14/2002	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	45,228.50	
429	314032000272	13	5/14/2002	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	53,205.00	
430	314032000272	14	5/14/2002	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	31,597.91	
431	314032000272	15	5/14/2002	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	46,200.00	
432	314032000272	16	5/14/2002	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	374,208.41	

433	314032000272	17	5/31/2006	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	593,591.24	
434	314032000272	18	8/31/2006	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	34,625.09	
435	314032000272	19	12/28/2006	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	109,134.27	
436	314032000272	20	12/31/2008	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	48,983.17	
437	314032000272	22	12/31/2008	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	136,637.25	
438	314032000272	23	12/30/2013	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	106,101.20	
439	314032000272	24	5/16/2014	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	81,258.72	
440	314032000272	25	8/27/2015	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	193,980.18	
441	314032000272	26	8/27/2015	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	193,980.18	
442	314032000272	27	8/27/2015	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	193,980.18	
443	314032000272	28	8/27/2015	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	193,980.15	
444	314032000272	29	6/3/2016	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	314,878.40	
445	314032000272	30	6/3/2016	CT-NAUGHTON U2 COOLING TOWER STRUCTURE & EQUX	314,878.36	
446	314033000272	0	12/31/1998	CW-NAUGHTON U2 CIRCULATING WATER EQUIPMENT	-	
447	314033000272	1	12/31/1968	CW-NAUGHTON U2 CIRCULATING WATER EQUIPMENT	176,647.57	
448	314033000272	5	12/31/1994	CW-NAUGHTON U2 CIRCULATING WATER EQUIPMENT	132,146.78	
449	314033000272	6	8/10/2000	CW-NAUGHTON U2 CIRCULATING WATER EQUIPMENT	20,439.06	
450	314033000272	7	12/21/2001	CW-NAUGHTON U2 CIRCULATING WATER EQUIPMENT	23,838.70	
451	314033000272	8	3/28/2002	CW-NAUGHTON U2 CIRCULATING WATER EQUIPMENT	9,448.69	
452	314033000272	9	5/14/2002	CW-NAUGHTON U2 CIRCULATING WATER EQUIPMENT	506,174.71	
453	314033000272	10	5/14/2002	CW-NAUGHTON U2 CIRCULATING WATER EQUIPMENT	260,858.53	
454	314033000272	11	12/31/1998	CW-NAUGHTON U2 CIRCULATING WATER EQUIPMENT	34,250.14	
455	314033000272	12	5/26/2005	CW-NAUGHTON U2 CIRCULATING WATER EQUIPMENT	48,009.11	
456	314033000272	13	9/28/2007	CW-NAUGHTON U2 CIRCULATING WATER EQUIPMENT	44,193.76	
457	314033000272	14	4/28/2008	CW-NAUGHTON U2 CIRCULATING WATER EQUIPMENT	13,361.15	
458	314033000272	15	11/15/2011	CW-NAUGHTON U2 CIRCULATING WATER EQUIPMENT	180,668.92	
459	314033000272	16	6/3/2016	CW-NAUGHTON U2 CIRCULATING WATER EQUIPMENT	238,032.66	
460	314033000272	17	12/28/2017	CW-NAUGHTON U2 CIRCULATING WATER EQUIPMENT	69,423.98	
461	314050000272	6	12/31/1996	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	17,929.52	
462	314050000272	7	7/1/2000	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	12,426.93	
463	314050000272	9	5/14/2002	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	10,879.17	
464	314050000272	11	12/31/1998	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	31,005.01	
465	314050000272	12	5/31/2006	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	344,698.50	
466	314050000272	13	5/31/2006	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	43,717.59	
467	314050000272	14	7/18/2006	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	367,694.76	
468	314050000272	15	11/15/2011	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	1,869,820.60	
469	314050000272	16	11/15/2011	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	39,427.48	
470	314050000272	17	11/15/2011	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	89,353.08	
471	314050000272	18	3/28/2013	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	35,679.29	2,862,631.93
472	314062000272	0	12/31/1998	LO-NAUGHTON U2 LUBE OIL EQUIPMENT	-	
473	314062000272	3	12/31/1990	LO-NAUGHTON U2 LUBE OIL EQUIPMENT	6,559.09	
474	314062000272	4	12/28/2006	LO-NAUGHTON U2 LUBE OIL EQUIPMENT	33,740.84	
475	314062000272	5	1/24/2012	LO-NAUGHTON U2 LUBE OIL EQUIPMENT	48,858.80	
476	314062000272	6	6/3/2016	LO-NAUGHTON U2 LUBE OIL EQUIPMENT	68,642.53	
477	314065000272	0	12/31/1998	MS-MISCELLANEOUS	-	
478	314082000272	2	5/14/2002	SP - CAPITALIZED SPARE PARTS	87,376.57	
479	314082000272	3	5/14/2002	SP - CAPITALIZED SPARE PARTS	19,681.75	
480	314082000272	4	8/29/2005	SP - CAPITALIZED SPARE PARTS	102,301.19	
481	314082000272	5	12/29/2005	SP - CAPITALIZED SPARE PARTS	40,979.78	
482	314082000272	6	7/31/2006	SP - CAPITALIZED SPARE PARTS	389,028.04	
483	314084000272	0	12/31/1998	TB-NAUGHTON U2 TURBINE EQUIPMENT	-	
484	314084000272	1	12/31/1968	TB-NAUGHTON U2 TURBINE EQUIPMENT	3,383,038.37	
485	314084000272	3	12/31/1990	TB-NAUGHTON U2 TURBINE EQUIPMENT	9,775.92	
486	314084000272	4	12/31/1996	TB-NAUGHTON U2 TURBINE EQUIPMENT	6,562.76	
487	314084000272	6	12/31/1996	TB-NAUGHTON U2 TURBINE EQUIPMENT	267,334.68	
488	314084000272	9	12/31/1996	TB-NAUGHTON U2 TURBINE EQUIPMENT	25,799.53	
489	314084000272	10	12/31/1996	TB-NAUGHTON U2 TURBINE EQUIPMENT	34,910.10	
490	314084000272	11	5/9/2000	TB-NAUGHTON U2 TURBINE EQUIPMENT	68,486.05	
491	314084000272	12	5/14/2002	TB-NAUGHTON U2 TURBINE EQUIPMENT	2,106,073.03	
492	314084000272	13	5/14/2002	TB-NAUGHTON U2 TURBINE EQUIPMENT	17,922.47	
493	314084000272	14	5/14/2002	TB-NAUGHTON U2 TURBINE EQUIPMENT	47,225.36	
494	314084000272	19	12/31/1968	TB-NAUGHTON U2 TURBINE EQUIPMENT	217,227.76	
495	314084000272	20	12/31/1979	TB-NAUGHTON U2 TURBINE EQUIPMENT	413,035.10	
496	314084000272	21	5/28/2004	TB-NAUGHTON U2 TURBINE EQUIPMENT	20,650.46	
497	314084000272	22	7/6/2005	TB-NAUGHTON U2 TURBINE EQUIPMENT	63,605.73	
498	314084000272	23	4/28/2006	TB-NAUGHTON U2 TURBINE EQUIPMENT	60,065.44	
499	314084000272	24	5/31/2006	TB-NAUGHTON U2 TURBINE EQUIPMENT	427,494.92	
500	314084000272	25	5/31/2006	TB-NAUGHTON U2 TURBINE EQUIPMENT	346,641.87	
501	314084000272	26	5/31/2006	TB-NAUGHTON U2 TURBINE EQUIPMENT	1,051,476.27	
502	314084000272	27	5/31/2006	TB-NAUGHTON U2 TURBINE EQUIPMENT	131,704.52	
503	314084000272	28	5/31/2006	TB-NAUGHTON U2 TURBINE EQUIPMENT	133,574.60	
504	314084000272	29	5/31/2006	TB-NAUGHTON U2 TURBINE EQUIPMENT	8,314.66	
505	314084000272	31	7/31/2006	TB-NAUGHTON U2 TURBINE EQUIPMENT	504,875.37	

506		314084000272	32	7/31/2006	TB-NAUGHTON U2 TURBINE EQUIPMENT	198,641.24
507		314084000272	33	10/30/2009	TB-NAUGHTON U2 TURBINE EQUIPMENT	36,529.34
508		314084000272	34	11/15/2011	TB-NAUGHTON U2 TURBINE EQUIPMENT	68,088.77
509		314084000272	35	11/15/2011	TB-NAUGHTON U2 TURBINE EQUIPMENT	136,176.52
510		314084000272	36	11/15/2011	TB-NAUGHTON U2 TURBINE EQUIPMENT	68,088.78
511		314084000272	37	6/3/2016	TB-NAUGHTON U2 TURBINE EQUIPMENT	727,466.65
512		314084000272	38	6/3/2016	TB-NAUGHTON U2 TURBINE EQUIPMENT	519,619.03
513		314084000272	39	6/3/2016	TB-NAUGHTON U2 TURBINE EQUIPMENT	883,352.35
514		314084000272	40	6/3/2016	TB-NAUGHTON U2 TURBINE EQUIPMENT	259,809.53
515		314084000272	41	6/3/2016	TB-NAUGHTON U2 TURBINE EQUIPMENT	207,847.59
516		314084000272	42	6/3/2016	TB-NAUGHTON U2 TURBINE EQUIPMENT	89,946.91
517		314084000272	43	6/3/2016	TB-NAUGHTON U2 TURBINE EQUIPMENT	179,893.80
518		314084000272	44	6/3/2016	TB-NAUGHTON U2 TURBINE EQUIPMENT	89,946.90
519		314096000272	0	12/31/1998	WT-WATER TREATMENT - BOILER MAINT	-
520		314099000272	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-
521	*	Location	000272		NAUGHTON NO 2 STEAM ELECTRIC STATIO	23,998,929.85
522		314028000273	0	12/31/1998	CN-NAU U3 CONDENSER EQUIPMENT	-
523		314028000273	1	12/31/1971	CN-NAU U3 CONDENSER EQUIPMENT	830,244.57
524		314028000273	2	12/31/1987	CN-NAU U3 CONDENSER EQUIPMENT	26,045.10
525		314028000273	3	12/31/1989	CN-NAU U3 CONDENSER EQUIPMENT	5,784.20
526		314028000273	4	12/31/1995	CN-NAU U3 CONDENSER EQUIPMENT	46,575.90
527		314028000273	5	12/31/1995	CN-NAU U3 CONDENSER EQUIPMENT	515,035.89
528		314028000273	6	12/31/1993	CN-NAU U3 CONDENSER EQUIPMENT	23,927.14
529		314028000273	7	1/14/2003	CN-NAU U3 CONDENSER EQUIPMENT	36,066.06
530		314028000273	8	2/28/2008	CN-NAU U3 CONDENSER EQUIPMENT	32,676.72
531		314028000273	9	2/28/2008	CN-NAU U3 CONDENSER EQUIPMENT	14,004.31
532		314028000273	10	4/29/2009	CN-NAU U3 CONDENSER EQUIPMENT	42,626.89
533		314028000273	11	5/27/2015	CN-NAU U3 CONDENSER EQUIPMENT	412,135.93
534		314032000273	0	12/31/1998	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	-
535		314032000273	4	12/31/1995	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	306,153.08
536		314032000273	6	12/31/1995	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	297,394.07
537		314032000273	7	6/4/1999	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	565,673.34
538		314032000273	8	1/6/2002	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	8,904.17
539		314032000273	9	1/23/2002	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	18,437.32
540		314032000273	10	11/25/2003	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	1,969,567.36
541		314032000273	11	11/25/2003	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	220,576.86
542		314032000273	12	11/25/2003	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	131,622.61
543		314032000273	14	11/25/2003	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	159,922.90
544		314032000273	15	12/31/1998	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	24,834.71
545		314032000273	17	5/31/2006	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	179,503.23
546		314032000273	18	6/29/2006	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	289,823.35
547		314032000273	19	1/31/2008	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	4,383.76
548		314032000273	20	4/25/2008	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	185,161.57
549		314032000273	21	12/31/1995	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	20,860.00
550		314032000273	22	4/29/2009	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	1,048,862.71
551		314032000273	23	4/29/2009	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	174,810.44
552		314032000273	24	4/29/2009	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	174,810.44
553		314032000273	25	4/29/2009	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	114,438.44
554		314032000273	26	4/29/2009	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	174,810.44
555		314032000273	27	4/29/2009	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	174,810.44
556		314032000273	28	4/29/2009	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	349,620.92
557		314032000273	29	4/29/2009	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	174,810.44
558		314032000273	30	4/29/2009	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	174,810.44
559		314032000273	31	4/29/2009	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	699,241.82
560		314032000273	32	4/29/2009	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	174,810.54
561		314032000273	33	1/31/2013	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	53,761.96
562		314032000273	34	5/31/2013	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	38,665.75
563		314032000273	35	12/31/2013	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	12,072.88
564		314032000273	36	5/27/2015	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	450,824.05
565		314032000273	37	2/26/2016	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	49,280.63
566		314032000273	38	12/30/2016	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	29,213.90
567		314032000273	39	1/31/2018	CT-NAU U3 COOLING TOWER STRUCTURES & EQUIP	25,856.22
568		314033000273	0	12/31/1998	CW-NAU U3 CIRCULATING WATER EQUIPMENT	-
569		314033000273	1	12/31/1971	CW-NAU U3 CIRCULATING WATER EQUIPMENT	727,677.21
570		314033000273	4	12/31/1993	CW-NAU U3 CIRCULATING WATER EQUIPMENT	754,247.00
571		314033000273	5	6/4/1999	CW-NAU U3 CIRCULATING WATER EQUIPMENT	113,047.86
572		314033000273	6	6/4/1999	CW-NAU U3 CIRCULATING WATER EQUIPMENT	184,643.72
573		314033000273	7	11/7/2000	CW-NAU U3 CIRCULATING WATER EQUIPMENT	168,133.87
574		314033000273	8	12/21/2001	CW-NAU U3 CIRCULATING WATER EQUIPMENT	23,838.70
575		314033000273	9	3/28/2002	CW-NAU U3 CIRCULATING WATER EQUIPMENT	8,281.58
576		314033000273	10	10/24/2003	CW-NAU U3 CIRCULATING WATER EQUIPMENT	54,246.25
577		314033000273	11	5/26/2005	CW-NAU U3 CIRCULATING WATER EQUIPMENT	110,410.38
578		314033000273	12	9/29/2005	CW-NAU U3 CIRCULATING WATER EQUIPMENT	53,022.86

579	314033000273	13	9/28/2007	CW-NAU U3 CIRCULATING WATER EQUIPMENT	30,331.58	
580	314033000273	14	2/28/2008	CW-NAU U3 CIRCULATING WATER EQUIPMENT	5,237.76	
581	314033000273	15	4/25/2008	CW-NAU U3 CIRCULATING WATER EQUIPMENT	86,723.81	
582	314033000273	16	4/29/2009	CW-NAU U3 CIRCULATING WATER EQUIPMENT	101,185.50	
583	314033000273	17	5/26/2015	CW-NAU U3 CIRCULATING WATER EQUIPMENT	43,717.93	
584	314033000273	18	5/26/2015	CW-NAU U3 CIRCULATING WATER EQUIPMENT	4,857.55	
585	314033000273	19	12/31/2015	CW-NAU U3 CIRCULATING WATER EQUIPMENT	69,228.34	
586	314050000273	0	12/31/1998	GN-NAU U3 GENERATOR EQUIPMENT	-	
587	314050000273	2	12/31/1996	GN-NAU U3 GENERATOR EQUIPMENT	40,987.03	
588	314050000273	3	12/31/1993	GN-NAU U3 GENERATOR EQUIPMENT	355,107.86	
589	314050000273	4	12/31/1994	GN-NAU U3 GENERATOR EQUIPMENT	21,308.49	
590	314050000273	5	6/4/1999	GN-NAU U3 GENERATOR EQUIPMENT	78,884.45	
591	314050000273	6	6/19/2001	GN-NAU U3 GENERATOR EQUIPMENT	76,013.28	
592	314050000273	7	10/24/2003	GN-NAU U3 GENERATOR EQUIPMENT	3,587,313.81	
593	314050000273	8	10/24/2003	GN-NAU U3 GENERATOR EQUIPMENT	69,524.78	
594	314050000273	9	10/24/2003	GN-NAU U3 GENERATOR EQUIPMENT	112,093.01	
595	314050000273	10	10/24/2003	GN-NAU U3 GENERATOR EQUIPMENT	493,368.38	
596	314050000273	11	8/31/2006	GN-NAU U3 GENERATOR EQUIPMENT	5,784.37	
597	314050000273	13	4/29/2009	GN-NAU U3 GENERATOR EQUIPMENT	187,861.47	
598	314050000273	14	4/30/2009	GN-NAU U3 GENERATOR EQUIPMENT	2,818,914.93	
599	314050000273	15	5/28/2009	GN-NAU U3 GENERATOR EQUIPMENT	2,043,422.92	
600	314050000273	16	4/29/2009	GN-NAU U3 GENERATOR EQUIPMENT	514,346.09	
601	314050000273	17	5/16/2011	GN-NAU U3 GENERATOR EQUIPMENT	45,553.76	10,450,484.63
602	314062000273	0	12/31/1998	LO-NAU U3 LUBE OIL EQUIPMENT	-	
603	314062000273	1	12/31/1971	LO-NAU U3 LUBE OIL EQUIPMENT	71,131.69	
604	314062000273	2	12/31/1991	LO-NAU U3 LUBE OIL EQUIPMENT	22,562.88	
605	314062000273	3	12/31/1993	LO-NAU U3 LUBE OIL EQUIPMENT	11,618.71	
606	314082000273	0	12/31/1998	SP-NAU U3 CAPITALIZED SPARE PARTS FERC 314	-	
607	314082000273	1	12/31/1983	SP-NAU U3 CAPITALIZED SPARE PARTS FERC 314	10,589.21	
608	314082000273	5	6/4/2001	SP-NAU U3 CAPITALIZED SPARE PARTS FERC 314	25,292.40	
609	314082000273	6	2/26/2005	SP-NAU U3 CAPITALIZED SPARE PARTS FERC 314	11,069.00	
610	314082000273	7	2/26/2005	SP-NAU U3 CAPITALIZED SPARE PARTS FERC 314	11,069.00	
611	314082000273	8	7/18/2005	SP-NAU U3 CAPITALIZED SPARE PARTS FERC 314	163,734.29	
612	314082000273	12	1/31/2008	SP-NAU U3 CAPITALIZED SPARE PARTS FERC 314	42,933.47	
613	314082000273	13	2/26/2016	SP-NAU U3 CAPITALIZED SPARE PARTS FERC 314	25,693.82	
614	314084000273	0	12/31/1998	TB-NAU U3 TURBINE EQUIPMENT	-	
615	314084000273	1	12/31/1971	TB-NAU U3 TURBINE EQUIPMENT	5,023,967.86	
616	314084000273	2	12/31/1980	TB-NAU U3 TURBINE EQUIPMENT	32,693.60	
617	314084000273	3	12/31/1982	TB-NAU U3 TURBINE EQUIPMENT	103,439.01	
618	314084000273	4	12/31/1985	TB-NAU U3 TURBINE EQUIPMENT	293,074.80	
619	314084000273	5	12/31/1992	TB-NAU U3 TURBINE EQUIPMENT	66,074.43	
620	314084000273	7	12/31/1995	TB-NAU U3 TURBINE EQUIPMENT	381,272.61	
621	314084000273	8	6/28/1999	TB-NAU U3 TURBINE EQUIPMENT	116,137.27	
622	314084000273	9	5/9/2000	TB-NAU U3 TURBINE EQUIPMENT	67,173.77	
623	314084000273	10	10/24/2003	TB-NAU U3 TURBINE EQUIPMENT	1,313,392.55	
624	314084000273	13	10/24/2003	TB-NAU U3 TURBINE EQUIPMENT	755,460.00	
625	314084000273	14	12/30/2003	TB-NAU U3 TURBINE EQUIPMENT	53,161.25	
626	314084000273	15	12/31/1979	TB-NAU U3 TURBINE EQUIPMENT	377,612.87	
627	314084000273	16	12/31/1984	TB-NAU U3 TURBINE EQUIPMENT	140,569.78	
628	314084000273	17	12/31/1986	TB-NAU U3 TURBINE EQUIPMENT	127,926.17	
629	314084000273	18	12/14/2004	TB-NAU U3 TURBINE EQUIPMENT	121,316.62	
630	314084000273	19	9/27/2005	TB-NAU U3 TURBINE EQUIPMENT	196,988.57	
631	314084000273	20	12/31/1988	TB-NAU U3 TURBINE EQUIPMENT	22,577.75	
632	314084000273	21	4/30/2009	TB-NAU U3 TURBINE EQUIPMENT	459,856.49	
633	314084000273	22	4/30/2009	TB-NAU U3 TURBINE EQUIPMENT	491,500.49	
634	314084000273	23	4/30/2009	TB-NAU U3 TURBINE EQUIPMENT	753,634.07	
635	314084000273	24	4/30/2009	TB-NAU U3 TURBINE EQUIPMENT	294,900.32	
636	314084000273	25	4/30/2009	TB-NAU U3 TURBINE EQUIPMENT	622,567.27	
637	314084000273	26	4/30/2009	TB-NAU U3 TURBINE EQUIPMENT	622,567.27	
638	314084000273	28	5/16/2011	TB-NAU U3 TURBINE EQUIPMENT	68,330.62	
639	314084000273	29	4/30/2009	TB-NAU U3 TURBINE EQUIPMENT	19,363.20	
640	314084000273	30	5/27/2015	TB-NAU U3 TURBINE EQUIPMENT	1,772,796.92	
641	314084000273	31	5/27/2015	TB-NAU U3 TURBINE EQUIPMENT	443,199.23	
642	314084000273	32	5/27/2015	TB-NAU U3 TURBINE EQUIPMENT	68,737.80	
643	314084000273	33	5/27/2015	TB-NAU U3 TURBINE EQUIPMENT	137,475.63	
644	314084000273	34	5/27/2015	TB-NAU U3 TURBINE EQUIPMENT	68,737.77	
645	314084000273	35	5/27/2015	TB-NAU U3 TURBINE EQUIPMENT	50,169.29	
646	314084000273	36	12/31/2015	TB-NAU U3 TURBINE EQUIPMENT	63,775.19	
647	314084000273	37	6/27/2017	TB-NAU U3 TURBINE EQUIPMENT	39,762.48	
648	314096000273	0	12/31/1998	WT-NAU U3 WATER TREATMENT EQUIPMENT	-	
649	314096000273	1	12/31/1971	WT-NAU U3 WATER TREATMENT EQUIPMENT	34,269.70	
650	314099000273	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
651	* Location	000273		NAUGHTON NO 3 STEAM ELECTRIC STATIO	39,052,947.15	

652	314028000280	0	12/31/1998	CN-HUNTINGTON U0 CONDENSER SYSTEM	-	
653	314028000280	1	12/31/1994	CN-HUNTINGTON U0 CONDENSER SYSTEM	26,695.99	
654	314028000280	2	12/31/1994	CN-HUNTINGTON U0 CONDENSER SYSTEM	1,770,336.35	
655	314028000280	3	7/15/1999	CN-HUNTINGTON U0 CONDENSER SYSTEM	49,035.18	
656	314028000280	4	3/29/2000	CN-HUNTINGTON U0 CONDENSER SYSTEM	36,345.21	
657	314028000280	5	8/20/2003	CN-HUNTINGTON U0 CONDENSER SYSTEM	37,312.65	
658	314028000280	6	3/31/2005	CN-HUNTINGTON U0 CONDENSER SYSTEM	9,718.89	
659	314028000280	7	3/31/2006	CN-HUNTINGTON U0 CONDENSER SYSTEM	66,637.56	
660	314028000280	8	3/31/2006	CN-HUNTINGTON U0 CONDENSER SYSTEM	46,748.80	
661	314032000280	0	12/31/1998	CT-HUNTINGTON U0 COOLING TOWER EQUIPMENT	-	
662	314032000280	1	12/31/1974	CT-HUNTINGTON U0 COOLING TOWER EQUIPMENT	146,606.63	
663	314032000280	2	12/31/1979	CT-HUNTINGTON U0 COOLING TOWER EQUIPMENT	67,735.27	
664	314032000280	3	12/31/1990	CT-HUNTINGTON U0 COOLING TOWER EQUIPMENT	13,017.96	
665	314032000280	4	10/26/2005	CT-HUNTINGTON U0 COOLING TOWER EQUIPMENT	14,167.67	
666	314032000280	5	12/31/1980	CT-HUNTINGTON U0 COOLING TOWER EQUIPMENT	8,514.55	
667	314032000280	6	12/20/2007	CT-HUNTINGTON U0 COOLING TOWER EQUIPMENT	66,319.07	
668	314032000280	8	11/24/2014	CT-HUNTINGTON U0 COOLING TOWER EQUIPMENT	30,262.42	
669	314033000280	0	12/31/1998	CW-HUNTINGTON U0 CIRCULATING WATER EQUIPMENT	-	
670	314033000280	1	12/31/1974	CW-HUNTINGTON U0 CIRCULATING WATER EQUIPMENT	2,273,202.07	
671	314033000280	2	12/31/1977	CW-HUNTINGTON U0 CIRCULATING WATER EQUIPMENT	312,577.87	
672	314033000280	5	12/31/1984	CW-HUNTINGTON U0 CIRCULATING WATER EQUIPMENT	41,985.41	
673	314033000280	6	12/31/1987	CW-HUNTINGTON U0 CIRCULATING WATER EQUIPMENT	12,046.55	
674	314033000280	7	12/31/1994	CW-HUNTINGTON U0 CIRCULATING WATER EQUIPMENT	186,528.16	
675	314033000280	8	11/18/1999	CW-HUNTINGTON U0 CIRCULATING WATER EQUIPMENT	120,577.58	
676	314033000280	9	5/8/2003	CW-HUNTINGTON U0 CIRCULATING WATER EQUIPMENT	100,724.70	
677	314033000280	10	3/31/2006	CW-HUNTINGTON U0 CIRCULATING WATER EQUIPMENT	42,718.46	
678	314033000280	11	7/12/2006	CW-HUNTINGTON U0 CIRCULATING WATER EQUIPMENT	12,881.01	
679	314033000280	12	7/22/2008	CW-HUNTINGTON U0 CIRCULATING WATER EQUIPMENT	9,012.73	
680	314033000280	13	7/22/2008	CW-HUNTINGTON U0 CIRCULATING WATER EQUIPMENT	9,012.73	
681	314033000280	14	11/24/2014	CW-HUNTINGTON U0 CIRCULATING WATER EQUIPMENT	136,502.90	
682	314033000280	15	9/28/2016	CW-HUNTINGTON U0 CIRCULATING WATER EQUIPMENT	206,500.46	
683	314050000280	0	12/31/1998	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	-	
684	314050000280	1	12/31/1986	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	102,840.49	
685	314050000280	2	6/24/1999	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	5,879.57	
686	314050000280	3	12/31/1997	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	6,711.61	115,431.67
687	314062000280	0	12/19/2012	LO-LUBE OIL PUMPS & PUMP MOTORS	77,731.51	
688	314082000280	0	12/31/1998	SP-CAPITALIZED SPARE PARTS	-	
689	314082000280	2	12/31/1986	SP-CAPITALIZED SPARE PARTS	6,756.26	
690	314082000280	3	12/31/1995	SP-CAPITALIZED SPARE PARTS	529,014.82	
691	314082000280	4	12/29/2006	SP-CAPITALIZED SPARE PARTS	43,109.79	
692	314082000280	5	12/31/2011	SP-CAPITALIZED SPARE PARTS	68,895.04	
693	314082000280	6	10/7/2014	SP-CAPITALIZED SPARE PARTS	20,514.96	
694	314084000280	0	10/2/2000	TB-MAIN TURBINE	6,458.80	
695	314084000280	1	4/30/2012	TB-MAIN TURBINE	77,641.72	
696	314084000280	2	9/21/2018	TB-MAIN TURBINE	437,030.29	
697	314096000280	0	12/31/1998	WT-WATER TREATMENT - BOILER MAINT	-	
698	314096000280	1	12/31/1992	WT-WATER TREATMENT - BOILER MAINT	13,929.26	
699	314099000280	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
700	* Location	000280		HUNTINGTON PLANT COMMON FACILITIES	7,250,238.95	
701	314007000281	0	12/31/1998	AZ-AIR CONDITIONING SYSTEM	-	
702	314028000281	0	12/31/1998	CN-HUNTINGTON U1 CONDENSER SYSTEM	-	
703	314028000281	1	12/31/1977	CN-HUNTINGTON U1 CONDENSER SYSTEM	657,315.63	
704	314028000281	2	12/31/1992	CN-HUNTINGTON U1 CONDENSER SYSTEM	19,285.46	
705	314028000281	3	12/31/1994	CN-HUNTINGTON U1 CONDENSER SYSTEM	1,422,280.73	
706	314028000281	5	10/25/2005	CN-HUNTINGTON U1 CONDENSER SYSTEM	2,563,948.53	
707	314028000281	6	10/30/2018	CN-HUNTINGTON U1 CONDENSER SYSTEM	74,306.45	
708	314032000281	0	12/31/1998	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	-	
709	314032000281	1	12/31/1977	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	744,761.71	
710	314032000281	2	3/29/2000	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	29,812.95	
711	314032000281	3	10/11/2001	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	17,765.63	
712	314032000281	4	10/11/2001	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	74,292.31	
713	314032000281	5	12/31/1997	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	1,641,549.66	
714	314032000281	7	11/29/2010	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	454,896.28	
715	314032000281	8	11/30/2010	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	454,896.27	
716	314032000281	9	7/29/2016	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	541,234.63	
717	314032000281	10	9/26/2016	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	54,123.46	
718	314032000281	11	9/26/2016	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	108,246.93	
719	314032000281	12	9/26/2016	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	54,123.46	
720	314032000281	13	9/26/2016	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	54,123.46	
721	314032000281	14	9/26/2016	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	108,246.93	
722	314032000281	15	9/26/2016	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	162,370.39	
723	314032000281	16	2/24/2017	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	125,718.15	
724	314032000281	17	5/8/2017	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	2,127,321.68	

725	314032000281	18	10/30/2018	CT-HNT U1 COOLING TOWER STRUCTURES & EQUIPMEX	2,248,321.74	
726	314033000281	0	12/31/1998	CW-HUNTINGTON U1 CIRCULATING WATER EQUIPMENT	-	
727	314033000281	1	12/31/1977	CW-HUNTINGTON U1 CIRCULATING WATER EQUIPMENT	3,279,921.45	
728	314033000281	2	12/31/1987	CW-HUNTINGTON U1 CIRCULATING WATER EQUIPMENT	13,459.64	
729	314033000281	3	12/31/1990	CW-HUNTINGTON U1 CIRCULATING WATER EQUIPMENT	44,949.49	
730	314033000281	4	12/31/1997	CW-HUNTINGTON U1 CIRCULATING WATER EQUIPMENT	626,245.36	
731	314033000281	5	2/15/2006	CW-HUNTINGTON U1 CIRCULATING WATER EQUIPMENT	29,324.38	
732	314033000281	6	10/31/2014	CW-HUNTINGTON U1 CIRCULATING WATER EQUIPMENT	206,880.49	
733	314033000281	7	10/29/2014	CW-HUNTINGTON U1 CIRCULATING WATER EQUIPMENT	34,071.43	
734	314033000281	8	12/30/2014	CW-HUNTINGTON U1 CIRCULATING WATER EQUIPMENT	63,665.82	
735	314050000281	0	12/31/1998	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	-	
736	314050000281	1	12/31/1977	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	1,641,614.75	
737	314050000281	2	12/31/1980	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	47,422.99	
738	314050000281	3	12/31/1985	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	5,642.14	
739	314050000281	4	12/31/1989	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	62,454.17	
740	314050000281	5	12/31/1993	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	10,823.62	
741	314050000281	8	12/31/1996	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	8,482.76	
742	314050000281	9	6/27/2002	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	46,727.23	
743	314050000281	10	6/9/2004	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	37,642.84	
744	314050000281	11	12/31/1997	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	3,057.68	
745	314050000281	12	10/31/2005	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	2,282,314.24	
746	314050000281	13	10/31/2005	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	333,477.34	
747	314050000281	14	10/31/2005	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	1,857,945.08	
748	314050000281	15	10/31/2005	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	190,558.45	
749	314050000281	16	10/31/2005	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	356,358.50	
750	314050000281	17	3/16/2009	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	101,076.94	
751	314050000281	18	2/28/2012	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	352,174.20	
752	314050000281	19	10/31/2014	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	264,988.66	
753	314050000281	20	10/30/2018	GN-HUNTINGTON U1 GENERATOR EQUIPMENT	267,598.10	7,870,359.69
754	314062000281	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
755	314062000281	1	12/31/1977	LO-LUBE OIL PUMPS & PUMP MOTORS	3,322,961.83	
756	314062000281	2	12/31/1987	LO-LUBE OIL PUMPS & PUMP MOTORS	56,065.20	
757	314062000281	3	2/15/2006	LO-LUBE OIL PUMPS & PUMP MOTORS	37,558.16	
758	314062000281	4	3/31/2006	LO-LUBE OIL PUMPS & PUMP MOTORS	29,575.99	
759	314062000281	5	12/24/2008	LO-LUBE OIL PUMPS & PUMP MOTORS	74,068.97	
760	314082000281	4	12/31/1992	SP-CAPITALIZED SPARE PARTS	21,707.14	
761	314082000281	5	12/22/2006	SP-CAPITALIZED SPARE PARTS	86,835.56	
762	314082000281	6	12/31/1992	SP-CAPITALIZED SPARE PARTS	43,414.28	
763	314082000281	7	12/22/2006	SP-CAPITALIZED SPARE PARTS	499,264.22	
764	314084000281	0	12/31/1998	TB-HUNTINGTON U1 TURBINE EQUIPMENT	-	
765	314084000281	1	12/31/1977	TB-HUNTINGTON U1 TURBINE EQUIPMENT	1,616,193.54	
766	314084000281	2	12/31/1987	TB-HUNTINGTON U1 TURBINE EQUIPMENT	29,194.98	
767	314084000281	3	12/31/1988	TB-HUNTINGTON U1 TURBINE EQUIPMENT	327,020.82	
768	314084000281	5	12/31/1994	TB-HUNTINGTON U1 TURBINE EQUIPMENT	10,357.06	
769	314084000281	8	12/30/1999	TB-HUNTINGTON U1 TURBINE EQUIPMENT	37,432.66	
770	314084000281	9	10/11/2001	TB-HUNTINGTON U1 TURBINE EQUIPMENT	3,880.84	
771	314084000281	10	8/20/2003	TB-HUNTINGTON U1 TURBINE EQUIPMENT	17,715.12	
772	314084000281	11	8/20/2003	TB-HUNTINGTON U1 TURBINE EQUIPMENT	29,669.26	
773	314084000281	12	8/20/2003	TB-HUNTINGTON U1 TURBINE EQUIPMENT	23,476.06	
774	314084000281	13	6/9/2004	TB-HUNTINGTON U1 TURBINE EQUIPMENT	228,420.21	
775	314084000281	14	11/3/2004	TB-HUNTINGTON U1 TURBINE EQUIPMENT	2,018,779.45	
776	314084000281	15	10/31/2005	TB-HUNTINGTON U1 TURBINE EQUIPMENT	760,174.56	
777	314084000281	16	10/31/2005	TB-HUNTINGTON U1 TURBINE EQUIPMENT	214,254.81	
778	314084000281	17	10/31/2005	TB-HUNTINGTON U1 TURBINE EQUIPMENT	179,794.77	
779	314084000281	18	10/31/2005	TB-HUNTINGTON U1 TURBINE EQUIPMENT	153,905.86	
780	314084000281	19	10/31/2005	TB-HUNTINGTON U1 TURBINE EQUIPMENT	33,653.90	
781	314084000281	20	10/31/2005	TB-HUNTINGTON U1 TURBINE EQUIPMENT	78,334.51	
782	314084000281	21	10/31/2005	TB-HUNTINGTON U1 TURBINE EQUIPMENT	22,975.27	
783	314084000281	23	3/31/2006	TB-HUNTINGTON U1 TURBINE EQUIPMENT	2,619.97	
784	314084000281	24	12/20/2007	TB-HUNTINGTON U1 TURBINE EQUIPMENT	163,108.10	
785	314084000281	26	4/6/2009	TB-HUNTINGTON U1 TURBINE EQUIPMENT	36,769.12	
786	314084000281	27	11/30/2010	TB-HUNTINGTON U1 TURBINE EQUIPMENT	7,439,364.31	
787	314084000281	28	12/17/2010	TB-HUNTINGTON U1 TURBINE EQUIPMENT	342,617.69	
788	314084000281	29	11/30/2010	TB-HUNTINGTON U1 TURBINE EQUIPMENT	5,797,181.65	
789	314084000281	30	11/30/2010	TB-HUNTINGTON U1 TURBINE EQUIPMENT	11,594,363.31	
790	314084000281	32	12/19/2012	TB-HUNTINGTON U1 TURBINE EQUIPMENT	28,717.58	
791	314084000281	33	10/29/2014	TB-HUNTINGTON U1 TURBINE EQUIPMENT	23,261.32	
792	314084000281	34	1/31/2017	TB-HUNTINGTON U1 TURBINE EQUIPMENT	169,676.84	
793	314084000281	35	10/30/2018	TB-HUNTINGTON U1 TURBINE EQUIPMENT	281,517.26	
794	314084000281	36	10/30/2018	TB-HUNTINGTON U1 TURBINE EQUIPMENT	125,479.46	
795	314084000281	37	10/30/2018	TB-HUNTINGTON U1 TURBINE EQUIPMENT	70,464.91	
796	314084000281	38	10/30/2018	TB-HUNTINGTON U1 TURBINE EQUIPMENT	63,897.09	
797	314084000281	39	10/30/2018	TB-HUNTINGTON U1 TURBINE EQUIPMENT	32,571.92	

798	314084000281	40	10/30/2018	TB-HUNTINGTON U1 TURBINE EQUIPMENT	19,787.25	
799	314099000281	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
800	* Location	000281		HUNTINGTON NO 1 STEAM ELECTRIC STAT	62,055,903.00	
801	314028000282	0	12/31/1998	CN-HUNTINGTON U2 CONDENSER SYSTEM	-	
802	314028000282	1	12/31/1974	CN-HUNTINGTON U2 CONDENSER SYSTEM	712,675.95	
803	314028000282	2	12/31/1981	CN-HUNTINGTON U2 CONDENSER SYSTEM	39,051.76	
804	314028000282	4	12/31/1995	CN-HUNTINGTON U2 CONDENSER SYSTEM	16,765.48	
805	314028000282	5	12/31/1994	CN-HUNTINGTON U2 CONDENSER SYSTEM	36,230.48	
806	314028000282	6	12/31/1994	CN-HUNTINGTON U2 CONDENSER SYSTEM	1,951,118.74	
807	314028000282	7	2/18/2003	CN-HUNTINGTON U2 CONDENSER SYSTEM	2,096,134.74	
808	314028000282	8	12/29/2006	CN-HUNTINGTON U2 CONDENSER SYSTEM	14,232.28	
809	314028000282	9	4/28/2009	CN-HUNTINGTON U2 CONDENSER SYSTEM	14,439.13	
810	314032000282	0	12/31/1998	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	-	
811	314032000282	1	12/31/1974	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	311,362.38	
812	314032000282	2	12/31/1994	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	202,142.72	
813	314032000282	3	12/31/1994	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	173,130.44	
814	314032000282	6	12/31/1994	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	341,452.51	
815	314032000282	9	12/31/1996	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	502,184.81	
816	314032000282	11	12/31/1994	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	149,835.21	
817	314032000282	14	11/18/2008	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	616,111.13	
818	314032000282	15	11/18/2008	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	4,648.20	
819	314032000282	16	11/18/2008	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	259,036.54	
820	314032000282	17	3/3/2011	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	233,107.88	
821	314032000282	18	11/30/2012	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	36,113.76	
822	314032000282	19	7/9/2013	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	37,641.11	
823	314032000282	20	11/30/2015	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	515,529.78	
824	314032000282	21	5/9/2016	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	455,990.93	
825	314032000282	22	7/29/2016	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	536,224.78	
826	314032000282	23	9/26/2016	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	53,622.48	
827	314032000282	24	9/26/2016	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	107,244.96	
828	314032000282	25	9/26/2016	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	53,622.48	
829	314032000282	26	9/26/2016	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	53,622.48	
830	314032000282	27	9/26/2016	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	107,244.96	
831	314032000282	28	9/26/2016	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	160,867.44	
832	314032000282	29	2/24/2017	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	125,718.14	
833	314032000282	30	5/8/2017	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	2,004,051.10	
834	314032000282	31	8/23/2016	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	14,107.87	
835	314032000282	32	11/27/2019	CT-HNT U2 COOLING TOWER STRUCTURES & EQUIPMEX	2,320,089.66	
836	314033000282	0	12/31/1998	CW-PUMPS	-	
837	314033000282	1	12/31/1974	CW-PUMPS	1,310,166.02	
838	314033000282	2	12/31/1987	CW-PUMPS	13,459.64	
839	314033000282	3	12/31/1994	CW-PUMPS	63,659.86	
840	314033000282	4	12/31/1990	CW-PUMPS	42,198.97	
841	314033000282	5	12/31/1998	CW-PUMPS	568,758.74	
842	314033000282	6	2/18/2003	CW-PUMPS	92,486.56	
843	314033000282	7	11/21/2006	CW-PUMPS	97,960.11	
844	314033000282	8	12/29/2006	CW-PUMPS	12,507.74	
845	314033000282	9	12/31/1981	CW-PUMPS	130,262.10	
846	314033000282	10	10/29/2014	CW-PUMPS	33,950.08	
847	314033000282	11	10/18/2015	CW-PUMPS	162,170.13	
848	314050000282	0	12/31/1998	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	-	
849	314050000282	1	12/31/1980	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	10,821.81	
850	314050000282	2	12/31/1985	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	1,198.58	
851	314050000282	3	12/31/1990	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	53,428.04	
852	314050000282	4	12/31/1994	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	150,567.46	
853	314050000282	5	12/31/1994	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	114,020.93	
854	314050000282	6	12/31/1996	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	8,869.49	
855	314050000282	7	6/23/1999	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	404,725.66	
856	314050000282	8	6/23/1999	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	109,157.32	
857	314050000282	9	6/23/1999	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	14,009.04	
858	314050000282	10	6/23/1999	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	24,731.35	
859	314050000282	11	12/12/2002	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	71,070.95	
860	314050000282	12	6/9/2004	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	40,557.50	
861	314050000282	13	12/31/1989	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	15,424.24	
862	314050000282	15	11/22/2006	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	2,566,908.49	
863	314050000282	16	5/9/2007	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	377,648.13	
864	314050000282	17	4/29/2010	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	100,555.98	
865	314050000282	19	6/5/2006	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	364,630.41	
866	314050000282	20	11/30/2011	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	2,699,474.93	
867	314050000282	21	11/30/2011	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	7,304,319.36	14,432,119.67
868	314062000282	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
869	314062000282	1	12/31/1974	LO-LUBE OIL PUMPS & PUMP MOTORS	246,631.76	
870	314062000282	2	12/31/1987	LO-LUBE OIL PUMPS & PUMP MOTORS	89,334.55	

871	314062000282	3	12/31/1990	LO-LUBE OIL PUMPS & PUMP MOTORS	18,329.91	
872	314062000282	4	3/31/2006	LO-LUBE OIL PUMPS & PUMP MOTORS	29,576.00	
873	314062000282	5	12/24/2008	LO-LUBE OIL PUMPS & PUMP MOTORS	74,068.97	
874	314082000282	0	12/31/1998	SP-CAPITALIZED SPARE PARTS	-	
875	314082000282	2	12/31/1981	SP-CAPITALIZED SPARE PARTS	93,208.40	
876	314084000282	0	12/31/1998	TB-HUNTINGTON U2 TURBINE EQUIPMENT	-	
877	314084000282	1	12/31/1977	TB-HUNTINGTON U2 TURBINE EQUIPMENT	11,667,180.39	
878	314084000282	4	12/31/1988	TB-HUNTINGTON U2 TURBINE EQUIPMENT	303,778.40	
879	314084000282	5	12/31/1992	TB-HUNTINGTON U2 TURBINE EQUIPMENT	1,827,278.45	
880	314084000282	6	12/31/1993	TB-HUNTINGTON U2 TURBINE EQUIPMENT	17,944.69	
881	314084000282	7	12/31/1992	TB-HUNTINGTON U2 TURBINE EQUIPMENT	965,928.06	
882	314084000282	8	12/31/1992	TB-HUNTINGTON U2 TURBINE EQUIPMENT	82,406.64	
883	314084000282	9	12/31/1993	TB-HUNTINGTON U2 TURBINE EQUIPMENT	36,937.41	
884	314084000282	10	12/30/1999	TB-HUNTINGTON U2 TURBINE EQUIPMENT	37,432.65	
885	314084000282	11	12/31/1998	TB-HUNTINGTON U2 TURBINE EQUIPMENT	7,554,549.98	
886	314084000282	12	12/31/1998	TB-HUNTINGTON U2 TURBINE EQUIPMENT	83,180.37	
887	314084000282	13	12/31/1998	TB-HUNTINGTON U2 TURBINE EQUIPMENT	17,929.86	
888	314084000282	14	2/18/2003	TB-HUNTINGTON U2 TURBINE EQUIPMENT	160,194.58	
889	314084000282	15	2/18/2003	TB-HUNTINGTON U2 TURBINE EQUIPMENT	26,765.78	
890	314084000282	16	2/18/2003	TB-HUNTINGTON U2 TURBINE EQUIPMENT	11,310.77	
891	314084000282	17	8/20/2003	TB-HUNTINGTON U2 TURBINE EQUIPMENT	15,011.00	
892	314084000282	19	8/20/2003	TB-HUNTINGTON U2 TURBINE EQUIPMENT	51,793.98	
893	314084000282	20	8/20/2003	TB-HUNTINGTON U2 TURBINE EQUIPMENT	54,199.17	
894	314084000282	21	11/10/2004	TB-HUNTINGTON U2 TURBINE EQUIPMENT	32,222.19	
895	314084000282	22	12/31/1998	TB-HUNTINGTON U2 TURBINE EQUIPMENT	169,782.50	
896	314084000282	23	12/31/1988	TB-HUNTINGTON U2 TURBINE EQUIPMENT	61,831.16	
897	314084000282	24	12/31/1997	TB-HUNTINGTON U2 TURBINE EQUIPMENT	26,614.12	
898	314084000282	25	12/31/1997	TB-HUNTINGTON U2 TURBINE EQUIPMENT	23,368.18	
899	314084000282	26	3/31/2006	TB-HUNTINGTON U2 TURBINE EQUIPMENT	5,625.16	
900	314084000282	27	12/29/2006	TB-HUNTINGTON U2 TURBINE EQUIPMENT	371,462.53	
901	314084000282	28	12/29/2006	TB-HUNTINGTON U2 TURBINE EQUIPMENT	220,887.23	
902	314084000282	29	12/29/2006	TB-HUNTINGTON U2 TURBINE EQUIPMENT	307,904.46	
903	314084000282	30	12/29/2006	TB-HUNTINGTON U2 TURBINE EQUIPMENT	293,038.32	
904	314084000282	31	12/29/2006	TB-HUNTINGTON U2 TURBINE EQUIPMENT	55,288.79	
905	314084000282	32	12/29/2006	TB-HUNTINGTON U2 TURBINE EQUIPMENT	25,364.38	
906	314084000282	33	12/20/2007	TB-HUNTINGTON U2 TURBINE EQUIPMENT	167,977.76	
907	314084000282	34	12/31/1991	TB-HUNTINGTON U2 TURBINE EQUIPMENT	241.96	
908	314084000282	35	12/12/2008	TB-HUNTINGTON U2 TURBINE EQUIPMENT	15,438.40	
909	314084000282	36	11/16/2011	TB-HUNTINGTON U2 TURBINE EQUIPMENT	350,991.16	
910	314084000282	37	11/30/2011	TB-HUNTINGTON U2 TURBINE EQUIPMENT	268,355.24	
911	314084000282	38	11/30/2011	TB-HUNTINGTON U2 TURBINE EQUIPMENT	1,431,227.89	
912	314084000282	39	11/30/2011	TB-HUNTINGTON U2 TURBINE EQUIPMENT	89,451.74	
913	314084000282	40	10/30/2015	TB-HUNTINGTON U2 TURBINE EQUIPMENT	303,377.27	
914	314084000282	41	10/30/2015	TB-HUNTINGTON U2 TURBINE EQUIPMENT	39,751.64	
915	314084000282	42	1/31/2017	TB-HUNTINGTON U2 TURBINE EQUIPMENT	189,959.11	
916	314099000282	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
917	* Location	000282		HUNTINGTON NO 2 STEAM ELECTRIC STAT	59,130,184.89	
918	314032000300	0	11/14/2003	CT-HTR U0 COOLING TOWER STRUCTURES & EQUIPMEX	52,890.02	
919	314033000300	0	12/31/1998	CW-HUNTER U0 CIRCULATING WATER EQUIPMENT	-	
920	314033000300	1	12/31/1978	CW-HUNTER U0 CIRCULATING WATER EQUIPMENT	125,215.88	
921	314033000300	2	5/20/2005	CW-HUNTER U0 CIRCULATING WATER EQUIPMENT	55,545.50	
922	314033000300	3	5/20/2005	CW-HUNTER U0 CIRCULATING WATER EQUIPMENT	2,923.45	
923	314050000300	0	12/31/1998	GN-HUNTER U0 GENERATOR EQUIPMENT	-	
924	314050000300	1	12/31/1978	GN-HUNTER U0 GENERATOR EQUIPMENT	115,513.23	
925	314050000300	2	12/31/1989	GN-HUNTER U0 GENERATOR EQUIPMENT	678.34	116,191.57
926	314062000300	0	12/31/1998	LO-HUNTER U0 LUBE OIL EQUIPMENT	-	
927	314062000300	1	12/31/1978	LO-HUNTER U0 LUBE OIL EQUIPMENT	135,876.11	
928	314062000300	2	12/31/1994	LO-HUNTER U0 LUBE OIL EQUIPMENT	10,297.46	
929	314062000300	3	12/31/1994	LO-HUNTER U0 LUBE OIL EQUIPMENT	16,827.01	
930	314062000300	4	4/12/2006	LO-HUNTER U0 LUBE OIL EQUIPMENT	146,597.92	
931	314084000300	0	12/31/1998	TB-HTR U0 TURBINE EQUIPMENT	-	
932	314084000300	3	12/24/2009	TB-HTR U0 TURBINE EQUIPMENT	278,256.90	
933	314084000300	4	12/24/2009	TB-HTR U0 TURBINE EQUIPMENT	251,518.57	
934	314099000300	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
935	* Location	000300		HUNTER PLANT COMMON FACILITIES	1,192,140.39	
936	314007000301	0	12/31/1998	AZ-AIR CONDITIONING SYSTEM	-	
937	314007000301	1	12/31/1995	AZ-AIR CONDITIONING SYSTEM	17,601.06	
938	314022000301	0	12/31/1998	CD-CONDENSATE TANK FOUNDATIONS	-	
939	314022000301	1	12/31/1978	CD-CONDENSATE TANK FOUNDATIONS	1,805,857.57	
940	314022000301	2	12/31/1989	CD-CONDENSATE TANK FOUNDATIONS	292,762.20	
941	314022000301	3	12/31/1990	CD-CONDENSATE TANK FOUNDATIONS	1,620.40	
942	314028000301	0	12/31/1998	CN-HUNTER U1 CONDENSER SYSTEM	-	
943	314028000301	1	12/31/1990	CN-HUNTER U1 CONDENSER SYSTEM	936.42	

944	314028000301	3	8/19/2004	CN-HUNTER U1 CONDENSER SYSTEM	16,058.25
945	314028000301	4	5/19/2005	CN-HUNTER U1 CONDENSER SYSTEM	26,701.50
946	314028000301	5	9/21/2005	CN-HUNTER U1 CONDENSER SYSTEM	24,891.55
947	314028000301	7	12/31/1978	CN-HUNTER U1 CONDENSER SYSTEM	1,060.15
948	314028000301	8	12/31/1990	CN-HUNTER U1 CONDENSER SYSTEM	10,595.41
949	314028000301	9	5/21/2014	CN-HUNTER U1 CONDENSER SYSTEM	38,945.28
950	314028000301	10	4/27/2018	CN-HUNTER U1 CONDENSER SYSTEM	69,205.02
951	314032000301	0	12/31/1998	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	-
952	314032000301	1	12/31/1978	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	193,504.63
953	314032000301	2	12/31/1989	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	6,139.78
954	314032000301	3	12/31/1989	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	521,857.67
955	314032000301	4	12/31/1990	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	4,130.79
956	314032000301	5	12/31/1992	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	22,257.15
957	314032000301	6	3/30/2001	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	28,838.80
958	314032000301	7	3/30/2001	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	216,247.50
959	314032000301	8	3/30/2001	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	169,908.73
960	314032000301	9	12/31/1988	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	8,497.29
961	314032000301	10	3/27/2001	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	17,980.89
962	314032000301	11	3/24/2000	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	25,923.85
963	314032000301	12	12/31/1997	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	70,491.46
964	314032000301	13	12/12/2002	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	44,112.68
965	314032000301	14	12/12/2002	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	14,438.28
966	314032000301	15	12/31/1996	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	51,295.08
967	314032000301	16	12/31/1996	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	16,032.05
968	314032000301	17	12/31/1996	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	30,123.63
969	314032000301	18	6/16/2004	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	4,940,905.28
970	314032000301	20	6/14/2005	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	263,811.46
971	314032000301	22	12/31/1989	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	346.74
972	314032000301	23	12/31/1989	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	27,637.39
973	314032000301	24	12/31/1990	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	1,673.39
974	314032000301	25	12/9/2009	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	20,398.15
975	314032000301	26	4/26/2010	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	457,963.65
976	314032000301	27	12/16/2011	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	10,953.71
977	314032000301	28	10/31/2013	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	37,904.89
978	314032000301	29	5/21/2014	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	179,673.16
979	314032000301	30	12/24/2014	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	65,151.54
980	314032000301	31	12/30/2015	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	56,468.40
981	314032000301	32	12/15/2016	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	79,045.73
982	314032000301	33	5/31/2017	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	353,877.90
983	314032000301	34	4/23/2018	CT-HUNTER U1 COOLING TOWER STRUCTURES & EQUIX	1,159,409.71
984	314033000301	0	12/31/1998	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	-
985	314033000301	1	12/31/1978	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	4,066,961.93
986	314033000301	2	12/31/1984	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	14,301.04
987	314033000301	3	12/31/1989	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	2,967.56
988	314033000301	4	12/31/1992	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	34,438.18
989	314033000301	5	12/31/1995	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	11,471.69
990	314033000301	6	12/31/1994	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	29,556.20
991	314033000301	7	3/24/2000	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	402,832.79
992	314033000301	8	3/24/2000	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	220,997.93
993	314033000301	10	12/31/1995	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	130,188.87
994	314033000301	12	8/17/2004	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	46,366.61
995	314033000301	13	1/11/2005	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	29,447.89
996	314033000301	15	2/16/2006	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	39,070.61
997	314033000301	16	2/16/2006	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	42,440.31
998	314033000301	17	12/31/1989	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	53,712.09
999	314033000301	18	12/12/2008	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	33,861.39
1000	314033000301	19	4/28/2010	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	162,560.69
1001	314033000301	20	4/28/2010	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	282,392.17
1002	314033000301	21	5/28/2014	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	389,840.16
1003	314033000301	22	4/24/2018	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	447,679.84
1004	314033000301	23	4/27/2018	CW-HUNTER U1 CIRCULATING WATER EQUIPMENT	505,564.89
1005	314050000301	0	12/31/1998	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	-
1006	314050000301	1	12/31/1978	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	1,366,302.72
1007	314050000301	2	12/31/1983	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	5,029.74
1008	314050000301	3	12/31/1988	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	8,978.19
1009	314050000301	4	12/31/1991	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	29,705.99
1010	314050000301	5	12/31/1992	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	84,774.19
1011	314050000301	6	12/31/1991	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	17,906.67
1012	314050000301	8	12/31/1992	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	465,306.04
1013	314050000301	11	5/17/2001	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	11,113,562.08
1014	314050000301	12	5/17/2001	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	737,573.04
1015	314050000301	14	3/12/2004	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	324,695.69
1016	314050000301	15	5/17/2005	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	8,709.19

1017	314050000301	16	9/21/2005	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	216,271.23	
1018	314050000301	17	12/19/2006	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	9,020.29	
1019	314050000301	18	2/1/2007	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	1,457.05	
1020	314050000301	19	12/31/1990	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	20,947.22	
1021	314050000301	20	11/20/2013	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	39,608.62	
1022	314050000301	21	5/28/2014	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	344,245.70	
1023	314050000301	22	4/27/2018	GN-HTR U1 GENERATOR & ASSOC EQUIPMENT	557,107.64	15,351,201.29
1024	314062000301	0	12/31/1998	LO-HUNTER U1 LUBE OIL EQUIPMENT	-	
1025	314062000301	1	12/31/1978	LO-HUNTER U1 LUBE OIL EQUIPMENT	2,909,313.07	
1026	314062000301	2	12/31/1987	LO-HUNTER U1 LUBE OIL EQUIPMENT	92,521.42	
1027	314062000301	3	12/31/1994	LO-HUNTER U1 LUBE OIL EQUIPMENT	47,562.70	
1028	314062000301	4	11/17/2004	LO-HUNTER U1 LUBE OIL EQUIPMENT	49,595.56	
1029	314062000301	5	5/17/2005	LO-HUNTER U1 LUBE OIL EQUIPMENT	12,539.88	
1030	314062000301	6	3/9/2006	LO-HUNTER U1 LUBE OIL EQUIPMENT	90,500.86	
1031	314062000301	7	4/28/2010	LO-HUNTER U1 LUBE OIL EQUIPMENT	57,384.71	
1032	314082000301	0	8/22/2002	SP-CAPITALIZED SPARE PARTS	95,695.31	
1033	314082000301	1	8/17/2004	SP-CAPITALIZED SPARE PARTS	33,787.50	
1034	314084000301	0	12/31/1998	TB-HTR U1 TURBINE EQUIPMENT	-	
1035	314084000301	16	3/12/2004	TB-HTR U1 TURBINE EQUIPMENT	275,132.63	
1036	314084000301	17	6/2/2004	TB-HTR U1 TURBINE EQUIPMENT	174,361.89	
1037	314084000301	18	4/25/2005	TB-HTR U1 TURBINE EQUIPMENT	77,155.89	
1038	314084000301	19	5/17/2005	TB-HTR U1 TURBINE EQUIPMENT	233,351.96	
1039	314084000301	21	9/21/2005	TB-HTR U1 TURBINE EQUIPMENT	127,666.80	
1040	314084000301	25	4/19/2010	TB-HTR U1 TURBINE EQUIPMENT	7,023,564.66	
1041	314084000301	26	4/19/2010	TB-HTR U1 TURBINE EQUIPMENT	7,023,564.66	
1042	314084000301	27	4/19/2010	TB-HTR U1 TURBINE EQUIPMENT	14,034,371.46	
1043	314084000301	28	4/26/2010	TB-HTR U1 TURBINE EQUIPMENT	915,927.31	
1044	314084000301	29	4/27/2018	TB-HTR U1 TURBINE EQUIPMENT	177,822.66	
1045	314099000301	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
1046	* Location	000301		HUNTER NO 1 STEAM ELECTRIC STATION	67,152,911.23	
1047	314028000302	0	12/31/1998	CN-HUNTER U2 CONDENSER EQUIPMENT	-	
1048	314028000302	1	12/31/1980	CN-HUNTER U2 CONDENSER EQUIPMENT	1,311,764.59	
1049	314028000302	3	12/31/1995	CN-HUNTER U2 CONDENSER EQUIPMENT	1,255,563.49	
1050	314028000302	4	9/3/2002	CN-HUNTER U2 CONDENSER EQUIPMENT	71,764.63	
1051	314028000302	5	1/12/2004	CN-HUNTER U2 CONDENSER EQUIPMENT	17,429.03	
1052	314028000302	6	3/28/2015	CN-HUNTER U2 CONDENSER EQUIPMENT	30,030.97	
1053	314028000302	7	4/22/2019	CN-HUNTER U2 CONDENSER EQUIPMENT	143,448.26	
1054	314032000302	0	12/31/1998	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	-	
1055	314032000302	7	3/30/2001	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	17,691.56	
1056	314032000302	8	3/30/2001	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	20,711.35	
1057	314032000302	10	8/12/2002	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	103,574.68	
1058	314032000302	11	8/12/2002	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	29,982.13	
1059	314032000302	12	8/12/2002	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	139,008.14	
1060	314032000302	13	12/12/2002	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	19,645.78	
1061	314032000302	14	4/8/2003	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	13,819.03	
1062	314032000302	15	4/8/2003	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	30,758.50	
1063	314032000302	16	4/12/2004	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	26,063.70	
1064	314032000302	17	4/25/2005	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	169,626.25	
1065	314032000302	18	3/18/2005	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	3,963.52	
1066	314032000302	19	3/18/2005	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	27,706.87	
1067	314032000302	20	6/2/2006	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	4,599,535.02	
1068	314032000302	21	6/1/2006	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	303,728.99	
1069	314032000302	22	12/31/1988	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	6,323.29	
1070	314032000302	23	12/31/1984	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	1,121.85	
1071	314032000302	24	12/30/2008	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	14,029.67	
1072	314032000302	25	4/26/2011	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	605,053.36	
1073	314032000302	26	12/30/2013	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	30,392.68	
1074	314032000302	27	4/5/2019	CT-HUNTER U2 COOLING TOWER STRUCTURE & EQUIPX	145,236.83	
1075	314033000302	0	12/31/1998	CW-HUNTER U2 CIRCULATING WATER EQUIPMENT	-	
1076	314033000302	1	12/31/1980	CW-HUNTER U2 CIRCULATING WATER EQUIPMENT	1,916,303.73	
1077	314033000302	5	12/31/1995	CW-HUNTER U2 CIRCULATING WATER EQUIPMENT	9,216.67	
1078	314033000302	7	12/31/1997	CW-HUNTER U2 CIRCULATING WATER EQUIPMENT	315,407.46	
1079	314033000302	8	7/10/1997	CW-HUNTER U2 CIRCULATING WATER EQUIPMENT	12,465.93	
1080	314033000302	9	12/31/1994	CW-HUNTER U2 CIRCULATING WATER EQUIPMENT	4,725.55	
1081	314033000302	10	3/24/2006	CW-HUNTER U2 CIRCULATING WATER EQUIPMENT	13,022.31	
1082	314033000302	11	5/20/2006	CW-HUNTER U2 CIRCULATING WATER EQUIPMENT	145,285.82	
1083	314033000302	13	12/12/2008	CW-HUNTER U2 CIRCULATING WATER EQUIPMENT	18,985.45	
1084	314033000302	14	4/8/2009	CW-HUNTER U2 CIRCULATING WATER EQUIPMENT	70,758.15	
1085	314033000302	15	4/1/2015	CW-HUNTER U2 CIRCULATING WATER EQUIPMENT	7,770.88	
1086	314033000302	16	4/30/2015	CW-HUNTER U2 CIRCULATING WATER EQUIPMENT	247,779.81	
1087	314033000302	17	12/30/2015	CW-HUNTER U2 CIRCULATING WATER EQUIPMENT	147,919.79	
1088	314033000302	18	4/22/2019	CW-HUNTER U2 CIRCULATING WATER EQUIPMENT	202,659.50	
1089	314033000302	19	4/22/2019	CW-HUNTER U2 CIRCULATING WATER EQUIPMENT	312,656.97	

1090	314050000302	0	12/31/1998	GN-HUNTER U2 GENERATOR EQUIPMENT	-	
1091	314050000302	1	12/31/1980	GN-HUNTER U2 GENERATOR EQUIPMENT	2,209,443.71	
1092	314050000302	4	12/31/1991	GN-HUNTER U2 GENERATOR EQUIPMENT	88,180.76	
1093	314050000302	5	12/31/1994	GN-HUNTER U2 GENERATOR EQUIPMENT	69,715.86	
1094	314050000302	6	2/19/2001	GN-HUNTER U2 GENERATOR EQUIPMENT	21,523.83	
1095	314050000302	7	6/28/2002	GN-HUNTER U2 GENERATOR EQUIPMENT	4,752,702.67	
1096	314050000302	8	7/10/2002	GN-HUNTER U2 GENERATOR EQUIPMENT	45,988.92	
1097	314050000302	9	8/12/2002	GN-HUNTER U2 GENERATOR EQUIPMENT	355,888.79	
1098	314050000302	10	8/12/2002	GN-HUNTER U2 GENERATOR EQUIPMENT	723,393.96	
1099	314050000302	11	8/12/2002	GN-HUNTER U2 GENERATOR EQUIPMENT	38,346.96	
1100	314050000302	12	3/23/2004	GN-HUNTER U2 GENERATOR EQUIPMENT	10,447.93	
1101	314050000302	13	12/31/1989	GN-HUNTER U2 GENERATOR EQUIPMENT	24,902.61	
1102	314050000302	14	6/15/2006	GN-HUNTER U2 GENERATOR EQUIPMENT	151,217.41	
1103	314050000302	15	12/19/2006	GN-HUNTER U2 GENERATOR EQUIPMENT	6,100.05	
1104	314050000302	17	4/30/2015	GN-HUNTER U2 GENERATOR EQUIPMENT	201,302.82	
1105	314050000302	18	4/22/2019	GN-HUNTER U2 GENERATOR EQUIPMENT	172,147.99	8,871,304.27
1106	314062000302	0	12/31/1998	LO-HUNTER U2 LUBE OIL EQUIPMENT	-	
1107	314062000302	1	12/31/1980	LO-HUNTER U2 LUBE OIL EQUIPMENT	2,292,635.48	
1108	314062000302	2	12/31/1988	LO-HUNTER U2 LUBE OIL EQUIPMENT	112,367.53	
1109	314062000302	3	12/31/1994	LO-HUNTER U2 LUBE OIL EQUIPMENT	30,312.79	
1110	314062000302	4	4/12/2006	LO-HUNTER U2 LUBE OIL EQUIPMENT	27,408.30	
1111	314062000302	5	12/30/2015	LO-HUNTER U2 LUBE OIL EQUIPMENT	33,261.73	
1112	314084000302	0	12/31/1998	TB-HTR U2 TURBINE EQUIPMENT	-	
1113	314084000302	4	12/31/1991	TB-HTR U2 TURBINE EQUIPMENT	1,487,308.19	
1114	314084000302	7	6/27/2002	TB-HTR U2 TURBINE EQUIPMENT	504,414.49	
1115	314084000302	11	8/11/2006	TB-HTR U2 TURBINE EQUIPMENT	872,755.97	
1116	314084000302	15	4/28/2011	TB-HTR U2 TURBINE EQUIPMENT	4,637,458.29	
1117	314084000302	16	4/28/2011	TB-HTR U2 TURBINE EQUIPMENT	4,637,458.28	
1118	314084000302	17	4/28/2011	TB-HTR U2 TURBINE EQUIPMENT	9,272,959.21	
1119	314084000302	18	4/26/2011	TB-HTR U2 TURBINE EQUIPMENT	907,580.68	
1120	314084000302	19	12/31/1991	TB-HTR U2 TURBINE EQUIPMENT	43,268.39	
1121	314084000302	22	5/8/2019	TB-HTR U2 TURBINE EQUIPMENT	175,970.09	
1122	314084000302	23	4/30/2019	TB-HTR U2 TURBINE EQUIPMENT	125,171.23	
1123	314099000302	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
1124	* Location	000302		HUNTER NO 2 STEAM ELECTRIC STATION	46,594,567.11	
1125	314028000303	0	12/31/1998	CN-HUNTER U3 CONDENSER EQUIPMENT	-	
1126	314028000303	1	12/31/1983	CN-HUNTER U3 CONDENSER EQUIPMENT	3,801,142.29	
1127	314028000303	2	12/31/1991	CN-HUNTER U3 CONDENSER EQUIPMENT	18,105.90	
1128	314028000303	3	12/31/1997	CN-HUNTER U3 CONDENSER EQUIPMENT	2,311,471.66	
1129	314028000303	5	12/31/1997	CN-HUNTER U3 CONDENSER EQUIPMENT	259,650.72	
1130	314028000303	6	12/31/1997	CN-HUNTER U3 CONDENSER EQUIPMENT	18,101.71	
1131	314028000303	8	4/14/1998	CN-HUNTER U3 CONDENSER EQUIPMENT	50,211.11	
1132	314028000303	9	4/14/1998	CN-HUNTER U3 CONDENSER EQUIPMENT	52,797.44	
1133	314028000303	10	2/16/2006	CN-HUNTER U3 CONDENSER EQUIPMENT	31,622.77	
1134	314028000303	11	2/16/2006	CN-HUNTER U3 CONDENSER EQUIPMENT	28,046.65	
1135	314028000303	12	7/10/2006	CN-HUNTER U3 CONDENSER EQUIPMENT	118,483.62	
1136	314028000303	13	7/16/2007	CN-HUNTER U3 CONDENSER EQUIPMENT	161,292.18	
1137	314028000303	14	3/23/2016	CN-HUNTER U3 CONDENSER EQUIPMENT	36,275.00	
1138	314028000303	15	4/28/2016	CN-HUNTER U3 CONDENSER EQUIPMENT	107,888.04	
1139	314032000303	0	12/31/1998	CT-HTR U3 COOLING TOWER STRUCTURES & EQUIPMEX	-	
1140	314032000303	28	4/14/2016	CT-HTR U3 COOLING TOWER STRUCTURES & EQUIPMEX	8,962,362.03	
1141	314033000303	0	12/31/1998	CW-HUNTER U3 CIRCULATING WATER EQUIPMENT	-	
1142	314033000303	1	12/31/1983	CW-HUNTER U3 CIRCULATING WATER EQUIPMENT	5,159,026.80	
1143	314033000303	8	11/11/2010	CW-HUNTER U3 CIRCULATING WATER EQUIPMENT	153,802.43	
1144	314033000303	9	2/14/2011	CW-HUNTER U3 CIRCULATING WATER EQUIPMENT	27,199.20	
1145	314033000303	10	6/11/2013	CW-HUNTER U3 CIRCULATING WATER EQUIPMENT	41,864.79	
1146	314033000303	11	6/11/2013	CW-HUNTER U3 CIRCULATING WATER EQUIPMENT	31,398.59	
1147	314033000303	12	6/11/2013	CW-HUNTER U3 CIRCULATING WATER EQUIPMENT	31,398.58	
1148	314033000303	13	9/9/2015	CW-HUNTER U3 CIRCULATING WATER EQUIPMENT	77,526.37	
1149	314033000303	14	3/23/2016	CW-HUNTER U3 CIRCULATING WATER EQUIPMENT	196,740.60	
1150	314033000303	15	4/28/2016	CW-HUNTER U3 CIRCULATING WATER EQUIPMENT	665,387.14	
1151	314033000303	16	11/9/2016	CW-HUNTER U3 CIRCULATING WATER EQUIPMENT	121,814.05	
1152	314050000303	0	12/31/1998	GN-HUNTER U3 GENERATOR EQUIPMENT	-	
1153	314050000303	1	12/31/1983	GN-HUNTER U3 GENERATOR EQUIPMENT	3,141,193.98	
1154	314050000303	4	12/31/1993	GN-HUNTER U3 GENERATOR EQUIPMENT	383,176.54	
1155	314050000303	7	1/16/2003	GN-HUNTER U3 GENERATOR EQUIPMENT	73,502.87	
1156	314050000303	12	6/12/2007	GN-HUNTER U3 GENERATOR EQUIPMENT	32,467.49	
1157	314050000303	13	6/12/2007	GN-HUNTER U3 GENERATOR EQUIPMENT	158,517.73	
1158	314050000303	14	6/12/2007	GN-HUNTER U3 GENERATOR EQUIPMENT	227,324.31	
1159	314050000303	15	6/12/2007	GN-HUNTER U3 GENERATOR EQUIPMENT	234,107.49	
1160	314050000303	16	6/12/2007	GN-HUNTER U3 GENERATOR EQUIPMENT	1,157,944.17	
1161	314050000303	17	6/12/2007	GN-HUNTER U3 GENERATOR EQUIPMENT	580,972.42	
1162	314050000303	18	7/26/2007	GN-HUNTER U3 GENERATOR EQUIPMENT	302,149.93	

1163	314050000303	19	12/20/2007	GN-HUNTER U3 GENERATOR EQUIPMENT	12,435.25	
1164	314050000303	20	12/20/2007	GN-HUNTER U3 GENERATOR EQUIPMENT	16,007.75	
1165	314050000303	21	3/30/2012	GN-HUNTER U3 GENERATOR EQUIPMENT	168,434.75	
1166	314050000303	22	5/15/2012	GN-HUNTER U3 GENERATOR EQUIPMENT	120,947.50	
1167	314050000303	23	11/28/2012	GN-HUNTER U3 GENERATOR EQUIPMENT	127,845.04	
1168	314050000303	24	2/28/2016	GN-HUNTER U3 GENERATOR EQUIPMENT	8,535,011.25	
1169	314050000303	25	4/28/2016	GN-HUNTER U3 GENERATOR EQUIPMENT	3,845,139.58	
1170	314050000303	26	12/31/1983	GN-HUNTER U3 GENERATOR EQUIPMENT	1,004,109.14	
1171	314050000303	27	12/31/1983	GN-HUNTER U3 GENERATOR EQUIPMENT	2,906,521.63	
1172	314050000303	28	12/31/1983	GN-HUNTER U3 GENERATOR EQUIPMENT	278,269.76	
1173	314050000303	29	12/31/1983	GN-HUNTER U3 GENERATOR EQUIPMENT	966,025.82	
1174	314050000303	30	12/31/1983	GN-HUNTER U3 GENERATOR EQUIPMENT	526,463.43	
1175	314050000303	31	12/31/1983	GN-HUNTER U3 GENERATOR EQUIPMENT	2,415,812.93	27,214,380.76
1176	314062000303	0	12/31/1998	LO-HUNTER U3 LUBE OIL EQUIPMENT	-	
1177	314062000303	1	12/31/1983	LO-HUNTER U3 LUBE OIL EQUIPMENT	2,472,226.90	
1178	314062000303	2	12/31/1994	LO-HUNTER U3 LUBE OIL EQUIPMENT	46,721.04	
1179	314062000303	3	1/5/2016	LO-HUNTER U3 LUBE OIL EQUIPMENT	135,468.11	
1180	314082000303	0	12/31/1998	SP-HUNTER U3 FERC 314 CAPITALIZED SPARE PARTS	-	
1181	314082000303	1	12/31/1983	SP-HUNTER U3 FERC 314 CAPITALIZED SPARE PARTS	55,734.52	
1182	314082000303	3	12/31/1987	SP-HUNTER U3 FERC 314 CAPITALIZED SPARE PARTS	12,321.78	
1183	314082000303	6	5/13/2002	SP-HUNTER U3 FERC 314 CAPITALIZED SPARE PARTS	407,938.40	
1184	314082000303	7	5/13/2002	SP-HUNTER U3 FERC 314 CAPITALIZED SPARE PARTS	89,103.61	
1185	314082000303	9	11/17/2004	SP-HUNTER U3 FERC 314 CAPITALIZED SPARE PARTS	46,583.81	
1186	314082000303	14	2/7/2012	SP-HUNTER U3 FERC 314 CAPITALIZED SPARE PARTS	110,302.77	
1187	314082000303	15	12/9/2016	SP-HUNTER U3 FERC 314 CAPITALIZED SPARE PARTS	368,051.24	
1188	314082000303	16	12/30/2016	SP-HUNTER U3 FERC 314 CAPITALIZED SPARE PARTS	182,161.79	
1189	314084000303	0	12/31/1998	TB-HUNTER U3 TURBINE EQUIPMENT	-	
1190	314084000303	16	6/3/2001	TB-HUNTER U3 TURBINE EQUIPMENT	145,610.43	
1191	314084000303	17	12/29/2003	TB-HUNTER U3 TURBINE EQUIPMENT	160,241.63	
1192	314084000303	18	5/13/2007	TB-HUNTER U3 TURBINE EQUIPMENT	54,823.82	
1193	314084000303	19	6/18/2007	TB-HUNTER U3 TURBINE EQUIPMENT	2,029,950.49	
1194	314084000303	20	7/26/2007	TB-HUNTER U3 TURBINE EQUIPMENT	3,465,855.27	
1195	314084000303	21	7/26/2007	TB-HUNTER U3 TURBINE EQUIPMENT	70,738.13	
1196	314084000303	22	7/26/2007	TB-HUNTER U3 TURBINE EQUIPMENT	53,495.46	
1197	314084000303	24	3/30/2012	TB-HUNTER U3 TURBINE EQUIPMENT	6,236,683.30	
1198	314084000303	25	3/30/2012	TB-HUNTER U3 TURBINE EQUIPMENT	6,236,683.30	
1199	314084000303	26	3/30/2012	TB-HUNTER U3 TURBINE EQUIPMENT	12,458,781.23	
1200	314099000303	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
1201	* Location	000303		HUNTER NO 3 STEAM ELECTRIC STATION	84,517,467.46	
1202	314028000305	0	12/31/1998	CN-CONDENSER SYSTEM TUBES	-	
1203	314028000305	1	12/31/1980	CN-CONDENSER SYSTEM TUBES	122,221.02	
1204	314028000305	2	12/31/1995	CN-CONDENSER SYSTEM TUBES	2,620,339.02	
1205	314033000305	0	12/31/1998	CW-PUMPS	-	
1206	314033000305	1	12/31/1978	CW-PUMPS	102,475.32	
1207	314033000305	2	12/31/1980	CW-PUMPS	30,390.46	
1208	314033000305	3	4/6/2005	CW-PUMPS	42,626.68	
1209	314033000305	4	4/6/2005	CW-PUMPS	5,760.37	
1210	314033000305	5	4/6/2005	CW-PUMPS	9,216.57	
1211	314050000305	0	12/31/1998	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	-	
1212	314050000305	5	2/10/2010	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	69,822.40	69,822.40
1213	314062000305	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
1214	314062000305	1	12/31/1980	LO-LUBE OIL PUMPS & PUMP MOTORS	47,320.86	
1215	314082000305	0	12/31/1998	SP-HUNTER 305 FERC 314 CAPITALIZED SPARE PARX	-	
1216	314082000305	1	12/31/1978	SP-HUNTER 305 FERC 314 CAPITALIZED SPARE PARX	16,967.01	
1217	314082000305	2	12/31/1980	SP-HUNTER 305 FERC 314 CAPITALIZED SPARE PARX	17,364.13	
1218	314082000305	4	12/31/1993	SP-HUNTER 305 FERC 314 CAPITALIZED SPARE PARX	60,044.49	
1219	314082000305	7	12/31/1983	SP-HUNTER 305 FERC 314 CAPITALIZED SPARE PARX	16,553.81	
1220	314082000305	8	12/31/1983	SP-HUNTER 305 FERC 314 CAPITALIZED SPARE PARX	12,896.24	
1221	314082000305	10	12/31/1983	SP-HUNTER 305 FERC 314 CAPITALIZED SPARE PARX	9,230.46	
1222	314082000305	11	12/31/1983	SP-HUNTER 305 FERC 314 CAPITALIZED SPARE PARX	11,304.68	
1223	314082000305	12	12/31/1983	SP-HUNTER 305 FERC 314 CAPITALIZED SPARE PARX	25,949.62	
1224	314082000305	15	12/30/2016	SP-HUNTER 305 FERC 314 CAPITALIZED SPARE PARX	337,848.31	
1225	314082000305	16	3/9/2017	SP-HUNTER 305 FERC 314 CAPITALIZED SPARE PARX	204,118.70	
1226	314084000305	0	12/31/1998	TB-TURBINE I P COUPLER	-	
1227	314084000305	1	12/31/1994	TB-TURBINE I P COUPLER	10,043.06	
1228	314084000305	2	12/31/1994	TB-TURBINE I P COUPLER	10,043.06	
1229	314084000305	3	12/31/1994	TB-TURBINE I P COUPLER	10,043.06	
1230	* Location	000305		HUNTER PLANT COMMON FACILTIES - UNI	3,792,579.33	
1231	314007000381	0	12/31/1998	AZ-AIR CONDITIONING SYSTEM	-	
1232	314007000381	1	12/31/1984	AZ-AIR CONDITIONING SYSTEM	746,869.88	
1233	314009000381	0	12/31/1998	BC-BOILER CONTROLS	-	
1234	314022000381	0	12/31/1998	CD-CONDENSATE TANK FOUNDATIONS	-	
1235	314022000381	1	12/31/1984	CD-CONDENSATE TANK FOUNDATIONS	213,020.03	

1236	314028000381	0	12/31/1998	CN-BLUNDELL U1 CONDENSER EQUIPMENT	-	
1237	314028000381	1	12/31/1984	CN-BLUNDELL U1 CONDENSER EQUIPMENT	666,667.19	
1238	314028000381	2	12/31/1995	CN-BLUNDELL U1 CONDENSER EQUIPMENT	10,273.86	
1239	314028000381	3	1/31/2014	CN-BLUNDELL U1 CONDENSER EQUIPMENT	12,989.66	
1240	314028000381	4	5/9/2018	CN-BLUNDELL U1 CONDENSER EQUIPMENT	45,593.63	
1241	314032000381	0	12/31/1998	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	-	
1242	314032000381	1	12/31/1984	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	1,553,037.90	
1243	314032000381	2	12/31/1987	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	3,988.85	
1244	314032000381	3	12/31/1994	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	6,958.96	
1245	314032000381	4	12/31/1995	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	17,198.87	
1246	314032000381	6	12/1/1999	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	138,706.08	
1247	314032000381	7	12/1/1999	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	17,511.27	
1248	314032000381	8	2/9/2004	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	35,967.68	
1249	314032000381	9	3/22/2005	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	11,615.55	
1250	314032000381	11	3/31/2006	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	94,690.81	
1251	314032000381	12	2/28/2006	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	15,586.78	
1252	314032000381	13	9/14/2007	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	237,963.67	
1253	314032000381	14	9/14/2004	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	12,997.14	
1254	314032000381	15	5/28/2013	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	283,802.84	
1255	314032000381	16	10/27/2016	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	99,281.72	
1256	314032000381	17	9/5/2018	CT-BLUNDELL U1 COOLING TOWER STRUCTURE & EQUX	28,807.81	
1257	314033000381	0	12/31/1998	CW-BLUNDELL U1 CIRCULATING WATER EQUIPMENT	-	
1258	314033000381	1	12/31/1984	CW-BLUNDELL U1 CIRCULATING WATER EQUIPMENT	3,199,616.52	
1259	314033000381	3	12/31/1985	CW-BLUNDELL U1 CIRCULATING WATER EQUIPMENT	16,845.69	
1260	314033000381	4	9/20/2012	CW-BLUNDELL U1 CIRCULATING WATER EQUIPMENT	95,029.92	
1261	314050000381	0	12/31/1998	GN-BLUNDELL U1 GENERATOR EQUIPMENT	-	
1262	314050000381	1	12/31/1984	GN-BLUNDELL U1 GENERATOR EQUIPMENT	2,382,416.98	
1263	314050000381	2	12/31/1987	GN-BLUNDELL U1 GENERATOR EQUIPMENT	6,896.09	
1264	314050000381	3	12/2/2004	GN-BLUNDELL U1 GENERATOR EQUIPMENT	210,287.83	
1265	314050000381	4	12/2/2004	GN-BLUNDELL U1 GENERATOR EQUIPMENT	8,135.74	
1266	314050000381	5	3/28/2006	GN-BLUNDELL U1 GENERATOR EQUIPMENT	9,750.90	
1267	314050000381	6	9/5/2007	GN-BLUNDELL U1 GENERATOR EQUIPMENT	282,436.54	
1268	314050000381	7	12/17/2012	GN-BLUNDELL U1 GENERATOR EQUIPMENT	105,761.98	
1269	314050000381	8	5/28/2013	GN-BLUNDELL U1 GENERATOR EQUIPMENT	469,960.17	3,475,646.23
1270	314062000381	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
1271	314062000381	1	12/31/1984	LO-LUBE OIL PUMPS & PUMP MOTORS	520,123.52	
1272	314082000381	0	12/31/1998	SP-CAPITALIZED SPARE PARTS	-	
1273	314082000381	1	12/31/1987	SP-CAPITALIZED SPARE PARTS	35,554.93	
1274	314082000381	2	12/31/1987	SP-CAPITALIZED SPARE PARTS	35,554.93	
1275	314082000381	3	12/31/1987	SP-CAPITALIZED SPARE PARTS	33,677.80	
1276	314084000381	0	12/31/1998	TB-BLUNDELL U1 TURBINE EQUIPMENT	-	
1277	314084000381	1	12/31/1984	TB-BLUNDELL U1 TURBINE EQUIPMENT	17,676.92	
1278	314084000381	2	12/31/1992	TB-BLUNDELL U1 TURBINE EQUIPMENT	9,532.53	
1279	314084000381	3	12/31/1993	TB-BLUNDELL U1 TURBINE EQUIPMENT	101,268.34	
1280	314084000381	4	12/31/1995	TB-BLUNDELL U1 TURBINE EQUIPMENT	350,981.18	
1281	314084000381	5	8/30/2001	TB-BLUNDELL U1 TURBINE EQUIPMENT	3,133,591.48	
1282	314084000381	6	3/28/2003	TB-BLUNDELL U1 TURBINE EQUIPMENT	122,491.54	
1283	314084000381	9	12/2/2004	TB-BLUNDELL U1 TURBINE EQUIPMENT	28,043.86	
1284	314084000381	10	7/13/2007	TB-BLUNDELL U1 TURBINE EQUIPMENT	75,989.29	
1285	314084000381	11	5/28/2013	TB-BLUNDELL U1 TURBINE EQUIPMENT	2,295,994.30	
1286	* Location	000381		BLUNDELL GEOTHERMAL PLANT UNIT 1	17,801,149.16	
1287	314007000382	1	12/1/2007	AZ - BLUNDELL U2 PENTANE AIR COOLED CONDENSER	4,089,558.00	
1288	314050000382	1	12/1/2007	GN - BLUNDELL U2 STEAM/ORC GENERATOR	4,671,294.78	4,671,294.78
1289	314082000382	1	12/1/2007	SP-BLUNDELL U2 FERC 314 CAPITAL SPARES	87,405.30	
1290	314082000382	2	12/1/2007	SP-BLUNDELL U2 FERC 314 CAPITAL SPARES	110,018.70	
1291	314082000382	3	6/15/2015	SP-BLUNDELL U2 FERC 314 CAPITAL SPARES	96,132.97	
1292	314082000382	4	1/22/2018	SP-BLUNDELL U2 FERC 314 CAPITAL SPARES	129,834.17	
1293	314084000382	1	12/1/2007	TB - BLUNDELL U2 ORC TURBINE	3,547,231.00	
1294	314084000382	2	12/1/2007	TB - BLUNDELL U2 ORC TURBINE	3,310,639.00	
1295	314084000382	3	12/29/2011	TB - BLUNDELL U2 ORC TURBINE	173,344.89	
1296	314084000382	4	12/27/2012	TB - BLUNDELL U2 ORC TURBINE	9,743.87	
1297	314084000382	5	8/8/2016	TB - BLUNDELL U2 ORC TURBINE	288,727.76	
1298	* Location	000382		BLUNDELL GEOTHERMAL PLANT UNIT 2	16,513,930.44	
1299	314028000400	1	4/7/1999	CN-CONDENSER SYSTEM TUBES	2,111.29	
1300	314033000400	0	12/31/1998	CW-PUMPS	-	
1301	314033000400	1	12/31/1979	CW-PUMPS	1,929,408.20	
1302	314033000400	2	12/31/1989	CW-PUMPS	20,690.00	
1303	314033000400	4	12/31/1995	CW-PUMPS	9,233.04	
1304	314033000400	5	2/13/2006	CW-PUMPS	1,205.12	
1305	314050000400	0	12/31/1998	GN-CRAIG U0 GENERATOR EQUIPMENT	-	
1306	314050000400	1	12/31/1983	GN-CRAIG U0 GENERATOR EQUIPMENT	8,557.00	
1307	314050000400	2	12/31/1986	GN-CRAIG U0 GENERATOR EQUIPMENT	36,860.00	
1308	314050000400	3	12/31/1989	GN-CRAIG U0 GENERATOR EQUIPMENT	1,048.00	

1309		314050000400	4	12/31/1985	GN-CRAIG U0 GENERATOR EQUIPMENT	179.00	
1310		314050000400	5	11/5/2004	GN-CRAIG U0 GENERATOR EQUIPMENT	9,912.18	
1311		314050000400	6	1/26/2006	GN-CRAIG U0 GENERATOR EQUIPMENT	34,495.24	
1312		314050000400	7	11/16/2010	GN-CRAIG U0 GENERATOR EQUIPMENT	25,813.20	116,864.62
1313		314062000400	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
1314		314062000400	1	12/31/1979	LO-LUBE OIL PUMPS & PUMP MOTORS	18,456.00	
1315		314062000400	2	11/25/2003	LO-LUBE OIL PUMPS & PUMP MOTORS	8,022.42	
1316		314062000400	3	2/2/2006	LO-LUBE OIL PUMPS & PUMP MOTORS	1,554.35	
1317		314082000400	1	12/24/2015	SP-CRAIG COMMON FERC 314 CAPITAL SPARE PARTS	13,145.92	
1318		314084000400	0	12/31/1998	TB-CRAIG U0 TURBINE EQUIPMENT	-	
1319		314084000400	1	12/31/1995	TB-CRAIG U0 TURBINE EQUIPMENT	1,416.63	
1320		314084000400	2	12/31/1995	TB-CRAIG U0 TURBINE EQUIPMENT	1,491.63	
1321		314084000400	3	12/31/1994	TB-CRAIG U0 TURBINE EQUIPMENT	967.85	
1322		314084000400	4	12/31/1993	TB-CRAIG U0 TURBINE EQUIPMENT	2,491.01	
1323		314084000400	5	12/31/1993	TB-CRAIG U0 TURBINE EQUIPMENT	1,899.73	
1324		314084000400	6	8/30/2002	TB-CRAIG U0 TURBINE EQUIPMENT	13,012.29	
1325		314084000400	7	9/27/2002	TB-CRAIG U0 TURBINE EQUIPMENT	29,852.47	
1326		314084000400	8	11/25/2003	TB-CRAIG U0 TURBINE EQUIPMENT	24,898.00	
1327		314099000400	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
1328	*	Location	000400		CRAIG PLANT - COMMON, UNITS 1, 2 &	2,196,720.57	
1329		314022000401	0	12/31/1998	CD-CONDENSATE TANK FOUNDATIONS	-	
1330		314022000401	1	12/31/1980	CD-CONDENSATE TANK FOUNDATIONS	552,618.94	
1331		314028000401	0	12/31/1998	CN-CONDENSER SYSTEM TUBES	-	
1332		314028000401	1	12/31/1993	CN-CONDENSER SYSTEM TUBES	8,133.41	
1333		314028000401	3	11/25/2003	CN-CONDENSER SYSTEM TUBES	239,908.74	
1334		314028000401	4	7/29/2011	CN-CONDENSER SYSTEM TUBES	40,323.50	
1335		314028000401	5	4/30/2012	CN-CONDENSER SYSTEM TUBES	21,921.17	
1336		314032000401	0	12/31/1998	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	-	
1337		314032000401	1	12/31/1980	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	138,171.51	
1338		314032000401	2	12/31/1988	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	23,826.00	
1339		314032000401	3	12/31/1993	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	3,660.58	
1340		314032000401	4	12/31/1996	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	59,030.07	
1341		314032000401	5	12/31/1996	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	4,612.51	
1342		314032000401	6	12/31/1993	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	52,626.13	
1343		314032000401	7	12/31/1995	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	37,595.88	
1344		314032000401	8	12/31/1996	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	73,428.98	
1345		314032000401	9	12/31/1997	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	69,001.89	
1346		314032000401	10	12/31/1993	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	9,617.50	
1347		314032000401	11	9/5/2000	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	41,605.47	
1348		314032000401	12	12/31/1998	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	34,571.29	
1349		314032000401	13	10/2/2000	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	29,940.16	
1350		314032000401	14	10/2/2000	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	64,157.49	
1351		314032000401	15	10/2/2000	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	12,831.50	
1352		314032000401	16	11/27/2002	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	76,582.61	
1353		314032000401	17	9/15/2006	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	121,890.41	
1354		314032000401	18	9/15/2006	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	571,439.27	
1355		314032000401	19	4/16/2008	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	357,384.41	
1356		314032000401	20	3/31/2014	CT-CRAIG U1 COOLING TOWER STRUCTURES & EQUIPX	359,965.57	
1357		314033000401	0	12/31/1998	CW-PUMPS	-	
1358		314033000401	1	12/31/1980	CW-PUMPS	1,375,249.64	
1359		314033000401	2	12/31/1993	CW-PUMPS	5,793.61	
1360		314033000401	3	8/30/2002	CW-PUMPS	7,933.81	
1361		314033000401	4	6/24/2008	CW-PUMPS	193,448.77	
1362		314033000401	5	10/15/2010	CW-PUMPS	4,078.16	
1363		314050000401	0	12/31/1998	GN-CRAIG U1 GENERATOR EQUIPMENT	-	
1364		314050000401	1	12/31/1980	GN-CRAIG U1 GENERATOR EQUIPMENT	1,262,144.60	
1365		314050000401	2	12/31/1991	GN-CRAIG U1 GENERATOR EQUIPMENT	10,807.00	
1366		314050000401	4	12/31/1993	GN-CRAIG U1 GENERATOR EQUIPMENT	3,616.16	
1367		314050000401	5	12/31/1997	GN-CRAIG U1 GENERATOR EQUIPMENT	1,230.63	
1368		314050000401	6	12/31/1997	GN-CRAIG U1 GENERATOR EQUIPMENT	9,415.84	
1369		314050000401	7	12/31/1997	GN-CRAIG U1 GENERATOR EQUIPMENT	11,022.46	
1370		314050000401	8	8/30/2002	GN-CRAIG U1 GENERATOR EQUIPMENT	3,558.61	
1371		314050000401	9	10/27/2009	GN-CRAIG U1 GENERATOR EQUIPMENT	29,734.96	
1372		314050000401	10	7/29/2011	GN-CRAIG U1 GENERATOR EQUIPMENT	827,403.32	
1373		314050000401	11	7/29/2011	GN-CRAIG U1 GENERATOR EQUIPMENT	120,000.93	
1374		314050000401	12	7/29/2011	GN-CRAIG U1 GENERATOR EQUIPMENT	12,668.22	
1375		314050000401	13	7/29/2011	GN-CRAIG U1 GENERATOR EQUIPMENT	127,224.23	
1376		314050000401	14	1/8/2014	GN-CRAIG U1 GENERATOR EQUIPMENT	17,909.20	
1377		314050000401	15	3/4/2014	GN-CRAIG U1 GENERATOR EQUIPMENT	470,596.46	
1378		314050000401	16	2/15/2017	GN-CRAIG U1 GENERATOR EQUIPMENT	74,636.66	2,981,969.28
1379		314062000401	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
1380		314062000401	1	12/31/1980	LO-LUBE OIL PUMPS & PUMP MOTORS	873,836.09	
1381		314062000401	2	11/25/2003	LO-LUBE OIL PUMPS & PUMP MOTORS	16,249.44	

1382		314084000401	0	12/31/1998	TB-CRAIG U1 TURBINE EQUIPMENT	-	
1383		314084000401	11	4/7/1999	TB-CRAIG U1 TURBINE EQUIPMENT	23,633.36	
1384		314084000401	14	8/30/2002	TB-CRAIG U1 TURBINE EQUIPMENT	13,893.62	
1385		314084000401	15	5/18/2004	TB-CRAIG U1 TURBINE EQUIPMENT	67,198.84	
1386		314084000401	16	11/21/2005	TB-CRAIG U1 TURBINE EQUIPMENT	16,013.42	
1387		314084000401	17	1/28/2010	TB-CRAIG U1 TURBINE EQUIPMENT	261,229.13	
1388		314084000401	18	6/3/2011	TB-CRAIG U1 TURBINE EQUIPMENT	3,284,677.09	
1389		314084000401	19	7/29/2011	TB-CRAIG U1 TURBINE EQUIPMENT	100,238.39	
1390		314084000401	20	12/8/2016	TB-CRAIG U1 TURBINE EQUIPMENT	644,226.58	
1391		314099000401	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
1392	* Location	000401		CRAIG	PLANT UNIT 1	12,874,514.22	
1393		314028000402	0	12/31/1998	CN-CONDENSER SYSTEM TUBES	-	
1394		314028000402	1	12/31/1979	CN-CONDENSER SYSTEM TUBES	443,566.57	
1395		314028000402	2	12/31/1997	CN-CONDENSER SYSTEM TUBES	11,037.56	
1396		314028000402	3	12/31/1997	CN-CONDENSER SYSTEM TUBES	4,160.07	
1397		314028000402	4	12/31/1994	CN-CONDENSER SYSTEM TUBES	97,502.70	
1398		314028000402	6	7/27/2004	CN-CONDENSER SYSTEM TUBES	232,844.06	
1399		314028000402	7	4/23/2010	CN-CONDENSER SYSTEM TUBES	31,288.74	
1400		314028000402	8	4/30/2012	CN-CONDENSER SYSTEM TUBES	21,546.95	
1401		314032000402	0	12/31/1998	CT-CRAIG U2 COOLING TOWER STRUCTURES & EQUIPX	-	
1402		314032000402	1	12/31/1979	CT-CRAIG U2 COOLING TOWER STRUCTURES & EQUIPX	289,510.10	
1403		314032000402	2	12/31/1987	CT-CRAIG U2 COOLING TOWER STRUCTURES & EQUIPX	26,791.00	
1404		314032000402	3	12/31/1993	CT-CRAIG U2 COOLING TOWER STRUCTURES & EQUIPX	3,660.58	
1405		314032000402	4	12/31/1996	CT-CRAIG U2 COOLING TOWER STRUCTURES & EQUIPX	39,107.58	
1406		314032000402	5	12/31/1997	CT-CRAIG U2 COOLING TOWER STRUCTURES & EQUIPX	4,737.70	
1407		314032000402	6	12/31/1993	CT-CRAIG U2 COOLING TOWER STRUCTURES & EQUIPX	69,081.28	
1408		314032000402	7	12/31/1995	CT-CRAIG U2 COOLING TOWER STRUCTURES & EQUIPX	98,093.26	
1409		314032000402	10	12/31/1993	CT-CRAIG U2 COOLING TOWER STRUCTURES & EQUIPX	9,097.57	
1410		314032000402	14	7/27/2004	CT-CRAIG U2 COOLING TOWER STRUCTURES & EQUIPX	83,550.88	
1411		314032000402	15	9/15/2006	CT-CRAIG U2 COOLING TOWER STRUCTURES & EQUIPX	230,535.58	
1412		314032000402	16	7/18/2007	CT-CRAIG U2 COOLING TOWER STRUCTURES & EQUIPX	422,173.97	
1413		314032000402	18	5/6/2008	CT-CRAIG U2 COOLING TOWER STRUCTURES & EQUIPX	166,191.76	
1414		314032000402	19	6/9/2017	CT-CRAIG U2 COOLING TOWER STRUCTURES & EQUIPX	382,059.95	
1415		314032000402	20	6/9/2017	CT-CRAIG U2 COOLING TOWER STRUCTURES & EQUIPX	93,228.32	
1416		314033000402	0	12/31/1998	CW-PUMPS	-	
1417		314033000402	1	12/31/1979	CW-PUMPS	934,435.32	
1418		314033000402	2	12/31/1993	CW-PUMPS	5,761.39	
1419		314033000402	3	12/31/1995	CW-PUMPS	20,141.75	
1420		314033000402	4	6/8/2007	CW-PUMPS	204,074.15	
1421		314033000402	5	10/15/2010	CW-PUMPS	4,813.51	
1422		314050000402	0	12/31/1998	GN-CRAIG U2 GENERATOR EQUIPMENT	-	
1423		314050000402	1	12/31/1979	GN-CRAIG U2 GENERATOR EQUIPMENT	1,121,880.51	
1424		314050000402	2	12/31/1993	GN-CRAIG U2 GENERATOR EQUIPMENT	16,935.34	
1425		314050000402	5	2/25/2002	GN-CRAIG U2 GENERATOR EQUIPMENT	2,705.83	
1426		314050000402	6	1/27/2010	GN-CRAIG U2 GENERATOR EQUIPMENT	28,344.10	
1427		314050000402	7	6/17/2013	GN-CRAIG U2 GENERATOR EQUIPMENT	17,013.64	
1428		314050000402	8	6/17/2013	GN-CRAIG U2 GENERATOR EQUIPMENT	123,175.83	
1429		314050000402	9	6/17/2013	GN-CRAIG U2 GENERATOR EQUIPMENT	1,654,622.34	
1430		314050000402	10	7/8/2013	GN-CRAIG U2 GENERATOR EQUIPMENT	978,454.47	
1431		314050000402	11	6/9/2017	GN-CRAIG U2 GENERATOR EQUIPMENT	75,008.72	4,018,140.78
1432		314062000402	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
1433		314062000402	1	12/31/1979	LO-LUBE OIL PUMPS & PUMP MOTORS	899,911.78	
1434		314084000402	0	12/31/1998	TB-CRAIG U2 TURBINE EQUIPMENT	-	
1435		314084000402	12	7/29/2011	TB-CRAIG U2 TURBINE EQUIPMENT	2,662,175.19	
1436		314084000402	13	6/17/2013	TB-CRAIG U2 TURBINE EQUIPMENT	586,295.82	
1437		314084000402	14	6/17/2013	TB-CRAIG U2 TURBINE EQUIPMENT	479,046.17	
1438		314084000402	15	6/9/2017	TB-CRAIG U2 TURBINE EQUIPMENT	526,124.48	
1439		314099000402	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
1440	* Location	000402		CRAIG	PLANT UNIT 2	13,100,686.52	
1441		314028000405	0	12/31/1998	CN-CONDENSER SYSTEM TUBES	-	
1442		314028000405	1	12/31/1995	CN-CONDENSER SYSTEM TUBES	2,222.47	
1443		314028000405	2	12/31/1994	CN-CONDENSER SYSTEM TUBES	100,591.14	
1444		314028000405	3	11/30/1999	CN-CONDENSER SYSTEM TUBES	9,268.45	
1445		314028000405	4	9/27/2002	CN-CONDENSER SYSTEM TUBES	782.52	
1446		314028000405	5	1/26/2006	CN-CONDENSER SYSTEM TUBES	11,711.77	
1447		314028000405	6	7/31/2012	CN-CONDENSER SYSTEM TUBES	4,636.71	
1448		314028000405	7	7/31/2012	CN-CONDENSER SYSTEM TUBES	3,124.74	
1449		314032000405	0	12/31/1998	CT-COOLING TOWER PIPING	-	
1450		314032000405	1	12/31/1993	CT-COOLING TOWER PIPING	1,013.19	
1451		314032000405	2	12/31/1993	CT-COOLING TOWER PIPING	3,397.61	
1452		314032000405	3	12/31/1994	CT-COOLING TOWER PIPING	23,149.52	
1453		314032000405	4	12/31/1995	CT-COOLING TOWER PIPING	13,556.07	
1454		314032000405	5	2/25/2002	CT-COOLING TOWER PIPING	9,091.18	

1455		314032000405	6	1/24/2006	CT-COOLING TOWER PIPING	15,934.38	
1456		314032000405	7	5/6/2013	CT-COOLING TOWER PIPING	64,058.12	
1457		314033000405	0	12/31/1998	CW-PUMPS	-	
1458		314033000405	1	12/31/1979	CW-PUMPS	580,442.30	
1459		314033000405	2	12/31/1997	CW-PUMPS	4,960.26	
1460		314033000405	3	12/31/1993	CW-PUMPS	7,672.23	
1461		314033000405	4	12/31/1997	CW-PUMPS	15,480.82	
1462		314033000405	5	10/2/2000	CW-PUMPS	13,325.73	
1463		314033000405	6	2/25/2002	CW-PUMPS	3,664.13	
1464		314033000405	7	11/27/2002	CW-PUMPS	4,083.08	
1465		314033000405	8	4/16/2008	CW-PUMPS	121,049.66	
1466		314033000405	9	9/30/2013	CW-PUMPS	121,642.55	
1467		314050000405	1	10/14/2015	GN-CRAIG 405 (U1,2) GENERATOR EQUIPMENT	18,928.49	18,928.49
1468		314062000405	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
1469		314062000405	1	12/31/1995	LO-LUBE OIL PUMPS & PUMP MOTORS	7,915.63	
1470		314065000405	0	12/31/1998	MS-MISCELLANEOUS	-	
1471		314082000405	0	8/25/2003	SP-CAPITALIZED SPARE PARTS	149,034.50	
1472		314082000405	1	4/14/2004	SP-CAPITALIZED SPARE PARTS	18,413.42	
1473		314084000405	0	12/31/1998	TB-TURBINE I P COUPLER	-	
1474		314084000405	1	12/31/1994	TB-TURBINE I P COUPLER	1,912.91	
1475		314084000405	2	4/19/2001	TB-TURBINE I P COUPLER	5,713.99	
1476		314084000405	3	1/29/2001	TB-TURBINE I P COUPLER	8,719.81	
1477		314084000405	4	1/29/2010	TB-TURBINE I P COUPLER	1,773.94	
1478	*	Location	000405		CRAIG PLANT - COMMON, UNITS 1 & 2	1,347,271.32	
1479		314033000410	0	1/16/2008	CW-HAYDEN U0 CIRCULATING WATER EQUIPMENT	103,417.00	
1480		314050000410	0	10/18/2012	GN-HAYDEN U0 GENERATOR EQUIPMENT	47,412.42	
1481		314050000410	1	6/17/2014	GN-HAYDEN U0 GENERATOR EQUIPMENT	5,012.23	52,424.65
1482		314062000410	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
1483		314062000410	1	12/31/1976	LO-LUBE OIL PUMPS & PUMP MOTORS	7,141.23	
1484		314062000410	2	12/31/1982	LO-LUBE OIL PUMPS & PUMP MOTORS	657.00	
1485		314062000410	4	12/31/1965	LO-LUBE OIL PUMPS & PUMP MOTORS	1,683.56	
1486		314062000410	5	12/31/1976	LO-LUBE OIL PUMPS & PUMP MOTORS	3,165.03	
1487		314084000410	0	12/31/1998	TB-TURBINE I P COUPLER	-	
1488		314084000410	1	12/31/1995	TB-TURBINE I P COUPLER	6,209.39	
1489		314084000410	2	4/27/2001	TB-TURBINE I P COUPLER	51,116.11	
1490		314084000410	3	1/20/2009	TB-TURBINE I P COUPLER	25,965.72	
1491	*	Location	000410		HAYDEN PLANT - COMMON	251,779.69	
1492		314009000411	0	12/31/1998	BC-BOILER CONTROLS	-	
1493		314009000411	1	12/31/1988	BC-BOILER CONTROLS	1,386.00	
1494		314028000411	0	12/31/1998	CN-HAYDEN U1 CONDENSER SYSTEM	-	
1495		314028000411	1	12/31/1965	CN-HAYDEN U1 CONDENSER SYSTEM	4,348.19	
1496		314028000411	2	12/31/1965	CN-HAYDEN U1 CONDENSER SYSTEM	86,690.54	
1497		314028000411	3	12/31/1965	CN-HAYDEN U1 CONDENSER SYSTEM	11,528.46	
1498		314028000411	4	3/28/2001	CN-HAYDEN U1 CONDENSER SYSTEM	1,321.30	
1499		314028000411	5	11/16/2010	CN-HAYDEN U1 CONDENSER SYSTEM	13,843.25	
1500		314028000411	6	12/20/2012	CN-HAYDEN U1 CONDENSER SYSTEM	5,772.29	
1501		314028000411	7	12/12/2013	CN-HAYDEN U1 CONDENSER SYSTEM	43,323.71	
1502		314028000411	8	12/12/2014	CN-HAYDEN U1 CONDENSER SYSTEM	3,448.78	
1503		314032000411	0	12/31/1998	CT-HAYDEN U1 COOLING TOWER STRUCTURES & EQUIP	-	
1504		314032000411	2	12/31/1982	CT-HAYDEN U1 COOLING TOWER STRUCTURES & EQUIP	26,238.00	
1505		314032000411	3	12/31/1988	CT-HAYDEN U1 COOLING TOWER STRUCTURES & EQUIP	6,781.00	
1506		314032000411	4	12/31/1989	CT-HAYDEN U1 COOLING TOWER STRUCTURES & EQUIP	23,163.00	
1507		314032000411	5	12/31/1990	CT-HAYDEN U1 COOLING TOWER STRUCTURES & EQUIP	27,572.00	
1508		314032000411	6	12/31/1965	CT-HAYDEN U1 COOLING TOWER STRUCTURES & EQUIP	88.40	
1509		314032000411	7	12/31/1965	CT-HAYDEN U1 COOLING TOWER STRUCTURES & EQUIP	1,974.63	
1510		314032000411	9	6/2/2000	CT-HAYDEN U1 COOLING TOWER STRUCTURES & EQUIP	726,724.87	
1511		314032000411	10	9/17/2009	CT-HAYDEN U1 COOLING TOWER STRUCTURES & EQUIP	5,090.56	
1512		314032000411	11	12/15/2011	CT-HAYDEN U1 COOLING TOWER STRUCTURES & EQUIP	22,845.58	
1513		314032000411	12	8/16/2012	CT-HAYDEN U1 COOLING TOWER STRUCTURES & EQUIP	231,744.31	
1514		314032000411	13	8/16/2012	CT-HAYDEN U1 COOLING TOWER STRUCTURES & EQUIP	35,222.20	
1515		314032000411	14	12/20/2012	CT-HAYDEN U1 COOLING TOWER STRUCTURES & EQUIP	20,780.27	
1516		314032000411	15	12/12/2014	CT-HAYDEN U1 COOLING TOWER STRUCTURES & EQUIP	7,045.55	
1517		314032000411	16	2/18/2016	CT-HAYDEN U1 COOLING TOWER STRUCTURES & EQUIP	8,017.59	
1518		314033000411	0	12/31/1998	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	-	
1519		314033000411	1	12/31/1965	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	267.82	
1520		314033000411	2	12/31/1985	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	2,119.00	
1521		314033000411	3	12/31/1991	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	8,765.00	
1522		314033000411	4	12/31/1965	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	1,156.49	
1523		314033000411	5	12/31/1965	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	411.26	
1524		314033000411	6	12/31/1965	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	2,110.89	
1525		314033000411	10	12/31/1965	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	2,120.34	
1526		314033000411	11	12/31/1965	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	26,759.89	
1527		314033000411	12	12/31/1998	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	3,732.03	

1528	314033000411	13	12/31/1965	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	86,165.87	
1529	314033000411	14	12/31/1965	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	854.19	
1530	314033000411	15	12/31/1965	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	2,110.65	
1531	314033000411	16	12/18/2009	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	19,309.22	
1532	314033000411	17	8/13/2014	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	19,878.38	
1533	314033000411	18	2/18/2016	CW-HAYDEN U1 CIRCULATING WATER EQUIPMENT	2,604.37	
1534	314050000411	0	12/31/1998	GN-HAYDEN U1 GENERATOR EQUIPMENT	-	
1535	314050000411	1	12/31/1965	GN-HAYDEN U1 GENERATOR EQUIPMENT	247,208.14	
1536	314050000411	2	12/31/1982	GN-HAYDEN U1 GENERATOR EQUIPMENT	50,813.00	
1537	314050000411	3	12/31/1983	GN-HAYDEN U1 GENERATOR EQUIPMENT	22,775.00	
1538	314050000411	4	12/31/1993	GN-HAYDEN U1 GENERATOR EQUIPMENT	12,272.96	
1539	314050000411	6	12/31/1993	GN-HAYDEN U1 GENERATOR EQUIPMENT	4,235.59	
1540	314050000411	7	12/31/1996	GN-HAYDEN U1 GENERATOR EQUIPMENT	13,163.69	
1541	314050000411	8	4/7/1999	GN-HAYDEN U1 GENERATOR EQUIPMENT	5,010.28	
1542	314050000411	9	4/7/1999	GN-HAYDEN U1 GENERATOR EQUIPMENT	6,724.05	
1543	314050000411	10	8/9/2000	GN-HAYDEN U1 GENERATOR EQUIPMENT	2,805.38	
1544	314050000411	12	8/30/1999	GN-HAYDEN U1 GENERATOR EQUIPMENT	1,061.26	
1545	314050000411	13	6/15/2009	GN-HAYDEN U1 GENERATOR EQUIPMENT	108,213.35	
1546	314050000411	14	6/15/2009	GN-HAYDEN U1 GENERATOR EQUIPMENT	130,102.94	
1547	314050000411	16	6/15/2009	GN-HAYDEN U1 GENERATOR EQUIPMENT	77,575.33	
1548	314050000411	17	8/16/2012	GN-HAYDEN U1 GENERATOR EQUIPMENT	690,526.27	
1549	314050000411	18	8/16/2012	GN-HAYDEN U1 GENERATOR EQUIPMENT	121,444.51	
1550	314050000411	19	12/12/2014	GN-HAYDEN U1 GENERATOR EQUIPMENT	2,408.31	
1551	314050000411	20	2/18/2016	GN-HAYDEN U1 GENERATOR EQUIPMENT	1,086.95	1,497,427.01
1552	314062000411	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
1553	314062000411	1	12/31/1965	LO-LUBE OIL PUMPS & PUMP MOTORS	228.79	
1554	314062000411	2	12/31/1965	LO-LUBE OIL PUMPS & PUMP MOTORS	2,744.79	
1555	314062000411	3	4/7/1999	LO-LUBE OIL PUMPS & PUMP MOTORS	143,930.28	
1556	314062000411	4	11/14/2013	LO-LUBE OIL PUMPS & PUMP MOTORS	64,268.22	
1557	314082000411	0	12/31/1998	SP-CAPITALIZED SPARE PARTS	-	
1558	314082000411	1	12/31/1994	SP-CAPITALIZED SPARE PARTS	12,674.31	
1559	314084000411	0	12/31/1998	TB-HAYDEN U1 TURBINE EQUIPMENT	-	
1560	314084000411	1	12/31/1965	TB-HAYDEN U1 TURBINE EQUIPMENT	1,066,988.96	
1561	314084000411	2	12/31/1982	TB-HAYDEN U1 TURBINE EQUIPMENT	171.00	
1562	314084000411	3	12/31/1994	TB-HAYDEN U1 TURBINE EQUIPMENT	46,371.68	
1563	314084000411	6	12/31/1994	TB-HAYDEN U1 TURBINE EQUIPMENT	119,061.03	
1564	314084000411	7	12/31/1997	TB-HAYDEN U1 TURBINE EQUIPMENT	62,378.38	
1565	314084000411	8	12/31/1993	TB-HAYDEN U1 TURBINE EQUIPMENT	675.12	
1566	314084000411	9	9/7/2000	TB-HAYDEN U1 TURBINE EQUIPMENT	15,685.83	
1567	314084000411	12	6/20/2003	TB-HAYDEN U1 TURBINE EQUIPMENT	165,955.88	
1568	314084000411	14	6/21/2012	TB-HAYDEN U1 TURBINE EQUIPMENT	166,449.13	
1569	314084000411	15	12/12/2014	TB-HAYDEN U1 TURBINE EQUIPMENT	1,762.50	
1570	314084000411	16	2/18/2016	TB-HAYDEN U1 TURBINE EQUIPMENT	4,751.37	
1571	314084000411	17	6/13/2018	TB-HAYDEN U1 TURBINE EQUIPMENT	425,290.82	
1572	314099000411	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
1573	* Location	000411		HAYDEN PLANT UNIT 1	5,290,130.98	
1574	314022000412	0	12/31/1998	CD-CONDENSATE TANK FOUNDATIONS	-	
1575	314022000412	1	12/31/1976	CD-CONDENSATE TANK FOUNDATIONS	1,442.48	
1576	314022000412	2	12/31/1976	CD-CONDENSATE TANK FOUNDATIONS	15,313.69	
1577	314028000412	0	12/31/1998	CN-HAYDEN U2 CONDENSER EQUIPMENT	-	
1578	314028000412	1	12/31/1976	CN-HAYDEN U2 CONDENSER EQUIPMENT	5,101.69	
1579	314028000412	2	12/31/1976	CN-HAYDEN U2 CONDENSER EQUIPMENT	4,905.55	
1580	314028000412	3	12/31/1976	CN-HAYDEN U2 CONDENSER EQUIPMENT	104,805.22	
1581	314028000412	4	12/31/1976	CN-HAYDEN U2 CONDENSER EQUIPMENT	10,283.05	
1582	314028000412	5	12/31/1976	CN-HAYDEN U2 CONDENSER EQUIPMENT	13,615.24	
1583	314028000412	6	2/4/2000	CN-HAYDEN U2 CONDENSER EQUIPMENT	7,941.43	
1584	314028000412	7	8/22/2011	CN-HAYDEN U2 CONDENSER EQUIPMENT	4,758.02	
1585	314028000412	8	2/18/2016	CN-HAYDEN U2 CONDENSER EQUIPMENT	1,692.13	
1586	314032000412	0	12/31/1998	CT-HAYDEN U2 COOLING TOWER STRUCTURES & EQUIX	-	
1587	314032000412	1	12/31/1976	CT-HAYDEN U2 COOLING TOWER STRUCTURES & EQUIX	1,780.15	
1588	314032000412	2	12/31/1982	CT-HAYDEN U2 COOLING TOWER STRUCTURES & EQUIX	156,332.00	
1589	314032000412	4	10/16/2000	CT-HAYDEN U2 COOLING TOWER STRUCTURES & EQUIX	15,761.43	
1590	314032000412	5	6/16/2008	CT-HAYDEN U2 COOLING TOWER STRUCTURES & EQUIX	8,393.81	
1591	314032000412	6	8/22/2011	CT-HAYDEN U2 COOLING TOWER STRUCTURES & EQUIX	665,233.81	
1592	314032000412	7	6/17/2014	CT-HAYDEN U2 COOLING TOWER STRUCTURES & EQUIX	53,338.22	
1593	314032000412	8	12/12/2014	CT-HAYDEN U2 COOLING TOWER STRUCTURES & EQUIX	9,235.66	
1594	314033000412	0	12/31/1998	CW-HAYDEN U2 CIRCULATING WATER EQUIPMENT	-	
1595	314033000412	1	12/31/1976	CW-HAYDEN U2 CIRCULATING WATER EQUIPMENT	46,897.78	
1596	314033000412	2	12/31/1989	CW-HAYDEN U2 CIRCULATING WATER EQUIPMENT	9,344.00	
1597	314033000412	3	12/31/1991	CW-HAYDEN U2 CIRCULATING WATER EQUIPMENT	4,094.00	
1598	314033000412	4	12/31/1976	CW-HAYDEN U2 CIRCULATING WATER EQUIPMENT	707.65	
1599	314033000412	5	12/31/1993	CW-HAYDEN U2 CIRCULATING WATER EQUIPMENT	928.47	
1600	314033000412	6	12/31/1976	CW-HAYDEN U2 CIRCULATING WATER EQUIPMENT	1,441.29	

1601	314033000412	7	12/31/1976	CW-HAYDEN U2 CIRCULATING WATER EQUIPMENT	3,681.47	
1602	314033000412	8	12/31/1993	CW-HAYDEN U2 CIRCULATING WATER EQUIPMENT	3,650.25	
1603	314033000412	9	12/31/1976	CW-HAYDEN U2 CIRCULATING WATER EQUIPMENT	28,177.79	
1604	314033000412	10	12/31/1997	CW-HAYDEN U2 CIRCULATING WATER EQUIPMENT	1,863.02	
1605	314033000412	11	6/28/1999	CW-HAYDEN U2 CIRCULATING WATER EQUIPMENT	382,422.89	
1606	314033000412	12	1/22/2014	CW-HAYDEN U2 CIRCULATING WATER EQUIPMENT	4,849.84	
1607	314033000412	13	6/23/2016	CW-HAYDEN U2 CIRCULATING WATER EQUIPMENT	498,849.71	
1608	314033000412	14	2/18/2016	CW-HAYDEN U2 CIRCULATING WATER EQUIPMENT	1,501.99	
1609	314050000412	0	12/31/1998	GN-HAYDEN U2 GENERATOR EQUIPMENT	-	
1610	314050000412	1	12/31/1976	GN-HAYDEN U2 GENERATOR EQUIPMENT	224,868.78	
1611	314050000412	2	12/31/1981	GN-HAYDEN U2 GENERATOR EQUIPMENT	3,167.00	
1612	314050000412	3	12/31/1982	GN-HAYDEN U2 GENERATOR EQUIPMENT	11,222.00	
1613	314050000412	4	12/31/1983	GN-HAYDEN U2 GENERATOR EQUIPMENT	5,448.00	
1614	314050000412	5	12/31/1984	GN-HAYDEN U2 GENERATOR EQUIPMENT	223.00	
1615	314050000412	6	12/31/1985	GN-HAYDEN U2 GENERATOR EQUIPMENT	3,097.00	
1616	314050000412	7	12/31/1993	GN-HAYDEN U2 GENERATOR EQUIPMENT	6,298.56	
1617	314050000412	9	12/31/1993	GN-HAYDEN U2 GENERATOR EQUIPMENT	2,691.78	
1618	314050000412	10	12/31/1996	GN-HAYDEN U2 GENERATOR EQUIPMENT	8,632.81	
1619	314050000412	12	6/19/2007	GN-HAYDEN U2 GENERATOR EQUIPMENT	26,588.36	
1620	314050000412	13	1/20/2009	GN-HAYDEN U2 GENERATOR EQUIPMENT	20,161.58	
1621	314050000412	14	8/22/2011	GN-HAYDEN U2 GENERATOR EQUIPMENT	4,000.42	
1622	314050000412	15	8/22/2011	GN-HAYDEN U2 GENERATOR EQUIPMENT	158,696.49	
1623	314050000412	16	8/22/2011	GN-HAYDEN U2 GENERATOR EQUIPMENT	70,493.39	
1624	314050000412	17	9/6/2012	GN-HAYDEN U2 GENERATOR EQUIPMENT	256,052.57	
1625	314050000412	18	2/18/2016	GN-HAYDEN U2 GENERATOR EQUIPMENT	820.33	802,462.07
1626	314062000412	0	9/21/2012	LO-LUBE OIL PUMPS & PUMP MOTORS	10,781.11	
1627	314062000412	1	11/14/2013	LO-LUBE OIL PUMPS & PUMP MOTORS	29,530.53	
1628	314082000412	0	12/31/1998	SP-CAPITALIZED SPARE PARTS	-	
1629	314082000412	1	12/31/1994	SP-CAPITALIZED SPARE PARTS	8,906.24	
1630	314084000412	0	12/31/1998	TB-HAYDEN U2 TURBINE EQUIPMENT	-	
1631	314084000412	1	12/31/1976	TB-HAYDEN U2 TURBINE EQUIPMENT	1,047,004.22	
1632	314084000412	2	12/31/1986	TB-HAYDEN U2 TURBINE EQUIPMENT	5,514.00	
1633	314084000412	3	12/31/1987	TB-HAYDEN U2 TURBINE EQUIPMENT	702.00	
1634	314084000412	4	12/31/1993	TB-HAYDEN U2 TURBINE EQUIPMENT	32,471.25	
1635	314084000412	5	12/31/1993	TB-HAYDEN U2 TURBINE EQUIPMENT	441.76	
1636	314084000412	6	12/31/1993	TB-HAYDEN U2 TURBINE EQUIPMENT	4,041.87	
1637	314084000412	7	10/25/2000	TB-HAYDEN U2 TURBINE EQUIPMENT	6,500.21	
1638	314084000412	8	2/4/2000	TB-HAYDEN U2 TURBINE EQUIPMENT	39,554.58	
1639	314084000412	9	6/5/2001	TB-HAYDEN U2 TURBINE EQUIPMENT	50,529.35	
1640	314084000412	10	6/16/2008	TB-HAYDEN U2 TURBINE EQUIPMENT	213,647.80	
1641	314084000412	11	8/22/2011	TB-HAYDEN U2 TURBINE EQUIPMENT	105,975.12	
1642	314084000412	12	12/12/2014	TB-HAYDEN U2 TURBINE EQUIPMENT	1,700.29	
1643	314084000412	13	6/23/2016	TB-HAYDEN U2 TURBINE EQUIPMENT	76,703.39	
1644	314084000412	14	2/18/2016	TB-HAYDEN U2 TURBINE EQUIPMENT	569.58	
1645	314099000412	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
1646	* Location	000412		HAYDEN PLANT UNIT 2	4,505,379.10	
1647	314028401000	0	12/31/1998	CN-CONDENSER SYSTEM TUBES	-	
1648	314028401000	3	6/6/2001	CN-CONDENSER SYSTEM TUBES	-	
1649	314028401000	4	9/24/2001	CN-CONDENSER SYSTEM TUBES	27,844.17	
1650	314028401000	5	6/13/2003	CN-CONDENSER SYSTEM TUBES	19,084.86	
1651	314028401000	6	6/13/2003	CN-CONDENSER SYSTEM TUBES	2,024.67	
1652	314028401000	9	1/26/2007	CN-CONDENSER SYSTEM TUBES	6,875.75	
1653	314028401000	10	1/15/2008	CN-CONDENSER SYSTEM TUBES	5,644.35	
1654	314028401000	11	1/16/2009	CN-CONDENSER SYSTEM TUBES	2,759.92	
1655	314028401000	12	1/16/2009	CN-CONDENSER SYSTEM TUBES	7,397.06	
1656	314028401000	13	1/19/2011	CN-CONDENSER SYSTEM TUBES	2,817.20	
1657	314028401000	14	10/12/2011	CN-CONDENSER SYSTEM TUBES	6,283.56	
1658	314028401000	15	1/19/2012	CN-CONDENSER SYSTEM TUBES	3,144.01	
1659	314028401000	16	1/19/2012	CN-CONDENSER SYSTEM TUBES	3,338.09	
1660	314028401000	17	12/11/2013	CN-CONDENSER SYSTEM TUBES	9,046.16	
1661	314028401000	18	7/14/2014	CN-CONDENSER SYSTEM TUBES	6,171.28	
1662	314032401000	0	12/31/1998	CT-COOLING TOWER PIPING	-	
1663	314032401000	5	9/24/2001	CT-COOLING TOWER PIPING	11,114.95	
1664	314032401000	6	6/13/2003	CT-COOLING TOWER PIPING	7,066.34	
1665	314032401000	7	1/18/2006	CT-COOLING TOWER PIPING	38,854.90	
1666	314032401000	8	7/13/2007	CT-COOLING TOWER PIPING	412,224.59	
1667	314032401000	9	9/11/2009	CT-COOLING TOWER PIPING	439,724.78	
1668	314032401000	10	11/10/2010	CT-COOLING TOWER PIPING	19,318.52	
1669	314032401000	11	1/19/2012	CT-COOLING TOWER PIPING	20,876.94	
1670	314033401000	0	12/31/1998	CW-COLSTRIP CIRCULATING WATER EQUIPMENT	-	
1671	314033401000	6	9/8/1999	CW-COLSTRIP CIRCULATING WATER EQUIPMENT	8,551.83	
1672	314033401000	7	4/14/2000	CW-COLSTRIP CIRCULATING WATER EQUIPMENT	1,478.06	
1673	314033401000	8	3/19/2002	CW-COLSTRIP CIRCULATING WATER EQUIPMENT	2,489.60	

1674	314033401000	10	3/11/2004	CW-COLSTRIP CIRCULATING WATER EQUIPMENT	69,250.85	
1675	314033401000	12	7/18/2006	CW-COLSTRIP CIRCULATING WATER EQUIPMENT	2,443.55	
1676	314033401000	13	7/13/2007	CW-COLSTRIP CIRCULATING WATER EQUIPMENT	47,749.63	
1677	314033401000	14	1/16/2009	CW-COLSTRIP CIRCULATING WATER EQUIPMENT	49,875.06	
1678	314033401000	15	1/15/2010	CW-COLSTRIP CIRCULATING WATER EQUIPMENT	18,821.30	
1679	314033401000	16	1/19/2012	CW-COLSTRIP CIRCULATING WATER EQUIPMENT	52,655.41	
1680	314033401000	17	3/19/2013	CW-COLSTRIP CIRCULATING WATER EQUIPMENT	23,730.10	
1681	314033401000	18	9/12/2013	CW-COLSTRIP CIRCULATING WATER EQUIPMENT	17,477.43	
1682	314033401000	19	1/14/2015	CW-COLSTRIP CIRCULATING WATER EQUIPMENT	8,594.21	
1683	314033401000	20	1/16/2015	CW-COLSTRIP CIRCULATING WATER EQUIPMENT	5,070.10	
1684	314050401000	0	12/31/1998	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	-	
1685	314050401000	9	6/12/2003	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	44,074.12	
1686	314050401000	12	6/16/2003	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	35,980.64	
1687	314050401000	13	6/11/2004	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	57,135.73	
1688	314050401000	14	6/14/2004	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	409,154.58	
1689	314050401000	15	6/14/2004	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	211,482.91	
1690	314050401000	16	6/14/2004	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	173,031.49	
1691	314050401000	18	7/13/2007	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	263,912.95	
1692	314050401000	19	8/12/2010	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	11,209.49	
1693	314050401000	20	7/13/2011	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	569,388.26	
1694	314050401000	21	7/15/2011	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	25,547.07	
1695	314050401000	22	10/11/2012	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	210,112.20	
1696	314050401000	24	7/12/2013	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	532,641.47	
1697	314050401000	25	10/23/2013	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	374,034.92	
1698	314050401000	26	2/12/2014	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	2,255,255.12	
1699	314050401000	27	8/18/2014	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	302,344.87	
1700	314050401000	28	7/14/2014	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	51,392.68	
1701	314050401000	29	7/19/2017	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	598,728.64	
1702	314050401000	30	7/19/2017	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	75,886.93	
1703	314050401000	31	7/19/2017	GN-COLSTRIP GENERATOR & ASSOC EQUIPMENT	80,642.85	6,281,956.92
1704	314062401000	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
1705	314062401000	2	12/31/1989	LO-LUBE OIL PUMPS & PUMP MOTORS	3,427.00	
1706	314062401000	3	12/31/1992	LO-LUBE OIL PUMPS & PUMP MOTORS	2,795.06	
1707	314062401000	4	12/31/1993	LO-LUBE OIL PUMPS & PUMP MOTORS	401.47	
1708	314062401000	5	12/31/1994	LO-LUBE OIL PUMPS & PUMP MOTORS	545.45	
1709	314062401000	6	3/1/1999	LO-LUBE OIL PUMPS & PUMP MOTORS	27,714.62	
1710	314065401000	0	12/31/1998	MS-MISCELLANEOUS	-	
1711	314081401000	0	12/31/1998	SO-SCRUBBER	-	
1712	314081401000	2	12/31/1992	SO-SCRUBBER	2,650.08	
1713	314082401000	0	12/31/1998	SP-COLSTRIP CAPITALIZED SPARE PARTS FERC 314	-	
1714	314082401000	1	12/31/1993	SP-COLSTRIP CAPITALIZED SPARE PARTS FERC 314	56,459.53	
1715	314082401000	2	6/12/2003	SP-COLSTRIP CAPITALIZED SPARE PARTS FERC 314	54,934.90	
1716	314082401000	4	6/10/2014	SP-COLSTRIP CAPITALIZED SPARE PARTS FERC 314	357,720.78	
1717	314084401000	0	12/31/1998	TB-COLSTRIP TURBINE EQUIPMENT	-	
1718	314084401000	1	12/31/1984	TB-COLSTRIP TURBINE EQUIPMENT	5,230,000.51	
1719	314084401000	2	12/31/1986	TB-COLSTRIP TURBINE EQUIPMENT	10,745,158.95	
1720	314084401000	3	12/31/1988	TB-COLSTRIP TURBINE EQUIPMENT	85,790.41	
1721	314084401000	4	12/31/1989	TB-COLSTRIP TURBINE EQUIPMENT	93,792.59	
1722	314084401000	5	12/31/1990	TB-COLSTRIP TURBINE EQUIPMENT	33,170.26	
1723	314084401000	6	12/31/1992	TB-COLSTRIP TURBINE EQUIPMENT	64,205.06	
1724	314084401000	7	12/31/1993	TB-COLSTRIP TURBINE EQUIPMENT	1,023,438.47	
1725	314084401000	8	12/31/1994	TB-COLSTRIP TURBINE EQUIPMENT	77,151.01	
1726	314084401000	9	12/31/1995	TB-COLSTRIP TURBINE EQUIPMENT	1,267,707.99	
1727	314084401000	10	12/31/1996	TB-COLSTRIP TURBINE EQUIPMENT	7,999.02	
1728	314084401000	11	12/31/1997	TB-COLSTRIP TURBINE EQUIPMENT	355,847.61	
1729	314084401000	12	12/31/1997	TB-COLSTRIP TURBINE EQUIPMENT	149,144.80	
1730	314084401000	13	12/31/1996	TB-COLSTRIP TURBINE EQUIPMENT	1,338,197.77	
1731	314084401000	15	12/15/1998	TB-COLSTRIP TURBINE EQUIPMENT	16,750.50	
1732	314084401000	17	4/14/2000	TB-COLSTRIP TURBINE EQUIPMENT	35,921.31	
1733	314084401000	18	7/1/1997	TB-COLSTRIP TURBINE EQUIPMENT	3,553.01	
1734	314084401000	19	9/7/1999	TB-COLSTRIP TURBINE EQUIPMENT	262,303.56	
1735	314084401000	20	10/23/2000	TB-COLSTRIP TURBINE EQUIPMENT	3,106.99	
1736	314084401000	21	6/6/2001	TB-COLSTRIP TURBINE EQUIPMENT	1,280.28	
1737	314084401000	22	10/23/2000	TB-COLSTRIP TURBINE EQUIPMENT	59,597.38	
1738	314084401000	25	9/24/2001	TB-COLSTRIP TURBINE EQUIPMENT	210,387.72	
1739	314084401000	26	6/13/2003	TB-COLSTRIP TURBINE EQUIPMENT	60,562.26	
1740	314084401000	29	11/22/2004	TB-COLSTRIP TURBINE EQUIPMENT	851.87	
1741	314084401000	30	6/11/2004	TB-COLSTRIP TURBINE EQUIPMENT	41,942.25	
1742	314084401000	31	6/11/2004	TB-COLSTRIP TURBINE EQUIPMENT	24,026.86	
1743	314084401000	32	6/11/2004	TB-COLSTRIP TURBINE EQUIPMENT	45,538.06	
1744	314084401000	33	6/11/2004	TB-COLSTRIP TURBINE EQUIPMENT	9,996.17	
1745	314084401000	34	6/11/2004	TB-COLSTRIP TURBINE EQUIPMENT	54,662.92	
1746	314084401000	35	6/14/2005	TB-COLSTRIP TURBINE EQUIPMENT	21,562.14	

1747	314084401000	36	7/18/2006	TB-COLSTRIP TURBINE EQUIPMENT	652,369.42	
1748	314084401000	37	3/24/2005	TB-COLSTRIP TURBINE EQUIPMENT	1,116,365.37	
1749	314084401000	38	1/18/2006	TB-COLSTRIP TURBINE EQUIPMENT	478.02	
1750	314084401000	40	7/18/2006	TB-COLSTRIP TURBINE EQUIPMENT	2,407.19	
1751	314084401000	41	7/18/2006	TB-COLSTRIP TURBINE EQUIPMENT	46,395.82	
1752	314084401000	42	7/18/2006	TB-COLSTRIP TURBINE EQUIPMENT	56,162.96	
1753	314084401000	43	7/18/2006	TB-COLSTRIP TURBINE EQUIPMENT	529,456.28	
1754	314084401000	44	7/13/2007	TB-COLSTRIP TURBINE EQUIPMENT	168,033.04	
1755	314084401000	45	8/24/2007	TB-COLSTRIP TURBINE EQUIPMENT	61,707.31	
1756	314084401000	46	8/24/2007	TB-COLSTRIP TURBINE EQUIPMENT	49,576.66	
1757	314084401000	47	1/30/2008	TB-COLSTRIP TURBINE EQUIPMENT	480,722.23	
1758	314084401000	48	11/12/2009	TB-COLSTRIP TURBINE EQUIPMENT	701,001.38	
1759	314084401000	49	12/11/2009	TB-COLSTRIP TURBINE EQUIPMENT	413,230.28	
1760	314084401000	50	12/11/2009	TB-COLSTRIP TURBINE EQUIPMENT	148,605.82	
1761	314084401000	51	7/13/2011	TB-COLSTRIP TURBINE EQUIPMENT	94,090.05	
1762	314084401000	52	7/13/2011	TB-COLSTRIP TURBINE EQUIPMENT	23,419.92	
1763	314084401000	53	7/13/2011	TB-COLSTRIP TURBINE EQUIPMENT	59,959.89	
1764	314084401000	54	7/13/2011	TB-COLSTRIP TURBINE EQUIPMENT	102,942.61	
1765	314084401000	55	7/13/2011	TB-COLSTRIP TURBINE EQUIPMENT	1,905,337.89	
1766	314084401000	56	7/15/2011	TB-COLSTRIP TURBINE EQUIPMENT	153,282.40	
1767	314084401000	57	7/15/2011	TB-COLSTRIP TURBINE EQUIPMENT	86,860.02	
1768	314084401000	58	7/15/2011	TB-COLSTRIP TURBINE EQUIPMENT	178,829.47	
1769	314084401000	59	7/15/2011	TB-COLSTRIP TURBINE EQUIPMENT	66,422.40	
1770	314084401000	60	10/12/2011	TB-COLSTRIP TURBINE EQUIPMENT	2,455.76	
1771	314084401000	61	7/12/2013	TB-COLSTRIP TURBINE EQUIPMENT	87,694.90	
1772	314084401000	62	7/12/2013	TB-COLSTRIP TURBINE EQUIPMENT	47,565.09	
1773	314084401000	63	7/12/2013	TB-COLSTRIP TURBINE EQUIPMENT	44,969.25	
1774	314084401000	64	7/12/2013	TB-COLSTRIP TURBINE EQUIPMENT	93,577.31	
1775	314084401000	65	7/15/2013	TB-COLSTRIP TURBINE EQUIPMENT	436,861.15	
1776	314084401000	66	9/12/2013	TB-COLSTRIP TURBINE EQUIPMENT	13,083.75	
1777	314084401000	67	12/11/2013	TB-COLSTRIP TURBINE EQUIPMENT	5,712.14	
1778	314084401000	68	7/14/2014	TB-COLSTRIP TURBINE EQUIPMENT	79,253.55	
1779	314084401000	69	10/21/2016	TB-COLSTRIP TURBINE EQUIPMENT	541,487.94	
1780	314084401000	70	10/21/2016	TB-COLSTRIP TURBINE EQUIPMENT	231,479.62	
1781	314084401000	71	10/21/2016	TB-COLSTRIP TURBINE EQUIPMENT	81,164.51	
1782	314084401000	72	7/19/2017	TB-COLSTRIP TURBINE EQUIPMENT	219,343.27	
1783	314084401000	73	7/19/2017	TB-COLSTRIP TURBINE EQUIPMENT	109,228.37	
1784	314084401000	74	12/16/2019	TB-COLSTRIP TURBINE EQUIPMENT	641,755.23	
1785	314093401000	0	12/31/1998	WP-GROUND & SURFACE WATER MONITORING SYSTEM	-	
1786	314097401000	0	12/31/1998	WW-WASTE WATER	-	
1787	314097401000	1	12/31/1993	WW-WASTE WATER	4,612.00	
1788	314099401000	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
1789	* Location	401000		COLSTRIP STEAM PLT	39,209,953.04	
1790	314032514000	0	12/31/1998	CT-DJ U0 COOLING TOWER STRUCTURES & EQUIPMENT	-	
1791	314032514000	25	12/1/2008	CT-DJ U0 COOLING TOWER STRUCTURES & EQUIPMENT	36,279.77	
1792	314032514000	27	12/12/2008	CT-DJ U0 COOLING TOWER STRUCTURES & EQUIPMENT	198,929.39	
1793	314032514000	28	3/31/2010	CT-DJ U0 COOLING TOWER STRUCTURES & EQUIPMENT	146,251.11	
1794	314032514000	29	4/13/2010	CT-DJ U0 COOLING TOWER STRUCTURES & EQUIPMENT	29,885.86	
1795	314032514000	30	4/25/2012	CT-DJ U0 COOLING TOWER STRUCTURES & EQUIPMENT	5,819,762.60	
1796	314032514000	31	11/5/2018	CT-DJ U0 COOLING TOWER STRUCTURES & EQUIPMENT	265,523.64	
1797	314032514000	32	7/21/2016	CT-DJ U0 COOLING TOWER STRUCTURES & EQUIPMENT	10,868.47	
1798	314032514000	33	7/21/2016	CT-DJ U0 COOLING TOWER STRUCTURES & EQUIPMENT	10,055.46	
1799	314032514000	34	11/13/2017	CT-DJ U0 COOLING TOWER STRUCTURES & EQUIPMENT	39,281.51	
1800	314033514000	0	12/31/1998	CW-DJ U0 CIRCULATING WATER EQUIPMENT	-	
1801	314033514000	16	12/31/1995	CW-DJ U0 CIRCULATING WATER EQUIPMENT	1,212,636.24	
1802	314033514000	18	12/31/2001	CW-DJ U0 CIRCULATING WATER EQUIPMENT	12,330.98	
1803	314033514000	20	4/16/2001	CW-DJ U0 CIRCULATING WATER EQUIPMENT	26,671.06	
1804	314033514000	21	11/27/2007	CW-DJ U0 CIRCULATING WATER EQUIPMENT	5,763.83	
1805	314033514000	22	8/10/2010	CW-DJ U0 CIRCULATING WATER EQUIPMENT	30,766.17	
1806	314033514000	23	1/3/2012	CW-DJ U0 CIRCULATING WATER EQUIPMENT	44,698.04	
1807	314033514000	24	2/27/2012	CW-DJ U0 CIRCULATING WATER EQUIPMENT	4,947.08	
1808	314050514000	0	12/31/1998	GN-DJ U0 GENERATOR EQUIPMENT	-	
1809	314050514000	14	3/8/2004	GN-DJ U0 GENERATOR EQUIPMENT	5,553.52	
1810	314050514000	15	12/1/2008	GN-DJ U0 GENERATOR EQUIPMENT	5,219.61	
1811	314050514000	16	2/27/2012	GN-DJ U0 GENERATOR EQUIPMENT	46,556.83	
1812	314050514000	17	4/16/2012	GN-DJ U0 GENERATOR EQUIPMENT	9,428.56	
1813	314050514000	18	12/27/2012	GN-DJ U0 GENERATOR EQUIPMENT	11,418.55	78,177.07
1814	314062514000	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
1815	314062514000	1	12/31/1958	LO-LUBE OIL PUMPS & PUMP MOTORS	9,816.99	
1816	314062514000	2	12/31/1960	LO-LUBE OIL PUMPS & PUMP MOTORS	13,530.00	
1817	314062514000	3	12/31/1964	LO-LUBE OIL PUMPS & PUMP MOTORS	28,099.76	
1818	314062514000	4	12/31/1965	LO-LUBE OIL PUMPS & PUMP MOTORS	2,311.95	
1819	314062514000	5	12/31/1972	LO-LUBE OIL PUMPS & PUMP MOTORS	27,833.86	

1820		314062514000	6	12/31/1973	LO-LUBE OIL PUMPS & PUMP MOTORS	28,424.33	
1821		314062514000	7	12/31/1979	LO-LUBE OIL PUMPS & PUMP MOTORS	20,411.06	
1822		314062514000	8	12/31/1980	LO-LUBE OIL PUMPS & PUMP MOTORS	10,019.17	
1823		314062514000	9	12/31/1986	LO-LUBE OIL PUMPS & PUMP MOTORS	12,174.13	
1824		314062514000	10	12/31/1988	LO-LUBE OIL PUMPS & PUMP MOTORS	32,924.95	
1825		314062514000	11	3/22/2006	LO-LUBE OIL PUMPS & PUMP MOTORS	4,682.20	
1826		314062514000	12	4/9/2018	LO-LUBE OIL PUMPS & PUMP MOTORS	75,871.41	
1827		314082514000	0	12/31/1998	SP-CAPITALIZED SPARE PARTS	-	
1828		314082514000	1	12/31/1991	SP-CAPITALIZED SPARE PARTS	36,033.61	
1829		314082514000	3	12/31/1997	SP-CAPITALIZED SPARE PARTS	180,000.00	
1830		314084514000	0	12/31/1998	TB-DAVE JOHNSTON U0 TURBINE EQUIPMENT	-	
1831		314084514000	13	12/31/1982	TB-DAVE JOHNSTON U0 TURBINE EQUIPMENT	31,376.57	
1832		314084514000	14	12/31/1983	TB-DAVE JOHNSTON U0 TURBINE EQUIPMENT	30,790.28	
1833		314084514000	15	12/31/1985	TB-DAVE JOHNSTON U0 TURBINE EQUIPMENT	38,985.30	
1834		314084514000	16	12/31/1988	TB-DAVE JOHNSTON U0 TURBINE EQUIPMENT	87,852.34	
1835		314084514000	19	12/31/1992	TB-DAVE JOHNSTON U0 TURBINE EQUIPMENT	42,868.13	
1836		314084514000	20	12/31/1995	TB-DAVE JOHNSTON U0 TURBINE EQUIPMENT	172,553.05	
1837		314084514000	21	2/25/2004	TB-DAVE JOHNSTON U0 TURBINE EQUIPMENT	272,912.74	
1838		314084514000	22	5/7/2004	TB-DAVE JOHNSTON U0 TURBINE EQUIPMENT	16,232.99	
1839		314084514000	24	10/14/2004	TB-DAVE JOHNSTON U0 TURBINE EQUIPMENT	462,507.97	
1840		314084514000	26	4/18/2005	TB-DAVE JOHNSTON U0 TURBINE EQUIPMENT	126,679.36	
1841		314084514000	27	2/20/2007	TB-DAVE JOHNSTON U0 TURBINE EQUIPMENT	35,836.54	
1842		314084514000	28	9/11/2014	TB-DAVE JOHNSTON U0 TURBINE EQUIPMENT	8,717.42	
1843		314097514000	0	12/31/1998	WW-WASTE WATER	-	
1844		314097514000	1	12/31/1996	WW-WASTE WATER	63,033.82	
1845	*	Location	514000		DAVE JOHNSTON STEAM PLANT	9,845,308.21	
1846		314028514001	0	12/31/1998	CN-DJ U1 CONDENSER EQUIPMENT	-	
1847		314028514001	2	12/31/1958	CN-DJ U1 CONDENSER EQUIPMENT	385,650.48	
1848		314028514001	4	12/31/1963	CN-DJ U1 CONDENSER EQUIPMENT	4,524.41	
1849		314028514001	5	12/31/1964	CN-DJ U1 CONDENSER EQUIPMENT	15,422.00	
1850		314028514001	6	12/31/1982	CN-DJ U1 CONDENSER EQUIPMENT	3,470.73	
1851		314028514001	7	12/31/1988	CN-DJ U1 CONDENSER EQUIPMENT	493,391.23	
1852		314028514001	9	12/5/2007	CN-DJ U1 CONDENSER EQUIPMENT	36,770.34	
1853		314028514001	10	4/25/2012	CN-DJ U1 CONDENSER EQUIPMENT	8,588.59	
1854		314028514001	11	4/20/2016	CN-DJ U1 CONDENSER EQUIPMENT	103,823.98	
1855		314028514001	12	9/11/2017	CN-DJ U1 CONDENSER EQUIPMENT	45,101.27	
1856		314032514001	0	12/31/1998	CT-DJ U1 COOLING TOWER STRUCTURES & EQUIPMENT	-	
1857		314032514001	4	12/31/1976	CT-DJ U1 COOLING TOWER STRUCTURES & EQUIPMENT	7,922.90	
1858		314032514001	5	12/31/1977	CT-DJ U1 COOLING TOWER STRUCTURES & EQUIPMENT	1,276.76	
1859		314032514001	6	12/31/1979	CT-DJ U1 COOLING TOWER STRUCTURES & EQUIPMENT	10,603.59	
1860		314032514001	7	12/31/1988	CT-DJ U1 COOLING TOWER STRUCTURES & EQUIPMENT	4,622.69	
1861		314032514001	10	12/31/1992	CT-DJ U1 COOLING TOWER STRUCTURES & EQUIPMENT	138,946.88	
1862		314033514001	1	12/31/1958	CW - DJ U1 CIRCULATING WATER EQUIPMENT	260,925.11	
1863		314033514001	2	12/31/1965	CW - DJ U1 CIRCULATING WATER EQUIPMENT	190.64	
1864		314033514001	3	12/31/1967	CW - DJ U1 CIRCULATING WATER EQUIPMENT	2,311.94	
1865		314033514001	4	12/31/1968	CW - DJ U1 CIRCULATING WATER EQUIPMENT	2,500.53	
1866		314033514001	5	12/31/1970	CW - DJ U1 CIRCULATING WATER EQUIPMENT	4,627.07	
1867		314033514001	6	12/31/1975	CW - DJ U1 CIRCULATING WATER EQUIPMENT	565,591.33	
1868		314033514001	7	12/31/1978	CW - DJ U1 CIRCULATING WATER EQUIPMENT	200.09	
1869		314033514001	8	12/31/1988	CW - DJ U1 CIRCULATING WATER EQUIPMENT	6,035.62	
1870		314033514001	9	12/31/1992	CW - DJ U1 CIRCULATING WATER EQUIPMENT	28,993.73	
1871		314033514001	10	3/8/2004	CW - DJ U1 CIRCULATING WATER EQUIPMENT	18,956.30	
1872		314033514001	11	6/9/2006	CW - DJ U1 CIRCULATING WATER EQUIPMENT	47,510.88	
1873		314033514001	12	12/12/2008	CW - DJ U1 CIRCULATING WATER EQUIPMENT	73,312.14	
1874		314033514001	13	8/31/2009	CW - DJ U1 CIRCULATING WATER EQUIPMENT	101,233.05	
1875		314033514001	16	7/21/2016	CW - DJ U1 CIRCULATING WATER EQUIPMENT	90,878.79	
1876		314033514001	17	11/23/2016	CW - DJ U1 CIRCULATING WATER EQUIPMENT	96,713.88	
1877		314033514001	18	5/9/2017	CW - DJ U1 CIRCULATING WATER EQUIPMENT	49,737.15	
1878		314050514001	0	12/31/1998	GN-DJ U1 GENERATOR EQUIPMENT	-	
1879		314050514001	1	12/31/1996	GN-DJ U1 GENERATOR EQUIPMENT	24,653.51	
1880		314050514001	2	12/31/1997	GN-DJ U1 GENERATOR EQUIPMENT	127,233.69	
1881		314050514001	5	7/28/2002	GN-DJ U1 GENERATOR EQUIPMENT	1,637.99	
1882		314050514001	9	12/31/1983	GN-DJ U1 GENERATOR EQUIPMENT	15,122.88	
1883		314050514001	10	12/31/1987	GN-DJ U1 GENERATOR EQUIPMENT	2,493.59	
1884		314050514001	11	10/21/2002	GN-DJ U1 GENERATOR EQUIPMENT	56,850.01	
1885		314050514001	12	10/24/2002	GN-DJ U1 GENERATOR EQUIPMENT	237,404.11	
1886		314050514001	13	11/21/2003	GN-DJ U1 GENERATOR EQUIPMENT	160,353.54	
1887		314050514001	14	11/21/2003	GN-DJ U1 GENERATOR EQUIPMENT	13,350.68	
1888		314050514001	15	9/29/2005	GN-DJ U1 GENERATOR EQUIPMENT	49,956.53	
1889		314050514001	17	1/4/2007	GN-DJ U1 GENERATOR EQUIPMENT	109,204.04	
1890		314050514001	18	10/29/2008	GN-DJ U1 GENERATOR EQUIPMENT	992,108.46	
1891		314050514001	19	4/20/2016	GN-DJ U1 GENERATOR EQUIPMENT	246,053.23	
1892		314050514001	20	5/10/2016	GN-DJ U1 GENERATOR EQUIPMENT	29,329.88	2,065,752.14

1893	314061514001	1	12/31/1997	LO-LUBE OIL PUMPS & PUMP MOTORS	19,807.11	
1894	314084514001	0	12/31/1998	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	-	
1895	314084514001	1	12/31/1991	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	8,558.12	
1896	314084514001	3	12/17/2001	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	30,416.31	
1897	314084514001	4	12/31/1958	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	1,522,219.70	
1898	314084514001	5	12/31/1975	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	92,416.48	
1899	314084514001	6	12/31/1978	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	105,747.89	
1900	314084514001	7	12/31/1997	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	659,032.44	
1901	314084514001	9	12/31/1997	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	26,114.13	
1902	314084514001	13	11/21/2003	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	26,445.90	
1903	314084514001	14	5/7/2004	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	6,987.39	
1904	314084514001	15	12/31/1989	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	452,158.31	
1905	314084514001	16	10/29/2008	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	707,231.92	
1906	314084514001	17	10/29/2008	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	707,231.92	
1907	314084514001	18	10/29/2008	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	1,060,847.94	
1908	314084514001	19	10/29/2008	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	176,808.00	
1909	314084514001	20	10/29/2008	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	353,615.98	
1910	314084514001	21	10/29/2008	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	530,423.98	
1911	314084514001	22	7/21/2016	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	53,456.91	
1912	314084514001	23	5/9/2017	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	22,912.52	
1913	314084514001	24	7/10/2018	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	2,022,171.99	
1914	314084514001	25	8/20/2018	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	171,135.01	
1915	314084514001	26	12/30/2016	TB-DAVE JOHNSTON U1 TURBINE EQUIPMENT	8,238.74	
1916	314099514001	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
1917	* Location	514001		DAVE JOHNSTON UNIT 1	13,439,564.93	
1918	314028514002	0	12/31/1998	CN-DJ U2 CONDENSER EQUIPMENT	-	
1919	314028514002	1	12/31/1993	CN-DJ U2 CONDENSER EQUIPMENT	10,535.56	
1920	314028514002	2	12/31/1960	CN-DJ U2 CONDENSER EQUIPMENT	461,727.23	
1921	314028514002	3	12/31/1961	CN-DJ U2 CONDENSER EQUIPMENT	1,719.74	
1922	314028514002	4	12/31/1986	CN-DJ U2 CONDENSER EQUIPMENT	570,065.87	
1923	314028514002	5	12/5/2007	CN-DJ U2 CONDENSER EQUIPMENT	55,868.40	
1924	314028514002	6	12/31/2009	CN-DJ U2 CONDENSER EQUIPMENT	35,446.47	
1925	314028514002	7	4/25/2012	CN-DJ U2 CONDENSER EQUIPMENT	8,588.59	
1926	314028514002	8	7/10/2018	CN-DJ U2 CONDENSER EQUIPMENT	211,093.43	
1927	314032514002	0	12/31/1998	CT-DJ U2 COOLING TOWER STRUCTURES & EQUIPMENT	-	
1928	314032514002	4	12/31/1976	CT-DJ U2 COOLING TOWER STRUCTURES & EQUIPMENT	4,220.30	
1929	314032514002	5	12/31/1977	CT-DJ U2 COOLING TOWER STRUCTURES & EQUIPMENT	1,276.75	
1930	314032514002	6	12/31/1979	CT-DJ U2 COOLING TOWER STRUCTURES & EQUIPMENT	10,603.60	
1931	314032514002	7	12/31/1988	CT-DJ U2 COOLING TOWER STRUCTURES & EQUIPMENT	4,622.69	
1932	314032514002	10	12/31/1992	CT-DJ U2 COOLING TOWER STRUCTURES & EQUIPMENT	138,946.88	
1933	314033514002	1	12/31/1960	CW - DJ U2 CIRCULATING WATER EQUIPMENT	127,569.35	
1934	314033514002	2	12/31/1968	CW - DJ U2 CIRCULATING WATER EQUIPMENT	2,500.53	
1935	314033514002	3	12/31/1975	CW - DJ U2 CIRCULATING WATER EQUIPMENT	565,591.33	
1936	314033514002	4	12/31/1988	CW - DJ U2 CIRCULATING WATER EQUIPMENT	6,035.62	
1937	314033514002	5	12/31/1992	CW - DJ U2 CIRCULATING WATER EQUIPMENT	28,993.73	
1938	314033514002	6	6/9/2006	CW - DJ U2 CIRCULATING WATER EQUIPMENT	47,496.62	
1939	314033514002	8	10/11/2011	CW - DJ U2 CIRCULATING WATER EQUIPMENT	86,083.49	
1940	314033514002	9	9/23/2014	CW - DJ U2 CIRCULATING WATER EQUIPMENT	129,654.15	
1941	314033514002	10	7/21/2016	CW - DJ U2 CIRCULATING WATER EQUIPMENT	102,151.05	
1942	314033514002	11	1/21/2016	CW - DJ U2 CIRCULATING WATER EQUIPMENT	34,198.12	
1943	314050514002	7	12/31/1981	GN-DJ U2 GENERATOR EQUIPMENT	3,160.90	
1944	314050514002	8	12/31/1982	GN-DJ U2 GENERATOR EQUIPMENT	15,253.96	
1945	314050514002	9	12/31/1983	GN-DJ U2 GENERATOR EQUIPMENT	6,098.05	
1946	314050514002	10	12/31/1987	GN-DJ U2 GENERATOR EQUIPMENT	2,493.59	
1947	314050514002	12	9/29/2005	GN-DJ U2 GENERATOR EQUIPMENT	49,869.82	
1948	314050514002	13	4/24/2007	GN-DJ U2 GENERATOR EQUIPMENT	96,808.52	
1949	314050514002	15	4/24/2007	GN-DJ U2 GENERATOR EQUIPMENT	6,307.28	
1950	314050514002	16	4/24/2007	GN-DJ U2 GENERATOR EQUIPMENT	278,137.32	
1951	314050514002	17	4/24/2007	GN-DJ U2 GENERATOR EQUIPMENT	385,300.11	
1952	314050514002	19	6/12/2008	GN-DJ U2 GENERATOR EQUIPMENT	863,301.80	
1953	314050514002	20	7/23/2018	GN-DJ U2 GENERATOR EQUIPMENT	278,031.30	1,984,762.65
1954	314084514002	0	12/31/1998	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	-	
1955	314084514002	2	12/31/1994	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	1,693,014.91	
1956	314084514002	3	12/31/1994	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	17,142.54	
1957	314084514002	7	7/27/1999	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	7,913.09	
1958	314084514002	8	12/17/2001	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	30,416.31	
1959	314084514002	9	12/31/1960	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	2,263,084.26	
1960	314084514002	10	12/31/1967	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	1,717.08	
1961	314084514002	11	12/31/1975	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	92,416.48	
1962	314084514002	12	12/31/1973	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	37,907.24	
1963	314084514002	14	12/31/1979	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	77,119.24	
1964	314084514002	16	5/7/2004	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	6,987.39	
1965	314084514002	17	5/7/2004	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	33,359.78	

1966		314084514002	18	4/24/2007	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	1,450,477.84	
1967		314084514002	22	12/31/1988	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	139,000.97	
1968		314084514002	23	12/31/1988	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	437,564.99	
1969		314084514002	24	12/31/1989	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	53,912.54	
1970		314084514002	25	6/12/2008	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	2,625,646.49	
1971		314084514002	26	6/18/2018	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	3,117,867.40	
1972		314084514002	27	7/10/2018	TB-DAVE JOHNSTON U2 TURBINE EQUIPMENT	171,390.08	
1973		314099514002	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
1974	*	Location	514002		DAVE JOHNSTON UNIT 2	16,886,690.78	
1975		314028514003	0	12/31/1998	CN-DJ U3 CONDENSER EQUIPMENT	-	
1976		314028514003	1	12/31/1993	CN-DJ U3 CONDENSER EQUIPMENT	10,434.58	
1977		314028514003	2	12/31/1964	CN-DJ U3 CONDENSER EQUIPMENT	376,824.01	
1978		314028514003	3	12/31/1986	CN-DJ U3 CONDENSER EQUIPMENT	43,587.80	
1979		314028514003	4	12/31/1991	CN-DJ U3 CONDENSER EQUIPMENT	642,241.64	
1980		314028514003	5	6/28/2005	CN-DJ U3 CONDENSER EQUIPMENT	326,220.09	
1981		314028514003	6	4/25/2012	CN-DJ U3 CONDENSER EQUIPMENT	8,588.59	
1982		314028514003	7	1/21/2016	CN-DJ U3 CONDENSER EQUIPMENT	37,728.80	
1983		314032514003	0	12/31/1998	CT-DJ U3 COOLING TOWER STRUCTURES & EQUIPMENT	-	
1984		314032514003	2	12/31/1998	CT-DJ U3 COOLING TOWER STRUCTURES & EQUIPMENT	6,007.14	
1985		314032514003	5	12/31/1976	CT-DJ U3 COOLING TOWER STRUCTURES & EQUIPMENT	11,737.69	
1986		314032514003	6	12/31/1977	CT-DJ U3 COOLING TOWER STRUCTURES & EQUIPMENT	2,614.03	
1987		314032514003	7	12/31/1979	CT-DJ U3 COOLING TOWER STRUCTURES & EQUIPMENT	10,603.61	
1988		314032514003	8	12/31/1988	CT-DJ U3 COOLING TOWER STRUCTURES & EQUIPMENT	4,622.69	
1989		314032514003	11	12/31/1992	CT-DJ U3 COOLING TOWER STRUCTURES & EQUIPMENT	138,946.88	
1990		314033514003	2	12/31/1964	CW-DJ U3 CIRCULATING WATER EQUIPMENT	500,126.50	
1991		314033514003	3	12/31/1968	CW-DJ U3 CIRCULATING WATER EQUIPMENT	2,500.53	
1992		314033514003	4	12/31/1975	CW-DJ U3 CIRCULATING WATER EQUIPMENT	565,024.34	
1993		314033514003	5	12/31/1988	CW-DJ U3 CIRCULATING WATER EQUIPMENT	6,035.62	
1994		314033514003	6	12/31/1989	CW-DJ U3 CIRCULATING WATER EQUIPMENT	197,956.61	
1995		314033514003	7	12/31/1990	CW-DJ U3 CIRCULATING WATER EQUIPMENT	14,712.49	
1996		314033514003	8	12/31/1992	CW-DJ U3 CIRCULATING WATER EQUIPMENT	28,993.73	
1997		314033514003	9	10/21/2002	CW-DJ U3 CIRCULATING WATER EQUIPMENT	192,693.84	
1998		314033514003	10	6/9/2006	CW-DJ U3 CIRCULATING WATER EQUIPMENT	47,496.62	
1999		314033514003	13	9/24/2010	CW-DJ U3 CIRCULATING WATER EQUIPMENT	50,286.09	
2000		314033514003	14	8/10/2015	CW-DJ U3 CIRCULATING WATER EQUIPMENT	50,795.13	
2001		314033514003	15	8/24/2015	CW-DJ U3 CIRCULATING WATER EQUIPMENT	40,380.28	
2002		314033514003	16	11/8/2018	CW-DJ U3 CIRCULATING WATER EQUIPMENT	131,513.98	
2003		314033514003	17	1/21/2016	CW-DJ U3 CIRCULATING WATER EQUIPMENT	33,253.62	
2004		314050514003	0	12/31/1998	GN-DJ U3 GENERATOR EQUIPMENT	-	
2005		314050514003	1	12/31/1996	GN-DJ U3 GENERATOR EQUIPMENT	7,707.11	
2006		314050514003	2	12/31/1994	GN-DJ U3 GENERATOR EQUIPMENT	2,164.97	
2007		314050514003	3	12/31/1996	GN-DJ U3 GENERATOR EQUIPMENT	19,614.84	
2008		314050514003	4	12/31/1994	GN-DJ U3 GENERATOR EQUIPMENT	36,458.79	
2009		314050514003	5	7/27/1999	GN-DJ U3 GENERATOR EQUIPMENT	35,729.14	
2010		314050514003	6	7/27/1999	GN-DJ U3 GENERATOR EQUIPMENT	41,389.66	
2011		314050514003	7	11/10/1999	GN-DJ U3 GENERATOR EQUIPMENT	1,344,824.07	
2012		314050514003	8	7/27/1999	GN-DJ U3 GENERATOR EQUIPMENT	31,617.59	
2013		314050514003	9	9/12/2000	GN-DJ U3 GENERATOR EQUIPMENT	63,934.01	
2014		314050514003	10	7/28/2002	GN-DJ U3 GENERATOR EQUIPMENT	1,637.99	
2015		314050514003	11	12/31/1964	GN-DJ U3 GENERATOR EQUIPMENT	41,299.77	
2016		314050514003	12	12/31/1979	GN-DJ U3 GENERATOR EQUIPMENT	10,139.29	
2017		314050514003	13	12/31/1980	GN-DJ U3 GENERATOR EQUIPMENT	2,802.97	
2018		314050514003	14	12/31/1981	GN-DJ U3 GENERATOR EQUIPMENT	9,729.95	
2019		314050514003	15	12/31/1982	GN-DJ U3 GENERATOR EQUIPMENT	10,187.85	
2020		314050514003	16	12/31/1985	GN-DJ U3 GENERATOR EQUIPMENT	9,388.59	
2021		314050514003	17	12/31/1987	GN-DJ U3 GENERATOR EQUIPMENT	2,493.59	
2022		314050514003	18	6/28/2005	GN-DJ U3 GENERATOR EQUIPMENT	302,637.99	
2023		314050514003	19	7/21/2005	GN-DJ U3 GENERATOR EQUIPMENT	359,647.17	
2024		314050514003	20	6/28/2005	GN-DJ U3 GENERATOR EQUIPMENT	185,404.87	
2025		314050514003	21	12/10/2004	GN-DJ U3 GENERATOR EQUIPMENT	49,211.57	
2026		314050514003	23	5/26/2010	GN-DJ U3 GENERATOR EQUIPMENT	123,823.47	
2027		314050514003	24	5/27/2010	GN-DJ U3 GENERATOR EQUIPMENT	375,778.40	
2028		314050514003	25	5/27/2010	GN-DJ U3 GENERATOR EQUIPMENT	300,622.69	
2029		314050514003	26	6/8/2015	GN-DJ U3 GENERATOR EQUIPMENT	-	
2030		314050514003	27	1/21/2016	GN-DJ U3 GENERATOR EQUIPMENT	18,773.41	3,387,019.75
2031		314082514003	2	3/28/2006	SP-CAPITALIZED SPARE PARTS	114,233.92	
2032		314082514003	3	5/27/2010	SP-CAPITALIZED SPARE PARTS	66,146.65	
2033		314082514003	4	5/27/2010	SP-CAPITALIZED SPARE PARTS	84,164.65	
2034		314084514003	0	12/31/1998	TB-DJ U3 TURBINE EQUIPMENT	-	
2035		314084514003	1	12/31/1979	TB-DJ U3 TURBINE EQUIPMENT	353,050.77	
2036		314084514003	2	12/31/1990	TB-DJ U3 TURBINE EQUIPMENT	507,783.98	
2037		314084514003	3	12/31/1991	TB-DJ U3 TURBINE EQUIPMENT	9,571.43	
2038		314084514003	4	12/31/1992	TB-DJ U3 TURBINE EQUIPMENT	1,522,362.18	

2039		314084514003	5	12/31/1992	TB-DJ U3 TURBINE EQUIPMENT	170,345.76
2040		314084514003	6	9/9/1999	TB-DJ U3 TURBINE EQUIPMENT	1,892,423.15
2041		314084514003	7	7/27/1999	TB-DJ U3 TURBINE EQUIPMENT	2,798,531.46
2042		314084514003	8	7/27/1999	TB-DJ U3 TURBINE EQUIPMENT	16,921.30
2043		314084514003	9	12/31/1964	TB-DJ U3 TURBINE EQUIPMENT	3,014,318.13
2044		314084514003	10	12/31/1972	TB-DJ U3 TURBINE EQUIPMENT	4,532.06
2045		314084514003	11	12/31/1973	TB-DJ U3 TURBINE EQUIPMENT	-
2046		314084514003	12	12/31/1975	TB-DJ U3 TURBINE EQUIPMENT	92,416.47
2047		314084514003	13	12/31/1978	TB-DJ U3 TURBINE EQUIPMENT	105,730.83
2048		314084514003	14	12/31/1979	TB-DJ U3 TURBINE EQUIPMENT	77,119.24
2049		314084514003	16	6/24/2005	TB-DJ U3 TURBINE EQUIPMENT	105,485.23
2050		314084514003	17	5/7/2004	TB-DJ U3 TURBINE EQUIPMENT	6,578.25
2051		314084514003	18	12/31/1998	TB-DJ U3 TURBINE EQUIPMENT	185,420.75
2052		314084514003	19	12/31/1989	TB-DJ U3 TURBINE EQUIPMENT	63,015.85
2053		314084514003	24	9/22/2014	TB-DJ U3 TURBINE EQUIPMENT	144,330.15
2054		314084514003	25	8/10/2015	TB-DJ U3 TURBINE EQUIPMENT	103,106.44
2055		314084514003	26	1/21/2016	TB-DJ U3 TURBINE EQUIPMENT	99,282.65
2056		314084514003	27	5/28/2019	TB-DJ U3 TURBINE EQUIPMENT	4,495,926.80
2057		314084514003	28	8/20/2019	TB-DJ U3 TURBINE EQUIPMENT	119,508.10
2058		314084514003	29	8/20/2019	TB-DJ U3 TURBINE EQUIPMENT	269,167.81
2059	*	Location	514003		DAVE JOHNSTON UNIT 3	23,290,420.69
2060		314022514004	1	12/31/1997	CD-CONDENSATE TANK FOUNDATIONS	15,136.21
2061		314028514004	0	12/31/1998	CN-DJ U4 CONDENSER EQUIPMENT	-
2062		314028514004	1	12/31/1993	CN-DJ U4 CONDENSER EQUIPMENT	9,142.60
2063		314028514004	2	3/27/2001	CN-DJ U4 CONDENSER EQUIPMENT	138,674.80
2064		314028514004	3	12/31/1972	CN-DJ U4 CONDENSER EQUIPMENT	742,407.51
2065		314028514004	4	12/31/1980	CN-DJ U4 CONDENSER EQUIPMENT	39,042.86
2066		314028514004	5	12/31/1985	CN-DJ U4 CONDENSER EQUIPMENT	17,381.79
2067		314028514004	6	12/31/1986	CN-DJ U4 CONDENSER EQUIPMENT	42,149.37
2068		314028514004	7	12/31/1987	CN-DJ U4 CONDENSER EQUIPMENT	21,147.61
2069		314028514004	8	12/31/1988	CN-DJ U4 CONDENSER EQUIPMENT	109,449.41
2070		314028514004	9	12/31/1989	CN-DJ U4 CONDENSER EQUIPMENT	2,259,236.27
2071		314028514004	10	12/31/1991	CN-DJ U4 CONDENSER EQUIPMENT	364,161.59
2072		314028514004	11	6/3/2003	CN-DJ U4 CONDENSER EQUIPMENT	55,199.74
2073		314028514004	12	1/6/2004	CN-DJ U4 CONDENSER EQUIPMENT	14,719.30
2074		314028514004	14	7/18/2011	CN-DJ U4 CONDENSER EQUIPMENT	119,135.43
2075		314028514004	15	4/25/2012	CN-DJ U4 CONDENSER EQUIPMENT	8,588.57
2076		314028514004	16	5/9/2017	CN-DJ U4 CONDENSER EQUIPMENT	165,291.83
2077		314028514004	18	12/11/2018	CN-DJ U4 CONDENSER EQUIPMENT	187,970.62
2078		314032514004	0	12/31/1998	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	-
2079		314032514004	2	12/31/1994	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	6,129.75
2080		314032514004	3	7/27/1999	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	168,887.76
2081		314032514004	4	3/8/1999	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	482.00
2082		314032514004	5	5/17/2000	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	32,072.81
2083		314032514004	6	10/15/2003	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	16,051.00
2084		314032514004	9	12/31/1978	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	26,910.12
2085		314032514004	10	12/31/1979	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	22,717.16
2086		314032514004	11	12/31/1980	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	77,261.64
2087		314032514004	12	12/31/1981	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	7,861.50
2088		314032514004	13	12/31/1985	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	5,174.42
2089		314032514004	14	12/31/1987	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	971,651.03
2090		314032514004	15	12/31/1988	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	4,622.68
2091		314032514004	16	12/31/1989	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	220,210.36
2092		314032514004	17	12/31/1990	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	9,124.71
2093		314032514004	18	12/31/1992	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	138,946.89
2094		314032514004	20	5/8/2003	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	295,164.32
2095		314032514004	21	5/8/2003	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	557,400.91
2096		314032514004	22	5/8/2003	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	464,544.64
2097		314032514004	24	11/6/2003	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	657,865.28
2098		314032514004	26	4/14/2005	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	20,705.29
2099		314032514004	27	6/28/2005	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	20,841.70
2100		314032514004	29	2/28/2006	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	91,850.19
2101		314032514004	30	2/28/2006	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	172,885.75
2102		314032514004	32	2/24/2000	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	28,814.73
2103		314032514004	33	12/12/2008	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	13,928.84
2104		314032514004	34	6/11/2009	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	-
2105		314032514004	35	8/11/2009	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	5,585,258.96
2106		314032514004	36	1/28/2010	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	12,957.75
2107		314032514004	37	4/13/2010	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	18,726.92
2108		314032514004	38	8/31/2011	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	173,506.05
2109		314032514004	39	1/3/2012	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	-
2110		314032514004	40	11/8/2012	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	34,522.76
2111		314032514004	41	6/10/2013	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	18,107.25

2112	314032514004	42	6/10/2013	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	24,002.65	
2113	314032514004	43	9/22/2014	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	90,939.62	
2114	314032514004	44	9/23/2014	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	89,243.39	
2115	314032514004	45	9/22/2014	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	27,110.51	
2116	314032514004	46	12/22/2014	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	97,403.62	
2117	314032514004	47	8/24/2015	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	39,421.01	
2118	314032514004	48	3/8/2016	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	16,715.14	
2119	314032514004	49	3/8/2016	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	26,388.23	
2120	314032514004	50	7/21/2016	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	31,034.15	
2121	314032514004	51	11/23/2016	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	39,750.12	
2122	314032514004	52	5/9/2017	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	95,609.36	
2123	314032514004	53	5/9/2017	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	35,630.23	
2124	314032514004	54	1/21/2016	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	67,110.47	
2125	314032514004	55	12/31/2018	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	79,469.10	
2126	314032514004	56	10/10/2016	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	12,146.40	
2127	314032514004	57	12/30/2016	CT-DJ U4 COOLING TOWER STRUCTURES & EQUIPMENT	16,188.67	
2128	314033514004	0	12/31/1998	CW-DJ U4 CIRCULATING WATER EQUIPMENT	-	
2129	314033514004	1	12/31/1972	CW-DJ U4 CIRCULATING WATER EQUIPMENT	166,877.57	
2130	314033514004	2	12/31/1993	CW-DJ U4 CIRCULATING WATER EQUIPMENT	37,045.50	
2131	314033514004	3	12/31/1996	CW-DJ U4 CIRCULATING WATER EQUIPMENT	90,578.95	
2132	314033514004	4	5/11/1999	CW-DJ U4 CIRCULATING WATER EQUIPMENT	171,419.58	
2133	314033514004	8	12/31/1991	CW-DJ U4 CIRCULATING WATER EQUIPMENT	24,162.00	
2134	314033514004	10	5/8/2003	CW-DJ U4 CIRCULATING WATER EQUIPMENT	33,460.39	
2135	314033514004	11	12/31/1997	CW-DJ U4 CIRCULATING WATER EQUIPMENT	671,283.14	
2136	314033514004	12	12/31/1996	CW-DJ U4 CIRCULATING WATER EQUIPMENT	46,056.16	
2137	314033514004	13	6/28/2005	CW-DJ U4 CIRCULATING WATER EQUIPMENT	92,000.59	
2138	314033514004	14	3/19/2003	CW-DJ U4 CIRCULATING WATER EQUIPMENT	26,383.86	
2139	314033514004	16	12/5/2007	CW-DJ U4 CIRCULATING WATER EQUIPMENT	50,423.99	
2140	314033514004	17	12/1/2008	CW-DJ U4 CIRCULATING WATER EQUIPMENT	126,326.72	
2141	314033514004	18	12/12/2008	CW-DJ U4 CIRCULATING WATER EQUIPMENT	45,079.64	
2142	314033514004	19	12/31/1993	CW-DJ U4 CIRCULATING WATER EQUIPMENT	80,935.51	
2143	314033514004	20	12/24/2009	CW-DJ U4 CIRCULATING WATER EQUIPMENT	83,386.13	
2144	314033514004	21	7/26/2013	CW-DJ U4 CIRCULATING WATER EQUIPMENT	63,924.80	
2145	314033514004	22	12/31/2013	CW-DJ U4 CIRCULATING WATER EQUIPMENT	7,594.63	
2146	314033514004	23	8/10/2015	CW-DJ U4 CIRCULATING WATER EQUIPMENT	142,209.35	
2147	314033514004	24	12/31/2018	CW-DJ U4 CIRCULATING WATER EQUIPMENT	768,084.20	
2148	314033514004	25	12/8/2016	CW-DJ U4 CIRCULATING WATER EQUIPMENT	42,274.54	
2149	314033514004	26	12/8/2016	CW-DJ U4 CIRCULATING WATER EQUIPMENT	41,848.38	
2150	314033514004	27	12/8/2016	CW-DJ U4 CIRCULATING WATER EQUIPMENT	8,931.14	
2151	314050514004	0	12/31/1998	GN-DJ U4 GENERATOR EQUIPMENT	-	
2152	314050514004	4	10/11/2001	GN-DJ U4 GENERATOR EQUIPMENT	116,605.89	
2153	314050514004	5	7/28/2002	GN-DJ U4 GENERATOR EQUIPMENT	1,637.98	
2154	314050514004	15	6/3/2003	GN-DJ U4 GENERATOR EQUIPMENT	43,129.29	
2155	314050514004	16	10/28/2003	GN-DJ U4 GENERATOR EQUIPMENT	29,430.57	
2156	314050514004	17	2/25/2004	GN-DJ U4 GENERATOR EQUIPMENT	34,491.92	
2157	314050514004	18	9/29/2005	GN-DJ U4 GENERATOR EQUIPMENT	114,127.84	
2158	314050514004	19	6/28/2005	GN-DJ U4 GENERATOR EQUIPMENT	33,328.39	
2159	314050514004	20	6/11/2009	GN-DJ U4 GENERATOR EQUIPMENT	157,960.90	
2160	314050514004	21	6/11/2009	GN-DJ U4 GENERATOR EQUIPMENT	127,373.24	
2161	314050514004	22	8/11/2009	GN-DJ U4 GENERATOR EQUIPMENT	372,610.69	
2162	314050514004	23	8/11/2009	GN-DJ U4 GENERATOR EQUIPMENT	2,559,926.18	
2163	314050514004	24	8/25/2009	GN-DJ U4 GENERATOR EQUIPMENT	722,794.20	
2164	314050514004	25	7/17/2012	GN-DJ U4 GENERATOR EQUIPMENT	66,175.56	
2165	314050514004	26	12/31/2018	GN-DJ U4 GENERATOR EQUIPMENT	136,339.30	
2166	314050514004	27	5/9/2017	GN-DJ U4 GENERATOR EQUIPMENT	27,459.41	4,543,391.36
2167	314082514004	7	12/12/2008	SP-CAPITALIZED SPARE PARTS	58,391.19	
2168	314082514004	8	12/12/2008	SP-CAPITALIZED SPARE PARTS	141,034.00	
2169	314082514004	9	12/12/2008	SP-CAPITALIZED SPARE PARTS	75,510.89	
2170	314084514004	0	12/31/1998	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	-	
2171	314084514004	1	12/31/1991	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	27,519.23	
2172	314084514004	2	12/31/1995	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	78,861.03	
2173	314084514004	3	12/31/1993	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	42,601.84	
2174	314084514004	4	4/10/2002	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	37,452.23	
2175	314084514004	5	12/31/1972	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	6,821,469.10	
2176	314084514004	6	12/31/1975	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	2,407.05	
2177	314084514004	7	12/31/1977	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	1,518.14	
2178	314084514004	8	12/31/1978	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	105,682.97	
2179	314084514004	9	11/6/2003	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	510,282.12	
2180	314084514004	10	11/6/2003	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	822,494.21	
2181	314084514004	11	11/6/2003	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	447,615.89	
2182	314084514004	12	11/6/2003	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	457,687.24	
2183	314084514004	13	12/31/1993	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	922,736.53	
2184	314084514004	14	6/6/2005	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	1,435,771.00	

2185		314084514004	15	12/31/1988	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	736,311.23	
2186		314084514004	16	6/11/2009	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	80,787.86	
2187		314084514004	17	8/10/2009	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	152,055.10	
2188		314084514004	18	8/10/2009	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	27,137.81	
2189		314084514004	19	8/31/2009	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	2,328,640.45	
2190		314084514004	20	10/4/2012	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	127,700.15	
2191		314084514004	21	11/8/2012	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	22,791.17	
2192		314084514004	22	8/31/1998	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	816,000.00	
2193		314084514004	23	5/9/2017	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	3,229,188.44	
2194		314084514004	24	12/11/2018	TB-DAVE JOHNSTON U4 TURBINE EQUIPMENT	133,187.93	
2195		314099514004	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
2196	*	Location	514004		DAVE JOHNSTON UNIT 4	41,978,696.28	
2197		314012517000	0	12/31/1998	BG-JB U0 BOILER COOLING WATER SYSTEM	-	
2198		314012517000	1	12/31/1989	BG-JB U0 BOILER COOLING WATER SYSTEM	21,098.44	
2199		314032517000	0	12/31/1998	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	-	
2200		314032517000	1	12/31/1989	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	50,866.27	
2201		314032517000	2	12/31/1976	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	2,900.59	
2202		314032517000	3	12/31/1983	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	5,693.00	
2203		314032517000	4	12/31/1987	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	8,223.00	
2204		314032517000	7	2/19/2005	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	19,175.83	
2205		314032517000	8	3/26/2005	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	25,185.30	
2206		314032517000	9	4/7/2006	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	65,133.40	
2207		314032517000	10	4/7/2006	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	28,728.15	
2208		314032517000	11	5/16/2006	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	44,195.78	
2209		314032517000	12	2/5/2007	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	101,545.87	
2210		314032517000	13	2/5/2007	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	29,866.44	
2211		314032517000	14	2/5/2007	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	5,973.28	
2212		314032517000	15	2/5/2007	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	8,959.93	
2213		314032517000	16	2/5/2007	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	14,933.22	
2214		314032517000	17	2/5/2007	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	11,946.58	
2215		314032517000	18	2/5/2007	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	41,813.00	
2216		314032517000	19	2/5/2007	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	41,813.00	
2217		314032517000	20	2/5/2007	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	20,906.51	
2218		314032517000	21	2/5/2007	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	20,906.47	
2219		314032517000	22	5/27/2008	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	32,793.88	
2220		314032517000	23	1/17/2008	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	45,131.84	
2221		314032517000	24	3/7/2003	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	10,763.48	
2222		314032517000	25	5/25/2004	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	10,763.48	
2223		314032517000	26	1/3/2018	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	363,927.98	
2224		314032517000	27	11/27/2018	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	156,141.53	
2225		314032517000	28	12/28/2018	CT-JIM BRIDGER U0 COOLING TOWER EQUIPMENT	95,221.65	
2226		314033517000	0	12/31/1998	CW-JB U0 CIRCULATING WATER EQUIPMENT	-	
2227		314033517000	2	12/31/1988	CW-JB U0 CIRCULATING WATER EQUIPMENT	281,322.34	
2228		314033517000	3	12/31/1995	CW-JB U0 CIRCULATING WATER EQUIPMENT	16,014.96	
2229		314033517000	4	12/31/1997	CW-JB U0 CIRCULATING WATER EQUIPMENT	63,569.10	
2230		314033517000	6	12/31/1989	CW-JB U0 CIRCULATING WATER EQUIPMENT	83,066.00	
2231		314033517000	7	12/31/1989	CW-JB U0 CIRCULATING WATER EQUIPMENT	77,688.67	
2232		314033517000	8	12/31/1991	CW-JB U0 CIRCULATING WATER EQUIPMENT	16,501.36	
2233		314033517000	11	2/21/2001	CW-JB U0 CIRCULATING WATER EQUIPMENT	20,195.87	
2234		314033517000	13	5/29/2002	CW-JB U0 CIRCULATING WATER EQUIPMENT	11,941.29	
2235		314033517000	14	3/9/2004	CW-JB U0 CIRCULATING WATER EQUIPMENT	76,888.67	
2236		314033517000	15	3/26/2005	CW-JB U0 CIRCULATING WATER EQUIPMENT	20,779.17	
2237		314033517000	16	7/10/2006	CW-JB U0 CIRCULATING WATER EQUIPMENT	19,582.38	
2238		314033517000	18	11/15/2017	CW-JB U0 CIRCULATING WATER EQUIPMENT	157,860.69	
2239		314033517000	19	5/1/2018	CW-JB U0 CIRCULATING WATER EQUIPMENT	107,822.95	
2240		314050517000	0	12/31/1998	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	-	
2241		314050517000	1	12/31/1987	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	30,159.92	
2242		314050517000	2	12/31/1997	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	19,832.83	
2243		314050517000	3	12/31/1976	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	6,899.57	
2244		314050517000	4	12/31/1995	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	98,772.41	
2245		314050517000	7	12/22/2006	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	2,109,660.31	
2246		314050517000	8	5/14/2012	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	40,672.88	
2247		314050517000	9	4/22/2013	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	32,237.39	
2248		314050517000	10	1/13/2014	GN-GENERATOR PROTECTION(PANELS,RELAYS,ACC.)	8,537.54	2,346,772.85
2249		314062517000	0	12/31/1998	LO-JB U0 LUBE OIL SYSTEM	-	
2250		314062517000	1	12/31/1989	LO-JB U0 LUBE OIL SYSTEM	26,385.79	
2251		314062517000	2	12/31/1976	LO-JB U0 LUBE OIL SYSTEM	17,917.00	
2252		314082517000	0	12/31/1998	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	-	
2253		314082517000	3	12/31/1993	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	22,681.33	
2254		314082517000	4	12/31/1994	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	593,766.36	
2255		314082517000	5	6/12/2001	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	225,498.13	
2256		314082517000	6	12/5/2001	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	38,694.17	
2257		314082517000	10	12/31/1993	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	10,052.02	

2258	314082517000	11	12/31/1994	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	70,666.70
2259	314082517000	12	12/31/1994	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	49,333.36
2260	314082517000	14	12/31/1990	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	133,333.33
2261	314082517000	21	5/4/2008	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	123,973.10
2262	314082517000	23	5/30/2008	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	180,589.54
2263	314082517000	24	8/29/2012	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	49,170.52
2264	314082517000	25	12/31/1975	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	860,484.80
2265	314082517000	26	2/28/2014	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	328,772.56
2266	314082517000	27	8/31/2015	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	1,046,790.35
2267	314082517000	28	6/16/2015	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	17,831.99
2268	314082517000	29	10/8/2016	SP-JB U0 FERC 314 CAPITALIZED SPARE PARTS	394,575.94
2269	314084517000	0	12/31/1998	TB-TURBINE I P COUPLER	-
2270	314084517000	1	12/31/1978	TB-TURBINE I P COUPLER	129.00
2271	314084517000	2	12/31/1989	TB-TURBINE I P COUPLER	11,621.37
2272	314084517000	3	12/31/1989	TB-TURBINE I P COUPLER	188,106.00
2273	314084517000	4	12/31/1976	TB-TURBINE I P COUPLER	245,538.33
2274	314084517000	5	12/31/1989	TB-TURBINE I P COUPLER	1,203.00
2275	314093517000	0	12/31/1998	WP-GROUND & SURFACE WATER MONITORING SYSTEM	-
2276	314093517000	1	12/31/1985	WP-GROUND & SURFACE WATER MONITORING SYSTEM	18,196.00
2277	314099517000	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-
2278	* Location	517000		JIM BRIDGER PLANT	9,239,924.89
2279	314008517001	0	12/31/1998	BA-JB U1 BOTTOM ASH EQUIPMENT	-
2280	314008517001	1	12/31/1974	BA-JB U1 BOTTOM ASH EQUIPMENT	19,222.00
2281	314012517001	0	12/31/1998	BG-JB U1 BOILER COOLING WATER SYSTEM	-
2282	314012517001	1	12/31/1974	BG-JB U1 BOILER COOLING WATER SYSTEM	36,316.00
2283	314012517001	2	12/31/1974	BG-JB U1 BOILER COOLING WATER SYSTEM	42,735.00
2284	314022517001	0	12/31/1998	CD-JIM BRIDGER U1 CONDENSATE SYSTEM	-
2285	314022517001	1	12/31/1974	CD-JIM BRIDGER U1 CONDENSATE SYSTEM	981,766.00
2286	314022517001	2	12/31/1984	CD-JIM BRIDGER U1 CONDENSATE SYSTEM	18,826.00
2287	314022517001	3	12/31/1986	CD-JIM BRIDGER U1 CONDENSATE SYSTEM	51.00
2288	314022517001	4	12/31/1974	CD-JIM BRIDGER U1 CONDENSATE SYSTEM	3,708.00
2289	314028517001	0	12/31/1998	CN-JB U1 CONDENSER & AUXILIARIES	-
2290	314028517001	1	12/31/1982	CN-JB U1 CONDENSER & AUXILIARIES	9,910.00
2291	314028517001	2	12/31/1974	CN-JB U1 CONDENSER & AUXILIARIES	694,441.80
2292	314028517001	3	12/31/1994	CN-JB U1 CONDENSER & AUXILIARIES	24,195.93
2293	314028517001	4	12/31/1974	CN-JB U1 CONDENSER & AUXILIARIES	123,635.42
2294	314028517001	5	8/1/1998	CN-JB U1 CONDENSER & AUXILIARIES	1,746,727.08
2295	314028517001	7	9/3/2010	CN-JB U1 CONDENSER & AUXILIARIES	44,295.64
2296	314028517001	8	12/20/2010	CN-JB U1 CONDENSER & AUXILIARIES	484,847.28
2297	314032517001	0	12/31/1998	CT-JB U1 COOLING TOWER STRUCTURES & EQUIPMEX	-
2298	314032517001	4	12/31/1974	CT-JB U1 COOLING TOWER STRUCTURES & EQUIPMEX	111,086.33
2299	314032517001	5	12/31/1979	CT-JB U1 COOLING TOWER STRUCTURES & EQUIPMEX	60,575.00
2300	314032517001	16	12/31/1991	CT-JB U1 COOLING TOWER STRUCTURES & EQUIPMEX	8,133.42
2301	314032517001	17	12/31/1987	CT-JB U1 COOLING TOWER STRUCTURES & EQUIPMEX	1,109.00
2302	314032517001	18	12/31/1995	CT-JB U1 COOLING TOWER STRUCTURES & EQUIPMEX	39,497.87
2303	314032517001	36	6/1/2006	CT-JB U1 COOLING TOWER STRUCTURES & EQUIPMEX	1,296,836.58
2304	314032517001	39	5/30/2014	CT-JB U1 COOLING TOWER STRUCTURES & EQUIPMEX	5,537,683.52
2305	314032517001	40	7/5/2018	CT-JB U1 COOLING TOWER STRUCTURES & EQUIPMEX	113,762.38
2306	314032517001	41	2/22/2019	CT-JB U1 COOLING TOWER STRUCTURES & EQUIPMEX	106,916.88
2307	314033517001	0	12/31/1998	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	-
2308	314033517001	1	12/31/1985	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	6,552.00
2309	314033517001	3	12/31/1991	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	26,057.48
2310	314033517001	4	12/31/1990	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	20,586.40
2311	314033517001	5	12/31/1994	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	11,055.99
2312	314033517001	6	12/31/1974	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	3,096.00
2313	314033517001	7	12/31/1974	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	187,733.33
2314	314033517001	8	12/31/1983	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	125,818.00
2315	314033517001	10	12/31/1974	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	188,143.00
2316	314033517001	11	9/29/1999	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	7,017.22
2317	314033517001	12	10/5/2000	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	91,881.67
2318	314033517001	14	12/20/1999	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	9,704.64
2319	314033517001	15	3/6/2003	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	19,267.36
2320	314033517001	16	4/14/2009	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	45,399.68
2321	314033517001	17	5/8/2010	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	426,208.26
2322	314033517001	18	5/8/2010	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	46,934.51
2323	314033517001	19	5/8/2010	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	82,229.49
2324	314033517001	20	6/8/2010	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	55,978.59
2325	314033517001	21	12/24/2013	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	40,046.85
2326	314033517001	22	5/30/2014	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	286,538.35
2327	314033517001	23	5/30/2014	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	62,094.39
2328	314033517001	24	5/30/2014	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	38,809.34
2329	314033517001	25	12/8/2014	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	115,558.89
2330	314033517001	26	5/23/2018	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	103,877.94

2331	314033517001	27	5/23/2018	CW-JIM BRIDGER U1 CIRCULATING WATER EQUIPMENT	101,508.81	
2332	314050517001	0	12/31/1998	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	-	
2333	314050517001	2	12/31/1981	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	329,743.00	
2334	314050517001	3	12/31/1983	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	31,846.00	
2335	314050517001	6	12/31/1982	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	22,389.00	
2336	314050517001	12	12/31/1996	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	6,700.26	
2337	314050517001	13	12/31/1996	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	48,016.65	
2338	314050517001	14	12/31/1992	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	21,707.13	
2339	314050517001	15	12/31/1996	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	207,200.08	
2340	314050517001	16	12/31/1986	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	432,033.00	
2341	314050517001	18	12/31/1996	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	22,199.21	
2342	314050517001	19	12/31/1974	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	1,136,101.06	
2343	314050517001	21	12/31/1995	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	5,441.80	
2344	314050517001	22	12/31/1974	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	171,663.00	
2345	314050517001	30	8/1/1998	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	60,873.68	
2346	314050517001	31	6/13/2002	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	34,316.16	
2347	314050517001	32	6/13/2002	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	39,560.17	
2348	314050517001	33	3/7/2003	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	9,090.58	
2349	314050517001	34	7/10/2003	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	65,734.72	
2350	314050517001	35	5/20/2004	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	1,799.34	
2351	314050517001	36	6/13/2002	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	24,550.96	
2352	314050517001	37	4/7/2006	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	37,211.83	
2353	314050517001	38	5/24/2006	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	139,402.11	
2354	314050517001	39	5/24/2006	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	270,604.10	
2355	314050517001	40	5/23/2006	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	59,375.90	
2356	314050517001	41	11/6/2006	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	188,035.37	
2357	314050517001	44	6/28/2010	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	5,767,057.98	
2358	314050517001	45	6/28/2010	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	2,373,893.33	
2359	314050517001	46	6/28/2010	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	418,922.34	
2360	314050517001	47	11/30/2010	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	136,949.00	
2361	314050517001	48	5/9/2014	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	8,333.83	
2362	314050517001	49	5/31/2018	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	212,687.75	
2363	314050517001	50	6/8/2018	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	70,391.43	
2364	314050517001	51	5/31/2018	GN-JIM BRIDGER U1 GENERATOR EQUIPMENT	75,281.21	12,429,111.98
2365	314062517001	0	12/31/1998	LO-JB U1 LUBE OIL SYSTEM	-	
2366	314062517001	1	12/31/1974	LO-JB U1 LUBE OIL SYSTEM	338,926.64	
2367	314062517001	2	12/31/1986	LO-JB U1 LUBE OIL SYSTEM	3,266.00	
2368	314062517001	3	12/31/1974	LO-JB U1 LUBE OIL SYSTEM	48,936.00	
2369	314062517001	4	7/13/2010	LO-JB U1 LUBE OIL SYSTEM	148,406.31	
2370	314084517001	0	12/31/1998	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	-	
2371	314084517001	1	12/31/1990	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	3,126,519.30	
2372	314084517001	3	12/31/1974	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	227,061.60	
2373	314084517001	4	12/31/1982	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	8,076.00	
2374	314084517001	5	12/31/1974	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	644,340.00	
2375	314084517001	7	12/31/1974	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	7,327.00	
2376	314084517001	8	12/31/1974	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	2,280,659.91	
2377	314084517001	9	12/31/1985	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	6,736.00	
2378	314084517001	10	12/31/1996	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	138,940.80	
2379	314084517001	11	12/31/1985	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	49,029.00	
2380	314084517001	12	12/31/1986	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	572.00	
2381	314084517001	14	8/1/1998	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	3,452,548.08	
2382	314084517001	15	8/1/1998	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	216,276.12	
2383	314084517001	16	8/1/1998	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	21,839.57	
2384	314084517001	17	8/1/1998	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	86,663.96	
2385	314084517001	18	5/24/2006	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	9,801.11	
2386	314084517001	19	5/24/2006	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	49,005.57	
2387	314084517001	20	5/24/2006	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	4,050.52	
2388	314084517001	21	5/24/2006	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	357,740.47	
2389	314084517001	23	5/23/2006	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	57,551.24	
2390	314084517001	25	6/30/2010	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	4,061,532.11	
2391	314084517001	26	6/30/2010	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	4,061,531.97	
2392	314084517001	27	9/7/2010	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	193,077.80	
2393	314084517001	28	7/9/2014	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	457,138.96	
2394	314084517001	29	7/9/2014	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	114,284.72	
2395	314084517001	30	7/9/2014	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	212,511.99	
2396	314084517001	31	6/10/2014	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	81,949.76	
2397	314084517001	32	7/9/2014	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	62,530.20	
2398	314084517001	33	5/8/2018	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	247,448.68	
2399	314084517001	34	5/31/2018	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	268,542.08	
2400	314084517001	35	5/31/2018	TB-JIM BRIDGER U1 TURBINE EQUIPMENT	108,949.17	
2401	314099517001	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
2402	* Location	517001		JIM BRIDGER UNIT 1	47,191,258.94	
2403	314012517002	0	12/31/1998	BG-JB U2 BOILER COOLING WATER SYSTEM	-	

2404	314012517002	1	12/31/1975	BG-JB U2 BOILER COOLING WATER SYSTEM	51,937.67
2405	314012517002	2	12/31/1975	BG-JB U2 BOILER COOLING WATER SYSTEM	42,970.00
2406	314022517002	0	12/31/1998	CD-JIM BRIDGER U2 CONDENSATE SYSTEM	-
2407	314022517002	1	12/31/1975	CD-JIM BRIDGER U2 CONDENSATE SYSTEM	723,824.00
2408	314022517002	2	12/31/1984	CD-JIM BRIDGER U2 CONDENSATE SYSTEM	18,827.00
2409	314022517002	3	12/31/1986	CD-JIM BRIDGER U2 CONDENSATE SYSTEM	52.00
2410	314022517002	4	12/31/1975	CD-JIM BRIDGER U2 CONDENSATE SYSTEM	3,668.00
2411	314028517002	0	12/31/1998	CN-JB U2 CONDENSER & AUXILIARIES	-
2412	314028517002	1	12/31/1982	CN-JB U2 CONDENSER & AUXILIARIES	9,910.00
2413	314028517002	2	12/31/1975	CN-JB U2 CONDENSER & AUXILIARIES	335,635.00
2414	314028517002	3	12/31/1975	CN-JB U2 CONDENSER & AUXILIARIES	11,180.00
2415	314028517002	4	12/31/1975	CN-JB U2 CONDENSER & AUXILIARIES	558,026.43
2416	314028517002	5	12/31/1997	CN-JB U2 CONDENSER & AUXILIARIES	1,665,813.85
2417	314028517002	6	12/31/1995	CN-JB U2 CONDENSER & AUXILIARIES	11,063.45
2418	314028517002	7	12/31/1975	CN-JB U2 CONDENSER & AUXILIARIES	130,484.00
2419	314028517002	8	4/30/2005	CN-JB U2 CONDENSER & AUXILIARIES	38,585.70
2420	314028517002	9	12/29/2009	CN-JB U2 CONDENSER & AUXILIARIES	575,731.79
2421	314028517002	10	5/17/2017	CN-JB U2 CONDENSER & AUXILIARIES	47,530.36
2422	314032517002	0	12/31/1998	CT-JB U2 COOLING TOWER STRUCTURES & EQUIPMEX	-
2423	314032517002	6	12/31/1975	CT-JB U2 COOLING TOWER STRUCTURES & EQUIPMEX	172,743.61
2424	314032517002	7	12/31/1979	CT-JB U2 COOLING TOWER STRUCTURES & EQUIPMEX	58,764.06
2425	314032517002	26	5/26/2005	CT-JB U2 COOLING TOWER STRUCTURES & EQUIPMEX	2,787,092.45
2426	314032517002	27	5/26/2005	CT-JB U2 COOLING TOWER STRUCTURES & EQUIPMEX	78,451.91
2427	314032517002	28	5/26/2005	CT-JB U2 COOLING TOWER STRUCTURES & EQUIPMEX	159,984.81
2428	314032517002	29	8/23/2005	CT-JB U2 COOLING TOWER STRUCTURES & EQUIPMEX	40,676.11
2429	314032517002	31	6/4/2009	CT-JB U2 COOLING TOWER STRUCTURES & EQUIPMEX	191,638.75
2430	314032517002	32	5/15/2013	CT-JB U2 COOLING TOWER STRUCTURES & EQUIPMEX	5,468,913.79
2431	314032517002	33	5/24/2017	CT-JB U2 COOLING TOWER STRUCTURES & EQUIPMEX	127,985.86
2432	314033517002	0	12/31/1998	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	-
2433	314033517002	2	12/31/1991	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	17,758.79
2434	314033517002	3	12/31/1991	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	26,057.49
2435	314033517002	4	12/31/1990	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	64,545.40
2436	314033517002	5	12/31/1994	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	11,056.00
2437	314033517002	6	12/31/1994	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	18,388.64
2438	314033517002	9	12/31/1994	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	70,705.09
2439	314033517002	11	12/31/1983	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	12,593.29
2440	314033517002	12	12/31/1985	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	96.00
2441	314033517002	13	12/31/1975	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	144,487.87
2442	314033517002	14	9/29/1999	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	7,017.22
2443	314033517002	15	12/20/2001	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	21,202.26
2444	314033517002	17	12/20/1999	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	9,704.64
2445	314033517002	18	6/4/2009	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	71,251.96
2446	314033517002	19	6/4/2009	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	426,190.71
2447	314033517002	20	6/30/2009	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	48,798.21
2448	314033517002	21	5/6/2013	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	263,887.94
2449	314033517002	22	1/10/2014	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	135,351.85
2450	314033517002	23	12/19/2016	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	317,037.89
2451	314033517002	24	5/17/2017	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	108,835.96
2452	314033517002	25	5/17/2017	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	81,461.21
2453	314033517002	26	11/15/2017	CW-J BRIDGER U2 CIRCULATING WATER EQUIPMENT	75,895.14
2454	314050517002	0	12/31/1998	GN-JB U2 GENERATOR EQUIPMENT	-
2455	314050517002	2	12/31/1981	GN-JB U2 GENERATOR EQUIPMENT	329,744.00
2456	314050517002	3	12/31/1983	GN-JB U2 GENERATOR EQUIPMENT	31,845.00
2457	314050517002	4	12/31/1985	GN-JB U2 GENERATOR EQUIPMENT	85.00
2458	314050517002	5	12/31/1982	GN-JB U2 GENERATOR EQUIPMENT	20,142.88
2459	314050517002	6	12/31/1984	GN-JB U2 GENERATOR EQUIPMENT	2,663.00
2460	314050517002	7	12/31/1987	GN-JB U2 GENERATOR EQUIPMENT	10,099.00
2461	314050517002	9	12/31/1997	GN-JB U2 GENERATOR EQUIPMENT	21,361.79
2462	314050517002	10	12/31/1980	GN-JB U2 GENERATOR EQUIPMENT	4,437.00
2463	314050517002	11	12/31/1982	GN-JB U2 GENERATOR EQUIPMENT	63.00
2464	314050517002	13	12/31/1996	GN-JB U2 GENERATOR EQUIPMENT	6,539.51
2465	314050517002	15	12/31/1975	GN-JB U2 GENERATOR EQUIPMENT	15,719.87
2466	314050517002	17	12/31/1975	GN-JB U2 GENERATOR EQUIPMENT	1,193,099.75
2467	314050517002	18	12/31/1997	GN-JB U2 GENERATOR EQUIPMENT	76,839.84
2468	314050517002	19	12/31/1975	GN-JB U2 GENERATOR EQUIPMENT	89,595.00
2469	314050517002	20	12/31/1995	GN-JB U2 GENERATOR EQUIPMENT	5,441.81
2470	314050517002	21	12/31/1975	GN-JB U2 GENERATOR EQUIPMENT	92,650.00
2471	314050517002	22	12/31/1979	GN-JB U2 GENERATOR EQUIPMENT	8,441.00
2472	314050517002	23	12/31/1980	GN-JB U2 GENERATOR EQUIPMENT	1,730.00
2473	314050517002	25	12/31/1983	GN-JB U2 GENERATOR EQUIPMENT	38,269.00
2474	314050517002	26	12/31/1975	GN-JB U2 GENERATOR EQUIPMENT	145,211.78
2475	314050517002	27	12/31/1980	GN-JB U2 GENERATOR EQUIPMENT	2,905.00
2476	314050517002	28	12/31/1997	GN-JB U2 GENERATOR EQUIPMENT	153,678.86

2477	314050517002	29	12/31/1975	GN-JB U2 GENERATOR EQUIPMENT	17,600.00	
2478	314050517002	30	12/31/1994	GN-JB U2 GENERATOR EQUIPMENT	3,050.59	
2479	314050517002	31	12/31/1975	GN-JB U2 GENERATOR EQUIPMENT	116,448.00	
2480	314050517002	32	9/30/1997	GN-JB U2 GENERATOR EQUIPMENT	545,613.24	
2481	314050517002	33	6/12/2001	GN-JB U2 GENERATOR EQUIPMENT	23,771.66	
2482	314050517002	35	3/7/2003	GN-JB U2 GENERATOR EQUIPMENT	9,090.58	
2483	314050517002	36	6/12/2001	GN-JB U2 GENERATOR EQUIPMENT	28,932.30	
2484	314050517002	37	4/29/2005	GN-JB U2 GENERATOR EQUIPMENT	4,578,188.52	
2485	314050517002	38	4/29/2005	GN-JB U2 GENERATOR EQUIPMENT	190,757.83	
2486	314050517002	39	5/26/2005	GN-JB U2 GENERATOR EQUIPMENT	202,516.23	
2487	314050517002	40	5/26/2005	GN-JB U2 GENERATOR EQUIPMENT	168,276.98	
2488	314050517002	41	6/22/2005	GN-JB U2 GENERATOR EQUIPMENT	25,247.33	
2489	314050517002	42	5/23/2006	GN-JB U2 GENERATOR EQUIPMENT	1,750,758.67	
2490	314050517002	43	5/30/2008	GN-JB U2 GENERATOR EQUIPMENT	125,276.38	
2491	314050517002	44	6/30/2009	GN-JB U2 GENERATOR EQUIPMENT	2,295,253.92	
2492	314050517002	45	6/30/2009	GN-JB U2 GENERATOR EQUIPMENT	405,044.82	
2493	314050517002	46	6/30/2009	GN-JB U2 GENERATOR EQUIPMENT	72,155.71	
2494	314050517002	47	6/30/2009	GN-JB U2 GENERATOR EQUIPMENT	55,458.98	
2495	314050517002	48	6/30/2009	GN-JB U2 GENERATOR EQUIPMENT	20,196.85	
2496	314050517002	49	6/30/2009	GN-JB U2 GENERATOR EQUIPMENT	14,426.33	
2497	314050517002	50	6/30/2009	GN-JB U2 GENERATOR EQUIPMENT	23,082.12	
2498	314050517002	51	10/28/2012	GN-JB U2 GENERATOR EQUIPMENT	8,744.30	
2499	314050517002	52	6/26/2017	GN-JB U2 GENERATOR EQUIPMENT	48,230.04	12,978,683.47
2500	314062517002	0	12/31/1998	LO-JB U2 LUBE OIL SYSTEM	-	
2501	314062517002	1	12/31/1975	LO-JB U2 LUBE OIL SYSTEM	230,033.00	
2502	314062517002	2	12/31/1986	LO-JB U2 LUBE OIL SYSTEM	3,266.00	
2503	314062517002	3	12/31/1975	LO-JB U2 LUBE OIL SYSTEM	49,125.00	
2504	314062517002	4	12/31/1975	LO-JB U2 LUBE OIL SYSTEM	204,452.67	
2505	314062517002	5	6/29/2009	LO-JB U2 LUBE OIL SYSTEM	43,513.83	
2506	314062517002	6	12/29/2009	LO-JB U2 LUBE OIL SYSTEM	151,181.37	
2507	314084517002	0	12/31/1998	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	-	
2508	314084517002	1	12/31/1992	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	18,444.85	
2509	314084517002	2	12/31/1993	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	9,027.39	
2510	314084517002	3	12/31/1995	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	31,335.20	
2511	314084517002	4	12/31/1975	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	729,404.48	
2512	314084517002	5	12/31/1982	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	8,076.00	
2513	314084517002	6	12/31/1975	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	526,210.00	
2514	314084517002	11	12/31/1975	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	233,079.28	
2515	314084517002	16	12/31/1975	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	544,541.67	
2516	314084517002	17	12/31/1997	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	207,176.99	
2517	314084517002	24	12/31/1991	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	33,578.52	
2518	314084517002	25	12/31/1975	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	182,652.18	
2519	314084517002	29	12/31/1975	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	4,596.67	
2520	314084517002	31	12/31/1975	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	531,507.00	
2521	314084517002	32	12/31/1975	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	35,143.00	
2522	314084517002	33	12/31/1975	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	105,428.00	
2523	314084517002	34	12/31/1993	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	40,196.15	
2524	314084517002	37	12/31/1985	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	6,735.00	
2525	314084517002	38	12/31/1975	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	185,921.27	
2526	314084517002	39	12/31/1975	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	126,608.67	
2527	314084517002	40	12/31/1975	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	175,713.00	
2528	314084517002	41	12/31/1985	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	23,632.00	
2529	314084517002	42	12/31/1986	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	572.00	
2530	314084517002	43	12/31/1975	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	210,857.00	
2531	314084517002	44	6/15/1997	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	85,555.57	
2532	314084517002	55	6/29/2009	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	15,009.03	
2533	314084517002	56	7/27/2009	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	168,343.72	
2534	314084517002	57	5/14/2013	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	4,264,770.79	
2535	314084517002	58	5/14/2013	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	4,264,770.79	
2536	314084517002	59	5/14/2013	TB-JIM BRIDGER U2 TURBINE EQUIPMENT	18,224,938.74	
2537	314099517002	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
2538	* Location	517002		JIM BRIDGER UNIT 2	59,897,894.46	
2539	314008517003	0	12/31/1998	BA-JB U3 BOTTOM ASH EQUIPMENT	-	
2540	314008517003	1	12/31/1976	BA-JB U3 BOTTOM ASH EQUIPMENT	10,385.00	
2541	314012517003	0	12/31/1998	BG-JB U3 BOILER COOLING WATER SYSTEM	-	
2542	314012517003	1	12/31/1976	BG-JB U3 BOILER COOLING WATER SYSTEM	30,902.07	
2543	314012517003	2	12/31/1976	BG-JB U3 BOILER COOLING WATER SYSTEM	26,914.00	
2544	314012517003	3	2/20/2007	BG-JB U3 BOILER COOLING WATER SYSTEM	47,713.18	
2545	314022517003	0	12/31/1998	CD-JIM BRIDGER U3 CONDENSATE SYSTEM	-	
2546	314022517003	1	12/31/1976	CD-JIM BRIDGER U3 CONDENSATE SYSTEM	567,969.04	
2547	314022517003	2	12/31/1984	CD-JIM BRIDGER U3 CONDENSATE SYSTEM	18,827.00	
2548	314022517003	3	12/31/1986	CD-JIM BRIDGER U3 CONDENSATE SYSTEM	52.00	
2549	314022517003	4	12/31/1976	CD-JIM BRIDGER U3 CONDENSATE SYSTEM	3,666.00	

2550	314028517003	0	12/31/1998	CN-JB U3 CONDENSER & AUXILIARIES	-
2551	314028517003	1	12/31/1976	CN-JB U3 CONDENSER & AUXILIARIES	1,462.00
2552	314028517003	2	12/31/1982	CN-JB U3 CONDENSER & AUXILIARIES	9,910.00
2553	314028517003	3	12/31/1996	CN-JB U3 CONDENSER & AUXILIARIES	1,657,908.23
2554	314028517003	4	12/31/1976	CN-JB U3 CONDENSER & AUXILIARIES	575,014.42
2555	314028517003	5	12/31/1976	CN-JB U3 CONDENSER & AUXILIARIES	430,377.00
2556	314028517003	6	12/31/1994	CN-JB U3 CONDENSER & AUXILIARIES	24,195.93
2557	314028517003	7	12/31/1976	CN-JB U3 CONDENSER & AUXILIARIES	128,897.23
2558	314028517003	9	5/8/2007	CN-JB U3 CONDENSER & AUXILIARIES	17,791.78
2559	314028517003	10	9/6/2007	CN-JB U3 CONDENSER & AUXILIARIES	260,700.44
2560	314028517003	11	10/31/2015	CN-JB U3 CONDENSER & AUXILIARIES	65,579.58
2561	314028517003	12	10/28/2015	CN-JB U3 CONDENSER & AUXILIARIES	32,280.22
2562	314032517003	0	12/31/1998	CT-JB U3 COOLING TOWER STRUCTURES & EQUIPMENT	-
2563	314032517003	3	12/31/1976	CT-JB U3 COOLING TOWER STRUCTURES & EQUIPMENT	30,583.86
2564	314032517003	4	12/31/1979	CT-JB U3 COOLING TOWER STRUCTURES & EQUIPMENT	60,574.00
2565	314032517003	15	12/31/1987	CT-JB U3 COOLING TOWER STRUCTURES & EQUIPMENT	1,109.00
2566	314032517003	26	6/7/2007	CT-JB U3 COOLING TOWER STRUCTURES & EQUIPMENT	87,580.44
2567	314032517003	27	6/20/2007	CT-JB U3 COOLING TOWER STRUCTURES & EQUIPMENT	1,088,242.23
2568	314032517003	29	11/24/2015	CT-JB U3 COOLING TOWER STRUCTURES & EQUIPMENT	5,660,722.09
2569	314032517003	30	3/6/2019	CT-JB U3 COOLING TOWER STRUCTURES & EQUIPMENT	92,757.91
2570	314033517003	0	12/31/1998	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	-
2571	314033517003	1	12/31/1985	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	6,551.00
2572	314033517003	2	12/31/1991	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	17,758.78
2573	314033517003	3	12/31/1991	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	26,057.49
2574	314033517003	4	12/31/1990	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	64,545.40
2575	314033517003	5	12/31/1994	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	11,056.01
2576	314033517003	6	12/31/1976	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	3,330.00
2577	314033517003	7	12/31/1996	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	14,010.79
2578	314033517003	8	12/31/1995	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	99,857.72
2579	314033517003	9	12/31/1976	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	82,186.66
2580	314033517003	12	12/31/1976	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	96,634.87
2581	314033517003	13	12/31/1990	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	161,440.89
2582	314033517003	14	9/29/1999	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	7,019.36
2583	314033517003	15	1/22/1999	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	60,498.27
2584	314033517003	16	12/20/2001	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	20,345.31
2585	314033517003	18	12/20/1999	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	9,704.64
2586	314033517003	19	7/9/2007	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	53,401.94
2587	314033517003	20	7/9/2007	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	43,681.84
2588	314033517003	21	7/9/2007	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	131,045.44
2589	314033517003	23	5/11/2011	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	32,399.89
2590	314033517003	24	5/25/2011	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	462,272.54
2591	314033517003	25	5/25/2011	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	35,856.64
2592	314033517003	26	6/30/2011	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	62,791.35
2593	314033517003	27	11/30/2015	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	375,316.11
2594	314033517003	28	12/30/2015	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	134,056.65
2595	314033517003	29	9/30/2015	CW-J BRIDGER U3 CIRCULATING WATER EQUIPMENT	38,578.53
2596	314050517003	0	12/31/1998	GN-JB U3 GENERATOR EQUIPMENT	-
2597	314050517003	2	12/31/1981	GN-JB U3 GENERATOR EQUIPMENT	281,608.30
2598	314050517003	8	12/31/1987	GN-JB U3 GENERATOR EQUIPMENT	8,312.36
2599	314050517003	12	12/31/1996	GN-JB U3 GENERATOR EQUIPMENT	7,095.78
2600	314050517003	13	12/31/1976	GN-JB U3 GENERATOR EQUIPMENT	1,205,608.14
2601	314050517003	14	12/31/1996	GN-JB U3 GENERATOR EQUIPMENT	61,370.99
2602	314050517003	15	12/31/1976	GN-JB U3 GENERATOR EQUIPMENT	40,733.67
2603	314050517003	16	12/31/1995	GN-JB U3 GENERATOR EQUIPMENT	5,441.81
2604	314050517003	17	12/31/1976	GN-JB U3 GENERATOR EQUIPMENT	40,411.00
2605	314050517003	18	12/31/1979	GN-JB U3 GENERATOR EQUIPMENT	5,856.00
2606	314050517003	25	7/13/2000	GN-JB U3 GENERATOR EQUIPMENT	13,593.31
2607	314050517003	26	12/2/1998	GN-JB U3 GENERATOR EQUIPMENT	19,019.55
2608	314050517003	27	3/7/2003	GN-JB U3 GENERATOR EQUIPMENT	9,090.58
2609	314050517003	28	3/31/2003	GN-JB U3 GENERATOR EQUIPMENT	3,798,226.50
2610	314050517003	29	7/10/2003	GN-JB U3 GENERATOR EQUIPMENT	66,205.65
2611	314050517003	30	7/10/2003	GN-JB U3 GENERATOR EQUIPMENT	41,837.63
2612	314050517003	31	1/30/2004	GN-JB U3 GENERATOR EQUIPMENT	283,343.28
2613	314050517003	35	6/7/2007	GN-JB U3 GENERATOR EQUIPMENT	12,070.75
2614	314050517003	36	5/7/2007	GN-JB U3 GENERATOR EQUIPMENT	10,065.49
2615	314050517003	37	6/7/2007	GN-JB U3 GENERATOR EQUIPMENT	77,773.69
2616	314050517003	38	6/29/2007	GN-JB U3 GENERATOR EQUIPMENT	54,754.87
2617	314050517003	39	9/5/2007	GN-JB U3 GENERATOR EQUIPMENT	231,595.90
2618	314050517003	40	9/20/2007	GN-JB U3 GENERATOR EQUIPMENT	228,951.23
2619	314050517003	41	9/20/2007	GN-JB U3 GENERATOR EQUIPMENT	1,852,423.56
2620	314050517003	42	6/30/2011	GN-JB U3 GENERATOR EQUIPMENT	2,788,925.35
2621	314050517003	43	6/30/2011	GN-JB U3 GENERATOR EQUIPMENT	492,163.30
2622	314050517003	44	6/30/2011	GN-JB U3 GENERATOR EQUIPMENT	1,910,419.68

2623	314050517003	45	10/31/2015	GN-JB U3 GENERATOR EQUIPMENT	534,379.75	
2624	314050517003	46	11/25/2015	GN-JB U3 GENERATOR EQUIPMENT	166,942.71	
2625	314050517003	47	11/30/2015	GN-JB U3 GENERATOR EQUIPMENT	44,749.10	
2626	314050517003	48	10/31/2015	GN-JB U3 GENERATOR EQUIPMENT	82,894.67	14,375,864.60
2627	314062517003	0	12/31/1998	LO-JB U3 LUBE OIL SYSTEM	-	
2628	314062517003	1	12/31/1976	LO-JB U3 LUBE OIL SYSTEM	197,555.00	
2629	314062517003	2	12/31/1986	LO-JB U3 LUBE OIL SYSTEM	3,265.00	
2630	314062517003	3	12/31/1976	LO-JB U3 LUBE OIL SYSTEM	42,710.55	
2631	314062517003	4	11/30/2015	LO-JB U3 LUBE OIL SYSTEM	44,749.10	
2632	314082517003	0	12/31/1998	SP-CAPITALIZED SPARE PARTS	-	
2633	314082517003	2	1/30/2004	SP-CAPITALIZED SPARE PARTS	70,129.65	
2634	314082517003	3	6/7/2007	SP-CAPITALIZED SPARE PARTS	51,726.00	
2635	314084517003	0	12/31/1998	TB-J BRIDGER U3 TURBINE EQUIPMENT	-	
2636	314084517003	1	12/31/1976	TB-J BRIDGER U3 TURBINE EQUIPMENT	180,726.80	
2637	314084517003	3	12/31/1976	TB-J BRIDGER U3 TURBINE EQUIPMENT	474,074.11	
2638	314084517003	4	12/31/1996	TB-J BRIDGER U3 TURBINE EQUIPMENT	1,432,028.97	
2639	314084517003	5	12/31/1988	TB-J BRIDGER U3 TURBINE EQUIPMENT	143,675.00	
2640	314084517003	6	12/31/1996	TB-J BRIDGER U3 TURBINE EQUIPMENT	891,949.55	
2641	314084517003	7	12/31/1988	TB-J BRIDGER U3 TURBINE EQUIPMENT	1,364,403.00	
2642	314084517003	8	12/31/1988	TB-J BRIDGER U3 TURBINE EQUIPMENT	215,512.00	
2643	314084517003	9	12/31/1996	TB-J BRIDGER U3 TURBINE EQUIPMENT	388,693.71	
2644	314084517003	10	12/31/1996	TB-J BRIDGER U3 TURBINE EQUIPMENT	217,404.50	
2645	314084517003	11	12/31/1996	TB-J BRIDGER U3 TURBINE EQUIPMENT	744,655.16	
2646	314084517003	12	12/31/1988	TB-J BRIDGER U3 TURBINE EQUIPMENT	35,919.00	
2647	314084517003	13	12/31/1996	TB-J BRIDGER U3 TURBINE EQUIPMENT	388,693.71	
2648	314084517003	14	12/31/1988	TB-J BRIDGER U3 TURBINE EQUIPMENT	761,879.00	
2649	314084517003	15	12/31/1988	TB-J BRIDGER U3 TURBINE EQUIPMENT	502,861.00	
2650	314084517003	18	12/31/1996	TB-J BRIDGER U3 TURBINE EQUIPMENT	81,830.40	
2651	314084517003	20	12/31/1976	TB-J BRIDGER U3 TURBINE EQUIPMENT	4,386,055.25	
2652	314084517003	21	12/31/1992	TB-J BRIDGER U3 TURBINE EQUIPMENT	25,205.29	
2653	314084517003	22	12/31/1996	TB-J BRIDGER U3 TURBINE EQUIPMENT	20,457.74	
2654	314084517003	24	12/31/1996	TB-J BRIDGER U3 TURBINE EQUIPMENT	114,858.89	
2655	314084517003	25	12/31/1985	TB-J BRIDGER U3 TURBINE EQUIPMENT	23,631.00	
2656	314084517003	27	8/1/1998	TB-J BRIDGER U3 TURBINE EQUIPMENT	9,711.19	
2657	314084517003	29	5/8/2007	TB-J BRIDGER U3 TURBINE EQUIPMENT	114,285.43	
2658	314084517003	32	9/10/2007	TB-J BRIDGER U3 TURBINE EQUIPMENT	75,158.87	
2659	314084517003	33	9/10/2007	TB-J BRIDGER U3 TURBINE EQUIPMENT	279,190.02	
2660	314084517003	34	2/8/2008	TB-J BRIDGER U3 TURBINE EQUIPMENT	113,870.86	
2661	314084517003	35	6/30/2011	TB-J BRIDGER U3 TURBINE EQUIPMENT	183,004.59	
2662	314084517003	36	6/30/2011	TB-J BRIDGER U3 TURBINE EQUIPMENT	508,251.49	
2663	314084517003	37	6/30/2011	TB-J BRIDGER U3 TURBINE EQUIPMENT	26,750.07	
2664	314084517003	38	6/9/2011	TB-J BRIDGER U3 TURBINE EQUIPMENT	21,402.03	
2665	314084517003	39	6/27/2011	TB-J BRIDGER U3 TURBINE EQUIPMENT	41,985.20	
2666	314084517003	40	10/31/2015	TB-J BRIDGER U3 TURBINE EQUIPMENT	394,203.74	
2667	314084517003	41	11/11/2015	TB-J BRIDGER U3 TURBINE EQUIPMENT	816,615.96	
2668	314084517003	42	11/11/2015	TB-J BRIDGER U3 TURBINE EQUIPMENT	585,833.17	
2669	314084517003	43	11/11/2015	TB-J BRIDGER U3 TURBINE EQUIPMENT	372,802.90	
2670	314084517003	44	10/31/2015	TB-J BRIDGER U3 TURBINE EQUIPMENT	255,998.04	
2671	314084517003	45	10/31/2015	TB-J BRIDGER U3 TURBINE EQUIPMENT	22,026.07	
2672	314084517003	46	5/28/2019	TB-J BRIDGER U3 TURBINE EQUIPMENT	220,952.83	
2673	314099517003	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
2674	* Location	517003		JIM BRIDGER UNIT 3	44,205,069.21	
2675	314008517004	0	12/31/1998	BA-JB U4 BOTTOM ASH EQUIPMENT	-	
2676	314008517004	1	12/31/1979	BA-JB U4 BOTTOM ASH EQUIPMENT	38,227.00	
2677	314012517004	0	12/31/1998	BG-JB U4 BOILER COOLING WATER SYSTEM	-	
2678	314012517004	1	12/31/1979	BG-JB U4 BOILER COOLING WATER SYSTEM	82,420.00	
2679	314012517004	2	12/31/1979	BG-JB U4 BOILER COOLING WATER SYSTEM	73,699.00	
2680	314022517004	0	12/31/1998	CN-JIM BRIDGER U4 CONDENSATE SYSTEM	-	
2681	314022517004	1	12/31/1979	CN-JIM BRIDGER U4 CONDENSATE SYSTEM	1,179,242.00	
2682	314022517004	2	12/31/1984	CN-JIM BRIDGER U4 CONDENSATE SYSTEM	18,827.00	
2683	314022517004	3	12/31/1986	CN-JIM BRIDGER U4 CONDENSATE SYSTEM	51.00	
2684	314022517004	4	12/31/1979	CN-JIM BRIDGER U4 CONDENSATE SYSTEM	22,033.00	
2685	314028517004	0	12/31/1998	CN-JB U4 CONDENSER & AUXILIARIES	-	
2686	314028517004	1	12/31/1982	CN-JB U4 CONDENSER & AUXILIARIES	9,910.00	
2687	314028517004	2	12/31/1979	CN-JB U4 CONDENSER & AUXILIARIES	1,956,481.67	
2688	314028517004	4	12/31/1995	CN-JB U4 CONDENSER & AUXILIARIES	22,126.89	
2689	314028517004	5	12/31/1979	CN-JB U4 CONDENSER & AUXILIARIES	185,848.00	
2690	314028517004	6	6/28/1999	CN-JB U4 CONDENSER & AUXILIARIES	1,727,949.06	
2691	314028517004	7	5/6/2004	CN-JB U4 CONDENSER & AUXILIARIES	41,133.14	
2692	314028517004	9	5/30/2008	CN-JB U4 CONDENSER & AUXILIARIES	274,517.54	
2693	314028517004	10	5/30/2008	CN-JB U4 CONDENSER & AUXILIARIES	32,350.04	
2694	314028517004	11	9/30/2008	CN-JB U4 CONDENSER & AUXILIARIES	384,771.34	
2695	314028517004	12	9/30/2008	CN-JB U4 CONDENSER & AUXILIARIES	20,051.95	

2696	314028517004	13	12/9/2009	CN-JB U4 CONDENSER & AUXILIARIES	19,837.46
2697	314028517004	14	5/30/2012	CN-JB U4 CONDENSER & AUXILIARIES	50,819.15
2698	314028517004	15	11/8/2016	CN-JB U4 CONDENSER & AUXILIARIES	79,346.19
2699	314028517004	16	12/19/2016	CN-JB U4 CONDENSER & AUXILIARIES	34,217.79
2700	314028517004	17	1/5/2018	CN-JB U4 CONDENSER & AUXILIARIES	69,579.57
2701	314032517004	0	12/31/1998	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	-
2702	314032517004	1	12/31/1995	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	11,505.79
2703	314032517004	3	12/31/1985	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	6,979.00
2704	314032517004	4	12/31/1988	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	1,219.00
2705	314032517004	5	12/31/1990	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	103,567.92
2706	314032517004	6	12/31/1990	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	386,396.72
2707	314032517004	7	12/31/1990	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	47,311.15
2708	314032517004	8	12/31/1997	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	196,022.07
2709	314032517004	9	12/31/1979	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	654,540.39
2710	314032517004	10	12/31/1983	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	16,666.00
2711	314032517004	11	12/31/1995	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	4,799.34
2712	314032517004	12	12/31/1996	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	50,227.74
2713	314032517004	13	12/31/1996	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	290,435.51
2714	314032517004	14	12/31/1994	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	13,518.15
2715	314032517004	15	12/31/1986	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	114,924.00
2716	314032517004	16	12/31/1990	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	315,103.00
2717	314032517004	18	12/31/1984	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	16,240.00
2718	314032517004	19	12/31/1982	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	92,527.00
2719	314032517004	20	12/31/1990	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	4,166.16
2720	314032517004	21	12/31/1991	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	8,133.43
2721	314032517004	22	12/31/1987	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	1,108.00
2722	314032517004	23	12/31/1994	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	2,255.04
2723	314032517004	24	12/31/1990	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	56,547.49
2724	314032517004	25	12/31/1997	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	36,993.07
2725	314032517004	26	8/18/2000	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	64,957.25
2726	314032517004	27	12/20/2001	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	140,934.61
2727	314032517004	28	3/7/2003	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	20,290.31
2728	314032517004	29	1/30/2004	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	12,559.55
2729	314032517004	30	5/25/2004	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	4,367,900.13
2730	314032517004	31	2/5/2001	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	39,869.15
2731	314032517004	32	2/5/2001	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	22,149.53
2732	314032517004	33	2/5/2001	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	48,728.95
2733	314032517004	34	2/16/2005	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	66,734.02
2734	314032517004	35	7/10/2006	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	125,906.74
2735	314032517004	36	1/23/2009	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	29,630.64
2736	314032517004	37	5/31/2012	CT-JB U4 COOLING TOWER STRUCTURES & EQUIPMEX	33,066.58
2737	314033517004	0	12/31/1998	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	-
2738	314033517004	1	12/31/1990	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	16,623.77
2739	314033517004	2	12/31/1994	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	11,056.01
2740	314033517004	3	12/31/1979	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	9,730.00
2741	314033517004	4	12/31/1979	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	83,719.43
2742	314033517004	5	12/31/1992	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	31,963.18
2743	314033517004	6	12/31/1979	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	45,307.00
2744	314033517004	7	7/13/2000	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	16,417.77
2745	314033517004	9	3/15/2001	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	77,590.58
2746	314033517004	11	12/20/1999	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	9,704.64
2747	314033517004	13	12/6/2007	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	64,560.59
2748	314033517004	14	5/30/2008	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	51,824.70
2749	314033517004	16	8/12/2008	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	88,771.97
2750	314033517004	17	8/12/2008	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	477,870.79
2751	314033517004	18	8/12/2008	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	127,642.58
2752	314033517004	19	8/12/2008	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	31,910.66
2753	314033517004	20	6/30/2011	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	58,451.81
2754	314033517004	21	5/9/2012	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	281,324.74
2755	314033517004	22	5/31/2012	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	369,122.40
2756	314033517004	24	11/30/2015	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	175,271.58
2757	314033517004	25	5/6/2016	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	182,141.78
2758	314033517004	26	10/28/2016	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	201,490.95
2759	314033517004	27	10/26/2016	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	60,101.98
2760	314033517004	28	10/12/2018	CW-J BRIDGER U4 CIRCULATING WATER EQUIPMENT	120,587.69
2761	314050517004	0	12/31/1998	GN-JB U4 GENERATOR EQUIPMENT	-
2762	314050517004	1	12/31/1979	GN-JB U4 GENERATOR EQUIPMENT	257,531.00
2763	314050517004	2	12/31/1979	GN-JB U4 GENERATOR EQUIPMENT	80,829.97
2764	314050517004	3	12/31/1982	GN-JB U4 GENERATOR EQUIPMENT	22,388.00
2765	314050517004	4	12/31/1984	GN-JB U4 GENERATOR EQUIPMENT	12,382.00
2766	314050517004	5	12/31/1997	GN-JB U4 GENERATOR EQUIPMENT	21,542.09
2767	314050517004	6	12/31/1996	GN-JB U4 GENERATOR EQUIPMENT	7,001.90
2768	314050517004	7	12/31/1997	GN-JB U4 GENERATOR EQUIPMENT	50,149.51

2769	314050517004	9	12/31/1979	GN-JB U4 GENERATOR EQUIPMENT	60,265.00	
2770	314050517004	10	12/31/1995	GN-JB U4 GENERATOR EQUIPMENT	5,441.81	
2771	314050517004	11	12/31/1979	GN-JB U4 GENERATOR EQUIPMENT	317,437.00	
2772	314050517004	12	12/31/1979	GN-JB U4 GENERATOR EQUIPMENT	48,416.00	
2773	314050517004	13	12/31/1979	GN-JB U4 GENERATOR EQUIPMENT	16,335.00	
2774	314050517004	14	12/31/1994	GN-JB U4 GENERATOR EQUIPMENT	2,729.78	
2775	314050517004	15	6/4/1999	GN-JB U4 GENERATOR EQUIPMENT	43,220.69	
2776	314050517004	16	7/13/2000	GN-JB U4 GENERATOR EQUIPMENT	17,213.10	
2777	314050517004	17	8/1/1998	GN-JB U4 GENERATOR EQUIPMENT	23,189.17	
2778	314050517004	18	3/7/2003	GN-JB U4 GENERATOR EQUIPMENT	9,090.56	
2779	314050517004	19	5/25/2004	GN-JB U4 GENERATOR EQUIPMENT	2,848,992.87	
2780	314050517004	20	5/25/2004	GN-JB U4 GENERATOR EQUIPMENT	36,387.59	
2781	314050517004	21	5/25/2004	GN-JB U4 GENERATOR EQUIPMENT	191,521.41	
2782	314050517004	22	6/25/2004	GN-JB U4 GENERATOR EQUIPMENT	231,566.77	
2783	314050517004	23	6/25/2004	GN-JB U4 GENERATOR EQUIPMENT	1,422,481.59	
2784	314050517004	24	5/30/2008	GN-JB U4 GENERATOR EQUIPMENT	1,900,015.38	
2785	314050517004	25	5/30/2008	GN-JB U4 GENERATOR EQUIPMENT	267,607.79	
2786	314050517004	26	5/30/2008	GN-JB U4 GENERATOR EQUIPMENT	452,395.99	
2787	314050517004	28	5/30/2008	GN-JB U4 GENERATOR EQUIPMENT	2,186,662.21	
2788	314050517004	29	5/30/2008	GN-JB U4 GENERATOR EQUIPMENT	117,116.40	
2789	314050517004	30	5/30/2008	GN-JB U4 GENERATOR EQUIPMENT	439,186.74	
2790	314050517004	31	8/5/2008	GN-JB U4 GENERATOR EQUIPMENT	289,184.78	
2791	314050517004	32	5/9/2012	GN-JB U4 GENERATOR EQUIPMENT	6,733.05	
2792	314050517004	33	10/27/2016	GN-JB U4 GENERATOR EQUIPMENT	226,792.32	
2793	314050517004	34	11/18/2016	GN-JB U4 GENERATOR EQUIPMENT	131,723.59	11,743,531.06
2794	314062517004	0	12/31/1998	LO-JB U4 LUBE OIL SYSTEM	-	
2795	314062517004	1	12/31/1979	LO-JB U4 LUBE OIL SYSTEM	1,028,901.33	
2796	314062517004	2	12/31/1986	LO-JB U4 LUBE OIL SYSTEM	3,265.00	
2797	314062517004	3	12/31/1979	LO-JB U4 LUBE OIL SYSTEM	47,992.00	
2798	314062517004	4	5/25/2004	LO-JB U4 LUBE OIL SYSTEM	178,138.63	
2799	314062517004	5	9/30/2008	LO-JB U4 LUBE OIL SYSTEM	121,204.25	
2800	314082517004	4	1/23/2009	SP-CAPITALIZED SPARE PARTS	35,072.42	
2801	314082517004	5	2/25/2010	SP-CAPITALIZED SPARE PARTS	57,097.16	
2802	314082517004	6	12/30/2016	SP-CAPITALIZED SPARE PARTS	184,808.20	
2803	314084517004	0	12/31/1998	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	-	
2804	314084517004	1	12/31/1993	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	9,027.39	
2805	314084517004	2	12/31/1979	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	261,176.36	
2806	314084517004	3	12/31/1979	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	1,400,398.33	
2807	314084517004	4	12/31/1991	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	406,389.89	
2808	314084517004	5	12/31/1991	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	646,890.58	
2809	314084517004	6	12/31/1991	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	351,996.03	
2810	314084517004	7	12/31/1991	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	20,015.00	
2811	314084517004	8	12/31/1991	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	331,364.45	
2812	314084517004	9	12/31/1991	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	1,143,557.47	
2813	314084517004	11	12/31/1991	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	6,182.70	
2814	314084517004	12	12/31/1979	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	2,997,486.18	
2815	314084517004	13	12/31/1979	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	468,736.00	
2816	314084517004	14	12/31/1985	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	6,735.00	
2817	314084517004	15	12/31/1997	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	59,030.67	
2818	314084517004	16	12/31/1997	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	46,381.23	
2819	314084517004	17	12/31/1985	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	23,631.00	
2820	314084517004	19	12/20/1999	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	112,240.60	
2821	314084517004	20	7/13/2000	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	4,194,858.01	
2822	314084517004	21	7/13/2000	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	386,793.77	
2823	314084517004	22	8/18/2000	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	44,386.53	
2824	314084517004	23	5/25/2004	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	90,324.87	
2825	314084517004	25	5/25/2004	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	35,534.80	
2826	314084517004	26	5/30/2008	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	361,585.06	
2827	314084517004	27	5/30/2008	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	5,312.43	
2828	314084517004	28	11/20/2009	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	12,487.28	
2829	314084517004	29	5/30/2012	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	197,143.95	
2830	314084517004	30	4/30/2012	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	12,439.19	
2831	314084517004	31	5/31/2012	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	60,047.70	
2832	314084517004	32	10/27/2016	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	430,132.96	
2833	314084517004	33	10/27/2016	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	392,504.96	
2834	314084517004	34	10/27/2016	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	184,130.52	
2835	314084517004	35	10/27/2016	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	142,825.96	
2836	314084517004	36	10/27/2016	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	324,235.18	
2837	314084517004	37	11/18/2016	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	580,763.11	
2838	314084517004	38	10/27/2016	TB-JIM BRIDGER U4 TURBINE EQUIPMENT	170,671.46	
2839	314099517004	0	12/31/1998	99-OTHER UTILITY PLANT (MASS PROP/CONVERSION)	-	
2840	* Location	517004		JIM BRIDGER UNIT 4	45,637,965.49	
2841	314007519000	0	12/31/1998	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	-	

2842	314007519000	2	12/31/1994	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	765,236.68	
2843	314007519000	3	12/31/1993	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	124,050.67	
2844	314007519000	4	12/31/1994	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	337,631.04	
2845	314007519000	5	12/31/1991	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	21,673.95	
2846	314007519000	6	12/31/1993	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	21,945.47	
2847	314007519000	8	12/31/1995	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	453,441.43	
2848	314007519000	9	4/2/2003	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	6,836.99	
2849	314007519000	10	11/7/2002	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	9,191.60	
2850	314007519000	11	4/1/2004	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	74,692.98	
2851	314007519000	12	4/15/2005	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	78,856.42	
2852	314007519000	13	11/9/2007	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	18,730.51	
2853	314007519000	14	12/31/2008	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	556,634.05	
2854	314007519000	15	2/6/2009	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	156,551.87	
2855	314007519000	16	8/7/2009	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	19,282.31	
2856	314007519000	17	7/29/2010	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	13,527.28	
2857	314007519000	18	4/27/2011	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	19,481,226.14	
2858	314007519000	19	11/30/2011	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	27,727.83	
2859	314007519000	20	11/30/2011	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	19,112.36	
2860	314007519000	21	12/30/2011	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	104,604.95	
2861	314007519000	22	3/30/2012	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	63,741.26	
2862	314007519000	23	6/29/2012	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	32,975.53	
2863	314007519000	24	7/18/2016	AZ-WYODAK AIR COOLED CONDENSER SYSTEM	149,966.31	
2864	314022519000	0	12/31/1998	CD-CONDENSATE TANK FOUNDATIONS	-	
2865	314022519000	1	12/31/1978	CD-CONDENSATE TANK FOUNDATIONS	122,962.75	
2866	314022519000	2	12/31/1978	CD-CONDENSATE TANK FOUNDATIONS	343,980.21	
2867	314022519000	3	12/31/1978	CD-CONDENSATE TANK FOUNDATIONS	2,219.27	
2868	314022519000	4	12/31/1978	CD-CONDENSATE TANK FOUNDATIONS	695,985.56	
2869	314022519000	5	12/31/1978	CD-CONDENSATE TANK FOUNDATIONS	438,983.64	
2870	314028519000	0	12/31/1998	CN-CONDENSER SYSTEM TUBES	-	
2871	314028519000	1	12/31/1978	CN-CONDENSER SYSTEM TUBES	10,705,802.35	
2872	314032519000	0	12/31/1998	CT-WYODAK COOLING TOWER STRUCTURE & EQUIPMENT	-	
2873	314032519000	1	12/31/1978	CT-WYODAK COOLING TOWER STRUCTURE & EQUIPMENT	205,296.37	
2874	314032519000	2	12/31/1978	CT-WYODAK COOLING TOWER STRUCTURE & EQUIPMENT	10,026.26	
2875	314032519000	3	12/31/1978	CT-WYODAK COOLING TOWER STRUCTURE & EQUIPMENT	962,418.74	
2876	314032519000	4	2/12/2002	CT-WYODAK COOLING TOWER STRUCTURE & EQUIPMENT	45,704.05	
2877	314032519000	5	12/28/2017	CT-WYODAK COOLING TOWER STRUCTURE & EQUIPMENT	389,401.55	
2878	314032519000	6	12/28/2017	CT-WYODAK COOLING TOWER STRUCTURE & EQUIPMENT	71,415.43	
2879	314050519000	0	12/31/1998	GN-WYODAK GENERATOR EQUIPMENT	-	
2880	314050519000	1	12/31/1986	GN-WYODAK GENERATOR EQUIPMENT	6,734.85	
2881	314050519000	2	12/31/1978	GN-WYODAK GENERATOR EQUIPMENT	489,008.89	
2882	314050519000	3	12/31/1978	GN-WYODAK GENERATOR EQUIPMENT	352,539.03	
2883	314050519000	4	12/31/1981	GN-WYODAK GENERATOR EQUIPMENT	18,359.67	
2884	314050519000	5	12/31/1982	GN-WYODAK GENERATOR EQUIPMENT	4,034.58	
2885	314050519000	6	12/31/1989	GN-WYODAK GENERATOR EQUIPMENT	16,272.05	
2886	314050519000	7	12/31/1978	GN-WYODAK GENERATOR EQUIPMENT	2,228,175.03	
2887	314050519000	8	12/31/1991	GN-WYODAK GENERATOR EQUIPMENT	62,153.78	
2888	314050519000	9	12/31/1991	GN-WYODAK GENERATOR EQUIPMENT	33,279.36	
2889	314050519000	10	12/31/1997	GN-WYODAK GENERATOR EQUIPMENT	3,814.62	
2890	314050519000	11	12/31/1978	GN-WYODAK GENERATOR EQUIPMENT	489,110.74	
2891	314050519000	12	12/31/1983	GN-WYODAK GENERATOR EQUIPMENT	20,346.04	
2892	314050519000	13	10/7/1999	GN-WYODAK GENERATOR EQUIPMENT	14,370.35	
2893	314050519000	14	9/14/2000	GN-WYODAK GENERATOR EQUIPMENT	27,528.86	
2894	314050519000	15	3/24/2000	GN-WYODAK GENERATOR EQUIPMENT	5,580.31	
2895	314050519000	16	7/7/2000	GN-WYODAK GENERATOR EQUIPMENT	4,824.76	
2896	314050519000	17	9/14/2000	GN-WYODAK GENERATOR EQUIPMENT	352,437.90	
2897	314050519000	20	7/7/2006	GN-WYODAK GENERATOR EQUIPMENT	434,413.84	
2898	314050519000	22	7/7/2006	GN-WYODAK GENERATOR EQUIPMENT	134,822.03	
2899	314050519000	23	7/7/2006	GN-WYODAK GENERATOR EQUIPMENT	110,108.46	
2900	314050519000	24	7/7/2006	GN-WYODAK GENERATOR EQUIPMENT	1,171,448.96	
2901	314050519000	25	7/7/2006	GN-WYODAK GENERATOR EQUIPMENT	159,138.24	
2902	314050519000	26	7/7/2006	GN-WYODAK GENERATOR EQUIPMENT	389,043.46	
2903	314050519000	27	4/27/2011	GN-WYODAK GENERATOR EQUIPMENT	80,905.99	
2904	314050519000	28	4/28/2011	GN-WYODAK GENERATOR EQUIPMENT	3,054,739.62	
2905	314050519000	30	5/8/2014	GN-WYODAK GENERATOR EQUIPMENT	8,256.73	
2906	314050519000	31	7/18/2016	GN-WYODAK GENERATOR EQUIPMENT	666,315.45	10,337,763.60
2907	314062519000	0	12/31/1998	LO-LUBE OIL PUMPS & PUMP MOTORS	-	
2908	314062519000	1	12/31/1978	LO-LUBE OIL PUMPS & PUMP MOTORS	73,344.20	
2909	314062519000	2	12/31/1978	LO-LUBE OIL PUMPS & PUMP MOTORS	65,049.47	
2910	314082519000	0	12/31/1998	SP-CAPITALIZED SPARE PARTS	-	
2911	314082519000	1	12/31/1978	SP-CAPITALIZED SPARE PARTS	216,000.00	
2912	314082519000	2	12/31/1997	SP-CAPITALIZED SPARE PARTS	132,918.95	
2913	314082519000	3	12/31/1978	SP-CAPITALIZED SPARE PARTS	120,000.00	
2914	314082519000	4	4/15/2005	SP-CAPITALIZED SPARE PARTS	14,073.09	

2915		314082519000	5	7/7/2006	SP-CAPITALIZED SPARE PARTS	2,373,725.12	
2916		314084519000	0	12/31/1998	TB-WYODAK TURBINE EQUIPMENT	-	
2917		314084519000	1	12/31/1978	TB-WYODAK TURBINE EQUIPMENT	720,911.60	
2918		314084519000	2	12/31/1978	TB-WYODAK TURBINE EQUIPMENT	44,272.12	
2919		314084519000	3	12/31/1988	TB-WYODAK TURBINE EQUIPMENT	28,862.46	
2920		314084519000	4	12/31/1978	TB-WYODAK TURBINE EQUIPMENT	92,751.93	
2921		314084519000	5	12/31/1978	TB-WYODAK TURBINE EQUIPMENT	1,005,396.70	
2922		314084519000	6	12/31/1991	TB-WYODAK TURBINE EQUIPMENT	737,040.74	
2923		314084519000	7	12/31/1991	TB-WYODAK TURBINE EQUIPMENT	97,082.12	
2924		314084519000	9	12/31/1978	TB-WYODAK TURBINE EQUIPMENT	2,399,990.26	
2925		314084519000	10	12/31/1978	TB-WYODAK TURBINE EQUIPMENT	357,557.91	
2926		314084519000	11	12/31/1991	TB-WYODAK TURBINE EQUIPMENT	162,785.57	
2927		314084519000	12	12/31/1978	TB-WYODAK TURBINE EQUIPMENT	1,810,857.43	
2928		314084519000	13	12/31/1978	TB-WYODAK TURBINE EQUIPMENT	910,724.92	
2929		314084519000	14	12/31/1978	TB-WYODAK TURBINE EQUIPMENT	257,078.05	
2930		314084519000	15	12/31/1978	TB-WYODAK TURBINE EQUIPMENT	94,006.12	
2931		314084519000	17	12/31/1991	TB-WYODAK TURBINE EQUIPMENT	31,891.05	
2932		314084519000	18	12/31/1978	TB-WYODAK TURBINE EQUIPMENT	269,813.38	
2933		314084519000	19	12/31/1992	TB-WYODAK TURBINE EQUIPMENT	47,101.80	
2934		314084519000	20	12/31/1978	TB-WYODAK TURBINE EQUIPMENT	1,444,683.99	
2935		314084519000	21	9/14/2000	TB-WYODAK TURBINE EQUIPMENT	230,835.08	
2936		314084519000	22	9/14/2001	TB-WYODAK TURBINE EQUIPMENT	154,874.81	
2937		314084519000	23	1/13/2004	TB-WYODAK TURBINE EQUIPMENT	19,397.67	
2938		314084519000	24	4/1/2004	TB-WYODAK TURBINE EQUIPMENT	23,364.97	
2939		314084519000	32	4/27/2011	TB-WYODAK TURBINE EQUIPMENT	100,296.96	
2940		314084519000	33	4/27/2011	TB-WYODAK TURBINE EQUIPMENT	242,717.94	
2941		314084519000	35	4/28/2011	TB-WYODAK TURBINE EQUIPMENT	127,872.86	
2942		314084519000	36	7/26/2016	TB-WYODAK TURBINE EQUIPMENT	2,163,225.12	
2943		314084519000	37	7/26/2016	TB-WYODAK TURBINE EQUIPMENT	1,352,015.75	
2944		314084519000	38	7/26/2016	TB-WYODAK TURBINE EQUIPMENT	1,892,821.96	
2945		314084519000	39	7/26/2016	TB-WYODAK TURBINE EQUIPMENT	111,319.35	
2946	*	Location	519000		WYODAK PLANT	66,796,258.86	
2947	**	Asset Class	31400		Turbogenerator Units	1,003,750,218.08	
2948		333040000444	0	12/31/1998	EM-ELECTRIC EQUIP., STATION SUMP PUMPS	-	
2949		333040000444	1	12/31/1981	EM-ELECTRIC EQUIP., STATION SUMP PUMPS	1,074.75	
2950		333049000444	0	12/31/1998	GE-CUTLER GENERATOR EQUIPMENT	-	
2951		333049000444	1	12/31/1927	GE-CUTLER GENERATOR EQUIPMENT	225,470.73	
2952		333049000444	2	12/31/1936	GE-CUTLER GENERATOR EQUIPMENT	1,304.30	
2953		333049000444	3	12/31/1955	GE-CUTLER GENERATOR EQUIPMENT	1,760.26	
2954		333049000444	4	12/31/1956	GE-CUTLER GENERATOR EQUIPMENT	2,268.66	
2955		333049000444	5	12/31/1958	GE-CUTLER GENERATOR EQUIPMENT	11,886.89	
2956		333049000444	6	12/31/1959	GE-CUTLER GENERATOR EQUIPMENT	4,216.98	
2957		333049000444	7	12/31/1964	GE-CUTLER GENERATOR EQUIPMENT	16,625.40	
2958		333049000444	8	12/31/1983	GE-CUTLER GENERATOR EQUIPMENT	19,878.92	
2959		333049000444	9	12/31/1995	GE-CUTLER GENERATOR EQUIPMENT	24,549.18	
2960		333049000444	10	12/31/1981	GE-CUTLER GENERATOR EQUIPMENT	273,145.44	
2961		333049000444	11	2/21/2008	GE-CUTLER GENERATOR EQUIPMENT	580,196.03	
2962		333049000444	12	12/16/2008	GE-CUTLER GENERATOR EQUIPMENT	1,971,203.83	
2963		333049000444	13	12/16/2008	GE-CUTLER GENERATOR EQUIPMENT	584,060.36	
2964		333049000444	16	12/16/2015	GE-CUTLER GENERATOR EQUIPMENT	7,841.37	
2965		333049000444	17	7/13/2018	GE-CUTLER GENERATOR EQUIPMENT	77,771.33	3,802,179.68
2966		333052000444	0	12/31/1998	GV-CUTLER GOVERNOR EQUIPMENT	-	
2967		333052000444	3	2/14/2008	GV-CUTLER GOVERNOR EQUIPMENT	624,863.53	
2968		333052000444	4	12/16/2008	GV-CUTLER GOVERNOR EQUIPMENT	583,195.36	
2969		333052000444	5	12/5/2013	GV-CUTLER GOVERNOR EQUIPMENT	868.76	
2970		333052000444	6	9/30/2015	GV-CUTLER GOVERNOR EQUIPMENT	8,830.48	
2971		333052000444	7	8/19/2015	GV-CUTLER GOVERNOR EQUIPMENT	9,854.40	
2972		333088000444	0	12/31/1998	TU-CUTLER TURBINE EQUIPMENT	-	
2973		333088000444	1	12/31/1927	TU-CUTLER TURBINE EQUIPMENT	180,185.21	
2974		333088000444	2	12/31/1955	TU-CUTLER TURBINE EQUIPMENT	4,862.96	
2975		333088000444	3	12/31/1959	TU-CUTLER TURBINE EQUIPMENT	7,395.78	
2976		333088000444	4	12/31/1981	TU-CUTLER TURBINE EQUIPMENT	7,697.40	
2977		333088000444	5	2/21/2008	TU-CUTLER TURBINE EQUIPMENT	3,473,885.24	
2978		333088000444	6	12/16/2008	TU-CUTLER TURBINE EQUIPMENT	3,358,347.13	
2979		333088000444	7	10/13/2011	TU-CUTLER TURBINE EQUIPMENT	3,384.39	
2980		333088000444	8	12/30/2011	TU-CUTLER TURBINE EQUIPMENT	20,201.92	
2981	*	Location	000444		CUTLER HYDROELECTRIC STATION - PROJ	12,086,826.99	
2982		333049000445	0	12/31/1998	GE-GENERATOR, STATOR WINDING	-	
2983		333049000445	1	12/31/1982	GE-GENERATOR, STATOR WINDING	598,783.08	598,783.08
2984		333088000445	0	12/31/1998	TU-TURBINE, LUBE OIL SYSTEM	-	
2985		333088000445	2	4/7/2008	TU-TURBINE, LUBE OIL SYSTEM	60,959.50	
2986		333088000445	3	4/7/2008	TU-TURBINE, LUBE OIL SYSTEM	60,959.48	
2987	*	Location	000445		GRANITE HE PLANT AND SUBSTATION	720,702.06	

2988		333038000449	1	9/9/2008	DT - PIONEER DRAFT TUBE EQUIPMENT	62,508.84	
2989		333049000449	0	12/31/1998	GE-PIONEER GENERATOR EQUIPMENT	-	
2990		333049000449	1	12/31/1897	GE-PIONEER GENERATOR EQUIPMENT	17,224.30	
2991		333049000449	2	12/31/1954	GE-PIONEER GENERATOR EQUIPMENT	7,524.95	
2992		333049000449	3	12/31/1984	GE-PIONEER GENERATOR EQUIPMENT	68,543.14	
2993		333049000449	4	12/31/1989	GE-PIONEER GENERATOR EQUIPMENT	15,835.03	
2994		333049000449	5	12/31/1897	GE-PIONEER GENERATOR EQUIPMENT	3,916.36	
2995		333049000449	6	12/31/1954	GE-PIONEER GENERATOR EQUIPMENT	1,143.09	
2996		333049000449	7	12/31/1993	GE-PIONEER GENERATOR EQUIPMENT	70,354.93	
2997		333049000449	8	6/28/1999	GE-PIONEER GENERATOR EQUIPMENT	173,816.42	
2998		333049000449	9	9/9/2008	GE-PIONEER GENERATOR EQUIPMENT	20,836.27	
2999		333049000449	10	2/27/2012	GE-PIONEER GENERATOR EQUIPMENT	47,175.61	
3000		333049000449	11	8/8/2013	GE-PIONEER GENERATOR EQUIPMENT	2,175.25	428,545.35
3001		333052000449	0	12/31/1998	GV-HYDRAULIC ACTUATOR SYSTEM	-	
3002		333052000449	1	12/31/1922	GV-HYDRAULIC ACTUATOR SYSTEM	323.53	
3003		333088000449	0	12/31/1998	TU-PIONEER TURBINE EQUIPMENT	-	
3004		333088000449	1	12/31/1897	TU-PIONEER TURBINE EQUIPMENT	6,696.10	
3005		333088000449	3	12/31/1953	TU-PIONEER TURBINE EQUIPMENT	6,428.72	
3006		333088000449	5	12/31/1986	TU-PIONEER TURBINE EQUIPMENT	64,343.22	
3007		333088000449	7	12/30/2008	TU-PIONEER TURBINE EQUIPMENT	1,045,394.06	
3008		333088000449	8	12/18/2014	TU-PIONEER TURBINE EQUIPMENT	1,656.58	
3009	*	Location	000449		PIONEER HE PLANT,SUBSTATION & MAINT	1,615,896.40	
3010		333049000452	0	12/31/1998	GE-STAIRS GENERATOR EQUIPMENT	-	
3011		333049000452	2	12/31/1957	GE-STAIRS GENERATOR EQUIPMENT	11,256.70	
3012		333049000452	3	12/31/1986	GE-STAIRS GENERATOR EQUIPMENT	60,937.40	
3013		333049000452	4	12/31/1987	GE-STAIRS GENERATOR EQUIPMENT	5,495.88	
3014		333049000452	5	12/31/1895	GE-STAIRS GENERATOR EQUIPMENT	1,016.16	
3015		333049000452	6	12/31/1895	GE-STAIRS GENERATOR EQUIPMENT	9,597.71	
3016		333049000452	8	3/8/2011	GE-STAIRS GENERATOR EQUIPMENT	1,114.79	
3017		333049000452	9	10/13/2011	GE-STAIRS GENERATOR EQUIPMENT	3,131.14	92,549.78
3018		333052000452	0	12/31/1998	GV-HYDRAULIC ACTUATOR SYSTEM	-	
3019		333052000452	1	12/31/1895	GV-HYDRAULIC ACTUATOR SYSTEM	4,552.04	
3020		333088000452	0	12/31/1998	TU-STAIRS TURBINE EQUIPMENT	-	
3021		333088000452	1	12/31/1895	TU-STAIRS TURBINE EQUIPMENT	13,808.99	
3022		333088000452	2	12/31/1995	TU-STAIRS TURBINE EQUIPMENT	381,461.75	
3023		333088000452	3	12/31/1995	TU-STAIRS TURBINE EQUIPMENT	23,795.26	
3024		333088000452	4	11/6/2012	TU-STAIRS TURBINE EQUIPMENT	1,621.58	
3025	*	Location	000452		STAIRS HE PLANT AND SUBSTATION	517,789.40	
3026		333038000454	0	12/31/1998	DT-DRAFT TUBES	-	
3027		333038000454	1	12/31/1924	DT-DRAFT TUBES	322.43	
3028		333038000454	2	12/31/1996	DT-DRAFT TUBES	27,749.40	
3029		333049000454	0	12/31/1998	GE-WEBER GENERATOR EQUIPMENT	-	
3030		333049000454	1	12/31/1911	GE-WEBER GENERATOR EQUIPMENT	9,125.68	
3031		333049000454	4	12/31/1960	GE-WEBER GENERATOR EQUIPMENT	12,978.47	
3032		333049000454	5	12/31/1953	GE-WEBER GENERATOR EQUIPMENT	3,034.68	
3033		333049000454	6	12/31/1994	GE-WEBER GENERATOR EQUIPMENT	87,545.44	
3034		333049000454	7	12/31/1985	GE-WEBER GENERATOR EQUIPMENT	275,929.66	
3035		333049000454	9	5/27/2010	GE-WEBER GENERATOR EQUIPMENT	8,532.48	
3036		333049000454	10	10/31/2011	GE-WEBER GENERATOR EQUIPMENT	1,703.40	
3037		333049000454	11	2/2/2017	GE-WEBER GENERATOR EQUIPMENT	65,663.46	464,513.27
3038		333088000454	0	12/31/1998	TU-WEBER TURBINE EQUIPMENT	-	
3039		333088000454	1	12/31/1911	TU-WEBER TURBINE EQUIPMENT	19,008.97	
3040		333088000454	2	12/31/1925	TU-WEBER TURBINE EQUIPMENT	19,570.82	
3041		333088000454	3	12/31/1934	TU-WEBER TURBINE EQUIPMENT	104.54	
3042		333088000454	4	12/31/1953	TU-WEBER TURBINE EQUIPMENT	1,031.88	
3043		333088000454	5	12/31/1990	TU-WEBER TURBINE EQUIPMENT	361,799.06	
3044		333088000454	6	1/28/2011	TU-WEBER TURBINE EQUIPMENT	1,907.94	
3045		333088000454	7	8/12/2014	TU-WEBER TURBINE EQUIPMENT	39,413.11	
3046		333088000454	8	3/16/2018	TU-WEBER TURBINE EQUIPMENT	185,184.08	
3047	*	Location	000454		WEBER HYDROELECTRIC STATION - PROJE	1,120,605.50	
3048		333040000455	0	12/31/1998	EM-ELECTRIC EQUIP., STATION SUMP PUMPS	-	
3049		333040000455	1	12/31/1980	EM-ELECTRIC EQUIP., STATION SUMP PUMPS	780.39	
3050		333049000455	0	12/31/1998	GE-ASHTON GENERATOR EQUIPMENT	-	
3051		333049000455	1	12/31/1917	GE-ASHTON GENERATOR EQUIPMENT	15,290.09	
3052		333049000455	2	12/31/1925	GE-ASHTON GENERATOR EQUIPMENT	54,700.77	
3053		333049000455	3	12/31/1965	GE-ASHTON GENERATOR EQUIPMENT	6,554.38	
3054		333049000455	4	12/31/1992	GE-ASHTON GENERATOR EQUIPMENT	23,850.79	
3055		333049000455	5	12/31/1939	GE-ASHTON GENERATOR EQUIPMENT	197.67	
3056		333049000455	6	12/31/1982	GE-ASHTON GENERATOR EQUIPMENT	167,325.97	
3057		333049000455	7	12/31/1992	GE-ASHTON GENERATOR EQUIPMENT	100,305.39	
3058		333049000455	8	12/31/1992	GE-ASHTON GENERATOR EQUIPMENT	14,486.09	
3059		333049000455	9	12/31/1992	GE-ASHTON GENERATOR EQUIPMENT	367,497.94	
3060		333049000455	10	12/31/1992	GE-ASHTON GENERATOR EQUIPMENT	7,788.52	

3061		333049000455	11	12/31/1992	GE-ASHTON GENERATOR EQUIPMENT	122,899.18	
3062		333049000455	12	11/16/2007	GE-ASHTON GENERATOR EQUIPMENT	5,739.32	
3063		333049000455	13	11/7/2012	GE-ASHTON GENERATOR EQUIPMENT	16,306.81	
3064		333049000455	14	9/9/2015	GE-ASHTON GENERATOR EQUIPMENT	6,550.00	
3065		333049000455	15	10/24/2016	GE-ASHTON GENERATOR EQUIPMENT	13,007.64	922,500.56
3066		333052000455	0	12/31/1998	GV-HYDRAULIC ACTUATOR SYSTEM	-	
3067		333052000455	1	12/31/1951	GV-HYDRAULIC ACTUATOR SYSTEM	1,954.94	
3068		333088000455	0	12/31/1998	TU-TURBINE, LUBE OIL SYSTEM	-	
3069		333088000455	1	12/31/1925	TU-TURBINE, LUBE OIL SYSTEM	50,752.24	
3070		333088000455	2	12/31/1992	TU-TURBINE, LUBE OIL SYSTEM	11,982.30	
3071		333088000455	3	12/31/1992	TU-TURBINE, LUBE OIL SYSTEM	58,123.16	
3072		333088000455	4	12/31/1992	TU-TURBINE, LUBE OIL SYSTEM	931,541.40	
3073	*	Location	000455		ASHTON HE PLANT, SUBSTATION AND OFF	1,977,634.99	
3074		333038000457	0	12/31/1998	DT-DRAFT TUBES	-	
3075		333038000457	1	12/31/1980	DT-DRAFT TUBES	189,739.73	
3076		333049000457	0	12/31/1998	GE-GRACE GENERATOR EQUIPMENT	-	
3077		333049000457	1	12/31/1913	GE-GRACE GENERATOR EQUIPMENT	130,799.52	
3078		333049000457	4	12/31/1923	GE-GRACE GENERATOR EQUIPMENT	110,507.39	
3079		333049000457	5	12/31/1944	GE-GRACE GENERATOR EQUIPMENT	1,033.87	
3080		333049000457	8	12/31/1982	GE-GRACE GENERATOR EQUIPMENT	217,260.51	
3081		333049000457	9	12/31/1983	GE-GRACE GENERATOR EQUIPMENT	379,525.32	
3082		333049000457	14	12/31/1952	GE-GRACE GENERATOR EQUIPMENT	6,038.76	
3083		333049000457	15	12/31/1955	GE-GRACE GENERATOR EQUIPMENT	4,473.98	
3084		333049000457	16	12/31/1983	GE-GRACE GENERATOR EQUIPMENT	133,859.80	
3085		333049000457	18	8/30/2012	GE-GRACE GENERATOR EQUIPMENT	46,645.16	
3086		333049000457	19	12/28/2015	GE-GRACE GENERATOR EQUIPMENT	162,673.08	
3087		333049000457	20	12/14/2018	GE-GRACE GENERATOR EQUIPMENT	210,169.32	1,402,986.71
3088		333052000457	0	12/31/1998	GV-HYDRAULIC ACTUATOR SYSTEM	-	
3089		333052000457	1	12/31/1923	GV-HYDRAULIC ACTUATOR SYSTEM	4,070.85	
3090		333052000457	2	12/31/1929	GV-HYDRAULIC ACTUATOR SYSTEM	163.75	
3091		333052000457	3	12/31/1948	GV-HYDRAULIC ACTUATOR SYSTEM	1,752.74	
3092		333052000457	4	12/31/1985	GV-HYDRAULIC ACTUATOR SYSTEM	95,133.32	
3093		333052000457	5	12/31/1997	GV-HYDRAULIC ACTUATOR SYSTEM	525,087.05	
3094		333052000457	6	12/17/2007	GV-HYDRAULIC ACTUATOR SYSTEM	4,272.16	
3095		333052000457	7	12/2/2011	GV-HYDRAULIC ACTUATOR SYSTEM	2,706.82	
3096		333052000457	8	6/7/2016	GV-HYDRAULIC ACTUATOR SYSTEM	7,150.51	
3097		333052000457	9	8/10/2016	GV-HYDRAULIC ACTUATOR SYSTEM	4,519.42	
3098		333082000457	1	12/31/1993	SP - GRACE CAPITAL SPARES FERC 333	152,798.18	
3099		333088000457	0	12/31/1998	TU-TURBINE, LUBE OIL SYSTEM	-	
3100		333088000457	1	12/31/1913	TU-TURBINE, LUBE OIL SYSTEM	97,031.73	
3101		333088000457	2	12/31/1923	TU-TURBINE, LUBE OIL SYSTEM	135,504.68	
3102		333088000457	3	12/31/1925	TU-TURBINE, LUBE OIL SYSTEM	19,708.80	
3103		333088000457	4	12/31/1926	TU-TURBINE, LUBE OIL SYSTEM	393.58	
3104		333088000457	5	12/31/1948	TU-TURBINE, LUBE OIL SYSTEM	3,946.89	
3105		333088000457	6	12/31/1949	TU-TURBINE, LUBE OIL SYSTEM	16,660.58	
3106		333088000457	7	12/31/1950	TU-TURBINE, LUBE OIL SYSTEM	3,926.39	
3107		333088000457	8	12/31/1951	TU-TURBINE, LUBE OIL SYSTEM	7,548.70	
3108		333088000457	9	12/31/1952	TU-TURBINE, LUBE OIL SYSTEM	5,763.73	
3109		333088000457	10	12/31/1954	TU-TURBINE, LUBE OIL SYSTEM	2,345.21	
3110		333088000457	11	12/31/1956	TU-TURBINE, LUBE OIL SYSTEM	594.37	
3111		333088000457	12	12/31/1963	TU-TURBINE, LUBE OIL SYSTEM	480.59	
3112		333088000457	13	12/31/1925	TU-TURBINE, LUBE OIL SYSTEM	213.89	
3113	*	Location	000457		GRACE HE PLANT,SUBSTATION AND BUILD	2,684,500.38	
3114		333040000458	0	12/31/1998	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	120,797.44	
3115		333040000458	1	12/31/1917	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	46,374.14	
3116		333040000458	3	12/31/1951	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	3,030.35	
3117		333040000458	4	12/31/1953	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	3,232.67	
3118		333040000458	5	12/31/1954	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	2,463.31	
3119		333040000458	6	12/31/1956	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	3,649.86	
3120		333040000458	7	12/31/1980	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	152,804.61	
3121		333040000458	8	12/31/1986	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	2,279.09	
3122		333040000458	9	4/29/2005	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	85,792.57	
3123		333040000458	12	4/29/2005	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	26,477.44	
3124		333040000458	13	4/29/2005	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	238,061.42	
3125		333040000458	14	7/26/2006	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	958,786.89	
3126		333040000458	15	7/26/2006	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	809,182.51	
3127		333040000458	16	7/26/2006	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	703,873.84	
3128		333040000458	18	5/22/2007	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	1,033,744.95	
3129		333040000458	19	5/22/2007	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	1,222,186.85	
3130		333040000458	20	6/10/2009	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	1,465,254.06	
3131		333040000458	21	6/22/2009	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	778,748.53	
3132		333040000458	22	8/8/2011	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	11,567.50	
3133		333040000458	23	12/19/2013	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	121,936.71	

3134		333040000458	24	6/7/2016	EM-LIFTON ELECTRIC EQUIP - STATION PUMPS	8,353.82	
3135		333088000458	4	7/26/2006	TU-TURBINE, LUBE OIL SYSTEM	81,839.49	
3136	*	Location	000458		LIFTON PUMPING STATION AND SUBSTATI	7,880,438.05	
3137		333038000459	1	7/6/2015	DT-ONEIDA TURBINE DRAFT TUBE EQUIPMENT	297,797.29	
3138		333049000459	0	12/31/1998	GE-ONEIDA GENERATOR EQUIPMENT	-	
3139		333049000459	1	12/31/1915	GE-ONEIDA GENERATOR EQUIPMENT	192,160.47	
3140		333049000459	2	12/31/1921	GE-ONEIDA GENERATOR EQUIPMENT	599.29	
3141		333049000459	4	12/31/1948	GE-ONEIDA GENERATOR EQUIPMENT	5,548.46	
3142		333049000459	5	12/31/1950	GE-ONEIDA GENERATOR EQUIPMENT	2,687.05	
3143		333049000459	6	12/31/1953	GE-ONEIDA GENERATOR EQUIPMENT	6,208.41	
3144		333049000459	7	12/31/1964	GE-ONEIDA GENERATOR EQUIPMENT	21,614.20	
3145		333049000459	8	12/31/1981	GE-ONEIDA GENERATOR EQUIPMENT	29,628.62	
3146		333049000459	9	12/31/1982	GE-ONEIDA GENERATOR EQUIPMENT	294,081.57	
3147		333049000459	11	12/31/1985	GE-ONEIDA GENERATOR EQUIPMENT	218,153.09	
3148		333049000459	12	2/4/2005	GE-ONEIDA GENERATOR EQUIPMENT	55,540.84	
3149		333049000459	13	2/4/2005	GE-ONEIDA GENERATOR EQUIPMENT	379,384.53	
3150		333049000459	15	5/28/2013	GE-ONEIDA GENERATOR EQUIPMENT	23,658.31	
3151		333049000459	16	10/29/2013	GE-ONEIDA GENERATOR EQUIPMENT	11,209.48	
3152		333049000459	17	9/25/2015	GE-ONEIDA GENERATOR EQUIPMENT	109,710.02	
3153		333049000459	18	1/24/2017	GE-ONEIDA GENERATOR EQUIPMENT	2,946,456.86	
3154		333049000459	19	11/18/2015	GE-ONEIDA GENERATOR EQUIPMENT	14,150.36	
3155		333049000459	20	12/30/2018	GE-ONEIDA GENERATOR EQUIPMENT	258,270.24	
3156		333049000459	21	8/20/2019	GE-ONEIDA GENERATOR EQUIPMENT	207,129.27	4,776,191.07
3157		333052000459	0	12/31/1998	GV-ONEIDA GOVERNOR EQUIPMENT	-	
3158		333052000459	1	12/31/1915	GV-ONEIDA GOVERNOR EQUIPMENT	26,559.75	
3159		333052000459	2	12/31/1928	GV-ONEIDA GOVERNOR EQUIPMENT	235.32	
3160		333052000459	4	12/31/1952	GV-ONEIDA GOVERNOR EQUIPMENT	1,719.01	
3161		333052000459	5	12/31/1974	GV-ONEIDA GOVERNOR EQUIPMENT	6,266.38	
3162		333052000459	6	12/31/1981	GV-ONEIDA GOVERNOR EQUIPMENT	28,826.61	
3163		333052000459	7	12/31/1995	GV-ONEIDA GOVERNOR EQUIPMENT	172,195.69	
3164		333052000459	8	12/31/1996	GV-ONEIDA GOVERNOR EQUIPMENT	311,079.98	
3165		333052000459	9	2/3/2004	GV-ONEIDA GOVERNOR EQUIPMENT	40,500.40	
3166		333052000459	10	5/16/2005	GV-ONEIDA GOVERNOR EQUIPMENT	84,222.34	
3167		333052000459	11	8/8/2011	GV-ONEIDA GOVERNOR EQUIPMENT	2,229.97	
3168		333052000459	12	8/27/2012	GV-ONEIDA GOVERNOR EQUIPMENT	21,818.30	
3169		333052000459	13	8/27/2012	GV-ONEIDA GOVERNOR EQUIPMENT	1,377.15	
3170		333052000459	14	12/6/2012	GV-ONEIDA GOVERNOR EQUIPMENT	1,137.34	
3171		333052000459	15	12/20/2013	GV-ONEIDA GOVERNOR EQUIPMENT	7,398.70	
3172		333052000459	16	11/18/2014	GV-ONEIDA GOVERNOR EQUIPMENT	142,756.39	
3173		333088000459	0	12/31/1998	TU-ONEIDA TURBINE & ASSOC EQUIPMENT	-	
3174		333088000459	1	12/31/1915	TU-ONEIDA TURBINE & ASSOC EQUIPMENT	109,509.21	
3175		333088000459	10	2/4/2005	TU-ONEIDA TURBINE & ASSOC EQUIPMENT	844,973.03	
3176		333088000459	11	2/4/2005	TU-ONEIDA TURBINE & ASSOC EQUIPMENT	166,477.89	
3177		333088000459	12	8/2/2013	TU-ONEIDA TURBINE & ASSOC EQUIPMENT	216,692.83	
3178		333088000459	13	3/7/2014	TU-ONEIDA TURBINE & ASSOC EQUIPMENT	74,608.31	
3179		333088000459	14	4/14/2014	TU-ONEIDA TURBINE & ASSOC EQUIPMENT	66,016.52	
3180		333088000459	15	11/6/2018	TU-ONEIDA TURBINE & ASSOC EQUIPMENT	3,138,255.66	
3181		333088000459	16	8/7/2019	TU-ONEIDA TURBINE & ASSOC EQUIPMENT	2,610,279.08	
3182	*	Location	000459		ONEIDA HE PLANT AND SUBSTATION - PR	13,149,124.22	
3183		333049000460	0	12/31/1998	GE-GENERATOR, STATOR WINDING	-	
3184		333049000460	1	12/31/1910	GE-GENERATOR, STATOR WINDING	10,079.11	
3185		333049000460	2	12/31/1984	GE-GENERATOR, STATOR WINDING	56,151.35	
3186		333049000460	3	6/2/2008	GE-GENERATOR, STATOR WINDING	3,813.87	70,044.33
3187		333052000460	0	12/31/1998	GV-HYDRAULIC ACTUATOR SYSTEM	-	
3188		333052000460	1	12/31/1946	GV-HYDRAULIC ACTUATOR SYSTEM	3,209.00	
3189	*	Location	000460		PARIS HYDROELECTRIC STATION	73,253.33	
3190		333040000461	0	12/31/1998	EM-ELECTRIC EQUIP., STATION SUMP PUMPS	-	
3191		333049000461	0	12/31/1998	GE-SODA GENERATOR EQUIPMENT	-	
3192		333049000461	1	12/31/1924	GE-SODA GENERATOR EQUIPMENT	106,163.13	
3193		333049000461	2	12/31/1928	GE-SODA GENERATOR EQUIPMENT	517.29	
3194		333049000461	3	12/31/1956	GE-SODA GENERATOR EQUIPMENT	5,947.16	
3195		333049000461	4	12/31/1987	GE-SODA GENERATOR EQUIPMENT	194,289.81	
3196		333049000461	5	12/31/1947	GE-SODA GENERATOR EQUIPMENT	440.72	
3197		333049000461	6	12/31/1981	GE-SODA GENERATOR EQUIPMENT	132,759.94	
3198		333049000461	7	5/10/2011	GE-SODA GENERATOR EQUIPMENT	1,867,370.56	
3199		333049000461	8	11/29/2012	GE-SODA GENERATOR EQUIPMENT	33,930.97	2,341,419.58
3200		333052000461	0	12/31/1998	GV-HYDRAULIC ACTUATOR SYSTEM	-	
3201		333052000461	1	12/31/1948	GV-HYDRAULIC ACTUATOR SYSTEM	991.28	
3202		333088000461	0	12/31/1998	TU-SODA TURBINE EQUIPMENT	-	
3203		333088000461	1	12/31/1924	TU-SODA TURBINE EQUIPMENT	78,541.24	
3204		333088000461	2	12/31/1956	TU-SODA TURBINE EQUIPMENT	843.75	
3205		333088000461	3	12/31/1981	TU-SODA TURBINE EQUIPMENT	979,544.92	
3206		333088000461	4	5/10/2011	TU-SODA TURBINE EQUIPMENT	466,842.67	

3207		333088000461	5	5/10/2011	TU-SODA TURBINE EQUIPMENT		622,456.87	
3208		333088000461	6	5/10/2011	TU-SODA TURBINE EQUIPMENT		155,614.21	
3209	*	Location	000461		SODA HE PLANT AND SUBSTATION - PROJ		4,646,254.52	
3210		333049000463	0	12/31/1998	GE-GENERATOR, STATOR WINDING		-	
3211		333049000463	1	12/31/1917	GE-GENERATOR, STATOR WINDING		2,733.79	
3212		333049000463	2	12/31/1966	GE-GENERATOR, STATOR WINDING		300.00	
3213		333049000463	3	12/31/1967	GE-GENERATOR, STATOR WINDING		2,002.49	
3214		333049000463	4	12/31/1980	GE-GENERATOR, STATOR WINDING		32,072.89	
3215		333049000463	5	12/31/1987	GE-GENERATOR, STATOR WINDING		82,529.87	
3216		333049000463	6	12/31/1967	GE-GENERATOR, STATOR WINDING		300.00	119,939.04
3217		333088000463	0	12/31/1998	TU-TURBINE, LUBE OIL SYSTEM		-	
3218		333088000463	1	12/31/1917	TU-TURBINE, LUBE OIL SYSTEM		623.87	
3219		333088000463	2	12/26/2008	TU-TURBINE, LUBE OIL SYSTEM		38,185.65	
3220	*	Location	000463		GUNLOCK HE PLANT AND SUBSTATION		158,748.56	
3221		333049000464	0	12/31/1998	GE-GENERATOR, STATOR WINDING		-	
3222		333049000464	1	12/31/1920	GE-GENERATOR, STATOR WINDING		20,781.33	
3223		333049000464	2	12/31/1966	GE-GENERATOR, STATOR WINDING		300.00	
3224		333049000464	3	12/31/1992	GE-GENERATOR, STATOR WINDING		17,834.03	
3225		333049000464	4	12/31/1998	GE-GENERATOR, STATOR WINDING		104,014.68	142,930.04
3226		333052000464	1	12/31/1992	GV-HYDRAULIC ACTUATOR SYSTEM		1,168.05	
3227	*	Location	000464		VEYO HE PLANT, SUBSTATION, OFFICE A		144,098.09	
3228		333049000465	0	12/31/1998	GE-GENERATOR, STATOR WINDING		-	
3229		333049000465	1	12/31/1926	GE-GENERATOR, STATOR WINDING		11,134.73	
3230		333049000465	2	12/31/1990	GE-GENERATOR, STATOR WINDING		27,840.16	
3231		333049000465	3	12/31/1994	GE-GENERATOR, STATOR WINDING		16,220.50	
3232		333049000465	4	12/31/1994	GE-GENERATOR, STATOR WINDING		79,393.88	134,589.27
3233		333052000465	0	12/31/1998	GV-HYDRAULIC ACTUATOR SYSTEM		-	
3234		333052000465	1	12/31/1989	GV-HYDRAULIC ACTUATOR SYSTEM		26,918.85	
3235	*	Location	000465		SAND COVE HE PLANT AND SUBSTATION		161,508.12	
3236		333026000467	0	12/31/1998	CI-CONTROLS AND INSTRUMENTATION		-	
3237		333026000467	1	12/31/1986	CI-CONTROLS AND INSTRUMENTATION		111,035.44	
3238		333049000467	0	12/31/1998	GE-GENERATOR, STATOR WINDING		-	
3239		333049000467	1	12/31/1986	GE-GENERATOR, STATOR WINDING		107,326.14	
3240		333049000467	2	12/31/1986	GE-GENERATOR, STATOR WINDING		60,188.70	167,514.84
3241		333052000467	2	9/23/2005	GV-HYDRAULIC ACTUATOR SYSTEM		37,403.53	
3242		333088000467	0	12/31/1998	TU-TURBINE, LUBE OIL SYSTEM		-	
3243		333088000467	1	12/31/1986	TU-TURBINE, LUBE OIL SYSTEM		181,484.14	
3244	*	Location	000467		VIVA NAUGHTON H. E. PLANT		497,437.95	
3245		333049000468	0	12/31/1998	GE-LAST CHANCE GENERATOR EQUIPMENT		-	
3246		333049000468	1	12/31/1983	GE-LAST CHANCE GENERATOR EQUIPMENT		571,157.15	
3247		333049000468	3	12/31/1989	GE-LAST CHANCE GENERATOR EQUIPMENT		117,276.43	
3248		333049000468	4	7/19/2006	GE-LAST CHANCE GENERATOR EQUIPMENT		65,479.47	
3249		333049000468	5	7/19/2006	GE-LAST CHANCE GENERATOR EQUIPMENT		24,344.62	
3250		333049000468	6	7/25/2017	GE-LAST CHANCE GENERATOR EQUIPMENT		149,601.45	
3251		333049000468	7	7/10/2017	GE-LAST CHANCE GENERATOR EQUIPMENT		98,084.15	1,025,943.27
3252		333088000468	1	6/6/2018	TU-LAST CHANCE TURBINE EQUIPMENT		369,718.41	
3253	*	Location	000468		LAST CHANCE CANAL H. E. PLANT		1,395,661.68	
3254		333049016000	0	12/31/1998	GE-GENERATOR, STATOR WINDING		-	
3255		333049016000	1	12/31/1927	GE-GENERATOR, STATOR WINDING		1,341.22	
3256		333049016000	2	12/31/1926	GE-GENERATOR, STATOR WINDING		43.94	
3257		333049016000	3	12/31/1929	GE-GENERATOR, STATOR WINDING		1,105.93	
3258		333049016000	4	12/31/1924	GE-GENERATOR, STATOR WINDING		48,002.96	50,494.05
3259		333088016000	0	12/31/1998	TU-TURBINE, LUBE OIL SYSTEM		-	
3260		333088016000	1	12/31/1924	TU-TURBINE, LUBE OIL SYSTEM		52,663.47	
3261	*	Location	016000		EAST SIDE HYDRO PLANT		103,157.52	
3262		333049017000	0	12/31/1998	GE-GENERATOR, STATOR WINDING		-	
3263		333049017000	1	12/31/1924	GE-GENERATOR, STATOR WINDING		49.59	
3264		333049017000	2	12/31/1925	GE-GENERATOR, STATOR WINDING		996.15	
3265		333049017000	3	12/31/1908	GE-GENERATOR, STATOR WINDING		4,665.68	
3266		333049017000	4	12/31/1951	GE-GENERATOR, STATOR WINDING		11,327.43	
3267		333049017000	5	12/16/1999	GE-GENERATOR, STATOR WINDING		19,706.52	36,745.37
3268		333052017000	1	2/6/2004	GV-HYDRAULIC ACTUATOR SYSTEM		1,409.25	
3269		333088017000	0	12/31/1998	TU-TURBINE, LUBE OIL SYSTEM		-	
3270		333088017000	1	12/31/1911	TU-TURBINE, LUBE OIL SYSTEM		8,554.10	
3271	*	Location	017000		WEST SIDE HYDRO PLANT		46,708.72	
3272		333049018000	0	12/31/1998	GE - JC BOYLE GENERATOR EQUIPMENT		-	
3273		333049018000	1	12/31/1958	GE - JC BOYLE GENERATOR EQUIPMENT		560,323.48	
3274		333049018000	3	12/31/1961	GE - JC BOYLE GENERATOR EQUIPMENT		255.90	
3275		333049018000	4	12/31/1962	GE - JC BOYLE GENERATOR EQUIPMENT		225.02	
3276		333049018000	5	12/31/1990	GE - JC BOYLE GENERATOR EQUIPMENT		209,921.97	
3277		333049018000	6	12/31/1994	GE - JC BOYLE GENERATOR EQUIPMENT		12,795.87	
3278		333049018000	7	10/7/2003	GE - JC BOYLE GENERATOR EQUIPMENT		259,826.91	
3279		333049018000	8	12/31/1998	GE - JC BOYLE GENERATOR EQUIPMENT		11,732.09	

3280	333049018000	9	11/16/2004	GE - JC BOYLE GENERATOR EQUIPMENT	26,937.32	
3281	333049018000	10	11/16/2004	GE - JC BOYLE GENERATOR EQUIPMENT	23,075.44	
3282	333049018000	11	11/16/2004	GE - JC BOYLE GENERATOR EQUIPMENT	779,819.39	
3283	333049018000	12	11/16/2004	GE - JC BOYLE GENERATOR EQUIPMENT	36,397.19	
3284	333049018000	13	11/3/2005	GE - JC BOYLE GENERATOR EQUIPMENT	1,702,611.77	
3285	333049018000	14	12/9/2004	GE - JC BOYLE GENERATOR EQUIPMENT	18,604.75	
3286	333049018000	15	3/15/2005	GE - JC BOYLE GENERATOR EQUIPMENT	24,017.49	
3287	333049018000	16	11/3/2005	GE - JC BOYLE GENERATOR EQUIPMENT	17,870.04	
3288	333049018000	17	12/15/2008	GE - JC BOYLE GENERATOR EQUIPMENT	20,238.50	
3289	333049018000	18	10/13/2009	GE - JC BOYLE GENERATOR EQUIPMENT	5,750.71	
3290	333049018000	19	11/10/2009	GE - JC BOYLE GENERATOR EQUIPMENT	889.30	
3291	333049018000	20	7/13/2018	GE - JC BOYLE GENERATOR EQUIPMENT	4,375.59	
3292	333049018000	21	8/20/2019	GE - JC BOYLE GENERATOR EQUIPMENT	91,407.43	3,807,076.16
3293	333088018000	0	12/31/1998	TU-JC BOYLE TURBINE EQUIPMENT	-	
3294	333088018000	1	12/31/1958	TU-JC BOYLE TURBINE EQUIPMENT	619,701.62	
3295	333088018000	2	12/31/1987	TU-JC BOYLE TURBINE EQUIPMENT	53,048.10	
3296	333088018000	3	12/31/1988	TU-JC BOYLE TURBINE EQUIPMENT	25,878.01	
3297	333088018000	4	12/31/1989	TU-JC BOYLE TURBINE EQUIPMENT	33,287.71	
3298	333088018000	5	12/31/1990	TU-JC BOYLE TURBINE EQUIPMENT	28,185.67	
3299	333088018000	6	12/31/1994	TU-JC BOYLE TURBINE EQUIPMENT	999,781.96	
3300	333088018000	7	12/31/1994	TU-JC BOYLE TURBINE EQUIPMENT	19,232.64	
3301	333088018000	8	12/31/1994	TU-JC BOYLE TURBINE EQUIPMENT	32,961.58	
3302	333088018000	11	11/3/2005	TU-JC BOYLE TURBINE EQUIPMENT	2,338,747.96	
3303	333088018000	12	1/2/2007	TU-JC BOYLE TURBINE EQUIPMENT	415,185.49	
3304	333088018000	13	1/2/2007	TU-JC BOYLE TURBINE EQUIPMENT	42,710.70	
3305	333088018000	14	3/11/2011	TU-JC BOYLE TURBINE EQUIPMENT	152,394.81	
3306	333088018000	15	3/11/2011	TU-JC BOYLE TURBINE EQUIPMENT	19,049.35	
3307	333088018000	16	3/11/2011	TU-JC BOYLE TURBINE EQUIPMENT	19,049.33	
3308	333088018000	17	12/7/2011	TU-JC BOYLE TURBINE EQUIPMENT	7,232.82	
3309	333088018000	18	12/28/2016	TU-JC BOYLE TURBINE EQUIPMENT	4,759.44	
3310	333088018000	19	8/15/2017	TU-JC BOYLE TURBINE EQUIPMENT	-	
3311	333099018000	0	12/31/1998	99-Non Unitized Assets (CAATS)	-	
3312	* Location	018000		JC BOYLE HYDRO PLANT	8,618,283.35	
3313	333049023000	0	12/31/1998	GE-BEND GENERATOR EQUIPMENT	-	
3314	333049023000	1	12/31/1913	GE-BEND GENERATOR EQUIPMENT	3,085.93	
3315	333049023000	2	12/31/1916	GE-BEND GENERATOR EQUIPMENT	6,168.01	
3316	333049023000	3	12/31/1917	GE-BEND GENERATOR EQUIPMENT	7,184.20	
3317	333049023000	4	12/31/1952	GE-BEND GENERATOR EQUIPMENT	641.85	
3318	333049023000	5	12/31/1981	GE-BEND GENERATOR EQUIPMENT	595.97	
3319	333049023000	6	4/15/2011	GE-BEND GENERATOR EQUIPMENT	20,552.60	38,228.56
3320	333052023000	0	12/31/1998	GV-BEND GOVERNOR EQUIPMENT	-	
3321	333052023000	2	12/31/1952	GV-BEND GOVERNOR EQUIPMENT	2,685.66	
3322	333052023000	3	10/23/2014	GV-BEND GOVERNOR EQUIPMENT	10,521.94	
3323	333088023000	0	12/31/1998	TU-BEND TURBINE EQUIPMENT	-	
3324	333088023000	1	12/31/1913	TU-BEND TURBINE EQUIPMENT	4,142.60	
3325	333088023000	2	12/31/1916	TU-BEND TURBINE EQUIPMENT	7,843.26	
3326	333088023000	3	12/31/1917	TU-BEND TURBINE EQUIPMENT	14,567.64	
3327	333088023000	4	12/31/1986	TU-BEND TURBINE EQUIPMENT	9,059.12	
3328	333088023000	5	12/31/1987	TU-BEND TURBINE EQUIPMENT	16,377.88	
3329	333088023000	6	3/29/2018	TU-BEND TURBINE EQUIPMENT	297,882.33	
3330	* Location	023000		BEND HYDRO PLANT	401,308.99	
3331	333049029000	0	12/31/1998	GE-WALLOWA FALLS GENERATOR EQUIPMENT	-	
3332	333049029000	4	12/31/1967	GE-WALLOWA FALLS GENERATOR EQUIPMENT	41,082.22	
3333	333049029000	5	8/8/2008	GE-WALLOWA FALLS GENERATOR EQUIPMENT	47,596.62	
3334	333049029000	6	12/31/1997	GE-WALLOWA FALLS GENERATOR EQUIPMENT	112,764.18	
3335	333049029000	7	11/6/2015	GE-WALLOWA FALLS GENERATOR EQUIPMENT	72,892.89	274,335.91
3336	333052029000	0	12/31/1998	GV-HYDRAULIC ACTUATOR SYSTEM	-	
3337	333052029000	2	5/16/2001	GV-HYDRAULIC ACTUATOR SYSTEM	2,532.79	
3338	333052029000	3	12/31/1997	GV-HYDRAULIC ACTUATOR SYSTEM	83,179.85	
3339	333088029000	0	12/31/1998	TU-WALLOWA FALLS TURBINE EQUIPMENT	-	
3340	333088029000	1	12/31/1924	TU-WALLOWA FALLS TURBINE EQUIPMENT	3,742.56	
3341	333088029000	2	12/31/1938	TU-WALLOWA FALLS TURBINE EQUIPMENT	1,503.30	
3342	333088029000	3	12/31/1959	TU-WALLOWA FALLS TURBINE EQUIPMENT	175.82	
3343	333088029000	4	7/19/2012	TU-WALLOWA FALLS TURBINE EQUIPMENT	4,488.05	
3344	333088029000	5	12/31/1997	TU-WALLOWA FALLS TURBINE EQUIPMENT	436,701.59	
3345	* Location	029000		WALLOWA FALLS HYDRO PLANT	806,659.87	
3346	333049031000	0	12/31/1998	GE-GENERATOR, STATOR WINDING	-	
3347	333049031000	2	12/31/1966	GE-GENERATOR, STATOR WINDING	94,818.83	
3348	333049031000	3	12/31/1962	GE-GENERATOR, STATOR WINDING	543.05	
3349	333049031000	4	8/21/2007	GE-GENERATOR, STATOR WINDING	385,547.74	480,909.62
3350	333088031000	0	12/31/1998	TU-TURBINE, LUBE OIL SYSTEM	-	
3351	333088031000	1	12/31/1911	TU-TURBINE, LUBE OIL SYSTEM	18,177.00	
3352	333088031000	2	12/31/1954	TU-TURBINE, LUBE OIL SYSTEM	9,783.64	

3353	*	Location	031000		PROSPECT #1 HYDRO PLANT	508,870.26	
3354		333049032000	0	12/31/1998	GE-PROSPECT 2 GENERATOR EQUIPMENT	-	
3355		333049032000	1	12/31/1928	GE-PROSPECT 2 GENERATOR EQUIPMENT	124,085.00	
3356		333049032000	3	12/31/1963	GE-PROSPECT 2 GENERATOR EQUIPMENT	63,073.83	
3357		333049032000	4	12/31/1968	GE-PROSPECT 2 GENERATOR EQUIPMENT	14,419.86	
3358		333049032000	5	12/31/1970	GE-PROSPECT 2 GENERATOR EQUIPMENT	53,942.76	
3359		333049032000	6	12/31/1990	GE-PROSPECT 2 GENERATOR EQUIPMENT	34,032.24	
3360		333049032000	7	12/31/1996	GE-PROSPECT 2 GENERATOR EQUIPMENT	42,444.37	
3361		333049032000	8	12/31/1959	GE-PROSPECT 2 GENERATOR EQUIPMENT	1,704.51	
3362		333049032000	9	12/31/1990	GE-PROSPECT 2 GENERATOR EQUIPMENT	30,621.99	
3363		333049032000	10	12/31/1993	GE-PROSPECT 2 GENERATOR EQUIPMENT	139,660.98	
3364		333049032000	11	12/31/1968	GE-PROSPECT 2 GENERATOR EQUIPMENT	46,829.33	
3365		333049032000	12	12/16/1999	GE-PROSPECT 2 GENERATOR EQUIPMENT	4,612.00	
3366		333049032000	13	12/16/1999	GE-PROSPECT 2 GENERATOR EQUIPMENT	15,747.73	
3367		333049032000	14	8/31/2015	GE-PROSPECT 2 GENERATOR EQUIPMENT	9,437.39	
3368		333049032000	15	8/31/2015	GE-PROSPECT 2 GENERATOR EQUIPMENT	9,435.42	
3369		333049032000	16	12/12/2018	GE-PROSPECT 2 GENERATOR EQUIPMENT	290,172.27	
3370		333049032000	17	12/31/2018	GE-PROSPECT 2 GENERATOR EQUIPMENT	121,116.01	1,001,335.69
3371		333052032000	0	12/31/1998	GV-PROSPECT 2 GOVERNOR EQUIPMENT	-	
3372		333052032000	4	12/31/1996	GV-PROSPECT 2 GOVERNOR EQUIPMENT	52,781.64	
3373		333052032000	5	2/7/2000	GV-PROSPECT 2 GOVERNOR EQUIPMENT	178,287.40	
3374		333052032000	6	11/26/2002	GV-PROSPECT 2 GOVERNOR EQUIPMENT	113,210.48	
3375		333052032000	7	12/22/2003	GV-PROSPECT 2 GOVERNOR EQUIPMENT	11,093.82	
3376		333052032000	8	11/1/2004	GV-PROSPECT 2 GOVERNOR EQUIPMENT	12,343.78	
3377		333052032000	10	12/10/2007	GV-PROSPECT 2 GOVERNOR EQUIPMENT	4,267.21	
3378		333052032000	11	12/17/2007	GV-PROSPECT 2 GOVERNOR EQUIPMENT	2,550.50	
3379		333052032000	12	11/22/2010	GV-PROSPECT 2 GOVERNOR EQUIPMENT	7,752.55	
3380		333052032000	14	8/31/2015	GV-PROSPECT 2 GOVERNOR EQUIPMENT	17,353.25	
3381		333088032000	0	12/31/1998	TU-P2 TURBINE & RELATED EQUIPMENT	-	
3382		333088032000	1	12/31/1928	TU-P2 TURBINE & RELATED EQUIPMENT	159,623.11	
3383		333088032000	2	12/31/1961	TU-P2 TURBINE & RELATED EQUIPMENT	10,541.31	
3384		333088032000	3	12/31/1988	TU-P2 TURBINE & RELATED EQUIPMENT	131,373.50	
3385		333088032000	4	12/16/1999	TU-P2 TURBINE & RELATED EQUIPMENT	15,747.73	
3386		333088032000	5	12/16/1999	TU-P2 TURBINE & RELATED EQUIPMENT	119.12	
3387		333088032000	6	10/9/2003	TU-P2 TURBINE & RELATED EQUIPMENT	14,928.59	
3388		333088032000	7	12/31/1998	TU-P2 TURBINE & RELATED EQUIPMENT	67,072.81	
3389		333088032000	8	12/11/2007	TU-P2 TURBINE & RELATED EQUIPMENT	355,567.79	
3390		333088032000	9	12/11/2007	TU-P2 TURBINE & RELATED EQUIPMENT	54,119.72	
3391		333088032000	10	12/16/1999	TU-P2 TURBINE & RELATED EQUIPMENT	12,880.06	
3392		333088032000	11	12/16/1999	TU-P2 TURBINE & RELATED EQUIPMENT	34,823.88	
3393		333088032000	12	1/9/2007	TU-P2 TURBINE & RELATED EQUIPMENT	59,162.18	
3394		333088032000	13	12/7/2011	TU-P2 TURBINE & RELATED EQUIPMENT	3,365.59	
3395		333088032000	14	10/14/2015	TU-P2 TURBINE & RELATED EQUIPMENT	8,591.46	
3396	*	Location	032000		PROSPECT #2 HYDRO PLANT	2,328,893.17	
3397		333049033000	0	12/31/1998	GE-PROSPECT 3 GENERATOR EQUIPMENT	-	
3398		333049033000	1	12/31/1932	GE-PROSPECT 3 GENERATOR EQUIPMENT	17,439.74	
3399		333049033000	2	12/31/1997	GE-PROSPECT 3 GENERATOR EQUIPMENT	84,382.57	
3400		333049033000	3	12/31/1997	GE-PROSPECT 3 GENERATOR EQUIPMENT	7,953.81	
3401		333049033000	4	12/31/1997	GE-PROSPECT 3 GENERATOR EQUIPMENT	86,598.15	
3402		333049033000	5	12/31/1932	GE-PROSPECT 3 GENERATOR EQUIPMENT	34,259.54	
3403		333049033000	6	12/31/1998	GE-PROSPECT 3 GENERATOR EQUIPMENT	45,450.64	
3404		333049033000	8	12/28/2010	GE-PROSPECT 3 GENERATOR EQUIPMENT	4,086.66	
3405		333049033000	9	9/19/2014	GE-PROSPECT 3 GENERATOR EQUIPMENT	3,320.40	
3406		333049033000	10	11/28/2017	GE-PROSPECT 3 GENERATOR EQUIPMENT	105,344.44	
3407		333049033000	11	11/14/2018	GE-PROSPECT 3 GENERATOR EQUIPMENT	86,206.80	475,042.75
3408		333052033000	0	12/31/1998	GV-HYDRAULIC ACTUATOR SYSTEM	-	
3409		333052033000	1	12/31/1997	GV-HYDRAULIC ACTUATOR SYSTEM	403,799.53	
3410		333088033000	0	12/31/1998	TU-P3 TURBINE & RELATED EQUIPMENT	-	
3411		333088033000	1	12/31/1932	TU-P3 TURBINE & RELATED EQUIPMENT	54,716.31	
3412		333088033000	2	12/31/1964	TU-P3 TURBINE & RELATED EQUIPMENT	486.77	
3413		333088033000	3	12/31/1997	TU-P3 TURBINE & RELATED EQUIPMENT	48,408.42	
3414		333088033000	4	12/16/1999	TU-P3 TURBINE & RELATED EQUIPMENT	1,707.28	
3415		333088033000	5	12/31/1997	TU-P3 TURBINE & RELATED EQUIPMENT	935,109.17	
3416		333088033000	6	4/13/2009	TU-P3 TURBINE & RELATED EQUIPMENT	1,031.34	
3417		333088033000	7	12/7/2011	TU-P3 TURBINE & RELATED EQUIPMENT	7,610.04	
3418		333090033000	0	12/31/1998	WC-WATER CONVEYANCE SYSTEM	-	
3419		333099033000	0	12/31/1998	99-Non Unitized Assets (CAATS)	-	
3420	*	Location	033000		PROSPECT #3 HYDRO PLANT	1,927,911.61	
3421		333049034000	0	12/31/1998	GE-GENERATOR, STATOR WINDING	-	
3422		333049034000	1	12/31/1944	GE-GENERATOR, STATOR WINDING	19,286.07	
3423		333049034000	2	12/31/1965	GE-GENERATOR, STATOR WINDING	2,548.23	
3424		333049034000	3	12/18/2007	GE-GENERATOR, STATOR WINDING	142,064.86	163,899.16
3425		333088034000	0	12/31/1998	TU - PROSPECT 4 TURBINE EQUIPMENT	-	

3426		333088034000	1	12/31/1944	TU - PROSPECT 4 TURBINE EQUIPMENT	7,044.06	
3427		333088034000	2	1/29/2010	TU - PROSPECT 4 TURBINE EQUIPMENT	336,748.13	
3428		333088034000	3	1/29/2010	TU - PROSPECT 4 TURBINE EQUIPMENT	639,929.49	
3429		333088034000	4	1/29/2010	TU - PROSPECT 4 TURBINE EQUIPMENT	62,801.46	
3430		333088034000	5	1/29/2010	TU - PROSPECT 4 TURBINE EQUIPMENT	170,976.15	
3431	*	Location	034000		PROSPECT #4 HYDRO PLANT	1,381,398.45	
3432		333049036000	0	12/31/1998	GE-GENERATOR, STATOR WINDING	-	
3433		333049036000	1	12/31/1957	GE-GENERATOR, STATOR WINDING	66,023.73	
3434		333049036000	2	12/31/1958	GE-GENERATOR, STATOR WINDING	334.00	
3435		333049036000	3	12/31/1960	GE-GENERATOR, STATOR WINDING	1,058.00	
3436		333049036000	4	12/31/1961	GE-GENERATOR, STATOR WINDING	311.62	
3437		333049036000	5	12/31/1968	GE-GENERATOR, STATOR WINDING	1,218.40	68,945.75
3438		333088036000	0	12/31/1998	TU-TURBINE, LUBE OIL SYSTEM	-	
3439		333088036000	1	12/31/1957	TU-TURBINE, LUBE OIL SYSTEM	75,178.87	
3440		333088036000	2	12/31/1963	TU-TURBINE, LUBE OIL SYSTEM	2,291.49	
3441		333088036000	3	12/31/1975	TU-TURBINE, LUBE OIL SYSTEM	1,385.32	
3442		333088036000	4	12/31/1991	TU-TURBINE, LUBE OIL SYSTEM	62,711.03	
3443		333088036000	5	12/16/1999	TU-TURBINE, LUBE OIL SYSTEM	41,028.96	
3444	*	Location	036000		EAGLE POINT HYDRO PLANT	251,541.42	
3445		333049040000	0	12/31/1998	GE-LM1 GENERATOR & ASSOCIATED EQUIPMENT	-	
3446		333049040000	3	12/31/1973	GE-LM1 GENERATOR & ASSOCIATED EQUIPMENT	58,547.27	
3447		333049040000	4	12/31/1979	GE-LM1 GENERATOR & ASSOCIATED EQUIPMENT	100,205.56	
3448		333049040000	5	12/31/1993	GE-LM1 GENERATOR & ASSOCIATED EQUIPMENT	35,949.56	
3449		333049040000	6	10/26/2001	GE-LM1 GENERATOR & ASSOCIATED EQUIPMENT	1,470,997.62	
3450		333049040000	7	12/16/1999	GE-LM1 GENERATOR & ASSOCIATED EQUIPMENT	8,145.95	
3451		333049040000	8	12/13/2002	GE-LM1 GENERATOR & ASSOCIATED EQUIPMENT	21,338.11	
3452		333049040000	9	12/22/2003	GE-LM1 GENERATOR & ASSOCIATED EQUIPMENT	25,909.72	
3453		333049040000	10	3/31/2005	GE-LM1 GENERATOR & ASSOCIATED EQUIPMENT	52,830.90	
3454		333049040000	12	1/18/2007	GE-LM1 GENERATOR & ASSOCIATED EQUIPMENT	27,005.24	
3455		333049040000	13	11/15/2013	GE-LM1 GENERATOR & ASSOCIATED EQUIPMENT	248,318.61	
3456		333049040000	14	12/4/2013	GE-LM1 GENERATOR & ASSOCIATED EQUIPMENT	3,597.89	2,052,846.43
3457		333088040000	0	12/31/1998	TU-TURBINE, LUBE OIL SYSTEM	-	
3458		333088040000	1	12/31/1955	TU-TURBINE, LUBE OIL SYSTEM	507,143.80	
3459		333088040000	3	9/20/2002	TU-TURBINE, LUBE OIL SYSTEM	1,424,272.43	
3460		333088040000	4	10/9/2003	TU-TURBINE, LUBE OIL SYSTEM	15,911.72	
3461		333088040000	5	11/12/2003	TU-TURBINE, LUBE OIL SYSTEM	26,016.25	
3462		333088040000	6	5/27/2009	TU-TURBINE, LUBE OIL SYSTEM	4,382.28	
3463	*	Location	040000		LEMOLO #1 HYDRO PLANT	4,030,572.91	
3464		333038041000	1	11/16/2009	DT - LEMOLO 2 DRAFT TUBE EQUIPMENT	89,038.48	
3465		333049041000	0	12/31/1998	GE-GENERATOR, STATOR WINDING	-	
3466		333049041000	1	12/31/1956	GE-GENERATOR, STATOR WINDING	369,108.56	
3467		333049041000	2	12/31/1964	GE-GENERATOR, STATOR WINDING	1,229.06	
3468		333049041000	3	12/31/1966	GE-GENERATOR, STATOR WINDING	3,161.85	
3469		333049041000	5	12/31/1956	GE-GENERATOR, STATOR WINDING	7,178.50	
3470		333049041000	6	12/31/1969	GE-GENERATOR, STATOR WINDING	17,180.73	
3471		333049041000	7	12/31/1994	GE-GENERATOR, STATOR WINDING	33,070.16	
3472		333049041000	9	11/16/2009	GE-GENERATOR, STATOR WINDING	413,570.13	
3473		333049041000	10	11/16/2009	GE-GENERATOR, STATOR WINDING	1,423,202.04	2,267,701.03
3474		333052041000	1	11/16/2009	GV-GOVERNOR CONTROL SYSTEM	459,995.80	
3475		333052041000	2	12/27/2012	GV-GOVERNOR CONTROL SYSTEM	2,902.96	
3476		333088041000	0	12/31/1998	TU-LEMOLO 2 TURBINE EQUIPMENT	-	
3477		333088041000	1	12/31/1956	TU-LEMOLO 2 TURBINE EQUIPMENT	129,483.97	
3478		333088041000	4	11/16/2009	TU-LEMOLO 2 TURBINE EQUIPMENT	4,691,118.72	
3479		333088041000	5	6/12/2013	TU-LEMOLO 2 TURBINE EQUIPMENT	4,447.61	
3480		333088041000	6	12/30/2014	TU-LEMOLO 2 TURBINE EQUIPMENT	2,855.64	
3481	*	Location	041000		LEMOLO #2 HYDRO PLANT	7,647,544.21	
3482		333049042000	0	12/31/1998	GE-CLEARWATER 1 GENERATOR EQUIPMENT	-	
3483		333049042000	1	12/31/1953	GE-CLEARWATER 1 GENERATOR EQUIPMENT	337,827.14	
3484		333049042000	2	12/31/1954	GE-CLEARWATER 1 GENERATOR EQUIPMENT	6,295.38	
3485		333049042000	3	12/31/1958	GE-CLEARWATER 1 GENERATOR EQUIPMENT	1,158.32	
3486		333049042000	4	12/31/1960	GE-CLEARWATER 1 GENERATOR EQUIPMENT	14,560.00	
3487		333049042000	5	12/31/1961	GE-CLEARWATER 1 GENERATOR EQUIPMENT	497.57	
3488		333049042000	6	12/31/1966	GE-CLEARWATER 1 GENERATOR EQUIPMENT	1,657.94	
3489		333049042000	7	4/12/2002	GE-CLEARWATER 1 GENERATOR EQUIPMENT	34,003.83	
3490		333049042000	8	5/6/2013	GE-CLEARWATER 1 GENERATOR EQUIPMENT	131,286.03	527,286.21
3491		333088042000	0	12/31/1998	TU-TURBINE, LUBE OIL SYSTEM	-	
3492		333088042000	1	12/31/1953	TU-TURBINE, LUBE OIL SYSTEM	305,931.20	
3493		333088042000	2	12/31/1995	TU-TURBINE, LUBE OIL SYSTEM	25,768.12	
3494		333088042000	3	10/26/2001	TU-TURBINE, LUBE OIL SYSTEM	6,980.04	
3495		333088042000	4	12/16/1999	TU-TURBINE, LUBE OIL SYSTEM	3,865.76	
3496		333088042000	5	4/30/2008	TU-TURBINE, LUBE OIL SYSTEM	18,021.30	
3497	*	Location	042000		CLEARWATER #1 HYDRO PLANT	887,852.63	
3498		333049043000	0	12/31/1998	GE-CLEARWATER 2 GENERATOR EQUIPMENT	-	

3499		333049043000	1	12/31/1953	GE-CLEARWATER 2 GENERATOR EQUIPMENT	469,291.69	
3500		333049043000	2	12/31/1955	GE-CLEARWATER 2 GENERATOR EQUIPMENT	5,265.11	
3501		333049043000	3	12/31/1961	GE-CLEARWATER 2 GENERATOR EQUIPMENT	208.27	
3502		333049043000	4	12/31/1973	GE-CLEARWATER 2 GENERATOR EQUIPMENT	3,522.97	
3503		333049043000	5	12/31/1974	GE-CLEARWATER 2 GENERATOR EQUIPMENT	243.55	
3504		333049043000	6	12/31/1971	GE-CLEARWATER 2 GENERATOR EQUIPMENT	4,331.92	
3505		333049043000	7	5/13/2013	GE-CLEARWATER 2 GENERATOR EQUIPMENT	177,652.89	660,516.40
3506		333088043000	0	12/31/1998	TU-CLEARWATER 2 TURBINE EQUIPMENT	-	
3507		333088043000	1	12/31/1953	TU-CLEARWATER 2 TURBINE EQUIPMENT	385,896.00	
3508		333088043000	2	12/31/1994	TU-CLEARWATER 2 TURBINE EQUIPMENT	20,007.92	
3509		333088043000	3	10/26/2001	TU-CLEARWATER 2 TURBINE EQUIPMENT	6,980.05	
3510		333088043000	4	1/18/2007	TU-CLEARWATER 2 TURBINE EQUIPMENT	44,871.08	
3511		333088043000	5	5/4/2007	TU-CLEARWATER 2 TURBINE EQUIPMENT	65,012.08	
3512		333088043000	6	1/10/2008	TU-CLEARWATER 2 TURBINE EQUIPMENT	16,785.08	
3513		333088043000	7	1/10/2008	TU-CLEARWATER 2 TURBINE EQUIPMENT	6,825.88	
3514		333088043000	8	6/26/2013	TU-CLEARWATER 2 TURBINE EQUIPMENT	1,266.93	
3515	*	Location	043000		CLEARWATER #2 HYDRO PLANT	1,208,161.42	
3516		333049044000	0	12/31/1998	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	-	
3517		333049044000	1	12/31/1950	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	524,298.24	
3518		333049044000	2	12/31/1958	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	795.00	
3519		333049044000	3	12/31/1964	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	1,050.50	
3520		333049044000	4	12/31/1978	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	13,574.13	
3521		333049044000	5	12/31/1995	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	9,183.96	
3522		333049044000	6	12/31/1995	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	116,457.50	
3523		333049044000	7	12/31/1992	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	115,857.44	
3524		333049044000	8	12/31/1992	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	75,201.46	
3525		333049044000	9	12/31/1994	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	18,046.75	
3526		333049044000	10	12/16/1999	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	77,306.98	
3527		333049044000	11	3/31/2005	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	5,204.49	
3528		333049044000	12	10/10/2013	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	14,851.19	
3529		333049044000	13	10/14/2013	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	397,983.30	
3530		333049044000	14	10/27/2015	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	473,889.70	
3531		333049044000	15	12/28/2015	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	452,981.32	
3532		333049044000	16	12/18/2015	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	3,880.70	
3533		333049044000	17	10/6/2016	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	4,086.72	
3534		333049044000	18	4/4/2019	GE-TOKETEE GENERATOR & ASSOCIATED EQUIPMENT	337,268.17	2,641,917.55
3535		333052044000	0	12/31/1998	GV-HYDRAULIC ACTUATOR SYSTEM	-	
3536		333052044000	1	12/31/1996	GV-HYDRAULIC ACTUATOR SYSTEM	2,745.86	
3537		333052044000	2	1/7/2003	GV-HYDRAULIC ACTUATOR SYSTEM	189,550.04	
3538		333088044000	0	12/31/1998	TU-TOKETEE TURBINE EQUIPMENT	-	
3539		333088044000	1	12/31/1950	TU-TOKETEE TURBINE EQUIPMENT	639,171.26	
3540		333088044000	2	12/31/1961	TU-TOKETEE TURBINE EQUIPMENT	621.09	
3541		333088044000	3	12/31/1990	TU-TOKETEE TURBINE EQUIPMENT	219,889.10	
3542		333088044000	4	12/31/1950	TU-TOKETEE TURBINE EQUIPMENT	4,917.00	
3543		333088044000	5	12/31/1995	TU-TOKETEE TURBINE EQUIPMENT	9,637.60	
3544		333088044000	6	12/31/1993	TU-TOKETEE TURBINE EQUIPMENT	26,446.01	
3545		333088044000	7	12/31/1992	TU-TOKETEE TURBINE EQUIPMENT	44,380.99	
3546		333088044000	8	12/31/1993	TU-TOKETEE TURBINE EQUIPMENT	84,329.48	
3547		333088044000	9	11/18/2002	TU-TOKETEE TURBINE EQUIPMENT	22,579.96	
3548		333088044000	10	4/12/2002	TU-TOKETEE TURBINE EQUIPMENT	28,537.13	
3549		333088044000	11	7/3/2007	TU-TOKETEE TURBINE EQUIPMENT	75,180.99	
3550		333088044000	12	12/12/2008	TU-TOKETEE TURBINE EQUIPMENT	10,381.94	
3551		333088044000	13	4/2/2014	TU-TOKETEE TURBINE EQUIPMENT	2,027.61	
3552	*	Location	044000		TOKETEE HYDRO PLANT	4,002,313.61	
3553		333049045000	0	12/31/1998	GE-FISH CREEK GENERATOR EQUIPMENT	-	
3554		333049045000	1	12/31/1952	GE-FISH CREEK GENERATOR EQUIPMENT	166,714.70	
3555		333049045000	2	12/31/1961	GE-FISH CREEK GENERATOR EQUIPMENT	126.44	
3556		333049045000	3	12/31/1964	GE-FISH CREEK GENERATOR EQUIPMENT	339.46	
3557		333049045000	4	12/31/1975	GE-FISH CREEK GENERATOR EQUIPMENT	3,506.26	
3558		333049045000	5	12/31/1976	GE-FISH CREEK GENERATOR EQUIPMENT	721.16	
3559		333049045000	6	12/31/1987	GE-FISH CREEK GENERATOR EQUIPMENT	17,702.98	
3560		333049045000	7	12/31/1987	GE-FISH CREEK GENERATOR EQUIPMENT	8,456.11	
3561		333049045000	8	12/15/2014	GE-FISH CREEK GENERATOR EQUIPMENT	92,285.90	
3562		333049045000	9	3/30/2016	GE-FISH CREEK GENERATOR EQUIPMENT	3,338.78	293,191.79
3563		333052045000	0	9/26/2001	GV-HYDRAULIC ACTUATOR SYSTEM	5,538.12	
3564		333052045000	1	12/1/2004	GV-HYDRAULIC ACTUATOR SYSTEM	581,665.13	
3565		333088045000	0	12/31/1998	TU-TURBINE, LUBE OIL SYSTEM	-	
3566		333088045000	1	12/31/1952	TU-TURBINE, LUBE OIL SYSTEM	166,957.22	
3567		333088045000	2	12/31/1961	TU-TURBINE, LUBE OIL SYSTEM	20,794.80	
3568		333088045000	3	12/31/1987	TU-TURBINE, LUBE OIL SYSTEM	66,107.01	
3569		333088045000	4	12/31/1952	TU-TURBINE, LUBE OIL SYSTEM	3,557.50	
3570		333088045000	5	12/31/1952	TU-TURBINE, LUBE OIL SYSTEM	4,075.30	
3571	*	Location	045000		FISH CREEK HYDRO PLANT	1,141,886.87	

3572		333049046000	0	12/31/1998	GE-GENERATOR, STATOR WINDING	-	
3573		333049046000	1	12/31/1952	GE-GENERATOR, STATOR WINDING	232,585.76	
3574		333049046000	2	12/31/1955	GE-GENERATOR, STATOR WINDING	16,784.86	
3575		333049046000	3	12/31/1960	GE-GENERATOR, STATOR WINDING	357.00	
3576		333049046000	4	12/31/1964	GE-GENERATOR, STATOR WINDING	339.44	
3577		333049046000	5	4/12/2002	GE-GENERATOR, STATOR WINDING	16,509.45	
3578		333049046000	6	7/12/2004	GE-GENERATOR, STATOR WINDING	156,333.73	422,910.24
3579		333052046000	1	7/12/2004	GV-HYDRAULIC ACTUATOR SYSTEM	589,096.08	
3580		333052046000	2	7/30/2004	GV-HYDRAULIC ACTUATOR SYSTEM	3,084.38	
3581		333052046000	3	8/16/2004	GV-HYDRAULIC ACTUATOR SYSTEM	3,270.02	
3582		333052046000	4	3/31/2005	GV-HYDRAULIC ACTUATOR SYSTEM	5,251.51	
3583		333088046000	0	12/31/1998	TU-SODA SPRINGS TURBINE EQUIPMENT	-	
3584		333088046000	1	12/31/1952	TU-SODA SPRINGS TURBINE EQUIPMENT	277,014.20	
3585		333088046000	2	12/31/1952	TU-SODA SPRINGS TURBINE EQUIPMENT	3,518.00	
3586		333088046000	3	12/31/1952	TU-SODA SPRINGS TURBINE EQUIPMENT	1,016.32	
3587		333088046000	4	4/12/2002	TU-SODA SPRINGS TURBINE EQUIPMENT	13,876.08	
3588		333088046000	5	2/25/2015	TU-SODA SPRINGS TURBINE EQUIPMENT	4,429.00	
3589	* Location		046000		SODA SPRINGS HYDRO PLANT	1,323,465.83	
3590		333038047000	1	12/19/2011	DT-SLIDE CREEK DRAFT TUBE EQUIPMENT	342,690.66	
3591		333049047000	0	12/31/1998	GE-SLIDE CK GENERATOR EQUIPMENT	-	
3592		333049047000	1	12/31/1951	GE-SLIDE CK GENERATOR EQUIPMENT	173,921.92	
3593		333049047000	2	12/31/1953	GE-SLIDE CK GENERATOR EQUIPMENT	1,597.00	
3594		333049047000	3	12/31/1955	GE-SLIDE CK GENERATOR EQUIPMENT	17,104.69	
3595		333049047000	4	12/31/1958	GE-SLIDE CK GENERATOR EQUIPMENT	480.00	
3596		333049047000	7	12/31/1975	GE-SLIDE CK GENERATOR EQUIPMENT	2,859.73	
3597		333049047000	8	12/31/1956	GE-SLIDE CK GENERATOR EQUIPMENT	5,554.55	
3598		333049047000	10	7/13/2007	GE-SLIDE CK GENERATOR EQUIPMENT	74,912.12	
3599		333049047000	11	8/31/2009	GE-SLIDE CK GENERATOR EQUIPMENT	896.89	
3600		333049047000	12	12/19/2011	GE-SLIDE CK GENERATOR EQUIPMENT	272,633.22	
3601		333049047000	13	3/24/2016	GE-SLIDE CK GENERATOR EQUIPMENT	2,066.43	552,026.55
3602		333052047000	1	12/19/2011	GV-SLIDE CREEK GOVERNOR EQUIPMENT	263,348.49	
3603		333088047000	0	12/31/1998	TU-SLIDE CREEK TURBINE EQUIPMENT	-	
3604		333088047000	1	12/31/1951	TU-SLIDE CREEK TURBINE EQUIPMENT	25,676.00	
3605		333088047000	5	12/19/2011	TU-SLIDE CREEK TURBINE EQUIPMENT	4,535,164.92	
3606	* Location		047000		SLIDE CREEK HYDRO PLANT	5,718,906.62	
3607		333099048000	0	12/31/1998	99-Non Unitized Assets (CAATS)	-	
3608	* Location		048000		NORTH UMPQUA HYDRO-GENL	-	
3609		333038215000	1	5/10/2006	DT - TURBINE DRAFT TUBES	8,779.30	
3610		333049215000	0	12/31/1998	GE-MERWIN GENERATOR EQUIPMENT	-	
3611		333049215000	2	12/31/1949	GE-MERWIN GENERATOR EQUIPMENT	857,141.18	
3612		333049215000	3	12/31/1958	GE-MERWIN GENERATOR EQUIPMENT	1,111,927.75	
3613		333049215000	4	12/31/1967	GE-MERWIN GENERATOR EQUIPMENT	496.54	
3614		333049215000	5	12/31/1971	GE-MERWIN GENERATOR EQUIPMENT	2,922.58	
3615		333049215000	7	12/31/1978	GE-MERWIN GENERATOR EQUIPMENT	111,709.09	
3616		333049215000	8	12/31/1954	GE-MERWIN GENERATOR EQUIPMENT	2,052.99	
3617		333049215000	10	12/31/1933	GE-MERWIN GENERATOR EQUIPMENT	244,329.09	
3618		333049215000	11	12/31/1992	GE-MERWIN GENERATOR EQUIPMENT	1,427.08	
3619		333049215000	12	12/31/1933	GE-MERWIN GENERATOR EQUIPMENT	1,075.92	
3620		333049215000	13	12/31/1994	GE-MERWIN GENERATOR EQUIPMENT	30,947.45	
3621		333049215000	14	12/31/1997	GE-MERWIN GENERATOR EQUIPMENT	12,298.97	
3622		333049215000	15	12/31/1933	GE-MERWIN GENERATOR EQUIPMENT	5,774.28	
3623		333049215000	17	12/31/1989	GE-MERWIN GENERATOR EQUIPMENT	4,062.12	
3624		333049215000	18	12/31/1951	GE-MERWIN GENERATOR EQUIPMENT	6,212.30	
3625		333049215000	19	12/31/1971	GE-MERWIN GENERATOR EQUIPMENT	625,561.21	
3626		333049215000	20	6/6/2001	GE-MERWIN GENERATOR EQUIPMENT	5,650.07	
3627		333049215000	21	2/4/2002	GE-MERWIN GENERATOR EQUIPMENT	333,272.08	
3628		333049215000	22	2/4/2002	GE-MERWIN GENERATOR EQUIPMENT	102,160.42	
3629		333049215000	23	12/31/1997	GE-MERWIN GENERATOR EQUIPMENT	432,669.18	
3630		333049215000	24	12/31/1998	GE-MERWIN GENERATOR EQUIPMENT	63,228.89	
3631		333049215000	25	7/21/2008	GE-MERWIN GENERATOR EQUIPMENT	11,842.47	
3632		333049215000	26	11/5/2009	GE-MERWIN GENERATOR EQUIPMENT	8,298.07	
3633		333049215000	27	2/15/2010	GE-MERWIN GENERATOR EQUIPMENT	4,006.58	
3634		333049215000	28	9/3/2010	GE-MERWIN GENERATOR EQUIPMENT	8,282.63	
3635		333049215000	29	10/12/2010	GE-MERWIN GENERATOR EQUIPMENT	31,457.14	
3636		333049215000	30	12/24/2012	GE-MERWIN GENERATOR EQUIPMENT	86,073.21	
3637		333049215000	31	12/5/2014	GE-MERWIN GENERATOR EQUIPMENT	6,123.51	
3638		333049215000	32	8/17/2016	GE-MERWIN GENERATOR EQUIPMENT	100,530.23	
3639		333049215000	33	5/1/2015	GE-MERWIN GENERATOR EQUIPMENT	6,324.36	
3640		333049215000	34	11/14/2018	GE-MERWIN GENERATOR EQUIPMENT	110,514.00	4,328,371.39
3641		333052215000	0	12/31/1998	GV-MERWIN GOVERNOR EQUIPMENT	-	
3642		333052215000	3	12/31/1996	GV-MERWIN GOVERNOR EQUIPMENT	42,013.47	
3643		333052215000	4	12/31/1996	GV-MERWIN GOVERNOR EQUIPMENT	204,320.46	
3644		333052215000	5	5/16/2001	GV-MERWIN GOVERNOR EQUIPMENT	9,681.24	

3645		333052215000	6	12/31/1998	GV-MERWIN GOVERNOR EQUIPMENT	109,004.96	
3646		333052215000	7	12/31/1997	GV-MERWIN GOVERNOR EQUIPMENT	42,849.37	
3647		333052215000	8	9/17/2002	GV-MERWIN GOVERNOR EQUIPMENT	338,757.55	
3648		333052215000	9	10/9/2003	GV-MERWIN GOVERNOR EQUIPMENT	277,641.31	
3649		333052215000	10	3/12/2003	GV-MERWIN GOVERNOR EQUIPMENT	16,196.75	
3650		333052215000	11	10/7/2004	GV-MERWIN GOVERNOR EQUIPMENT	150,064.51	
3651		333052215000	12	1/8/2007	GV-MERWIN GOVERNOR EQUIPMENT	4,704.40	
3652		333052215000	13	9/13/2007	GV-MERWIN GOVERNOR EQUIPMENT	10,091.38	
3653		333052215000	14	9/11/2008	GV-MERWIN GOVERNOR EQUIPMENT	14,431.25	
3654		333052215000	15	9/15/2008	GV-MERWIN GOVERNOR EQUIPMENT	15,436.53	
3655		333052215000	16	9/13/2007	GV-MERWIN GOVERNOR EQUIPMENT	22,131.34	
3656		333052215000	17	2/24/2010	GV-MERWIN GOVERNOR EQUIPMENT	14,368.29	
3657		333052215000	18	5/23/2018	GV-MERWIN GOVERNOR EQUIPMENT	90,907.44	
3658		333088215000	0	12/31/1998	TU-MERWIN TURBINE EQUIPMENT	-	
3659		333088215000	1	12/31/1933	TU-MERWIN TURBINE EQUIPMENT	181,100.31	
3660		333088215000	2	12/31/1949	TU-MERWIN TURBINE EQUIPMENT	588,900.36	
3661		333088215000	3	12/31/1958	TU-MERWIN TURBINE EQUIPMENT	818,723.29	
3662		333088215000	4	12/31/1971	TU-MERWIN TURBINE EQUIPMENT	10,077.22	
3663		333088215000	5	12/31/1993	TU-MERWIN TURBINE EQUIPMENT	34,681.50	
3664		333088215000	6	12/31/1971	TU-MERWIN TURBINE EQUIPMENT	239,325.76	
3665		333088215000	7	12/31/1991	TU-MERWIN TURBINE EQUIPMENT	2,890.48	
3666		333088215000	8	2/4/2000	TU-MERWIN TURBINE EQUIPMENT	1,536.94	
3667		333088215000	9	5/16/2005	TU-MERWIN TURBINE EQUIPMENT	34,886.41	
3668		333088215000	10	5/16/2005	TU-MERWIN TURBINE EQUIPMENT	38,727.40	
3669		333088215000	11	5/16/2005	TU-MERWIN TURBINE EQUIPMENT	34,697.33	
3670		333088215000	12	5/25/2011	TU-MERWIN TURBINE EQUIPMENT	19,525.13	
3671		333088215000	13	5/31/2012	TU-MERWIN TURBINE EQUIPMENT	4,815.45	
3672		333088215000	14	10/6/2016	TU-MERWIN TURBINE EQUIPMENT	160,953.92	
3673		333088215000	15	12/20/2016	TU-MERWIN TURBINE EQUIPMENT	2,582.10	
3674		333088215000	16	12/20/2016	TU-MERWIN TURBINE EQUIPMENT	2,582.10	
3675		333099215000	0	12/31/1998	99-Non Unitized Assets (CAATS)	-	
3676	*	Location	215000		MERWIN HYDRO PLANT	7,875,756.64	
3677		333049215300	1	12/31/1995	GE-LEWIS RIVER GENERAL GENERATOR EQUIPMENT	170,384.33	
3678		333049215300	2	12/31/1997	GE-LEWIS RIVER GENERAL GENERATOR EQUIPMENT	252,396.44	422,780.77
3679		333052215300	1	10/28/2005	GV-HYDRAULIC ACTUATOR SYSTEM	11,854.87	
3680		333082215300	2	10/22/2008	SP - CAPITAL SPARES FERC 333	29,152.62	
3681	*	Location	215300		LEWIS RIVER GENERAL	463,788.26	
3682		333026218000	0	12/31/1998	CI-CONTROLS AND INSTRUMENTATION	-	
3683		333026218000	1	12/31/1989	CI-CONTROLS AND INSTRUMENTATION	3,698.77	
3684		333038218000	1	9/23/2014	DT-SWIFT 1 TURBINE DRAFT TUBE EQUIPMENT	19,749.76	
3685		333049218000	0	12/31/1998	GE-SWIFT 1 GENERATOR EQUIPMENT	-	
3686		333049218000	1	12/31/1958	GE-SWIFT 1 GENERATOR EQUIPMENT	3,292,495.87	
3687		333049218000	2	12/31/1964	GE-SWIFT 1 GENERATOR EQUIPMENT	9,837.19	
3688		333049218000	3	12/31/1968	GE-SWIFT 1 GENERATOR EQUIPMENT	4,060.04	
3689		333049218000	4	12/31/1970	GE-SWIFT 1 GENERATOR EQUIPMENT	5,630.81	
3690		333049218000	5	12/31/1981	GE-SWIFT 1 GENERATOR EQUIPMENT	12,762.16	
3691		333049218000	6	12/31/1997	GE-SWIFT 1 GENERATOR EQUIPMENT	86,352.94	
3692		333049218000	7	12/31/1997	GE-SWIFT 1 GENERATOR EQUIPMENT	10,826.22	
3693		333049218000	8	12/31/1997	GE-SWIFT 1 GENERATOR EQUIPMENT	34,644.24	
3694		333049218000	9	12/31/1991	GE-SWIFT 1 GENERATOR EQUIPMENT	35,139.60	
3695		333049218000	10	12/31/1992	GE-SWIFT 1 GENERATOR EQUIPMENT	1,427.08	
3696		333049218000	11	12/31/1994	GE-SWIFT 1 GENERATOR EQUIPMENT	17,054.00	
3697		333049218000	12	12/31/1988	GE-SWIFT 1 GENERATOR EQUIPMENT	832,170.26	
3698		333049218000	14	12/31/1991	GE-SWIFT 1 GENERATOR EQUIPMENT	857,141.87	
3699		333049218000	15	4/10/2001	GE-SWIFT 1 GENERATOR EQUIPMENT	404,141.46	
3700		333049218000	16	6/6/2001	GE-SWIFT 1 GENERATOR EQUIPMENT	28,681.04	
3701		333049218000	17	2/8/2000	GE-SWIFT 1 GENERATOR EQUIPMENT	4,617.20	
3702		333049218000	18	9/17/2002	GE-SWIFT 1 GENERATOR EQUIPMENT	346,781.43	
3703		333049218000	19	4/14/2004	GE-SWIFT 1 GENERATOR EQUIPMENT	378,843.34	
3704		333049218000	20	12/31/1998	GE-SWIFT 1 GENERATOR EQUIPMENT	1,620.56	
3705		333049218000	21	6/6/2008	GE-SWIFT 1 GENERATOR EQUIPMENT	103,535.56	
3706		333049218000	22	12/31/1958	GE-SWIFT 1 GENERATOR EQUIPMENT	92,254.83	
3707		333049218000	23	5/27/2009	GE-SWIFT 1 GENERATOR EQUIPMENT	36,157.67	
3708		333049218000	24	9/29/2009	GE-SWIFT 1 GENERATOR EQUIPMENT	2,631.62	
3709		333049218000	25	11/5/2009	GE-SWIFT 1 GENERATOR EQUIPMENT	121,809.41	
3710		333049218000	26	4/6/2010	GE-SWIFT 1 GENERATOR EQUIPMENT	209,179.03	
3711		333049218000	28	9/3/2010	GE-SWIFT 1 GENERATOR EQUIPMENT	8,962.54	
3712		333049218000	29	9/22/2014	GE-SWIFT 1 GENERATOR EQUIPMENT	3,232,959.46	
3713		333049218000	30	12/21/2015	GE-SWIFT 1 GENERATOR EQUIPMENT	82,964.40	
3714		333049218000	31	10/26/2016	GE-SWIFT 1 GENERATOR EQUIPMENT	15,734.96	
3715		333049218000	32	10/21/2016	GE-SWIFT 1 GENERATOR EQUIPMENT	3,634.14	
3716		333049218000	33	10/21/2016	GE-SWIFT 1 GENERATOR EQUIPMENT	3,332.74	
3717		333049218000	34	11/14/2018	GE-SWIFT 1 GENERATOR EQUIPMENT	148,467.87	10,425,851.54

3718		333052218000	0	12/31/1998	GV-SWIFT GOVERNOR EQUIPMENT	-	
3719		333052218000	3	3/22/2005	GV-SWIFT GOVERNOR EQUIPMENT	397,570.96	
3720		333052218000	4	5/19/2004	GV-SWIFT GOVERNOR EQUIPMENT	20,182.57	
3721		333052218000	5	1/8/2007	GV-SWIFT GOVERNOR EQUIPMENT	13,146.37	
3722		333052218000	6	12/22/2008	GV-SWIFT GOVERNOR EQUIPMENT	44,961.15	
3723		333052218000	7	2/24/2010	GV-SWIFT GOVERNOR EQUIPMENT	21,552.48	
3724		333052218000	8	12/31/2018	GV-SWIFT GOVERNOR EQUIPMENT	258,423.93	
3725		333052218000	9	3/13/2017	GV-SWIFT GOVERNOR EQUIPMENT	1,590.63	
3726		333082218000	1	6/9/2014	SP-SWIFT 1 CAPITAL SPARES FERC 333	1,614,208.77	
3727		333088218000	0	12/31/1998	TU-SWIFT 1 TURBINE EQUIPMENT	-	
3728		333088218000	1	12/31/1958	TU-SWIFT 1 TURBINE EQUIPMENT	3,002,975.62	
3729		333088218000	2	12/31/1970	TU-SWIFT 1 TURBINE EQUIPMENT	1,040.36	
3730		333088218000	3	12/31/1987	TU-SWIFT 1 TURBINE EQUIPMENT	68,039.78	
3731		333088218000	4	12/31/1994	TU-SWIFT 1 TURBINE EQUIPMENT	21,916.48	
3732		333088218000	6	1/29/2010	TU-SWIFT 1 TURBINE EQUIPMENT	114,459.23	
3733		333088218000	7	12/27/2012	TU-SWIFT 1 TURBINE EQUIPMENT	174,615.61	
3734		333088218000	8	10/16/2014	TU-SWIFT 1 TURBINE EQUIPMENT	452,830.78	
3735		333088218000	9	4/16/2018	TU-SWIFT 1 TURBINE EQUIPMENT	128,332.52	
3736		333099218000	0	12/31/1998	99-Non Unitized Assets (CAATS)	-	
3737	*	Location	218000		SWIFT HYDRO #1 PLANT	16,785,147.31	
3738		333038219000	0	12/31/1998	DT-DRAFT TUBES	-	
3739		333038219000	1	12/31/1994	DT-DRAFT TUBES	39,664.10	
3740		333038219000	2	12/31/1994	DT-DRAFT TUBES	25,547.96	
3741		333038219000	3	5/10/2006	DT-DRAFT TUBES	4,186.14	
3742		333049219000	0	12/31/1998	GE-YALE GENERATOR EQUIPMENT	-	
3743		333049219000	1	12/31/1953	GE-YALE GENERATOR EQUIPMENT	12,086.32	
3744		333049219000	2	12/31/1964	GE-YALE GENERATOR EQUIPMENT	1,129.11	
3745		333049219000	3	12/31/1990	GE-YALE GENERATOR EQUIPMENT	34,010.10	
3746		333049219000	4	12/31/1953	GE-YALE GENERATOR EQUIPMENT	2,400,528.89	
3747		333049219000	5	12/31/1970	GE-YALE GENERATOR EQUIPMENT	4,163.68	
3748		333049219000	6	12/31/1971	GE-YALE GENERATOR EQUIPMENT	7,164.42	
3749		333049219000	7	12/31/1986	GE-YALE GENERATOR EQUIPMENT	20,561.40	
3750		333049219000	8	12/31/1988	GE-YALE GENERATOR EQUIPMENT	1,672,452.57	
3751		333049219000	9	12/31/1994	GE-YALE GENERATOR EQUIPMENT	168,268.15	
3752		333049219000	10	12/31/1992	GE-YALE GENERATOR EQUIPMENT	1,151.12	
3753		333049219000	11	12/31/1994	GE-YALE GENERATOR EQUIPMENT	16,033.58	
3754		333049219000	12	12/31/1996	GE-YALE GENERATOR EQUIPMENT	46,065.67	
3755		333049219000	13	12/31/1994	GE-YALE GENERATOR EQUIPMENT	104,809.32	
3756		333049219000	14	12/4/2008	GE-YALE GENERATOR EQUIPMENT	30,872.58	
3757		333049219000	15	11/5/2009	GE-YALE GENERATOR EQUIPMENT	11,638.17	
3758		333049219000	16	12/3/2009	GE-YALE GENERATOR EQUIPMENT	146,715.54	
3759		333049219000	17	8/16/2011	GE-YALE GENERATOR EQUIPMENT	1,826.73	
3760		333049219000	18	11/14/2013	GE-YALE GENERATOR EQUIPMENT	3,286.77	
3761		333049219000	19	9/10/2014	GE-YALE GENERATOR EQUIPMENT	363,860.74	
3762		333049219000	20	9/10/2014	GE-YALE GENERATOR EQUIPMENT	441,855.44	
3763		333049219000	21	8/17/2016	GE-YALE GENERATOR EQUIPMENT	12,678.74	
3764		333049219000	22	4/30/2019	GE-YALE GENERATOR EQUIPMENT	1,106,244.61	6,607,403.65
3765		333052219000	0	12/31/1998	GV-YALE GOVERNOR EQUIPMENT	-	
3766		333052219000	3	5/16/2001	GV-YALE GOVERNOR EQUIPMENT	9,456.28	
3767		333052219000	4	3/12/2003	GV-YALE GOVERNOR EQUIPMENT	9,811.66	
3768		333052219000	5	10/7/2004	GV-YALE GOVERNOR EQUIPMENT	108,375.53	
3769		333052219000	7	9/14/2006	GV-YALE GOVERNOR EQUIPMENT	9,169.98	
3770		333052219000	8	12/22/2008	GV-YALE GOVERNOR EQUIPMENT	23,142.26	
3771		333052219000	9	9/10/2014	GV-YALE GOVERNOR EQUIPMENT	512,174.67	
3772		333052219000	10	9/10/2014	GV-YALE GOVERNOR EQUIPMENT	498,576.49	
3773		333088219000	0	12/31/1998	TU-YALE TURBINE EQUIPMENT	-	
3774		333088219000	1	12/31/1953	TU-YALE TURBINE EQUIPMENT	1,376,531.62	
3775		333088219000	2	12/31/1994	TU-YALE TURBINE EQUIPMENT	15,608.19	
3776		333088219000	3	12/31/1996	TU-YALE TURBINE EQUIPMENT	116,779.11	
3777		333088219000	4	12/31/1996	TU-YALE TURBINE EQUIPMENT	4,104,320.09	
3778		333088219000	5	12/31/1953	TU-YALE TURBINE EQUIPMENT	27,530.24	
3779		333088219000	6	4/11/2003	TU-YALE TURBINE EQUIPMENT	30,429.36	
3780		333088219000	7	10/31/2012	TU-YALE TURBINE EQUIPMENT	164,029.67	
3781		333088219000	8	8/28/2015	TU-YALE TURBINE EQUIPMENT	11,182.67	
3782		333088219000	9	11/21/2016	TU-YALE TURBINE EQUIPMENT	5,791.28	
3783		333099219000	0	12/31/1998	99-Non Unitized Assets (CAATS)	-	
3784	*	Location	219000		YALE HYDRO PLANT	13,699,710.95	
3785		333038410000	0	6/21/2001	DT-DRAFT TUBES	35,326.54	
3786		333049410000	0	12/31/1998	GE-BIGFORK GENERATOR EQUIPMENT	-	
3787		333049410000	1	12/31/1952	GE-BIGFORK GENERATOR EQUIPMENT	348.54	
3788		333049410000	2	12/31/1957	GE-BIGFORK GENERATOR EQUIPMENT	2,052.52	
3789		333049410000	3	12/31/1909	GE-BIGFORK GENERATOR EQUIPMENT	3,015.60	
3790		333049410000	4	12/31/1925	GE-BIGFORK GENERATOR EQUIPMENT	16,476.73	

3791	333049410000	5	12/31/1929	GE-BIGFORK GENERATOR EQUIPMENT	13,534.09	
3792	333049410000	6	12/31/1948	GE-BIGFORK GENERATOR EQUIPMENT	14,702.35	
3793	333049410000	7	12/31/1998	GE-BIGFORK GENERATOR EQUIPMENT	18,029.04	
3794	333049410000	8	8/7/2009	GE-BIGFORK GENERATOR EQUIPMENT	3,709.20	
3795	333049410000	9	7/2/2010	GE-BIGFORK GENERATOR EQUIPMENT	114,443.49	
3796	333049410000	10	12/7/2016	GE-BIGFORK GENERATOR EQUIPMENT	1,419.45	187,731.01
3797	333052410000	0	12/31/1998	GV-BIGFORK GOVERNOR SYSTEM	-	
3798	333052410000	1	12/31/1970	GV-BIGFORK GOVERNOR SYSTEM	1,267.89	
3799	333052410000	2	12/31/1983	GV-BIGFORK GOVERNOR SYSTEM	2,543.88	
3800	333052410000	3	12/31/1995	GV-BIGFORK GOVERNOR SYSTEM	394,467.92	
3801	333052410000	4	12/20/2012	GV-BIGFORK GOVERNOR SYSTEM	3,689.83	
3802	333088410000	0	12/31/1998	TU-BIGFORK TURBINE EQUIPMENT	-	
3803	333088410000	1	12/31/1925	TU-BIGFORK TURBINE EQUIPMENT	12,950.33	
3804	333088410000	2	12/31/1929	TU-BIGFORK TURBINE EQUIPMENT	20,165.00	
3805	333088410000	5	12/31/1950	TU-BIGFORK TURBINE EQUIPMENT	9,331.90	
3806	333088410000	6	12/31/1951	TU-BIGFORK TURBINE EQUIPMENT	874.90	
3807	333088410000	7	12/31/1985	TU-BIGFORK TURBINE EQUIPMENT	16,262.95	
3808	333088410000	10	6/21/2001	TU-BIGFORK TURBINE EQUIPMENT	282,612.16	
3809	333088410000	11	6/21/2001	TU-BIGFORK TURBINE EQUIPMENT	282,612.16	
3810	333088410000	12	6/21/2001	TU-BIGFORK TURBINE EQUIPMENT	49,457.11	
3811	333088410000	13	6/21/2001	TU-BIGFORK TURBINE EQUIPMENT	21,195.93	
3812	333088410000	14	6/21/2001	TU-BIGFORK TURBINE EQUIPMENT	35,326.49	
3813	333088410000	15	12/12/2008	TU-BIGFORK TURBINE EQUIPMENT	140,878.09	
3814	333088410000	16	10/27/2015	TU-BIGFORK TURBINE EQUIPMENT	47,414.61	
3815	333088410000	17	7/30/2015	TU-BIGFORK TURBINE EQUIPMENT	25,926.37	
3816	* Location	410000		BIG FORK HYDRO PLANT	1,570,035.07	
3817	333038610000	1	8/17/2009	DT - TURBINE DISCHARGE DRAFT TUBE EQUIPMENT	98,714.83	
3818	333049610000	0	12/31/1998	GE-IRON GATE GENERATOR EQUIPMENT	-	
3819	333049610000	1	12/31/1962	GE-IRON GATE GENERATOR EQUIPMENT	478,747.27	
3820	333049610000	2	12/31/1963	GE-IRON GATE GENERATOR EQUIPMENT	2,170.93	
3821	333049610000	3	12/31/1969	GE-IRON GATE GENERATOR EQUIPMENT	1,366.04	
3822	333049610000	4	4/5/2005	GE-IRON GATE GENERATOR EQUIPMENT	125,711.03	
3823	333049610000	5	4/27/2016	GE-IRON GATE GENERATOR EQUIPMENT	176,830.37	
3824	333049610000	6	2/6/2019	GE-IRON GATE GENERATOR EQUIPMENT	63,431.38	848,257.02
3825	333088610000	0	12/31/1998	TU-IRON GATE TURBINE & RELATED EQUIPMENT	-	
3826	333088610000	1	12/31/1962	TU-IRON GATE TURBINE & RELATED EQUIPMENT	558,936.20	
3827	333088610000	2	12/31/1966	TU-IRON GATE TURBINE & RELATED EQUIPMENT	293.66	
3828	333088610000	3	12/31/1962	TU-IRON GATE TURBINE & RELATED EQUIPMENT	3,839.48	
3829	333088610000	4	12/31/1963	TU-IRON GATE TURBINE & RELATED EQUIPMENT	3,476.50	
3830	333088610000	5	12/31/1962	TU-IRON GATE TURBINE & RELATED EQUIPMENT	5,053.45	
3831	333088610000	6	7/15/2004	TU-IRON GATE TURBINE & RELATED EQUIPMENT	738,767.62	
3832	333088610000	8	12/28/2011	TU-IRON GATE TURBINE & RELATED EQUIPMENT	2,889.19	
3833	333088610000	9	6/6/2013	TU-IRON GATE TURBINE & RELATED EQUIPMENT	4,301.81	
3834	333088610000	10	12/30/2015	TU-IRON GATE TURBINE & RELATED EQUIPMENT	3,104.31	
3835	333088610000	11	8/15/2017	TU-IRON GATE TURBINE & RELATED EQUIPMENT	4,274.43	
3836	* Location	610000		IRON GATE HYDRO PLANT	2,271,908.50	
3837	333049611000	0	12/31/1998	GE-COPCO 1 GENERATOR EQUIPMENT	-	
3838	333049611000	1	12/31/1918	GE-COPCO 1 GENERATOR EQUIPMENT	34,625.64	
3839	333049611000	2	12/31/1919	GE-COPCO 1 GENERATOR EQUIPMENT	1,172.57	
3840	333049611000	3	12/31/1920	GE-COPCO 1 GENERATOR EQUIPMENT	21.40	
3841	333049611000	4	12/31/1921	GE-COPCO 1 GENERATOR EQUIPMENT	876.85	
3842	333049611000	5	12/31/1923	GE-COPCO 1 GENERATOR EQUIPMENT	2,226.55	
3843	333049611000	6	12/31/1924	GE-COPCO 1 GENERATOR EQUIPMENT	120.20	
3844	333049611000	7	12/31/1926	GE-COPCO 1 GENERATOR EQUIPMENT	23,703.57	
3845	333049611000	8	12/31/1927	GE-COPCO 1 GENERATOR EQUIPMENT	7,511.39	
3846	333049611000	9	12/31/1928	GE-COPCO 1 GENERATOR EQUIPMENT	224.09	
3847	333049611000	10	12/31/1935	GE-COPCO 1 GENERATOR EQUIPMENT	105.17	
3848	333049611000	11	12/31/1941	GE-COPCO 1 GENERATOR EQUIPMENT	50.93	
3849	333049611000	12	12/31/1971	GE-COPCO 1 GENERATOR EQUIPMENT	15,166.61	
3850	333049611000	13	12/31/1973	GE-COPCO 1 GENERATOR EQUIPMENT	110,470.55	
3851	333049611000	14	12/31/1965	GE-COPCO 1 GENERATOR EQUIPMENT	596.14	
3852	333049611000	15	12/31/1993	GE-COPCO 1 GENERATOR EQUIPMENT	82,127.97	
3853	333049611000	16	12/31/1991	GE-COPCO 1 GENERATOR EQUIPMENT	69,240.96	
3854	333049611000	17	12/31/1926	GE-COPCO 1 GENERATOR EQUIPMENT	10,728.55	
3855	333049611000	18	12/31/1928	GE-COPCO 1 GENERATOR EQUIPMENT	7,055.04	
3856	333049611000	19	12/31/1961	GE-COPCO 1 GENERATOR EQUIPMENT	29,006.63	
3857	333049611000	20	12/31/1962	GE-COPCO 1 GENERATOR EQUIPMENT	43,539.18	
3858	333049611000	21	12/31/1964	GE-COPCO 1 GENERATOR EQUIPMENT	17,405.20	
3859	333049611000	22	12/16/1999	GE-COPCO 1 GENERATOR EQUIPMENT	3,206.43	
3860	333049611000	23	12/31/1996	GE-COPCO 1 GENERATOR EQUIPMENT	11,321.38	
3861	333049611000	24	12/31/1997	GE-COPCO 1 GENERATOR EQUIPMENT	20,260.70	
3862	333049611000	25	1/10/2018	GE-COPCO 1 GENERATOR EQUIPMENT	256,442.44	
3863	333049611000	26	1/31/2018	GE-COPCO 1 GENERATOR EQUIPMENT	130,786.42	877,992.56

3864		333052611000	0	12/31/1998	GV-COPCO 1 GOVERNOR EQUIPMENT	-	
3865		333052611000	1	12/31/1993	GV-COPCO 1 GOVERNOR EQUIPMENT	16,776.92	
3866		333052611000	2	12/31/1993	GV-COPCO 1 GOVERNOR EQUIPMENT	34,958.87	
3867		333052611000	3	12/31/1993	GV-COPCO 1 GOVERNOR EQUIPMENT	330,489.47	
3868		333052611000	4	12/16/1999	GV-COPCO 1 GOVERNOR EQUIPMENT	3,206.43	
3869		333052611000	5	9/7/2012	GV-COPCO 1 GOVERNOR EQUIPMENT	50,834.27	
3870		333052611000	6	9/28/2012	GV-COPCO 1 GOVERNOR EQUIPMENT	7,304.56	
3871		333052611000	7	10/30/2013	GV-COPCO 1 GOVERNOR EQUIPMENT	43,842.22	
3872		333088611000	0	12/31/1998	TU-TURBINE, LUBE OIL SYSTEM	-	
3873		333088611000	1	12/31/1918	TU-TURBINE, LUBE OIL SYSTEM	128,796.70	
3874		333088611000	2	12/31/1923	TU-TURBINE, LUBE OIL SYSTEM	35,766.20	
3875		333088611000	3	12/19/2001	TU-TURBINE, LUBE OIL SYSTEM	8,968.87	
3876		333088611000	4	12/31/1997	TU-TURBINE, LUBE OIL SYSTEM	2,180,784.77	
3877		333088611000	5	12/27/2010	TU-TURBINE, LUBE OIL SYSTEM	64,088.39	
3878	*	Location	611000		COPCO #1 HYDRO PLANT	3,783,810.23	
3879		333049612000	0	12/31/1998	GE-GENERATOR, STATOR WINDING	-	
3880		333049612000	11	12/31/1992	GE-GENERATOR, STATOR WINDING	13,632.30	
3881		333049612000	12	12/31/1990	GE-GENERATOR, STATOR WINDING	304,742.52	
3882		333049612000	13	12/31/1925	GE-GENERATOR, STATOR WINDING	197,602.03	
3883		333049612000	15	12/31/1952	GE-GENERATOR, STATOR WINDING	146,170.96	
3884		333049612000	16	12/31/1955	GE-GENERATOR, STATOR WINDING	161,564.76	
3885		333049612000	17	7/10/2001	GE-GENERATOR, STATOR WINDING	1,314.26	
3886		333049612000	18	7/10/2001	GE-GENERATOR, STATOR WINDING	13,899.09	
3887		333049612000	19	12/31/1998	GE-GENERATOR, STATOR WINDING	6,567.76	
3888		333049612000	20	12/8/2009	GE-GENERATOR, STATOR WINDING	19,389.55	864,883.23
3889		333052612000	0	12/31/1998	GV-COPCO 2 GOVERNOR EQUIPMENT	-	
3890		333052612000	1	12/31/1990	GV-COPCO 2 GOVERNOR EQUIPMENT	53,444.32	
3891		333052612000	2	12/31/1992	GV-COPCO 2 GOVERNOR EQUIPMENT	179,695.06	
3892		333052612000	3	10/12/2009	GV-COPCO 2 GOVERNOR EQUIPMENT	17,688.99	
3893		333052612000	4	11/17/2010	GV-COPCO 2 GOVERNOR EQUIPMENT	72,427.58	
3894		333052612000	5	10/30/2013	GV-COPCO 2 GOVERNOR EQUIPMENT	33,030.33	
3895		333052612000	6	12/9/2013	GV-COPCO 2 GOVERNOR EQUIPMENT	28,216.80	
3896		333088612000	0	12/31/1998	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	-	
3897		333088612000	1	12/31/1925	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	107,333.50	
3898		333088612000	2	12/31/1927	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	280.01	
3899		333088612000	3	12/31/1928	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	186.89	
3900		333088612000	4	12/31/1930	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	972.11	
3901		333088612000	5	12/31/1965	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	532.11	
3902		333088612000	6	12/31/1929	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	10,401.14	
3903		333088612000	7	12/31/1951	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	18,062.97	
3904		333088612000	8	12/31/1952	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	11,586.04	
3905		333088612000	9	12/31/1955	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	42,017.07	
3906		333088612000	10	10/12/2000	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	859,549.06	
3907		333088612000	11	10/12/2000	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	279,853.16	
3908		333088612000	12	10/12/2000	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	479,748.32	
3909		333088612000	13	10/12/2000	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	375,081.79	
3910		333088612000	14	10/12/2000	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	35,512.76	
3911		333088612000	15	10/18/2000	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	48,220.64	
3912		333088612000	16	7/10/2001	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	6,375.09	
3913		333088612000	17	8/26/2002	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	13,859.49	
3914		333088612000	18	12/7/2011	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	5,802.73	
3915		333088612000	19	5/7/2013	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	2,785.79	
3916		333088612000	20	12/22/2014	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	11,073.45	
3917		333088612000	21	11/12/2015	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	17,613.81	
3918		333088612000	22	3/29/2018	TU-COPCO 2 TURBINE & RELATED EQUIPMENT	3,591.87	
3919		333099612000	0	12/31/1998	99-Non Unitized Assets (CAATS)	-	
3920	*	Location	612000		COPCO #2 HYDRO PLANT	3,579,826.11	
3921		333049613000	0	12/31/1998	GE-FALL CREEK (CA) GENERATOR EQUIPMENT	-	
3922		333049613000	1	12/31/1903	GE-FALL CREEK (CA) GENERATOR EQUIPMENT	446.76	
3923		333049613000	2	12/31/1906	GE-FALL CREEK (CA) GENERATOR EQUIPMENT	14,113.44	
3924		333049613000	3	12/31/1947	GE-FALL CREEK (CA) GENERATOR EQUIPMENT	2,592.85	
3925		333049613000	4	7/10/2001	GE-FALL CREEK (CA) GENERATOR EQUIPMENT	19,037.80	
3926		333049613000	5	10/10/2016	GE-FALL CREEK (CA) GENERATOR EQUIPMENT	31,989.95	
3927		333049613000	6	1/31/2018	GE-FALL CREEK (CA) GENERATOR EQUIPMENT	22,731.29	
3928		333049613000	7	9/26/2018	GE-FALL CREEK (CA) GENERATOR EQUIPMENT	248,242.10	
3929		333049613000	8	9/26/2018	GE-FALL CREEK (CA) GENERATOR EQUIPMENT	175,410.43	
3930		333049613000	9	9/26/2018	GE-FALL CREEK (CA) GENERATOR EQUIPMENT	53,152.83	567,717.45
3931		333088613000	0	12/31/1998	TU-FALL CREEK (CA) TURBINE EQUIPMENT	-	
3932		333088613000	1	12/31/1903	TU-FALL CREEK (CA) TURBINE EQUIPMENT	5,011.24	
3933		333088613000	2	12/31/1906	TU-FALL CREEK (CA) TURBINE EQUIPMENT	12,022.56	
3934		333088613000	3	12/31/1987	TU-FALL CREEK (CA) TURBINE EQUIPMENT	69,652.30	
3935		333088613000	4	12/31/1991	TU-FALL CREEK (CA) TURBINE EQUIPMENT	4,873.76	
3936		333088613000	5	9/22/2014	TU-FALL CREEK (CA) TURBINE EQUIPMENT	31,186.71	

3937		333088613000	6	1/31/2018	TU-FALL CREEK (CA) TURBINE EQUIPMENT	7,568.48		
3938	*	Location	613000		FALL CREEK HYDRO PLANT - CA	698,032.50		
3939	**	Asset Class	33300		Water Wheels- Turb &	141,893,933.27		
3940		344082000221	1	5/30/2014	SP-LAKESIDE 2 FERC 344 CAPITAL SPARE PARTS	36,999.23		
3941		344082000221	2	5/30/2014	SP-LAKESIDE 2 FERC 344 CAPITAL SPARE PARTS	47,573.10		
3942		344082000221	3	5/30/2014	SP-LAKESIDE 2 FERC 344 CAPITAL SPARE PARTS	41,154.90		
3943		344082000221	4	5/30/2014	SP-LAKESIDE 2 FERC 344 CAPITAL SPARE PARTS	33,566.52		
3944		344082000221	5	5/30/2014	SP-LAKESIDE 2 FERC 344 CAPITAL SPARE PARTS	137,595.50		
3945		344082000221	6	5/30/2014	SP-LAKESIDE 2 FERC 344 CAPITAL SPARE PARTS	15,019.73		
3946	*	Location	000221		LAKE SIDE BLOCK 2 COMMON & STEELMIL	311,908.98		
3947		344050000222	1	5/30/2014	GN-LAKESIDE 2-1 GAS COMBUSTION TURBINE GENERX	18,766,359.00		18,766,359.00
3948	*	Location	000222		LAKE SIDE BLOCK 2 COMBUSTION TURBIN	18,766,359.00		
3949		344050000223	1	5/30/2014	GN-LAKESIDE 2-2 GAS COMBUSTION TURBINE GENERX	18,766,359.00		18,766,359.00
3950	*	Location	000223		LAKE SIDE BLOCK 2 COMBUSTION TURBIN	18,766,359.00		
3951		344028000224	1	5/30/2014	CN-LAKESIDE BLK 2 STEAM TURB CONDENSATE SYSTX	12,588,474.00		
3952		344032000224	1	5/30/2014	CT-STEAM TURBINE COOLING TOWER SYSTEM	14,012,215.00		
3953		344033000224	1	5/30/2014	CW-LAKESIDE BLK 2 STEAM TURB CIRCULATING WATX	5,586,050.00		
3954		344033000224	2	12/20/2017	CW-LAKESIDE BLK 2 STEAM TURB CIRCULATING WATX	51,853.07		
3955		344050000224	1	5/30/2014	GN-LAKESIDE BLK 2 STEAM TURBINE GENERATOR SYX	21,806,510.00		21,806,510.00
3956		344084000224	1	5/30/2014	TB-LAKESIDE BLK 2 STEAM TURBINE	62,178,551.08		
3957		344084000224	2	9/24/2014	TB-LAKESIDE BLK 2 STEAM TURBINE	6,273.92		
3958		344084000224	3	12/29/2015	TB-LAKESIDE BLK 2 STEAM TURBINE	75,123.26		
3959	*	Location	000224		LAKE SIDE BLOCK 2 STEAM TURBINE	116,305,050.33		
3960		344050000225	1	8/7/2013	GN-LAKE SIDE GENERATOR EQUIPMENT BLOCK 1 COMX	23,268.70		23,268.70
3961	*	Location	000225		LAKE SIDE BLOCK 1 COMMON & DYNAMO S	23,268.70		
3962		344050000226	1	9/7/2007	GN - GAS TURBINE GENERATOR BLOCK 1 1A	7,059,771.00		
3963		344050000226	2	3/31/2011	GN - GAS TURBINE GENERATOR BLOCK 1 1A	481,962.54		
3964		344050000226	3	12/12/2011	GN - GAS TURBINE GENERATOR BLOCK 1 1A	24,178.31		7,565,911.85
3965	*	Location	000226		LAKE SIDE BLOCK 1 COMBUSTION TURBIN	7,565,911.85		
3966		344050000227	1	9/7/2007	GN - GAS TURBINE GENERATOR BLOCK 1 1B	7,059,771.00		
3967		344050000227	2	3/31/2011	GN - GAS TURBINE GENERATOR BLOCK 1 1B	481,962.54		
3968		344050000227	3	12/12/2011	GN - GAS TURBINE GENERATOR BLOCK 1 1B	24,178.31		7,565,911.85
3969	*	Location	000227		LAKE SIDE BLOCK 1 COMBUSTION TURBIN	7,565,911.85		
3970		344028000228	1	9/7/2007	CN - STEAM TURBINE CONDENSATE SYS BLOCK 1	10,214,528.00		
3971		344028000228	2	12/31/2013	CN - STEAM TURBINE CONDENSATE SYS BLOCK 1	64,846.86		
3972		344032000228	1	9/7/2007	CT - COOLING TOWER SYSTEM BLOCK 1	8,156,028.00		
3973		344032000228	2	8/8/2008	CT - COOLING TOWER SYSTEM BLOCK 1	24,869.69		
3974		344032000228	3	11/21/2014	CT - COOLING TOWER SYSTEM BLOCK 1	114,377.12		
3975		344032000228	4	11/21/2014	CT - COOLING TOWER SYSTEM BLOCK 1	28,594.28		
3976		344032000228	5	6/30/2016	CT - COOLING TOWER SYSTEM BLOCK 1	63,529.62		
3977		344033000228	1	9/7/2007	CW - STEAM TURBINE CIRCULATING WATER SYS BLOX	6,128,716.00		
3978		344050000228	1	9/7/2007	GN - STEAM TURBINE GENERATOR BLOCK 1	6,448,276.00		
3979		344050000228	2	11/30/2009	GN - STEAM TURBINE GENERATOR BLOCK 1	665,573.42		
3980		344050000228	3	11/30/2009	GN - STEAM TURBINE GENERATOR BLOCK 1	108,349.17		
3981		344050000228	4	12/12/2011	GN - STEAM TURBINE GENERATOR BLOCK 1	24,185.56		7,246,384.15
3982		344082000228	1	2/18/2014	SP-LAKESIDE BLK 1 CAPITALIZED SPARE PARTS FEX	17,634.73		
3983		344082000228	2	12/21/2017	SP-LAKESIDE BLK 1 CAPITALIZED SPARE PARTS FEX	555,767.36		
3984		344084000228	1	9/7/2007	TB - STEAM TURBINE BLOCK 1	19,918,610.00		
3985		344084000228	2	7/13/2011	TB - STEAM TURBINE BLOCK 1	1,011,624.45		
3986		344084000228	3	6/2/2015	TB - STEAM TURBINE BLOCK 1	419,170.46		
3987		344084000228	4	9/24/2014	TB - STEAM TURBINE BLOCK 1	6,273.93		
3988		344084000228	5	5/29/2015	TB - STEAM TURBINE BLOCK 1	14,082.90		
3989		344084000228	6	12/29/2015	TB - STEAM TURBINE BLOCK 1	89,769.86		
3990	*	Location	000228		LAKE SIDE BLOCK 1 STEAM TURBINE	54,074,807.41		
3991		344050000235	1	12/14/2005	EAST SIDE MOBILE GENERATION EQUIPMENT	420,314.59		
3992		344050000235	2	12/13/2005	EAST SIDE MOBILE GENERATION EQUIPMENT	419,365.53		839,680.12
3993	*	Location	000235		EAST SIDE MOBILE GENERATION EQUIPME	839,680.12		
3994		344082000264	1	3/30/2015	SP-GADSBY PEAKERS FERC 344 CAPITALIZED SPAREX	77,192.72		
3995	*	Location	000264		GADSBY COMMON GAS PEAKERS & SUBSTAT	77,192.72		
3996		344350000265	1	8/29/2002	GN - GAS TURBINE GENERATOR	4,706,290.03		
3997		344350000265	2	12/21/2012	GN - GAS TURBINE GENERATOR	12,433.83		
3998		344350000265	3	2/21/2013	GN - GAS TURBINE GENERATOR	1,040,139.82		
3999	*	Location	000265		GADSBY NO 4 GAS TURBINE PEAKER	5,758,863.68		5,758,863.68
4000		344350000266	1	8/29/2002	GN-GADSBY U5 (PEAKER #2) GAS TURBINE GENERATX	4,671,985.71		
4001		344350000266	2	11/3/2011	GN-GADSBY U5 (PEAKER #2) GAS TURBINE GENERATX	179,355.92		
4002		344350000266	3	7/16/2014	GN-GADSBY U5 (PEAKER #2) GAS TURBINE GENERATX	741,389.12		
4003		344350000266	4	11/6/2014	GN-GADSBY U5 (PEAKER #2) GAS TURBINE GENERATX	225,480.62		
4004	*	Location	000266		GADSBY NO 5 GAS TURBINE PEAKER	5,818,211.37		5,818,211.37
4005		344350000267	1	8/29/2002	GN - GAS TURBINE GENERATOR	4,636,262.31		
4006		344350000267	2	6/4/2015	GN - GAS TURBINE GENERATOR	1,001,380.71		
4007		344350000267	3	1/27/2017	GN - GAS TURBINE GENERATOR	104,374.03		
4008		344350000267	4	4/25/2017	GN - GAS TURBINE GENERATOR	183,602.68		

4009		344350000267	5	12/31/2017	GN - GAS TURBINE GENERATOR	202,875.21	
4010	*	Location	000267		GADSBY NO 6 GAS TURBINE PEAKER	6,128,494.94	6,128,494.94
4011		344050000311	3	6/13/2005	GN - GAS TURBINE GENERATOR BLOCK 1 1A	6,499,254.76	
4012		344050000311	4	5/31/2005	GN - GAS TURBINE GENERATOR BLOCK 1 1A	11,595.39	
4013		344050000311	5	11/21/2012	GN - GAS TURBINE GENERATOR BLOCK 1 1A	76,002.74	
4014		344050000311	6	11/13/2012	GN - GAS TURBINE GENERATOR BLOCK 1 1A	46,999.65	
4015		344050000311	7	5/10/2016	GN - GAS TURBINE GENERATOR BLOCK 1 1A	60,857.15	
4016	*	Location	000311		CURRANT CREEK BLK 1 COMBUSTION TURB	6,694,709.69	6,694,709.69
4017		344050000312	3	5/24/2005	GN - GAS TURBINE GENERATOR BLOCK 1 1B	6,503,565.76	
4018		344050000312	4	11/13/2012	GN - GAS TURBINE GENERATOR BLOCK 1 1B	48,783.64	
4019		344050000312	5	11/21/2012	GN - GAS TURBINE GENERATOR BLOCK 1 1B	87,287.11	
4020		344050000312	6	5/10/2016	GN - GAS TURBINE GENERATOR BLOCK 1 1B	60,857.15	
4021	*	Location	000312		CURRANT CREEK BLK 1 COMBUSTION TURB	6,700,493.66	6,700,493.66
4022		344007000313	1	3/22/2006	AZ - AIR COOLED CONDENSER BLOCK 1	23,091,975.50	
4023		344007000313	2	11/13/2012	AZ - AIR COOLED CONDENSER BLOCK 1	28,628.46	
4024		344007000313	3	1/30/2013	AZ - AIR COOLED CONDENSER BLOCK 1	11,119.96	
4025		344007000313	4	7/11/2019	AZ - AIR COOLED CONDENSER BLOCK 1	20,012.00	
4026		344050000313	1	3/22/2006	GN - STEAM TURBINE GENERATOR BLOCK 1	13,198,940.86	13,198,940.86
4027		344082000313	1	3/22/2006	SP - CURRANT CK FERC 344 CAPITALIZED SPARE PX	10,390.00	
4028		344082000313	4	1/30/2013	SP - CURRANT CK FERC 344 CAPITALIZED SPARE PX	22,243.25	
4029		344082000313	5	10/24/2014	SP - CURRANT CK FERC 344 CAPITALIZED SPARE PX	62,719.94	
4030		344082000313	6	7/5/2018	SP - CURRANT CK FERC 344 CAPITALIZED SPARE PX	42,868.84	
4031		344084000313	1	3/22/2006	TB - STEAM TURBINE BLOCK 1	13,155,335.86	
4032		344084000313	2	11/21/2012	TB - STEAM TURBINE BLOCK 1	41,600.68	
4033		344084000313	3	11/28/2012	TB - STEAM TURBINE BLOCK 1	36,970.96	
4034	*	Location	000313		CURRANT CREEK BLK 1 STEAM TURBINE	49,722,806.31	
4035		344050000314	1	5/26/2011	GN-GAS TURBINE BLOCK 1 COMMON GENERATOR EQUIP	41,309.86	41,309.86
4036	*	Location	000314		CURRANT CREEK BLK 1 COMMON & SUBSTA	41,309.86	
4037		344050015058	0	12/31/1994	GN - MOAB CUST SERVICE CENTER SOLAR PANELS	-	
4038		344050015058	1	12/31/1994	GN - MOAB CUST SERVICE CENTER SOLAR PANELS	36,389.01	
4039	*	Location	015058		CANYON LANDS DISTRICT SERVICE CENTE	36,389.01	
4040		344050119850	0	12/31/1995	GN - OR HIGH DESERT MUSEUM (BEND) SOLAR PANEX	-	
4041		344050119850	2	12/31/1995	GN - OR HIGH DESERT MUSEUM (BEND) SOLAR PANEX	56,321.97	
4042	*	Location	119850		OREGON HIGH DESERT SOLAR GENERATING	56,321.97	
4043		344050122350	1	6/15/2009	WEST SIDE MOBILE GENERATION EQUIPMENT EQ# 38X	849,226.01	
4044	*	Location	122350		WEST SIDE MOBILE GENERATION EQUIPME	849,226.01	
4045		344005129500	0	12/31/1998	AI-ALARMS AND INFORMATION HANDLING	-	
4046		344023129500	0	12/31/1998	CE-CONTINUOUS	-	
4047		344023129500	1	12/31/1996	CE-CONTINUOUS	306,629.61	
4048		344028129500	0	12/31/1998	CN-HERMISTON CONDENSER SYSTEM	-	
4049		344028129500	1	12/31/1996	CN-HERMISTON CONDENSER SYSTEM	1,477,875.00	
4050		344028129500	2	8/11/2014	CN-HERMISTON CONDENSER SYSTEM	37,551.79	
4051		344032129500	1	8/11/2014	CT-HERMISTON COOLING TOWER STRUCTURES & EQUIX	593,363.94	
4052		344032129500	2	12/31/1996	CT-HERMISTON COOLING TOWER STRUCTURES & EQUIX	1,574,730.88	
4053		344032129500	3	12/17/2014	CT-HERMISTON COOLING TOWER STRUCTURES & EQUIX	6,896.02	
4054		344033129500	0	12/31/1998	CW-HERMISTON CIRCULATING WATER STRUCTURES & X	-	
4055		344033129500	1	12/31/1996	CW-HERMISTON CIRCULATING WATER STRUCTURES & X	86,308.99	
4056		344033129500	2	12/31/1996	CW-HERMISTON CIRCULATING WATER STRUCTURES & X	353,755.01	
4057		344033129500	3	12/31/1996	CW-HERMISTON CIRCULATING WATER STRUCTURES & X	403,439.91	
4058		344033129500	4	7/26/2006	CW-HERMISTON CIRCULATING WATER STRUCTURES & X	239,007.16	
4059		344033129500	5	5/29/2007	CW-HERMISTON CIRCULATING WATER STRUCTURES & X	233,987.65	
4060		344033129500	6	10/12/2015	CW-HERMISTON CIRCULATING WATER STRUCTURES & X	52,037.34	
4061		344050129500	0	12/31/1998	GN-HERMISTON GENERATOR EQUIPMENT	-	
4062		344050129500	1	12/31/1996	GN-HERMISTON GENERATOR EQUIPMENT	15,262,248.65	
4063		344050129500	2	10/10/2003	GN-HERMISTON GENERATOR EQUIPMENT	2,555,295.89	
4064		344050129500	3	8/30/2013	GN-HERMISTON GENERATOR EQUIPMENT	38,671.31	
4065		344050129500	4	8/11/2014	GN-HERMISTON GENERATOR EQUIPMENT	51,090.34	
4066		344050129500	5	10/22/2014	GN-HERMISTON GENERATOR EQUIPMENT	37,238.27	
4067		344050129500	6	7/13/2017	GN-HERMISTON GENERATOR EQUIPMENT	955,462.39	
4068		344050129500	7	12/29/2016	GN-HERMISTON GENERATOR EQUIPMENT	64,799.62	18,964,806.47
4069		344084129500	0	12/31/1998	TB-HERMISTON STEAM TURBINES	-	
4070		344084129500	1	12/31/1996	TB-HERMISTON STEAM TURBINES	16,863,712.51	
4071		344084129500	2	12/31/1996	TB-HERMISTON STEAM TURBINES	3,437.68	
4072		344084129500	3	8/25/2006	TB-HERMISTON STEAM TURBINES	339,859.31	
4073		344084129500	4	7/26/2006	TB-HERMISTON STEAM TURBINES	30,521.28	
4074		344084129500	5	8/25/2006	TB-HERMISTON STEAM TURBINES	152,596.25	
4075		344084129500	6	8/11/2014	TB-HERMISTON STEAM TURBINES	265,185.32	
4076		344084129500	7	12/17/2014	TB-HERMISTON STEAM TURBINES	31,989.95	
4077		344096129500	0	12/31/1998	WT-WATER TREATMENT	-	
4078		344096129500	1	12/31/1996	WT-WATER TREATMENT	278,005.13	
4079	*	Location	129500		HERMISTON U.S. GENERATING PROJECT	42,295,697.20	
4080		344092129600	10	9/16/2019	WG-LEANING JUNIPER GENERATORS	8,506,173.04	8,506,173.04
4081	*	Location	129600		LEANING JUNIPER 1 WIND PLANT	8,506,173.04	

4082		344050203301	1	10/1/2003	GN - GAS TURBINE GENERATOR BLOCK 1 1A	6,901,546.37	
4083		344050203301	2	6/12/2014	GN - GAS TURBINE GENERATOR BLOCK 1 1A	56,450.42	
4084		344050203301	3	6/18/2015	GN - GAS TURBINE GENERATOR BLOCK 1 1A	452,032.46	
4085	*	Location	203301		CHEHALIS COMBUSTION TURBINE A	7,410,029.25	7,410,029.25
4086		344050203302	1	10/1/2003	GN - GAS TURBINE GENERATOR BLOCK 1 1B	7,121,855.37	
4087		344050203302	2	6/12/2014	GN - GAS TURBINE GENERATOR BLOCK 1 1B	56,450.41	
4088	*	Location	203302		CHEHALIS COMBUSTION TURBINE B	7,178,305.78	7,178,305.78
4089		344007203303	1	10/1/2003	AZ - AIR COOLED CONDENSER BLOCK 1	25,034,990.63	
4090		344007203303	2	12/30/2010	AZ - AIR COOLED CONDENSER BLOCK 1	553,055.13	
4091		344050203303	1	10/1/2003	GN - STEAM TURBINE GENERATOR BLOCK 1	7,149,892.36	7,149,892.36
4092		344084203303	1	10/1/2003	TB - STEAM TURBINE BLOCK 1	20,008,068.10	
4093		344084203303	2	11/21/2012	TB - STEAM TURBINE BLOCK 1	1,138,937.15	
4094		344084203303	3	6/2/2015	TB - STEAM TURBINE BLOCK 1	115,643.42	
4095		344084203303	4	6/18/2015	TB - STEAM TURBINE BLOCK 1	1,326,054.15	
4096		344084203303	5	2/20/2015	TB - STEAM TURBINE BLOCK 1	48,525.87	
4097		344084203303	6	8/10/2016	TB - STEAM TURBINE BLOCK 1	171,250.43	
4098	*	Location	203303		CHEHALIS STEAM TURBINE	55,546,417.24	
4099		344092205200	5	12/24/2019	WG - GOODNOE U1 GENERATORS	7,173,098.82	7,173,098.82
4100	*	Location	205200		GOODNOE HILLS WIND PLANT UNIT 1	7,173,098.82	
4101		344082206100	8	8/29/2014	SP-MARENGO U0 FERC 344 CAPITALIZED SPARE PARX	40,204.70	
4102		344082206100	9	8/29/2014	SP-MARENGO U0 FERC 344 CAPITALIZED SPARE PARX	82,201.52	
4103		344082206100	10	11/21/2014	SP-MARENGO U0 FERC 344 CAPITALIZED SPARE PARX	79,158.56	
4104		344082206100	11	11/28/2014	SP-MARENGO U0 FERC 344 CAPITALIZED SPARE PARX	51,856.63	
4105		344082206100	12	3/3/2016	SP-MARENGO U0 FERC 344 CAPITALIZED SPARE PARX	96,871.00	
4106		344082206100	13	3/3/2016	SP-MARENGO U0 FERC 344 CAPITALIZED SPARE PARX	90,648.44	
4107		344082206100	14	5/29/2015	SP-MARENGO U0 FERC 344 CAPITALIZED SPARE PARX	86,487.73	
4108		344082206100	15	3/3/2016	SP-MARENGO U0 FERC 344 CAPITALIZED SPARE PARX	89,941.23	
4109		344082206100	16	7/31/2015	SP-MARENGO U0 FERC 344 CAPITALIZED SPARE PARX	86,362.45	
4110		344082206100	17	11/30/2016	SP-MARENGO U0 FERC 344 CAPITALIZED SPARE PARX	79,085.52	
4111		344082206100	18	8/23/2016	SP-MARENGO U0 FERC 344 CAPITALIZED SPARE PARX	89,752.04	
4112		344082206100	19	3/22/2017	SP-MARENGO U0 FERC 344 CAPITALIZED SPARE PARX	82,298.72	
4113		344082206100	20	4/3/2017	SP-MARENGO U0 FERC 344 CAPITALIZED SPARE PARX	37,779.08	
4114		344082206100	21	4/3/2017	SP-MARENGO U0 FERC 344 CAPITALIZED SPARE PARX	85,541.04	
4115		344082206100	22	4/24/2017	SP-MARENGO U0 FERC 344 CAPITALIZED SPARE PARX	75,450.07	
4116	*	Location	206100		MARENGO WIND PLANT COMMON	1,153,638.73	
4117		344015206110	0	5/29/2015	Replaced by Re-powering - 2015 Cap Proj CompX	91,793.00	
4118		344016206110	0	8/2/2016	Replaced by Re-powering - 2016 Cap Proj CompX	171,091.99	
4119		344017206110	0	4/20/2017	Replaced by Re-powering - 2017 Cap Proj CompX	1,020,542.62	
4120		344018206110	0	3/8/2018	Replaced by Re-powering - 2018 Cap Proj CompX	288,142.77	
4121		344092206110	1	8/3/2007	WG-MARENGO U1 GENERATOR EQUIPMENT	5,134,200.15	
4122		344092206110	2	2/28/2013	WG-MARENGO U1 GENERATOR EQUIPMENT	12,317.37	
4123		344092206110	3	2/28/2013	WG-MARENGO U1 GENERATOR EQUIPMENT	10,191.09	
4124		344092206110	4	4/25/2013	WG-MARENGO U1 GENERATOR EQUIPMENT	27,469.01	
4125		344092206110	6	7/16/2013	WG-MARENGO U1 GENERATOR EQUIPMENT	9,000.74	
4126		344092206110	7	7/16/2013	WG-MARENGO U1 GENERATOR EQUIPMENT	23,178.40	
4127		344092206110	8	7/16/2013	WG-MARENGO U1 GENERATOR EQUIPMENT	24,686.57	
4128		344092206110	9	10/30/2013	WG-MARENGO U1 GENERATOR EQUIPMENT	35,771.31	
4129		344092206110	10	10/30/2013	WG-MARENGO U1 GENERATOR EQUIPMENT	20,868.59	
4130		344092206110	11	11/26/2013	WG-MARENGO U1 GENERATOR EQUIPMENT	21,190.88	
4131		344092206110	12	12/30/2013	WG-MARENGO U1 GENERATOR EQUIPMENT	17,969.27	
4132		344092206110	13	1/31/2014	WG-MARENGO U1 GENERATOR EQUIPMENT	24,944.15	
4133		344092206110	15	3/31/2014	WG-MARENGO U1 GENERATOR EQUIPMENT	27,984.99	
4134		344092206110	16	3/31/2014	WG-MARENGO U1 GENERATOR EQUIPMENT	19,429.61	
4135		344092206110	20	9/30/2014	WG-MARENGO U1 GENERATOR EQUIPMENT	21,104.80	
4136		344092206110	21	6/30/2014	WG-MARENGO U1 GENERATOR EQUIPMENT	21,598.23	
4137		344092206110	22	10/31/2014	WG-MARENGO U1 GENERATOR EQUIPMENT	17,607.97	
4138		344092206110	23	10/30/2013	WG-MARENGO U1 GENERATOR EQUIPMENT	113,309.74	
4139		344092206110	24	2/27/2015	WG-MARENGO U1 GENERATOR EQUIPMENT	120,779.32	
4140		344092206110	25	2/27/2015	WG-MARENGO U1 GENERATOR EQUIPMENT	18,218.19	
4141		344092206110	26	10/30/2013	WG-MARENGO U1 GENERATOR EQUIPMENT	56,654.87	
4142		344092206110	27	3/3/2016	WG-MARENGO U1 GENERATOR EQUIPMENT	26,653.58	
4143		344092206110	28	10/30/2013	WG-MARENGO U1 GENERATOR EQUIPMENT	56,654.87	
4144		344092206110	29	3/3/2016	WG-MARENGO U1 GENERATOR EQUIPMENT	98,830.38	
4145		344092206110	30	5/9/2016	WG-MARENGO U1 GENERATOR EQUIPMENT	167,527.42	
4146		344092206110	31	2/27/2015	WG-MARENGO U1 GENERATOR EQUIPMENT	30,040.62	
4147		344092206110	32	2/27/2015	WG-MARENGO U1 GENERATOR EQUIPMENT	24,762.85	
4148		344092206110	34	11/30/2016	WG-MARENGO U1 GENERATOR EQUIPMENT	18,828.95	
4149		344092206110	35	8/29/2014	WG-MARENGO U1 GENERATOR EQUIPMENT	88,692.94	
4150		344092206110	36	3/22/2017	WG-MARENGO U1 GENERATOR EQUIPMENT	129,538.40	
4151		344092206110	37	4/3/2017	WG-MARENGO U1 GENERATOR EQUIPMENT	127,123.11	
4152		344092206110	38	4/3/2017	WG-MARENGO U1 GENERATOR EQUIPMENT	111,603.56	
4153		344092206110	39	8/26/2015	WG-MARENGO U1 GENERATOR EQUIPMENT	17,682.69	
4154		344092206110	40	12/30/2013	WG-MARENGO U1 GENERATOR EQUIPMENT	80,717.54	

4155		344092206110	41	3/22/2017	WG-MARENGO U1 GENERATOR EQUIPMENT	-	
4156		344092206110	42	7/17/2017	WG-MARENGO U1 GENERATOR EQUIPMENT	-	
4157		344092206110	43	5/9/2017	WG-MARENGO U1 GENERATOR EQUIPMENT	-	6,757,132.16
4158	*	Location	206110		MARENGO WIND PLANT UNIT 1	8,328,702.54	
4159		344015206120	0	11/30/2015	Replaced by Re-powering - 2015 Cap Proj CompX	87,163.81	
4160		344016206120	0	8/23/2016	Replaced by Re-powering - 2016 Cap Proj CompX	34,745.96	
4161		344017206120	0	1/3/2017	Replaced by Re-powering - 2017 Cap Proj CompX	227,143.55	
4162		344018206120	0	2/22/2018	Replaced by Re-powering - 2018 Cap Proj CompX	317,471.50	
4163		344092206120	1	6/26/2008	WG - MARENGO U2 GENERATOR EQUIPMENT	2,379,504.00	
4164		344092206120	3	4/30/2013	WG - MARENGO U2 GENERATOR EQUIPMENT	26,382.72	
4165		344092206120	4	7/16/2013	WG - MARENGO U2 GENERATOR EQUIPMENT	79,594.89	
4166		344092206120	5	12/30/2013	WG - MARENGO U2 GENERATOR EQUIPMENT	36,696.71	
4167		344092206120	6	11/15/2011	WG - MARENGO U2 GENERATOR EQUIPMENT	120,567.87	
4168		344092206120	7	11/26/2013	WG - MARENGO U2 GENERATOR EQUIPMENT	79,558.24	
4169		344092206120	8	11/26/2013	WG - MARENGO U2 GENERATOR EQUIPMENT	15,146.69	
4170		344092206120	9	8/29/2014	WG - MARENGO U2 GENERATOR EQUIPMENT	13,075.06	
4171		344092206120	10	12/31/2012	WG - MARENGO U2 GENERATOR EQUIPMENT	134,727.87	
4172		344092206120	11	6/16/2014	WG - MARENGO U2 GENERATOR EQUIPMENT	21,330.11	
4173		344092206120	12	10/31/2014	WG - MARENGO U2 GENERATOR EQUIPMENT	15,291.38	
4174		344092206120	13	10/30/2015	WG - MARENGO U2 GENERATOR EQUIPMENT	126,114.82	
4175		344092206120	14	3/3/2016	WG - MARENGO U2 GENERATOR EQUIPMENT	101,050.54	
4176		344092206120	15	5/29/2015	WG - MARENGO U2 GENERATOR EQUIPMENT	24,604.36	
4177		344092206120	16	11/26/2013	WG - MARENGO U2 GENERATOR EQUIPMENT	73,629.69	
4178		344092206120	17	4/24/2017	WG - MARENGO U2 GENERATOR EQUIPMENT	139,998.45	3,387,273.40
4179	*	Location	206120		MARENGO WIND PLANT UNIT 2	4,053,798.22	
4180		344050502001	1	5/25/2007	GN - ATLANTIC CITY, WY REMOTE SOLAR PANEL	5,545.93	
4181	*	Location	502001		ATLANTIC CITY REMOTE SOLAR PANEL	5,545.93	
4182		344092505110	0	12/31/2008	WG - GLENROCK U1 GENERATORS	-	
4183		344092505110	1	12/31/2008	WG - GLENROCK U1 GENERATORS	632,207.88	
4184		344092505110	4	9/24/2019	WG - GLENROCK U1 GENERATORS	7,881,956.18	8,514,164.06
4185	*	Location	505110		GLENROCK WIND PLANT UNIT 1	8,514,164.06	
4186		344092505120	1	1/17/2009	WG - ROLLING HILLS GENERATOR EQUIPMENT	1,591,305.82	
4187		344092505120	2	10/17/2019	WG - ROLLING HILLS GENERATOR EQUIPMENT	6,235,955.34	
4188		344092505120	3	5/6/2016	WG - ROLLING HILLS GENERATOR EQUIPMENT	6,042.10	
4189		344092505120	4	5/6/2016	WG - ROLLING HILLS GENERATOR EQUIPMENT	6,436.24	
4190		344092505120	5	7/8/2016	WG - ROLLING HILLS GENERATOR EQUIPMENT	1,543.03	
4191		344092505120	6	5/16/2018	WG - ROLLING HILLS GENERATOR EQUIPMENT	2,638.98	
4192		344092505120	7	6/12/2019	WG - ROLLING HILLS GENERATOR EQUIPMENT	6,295.34	7,850,216.85
4193	*	Location	505120		ROLLING HILLS WIND PLANT	7,850,216.85	
4194		344092505130	1	1/17/2009	WG - GLENROCK U3 GENERATOR EQUIPMENT	559,008.46	
4195		344092505130	3	11/25/2019	WG - GLENROCK U3 GENERATOR EQUIPMENT	2,595,492.54	3,154,501.00
4196	*	Location	505130		GLENROCK WIND PLANT UNIT 3	3,154,501.00	
4197		344092506110	0	12/31/2008	WG - SEVEN MILE HILL U1 GENERATOR EQUIPMENT	-	
4198		344092506110	3	9/9/2019	WG - SEVEN MILE HILL U1 GENERATOR EQUIPMENT	8,956,558.45	8,956,558.45
4199	*	Location	506110		SEVEN MILE HILL WIND PLANT UNIT 1	8,956,558.45	
4200		344092506120	0	12/31/2008	WG - SEVEN MILE HILL U2 GENERATOR EQUIPMENT	-	
4201		344092506120	2	9/9/2019	WG - SEVEN MILE HILL U2 GENERATOR EQUIPMENT	1,769,912.15	1,769,912.15
4202	*	Location	506120		SEVEN MILE HILL WIND PLANT UNIT 2	1,769,912.15	
4203		344016509110	0	8/3/2016	Replaced by Re-powering - 2016 Cap Proj CompX	19,439.13	
4204		344017509110	0	2/2/2017	Replaced by Re-powering - 2017 Cap Proj CompX	66,186.89	
4205		344082509110	1	10/1/2010	SP-DUNLAP FERC 344 CAPITALIZED SPARE PARTS	131,936.75	
4206		344092509110	1	10/1/2010	WG - DUNLAP U1 WIND GENERATOR EQUIPMENT	5,394,264.02	
4207		344092509110	2	10/31/2014	WG - DUNLAP U1 WIND GENERATOR EQUIPMENT	1,001,384.99	
4208		344092509110	3	11/20/2015	WG - DUNLAP U1 WIND GENERATOR EQUIPMENT	10,563.45	
4209		344092509110	4	8/30/2019	WG - DUNLAP U1 WIND GENERATOR EQUIPMENT	42,125.96	6,448,338.42
4210	*	Location	509110		DUNLAP WIND PLANT UNIT 1	6,665,901.19	
4211		344092510110	4	12/20/2019	WG - HIGH PLAINS WIND GENERATOR EQUIPMENT	8,817,598.55	8,817,598.55
4212	*	Location	510110		HIGH PLAINS WIND PLANT	8,817,598.55	
4213		344092510120	3	11/17/2019	WG - MCFADDEN RIDGE WIND GENERATOR EQUIPMENT	2,515,971.89	2,515,971.89
4214	*	Location	510120		MCFADDEN RIDGE WIND PLANT	2,515,971.89	
4215		344050525000	0	12/31/1994	GN - GREEN RIVER SOLAR PANELS	-	
4216		344050525000	1	12/31/1994	GN - GREEN RIVER SOLAR PANELS	54,223.15	
4217		344050525000	2	12/31/1998	GN - GREEN RIVER SOLAR PANELS	863.63	
4218	*	Location	525000		GREEN RIVER SOLAR	55,086.78	
4219		344014576500	0	12/31/2014	Replaced by Re-powering - 2014 Cap Proj CompX	-	
4220		344015576500	0	12/31/2015	Replaced by Re-powering - 2015 Cap Proj CompX	-	
4221		344016576500	0	7/15/2016	Replaced by Re-powering - 2016 Cap Proj CompX	145,998.35	
4222		344016576500	1	12/31/2016	Replaced by Re-powering - 2016 Cap Proj CompX	-	
4223		344017576500	0	5/18/2017	Replaced by Re-powering - 2017 Cap Proj CompX	64,498.25	
4224		344019576500	0	3/26/2019	Replaced by Re-powering - 2019 Cap Proj CompX	21,538.57	
4225		344082576500	3	2/3/2016	SP-FOOTE CREEK FERC 344 CAPITALIZED SPARE PAX	45,614.98	
4226		344082576500	4	11/2/2015	SP-FOOTE CREEK FERC 344 CAPITALIZED SPARE PAX	42,066.25	
4227		344092576500	1	12/31/1998	WG - WIND GENERATION GENERATORS	1,498,502.14	

4228	344092576500	2	4/9/2015	WG - WIND GENERATION GENERATORS	99,839.43		
4229	344092576500	3	10/9/2015	WG - WIND GENERATION GENERATORS	14,616.04		
4230	344092576500	4	8/29/2014	WG - WIND GENERATION GENERATORS	72,322.24		
4231	344092576500	5	7/31/2015	WG - WIND GENERATION GENERATORS	14,833.93		
4232	344092576500	6	7/6/2015	WG - WIND GENERATION GENERATORS	44,556.14		
4233	344092576500	7	7/24/2019	WG - WIND GENERATION GENERATORS	27,660.12		1,772,330.04
4234	344098576500	0	12/31/1998	Replaced by Re-powering - 1998 Cap Proj CompX	-		
4235	* Location	576500		FOOTE CREEK WIND PLANT	2,092,046.44		
4236	** Asset Class	34400		Generators	498,146,640.57		
4237	***Company Code	1000		PacifiCorp	1,643,790,791.92		504,125,219.65

GENERATOR & TURBINE ASSETS AT GADSBY, CHEHALIS, LAKE SIDE, AND CURRANT CREEK
ASSET IN CLASSES 314 & 344 WITH PRU OF GN (GENERATOR), GT (COMBUSTION TURBINE), & TB (STEAM TURBINE)
AT 12/31/19

	Sum of Acquis.val.							
	PRU	Location	LOC DESCRIPTION	Asset Class	Total			
1	GN	000222	LAKE SIDE BLOCK 2 COMBUSTION TURBINE 2-1	34400	18,766,359			
2		000223	LAKE SIDE BLOCK 2 COMBUSTION TURBINE 2-2	34400	18,766,359			
3		000224	LAKE SIDE BLOCK 2 STEAM TURBINE	34400	21,806,510			
4		000225	LAKE SIDE BLOCK 1 COMMON & DYNAMO SUB	34400	23,269			
5		000226	LAKE SIDE BLOCK 1 COMBUSTION TURBINE 1-1	34400	7,565,912			
6		000227	LAKE SIDE BLOCK 1 COMBUSTION TURBINE 1-2	34400	7,565,912			
7		000228	LAKE SIDE BLOCK 1 STEAM TURBINE	34400	7,246,384	81,740,705		
8		000260	GADSBY PLANT COMMON FACILITIES AND SUBST	31400	49,448			
9				31500	66,553			
10		000261	GADSBY NO 1 STEAM ELECTRIC STATION	31400	338,423			
11		000262	GADSBY NO 2 STEAM ELECTRIC STATION	31400	1,156,217			
12		000263	GADSBY NO 3 STEAM ELECTRIC STATION	31400	658,751			
13		000265	GADSBY NO 4 GAS TURBINE PEAKER	34400	5,758,864			
14		000266	GADSBY NO 5 GAS TURBINE PEAKER	34400	5,818,211			
15		000267	GADSBY NO 6 GAS TURBINE PEAKER	34400	6,128,495	19,974,963		
16		000311	CURRANT CREEK BLK 1 COMBUSTION TURBINE A	34400	6,694,710			
17		000312	CURRANT CREEK BLK 1 COMBUSTION TURBINE B	34400	6,700,494			
18		000313	CURRANT CREEK BLK 1 STEAM TURBINE	34400	13,198,941			
19		000314	CURRANT CREEK BLK 1 COMMON & SUBSTATION	34400	41,310	26,635,454		
20		203301	CHEHALIS COMBUSTION TURBINE A	34400	7,410,029			
21		203302	CHEHALIS COMBUSTION TURBINE B	34400	7,178,306			
22		203303	CHEHALIS STEAM TURBINE	34400	7,149,892	21,738,227		
23	GN Total				150,089,349			
24	GT	000222	LAKE SIDE BLOCK 2 COMBUSTION TURBINE 2-1	34300	40,901,218			
25		000223	LAKE SIDE BLOCK 2 COMBUSTION TURBINE 2-2	34300	40,932,953		Lake Side	323,427,959
26		000226	LAKE SIDE BLOCK 1 COMBUSTION TURBINE 1-1	34300	38,483,104			
27		000227	LAKE SIDE BLOCK 1 COMBUSTION TURBINE 1-2	34300	37,650,500	157,967,774	Gadsby	73,311,149
28		000264	GADSBY COMMON GAS PEAKERS & SUBSTATION	34300	1,293,878			
29		000265	GADSBY NO 4 GAS TURBINE PEAKER	34300	13,622,348		Currant	99,462,890
30		000266	GADSBY NO 5 GAS TURBINE PEAKER	34300	14,555,300			
31		000267	GADSBY NO 6 GAS TURBINE PEAKER	34300	12,454,520	41,926,046	Chehalis	113,033,534
32		000311	CURRANT CREEK BLK 1 COMBUSTION TURBINE A	34300	25,921,433			
33		000312	CURRANT CREEK BLK 1 COMBUSTION TURBINE B	34300	25,179,724		Total	609,235,531
34		000314	CURRANT CREEK BLK 1 COMMON & SUBSTATION	34300	8,492,372	59,593,528		
35		203300	CHEHALIS PLANT COMMON & SUBSTATION	34300	630,027			-
36		203301	CHEHALIS COMBUSTION TURBINE A	34300	32,592,047			
37		203302	CHEHALIS COMBUSTION TURBINE B	34300	35,264,753	68,486,827		
38	GT Total				327,974,176	327,974,176		
39	TB	000224	LAKE SIDE BLOCK 2 STEAM TURBINE	34400	62,259,948			
40		000228	LAKE SIDE BLOCK 1 STEAM TURBINE	34400	21,459,532	83,719,480		
41		000261	GADSBY NO 1 STEAM ELECTRIC STATION	31200	258,560			
42				31400	2,733,512			
43		000262	GADSBY NO 2 STEAM ELECTRIC STATION	31400	3,955,640			
44				31500	65,877			
45		000263	GADSBY NO 3 STEAM ELECTRIC STATION	31100	2,052			
46				31400	4,297,745			
47				31500	96,754	11,410,140		
48		000313	CURRANT CREEK BLK 1 STEAM TURBINE	34400	13,233,908	13,233,908		
49		203303	CHEHALIS STEAM TURBINE	34400	22,808,479	22,808,479		
50	TB Total				131,172,007	131,172,007		
51	Grand Total				609,235,531			

	Generating Facility	GSU	Depr for year
1	Total Jim Bridger	14,443,972	251,325
2	Total Lake Side	10,669,330	185,646
3	Lemolo	3,777,087	65,721
4	Toketee	354,719	6,172
5	Slide Creek	1,559,207	- 27,130
6	Soda Springs	109,437	1,904
7	Clearwater	1,386,748	24,129
8	Fish Creek	108,663	1,891
9	Prospect	738,122	12,843
10	Copco	627,922	10,926
11	Copco	2,843,340	49,474
12	Total Copco	3,471,263	60,400
13	JC Boyle	1,509,023	26,257
14	Irongate	134,801	2,346
15	Total Ashton	314,892	5,479
16	Marengo	4,232,780	73,650

FERC 334 ASSET SUMMARY FOR SELECTED HYDRO PLANTS
Investment at 12/31/19

	LOC	LOC DESCRIPTION	Total	Amount Allocated To Real and Reactive Power
1	000444	CUTLER HYDROELECTRIC STATION - PROJECT	$ 2,953,535	$ 2,090,384
2	000455	ASHTON HE PLANT, SUBSTATION AND OFFICE -	1,330,021	351,281
3	000457	GRACE HE PLANT,SUBSTATION AND BUILDINGS	3,098,769	511,336
4	000459	ONEIDA HE PLANT AND SUBSTATION - PROJECT	2,369,988	829,066
5	000461	SODA HE PLANT AND SUBSTATION - PROJECT	795,944	334,292
6	018000	JC BOYLE HYDRO PLANT	6,860,818	3,294,206
7	031000-034000	PROSPECT HYDRO PLANT	8,677,601	764,114
8	040000-041000	LEMOLO HYDRO PLANT	6,861,037	2,554,803
9	042000-043000	CLEARWATER HYDRO PLANT	1,506,236	146,590
10	044000	TOKETEE HYDRO PLANT	2,228,261	1,036,967
11	045000	FISH CREEK HYDRO PLANT	1,844,126	56,301
12	046000	SODA SPRINGS HYDRO PLANT	1,294,157	184,981
13	047000	SLIDE CREEK HYDRO PLANT	3,256,965	2,494,839
14	215000	MERWIN HYDRO PLANT	7,319,103	1,207,933
15	218000	SWIFT HYDRO #1 PLANT	8,079,631	1,748,245
16	219000	YALE HYDRO PLANT	3,855,140	1,732,428
17	610000	IRON GATE HYDRO PLANT	911,415	184,798
18	611000-612000	COPCO HYDRO PLANT	8,857,966	5,770,972
19	Total		$ 72,100,713	$ 25,293,535

Note: This schedule does not contain minor amounts in Account 106. Therefore, it differs slightly from the total AEE investment in Att 8a - Detail Investment Data.

	Asset	SUB	CLASS	LOC	LOC DESCRIPTIO	Capitalized on	PRU	Asset description	Asset description	Acquis.val.	Allocation to Real and Reactive Power Generation
1	3340030	2	33400	000444	CUTLER HYDROELE(	12/16/2008	AF	AF-ACCESSORY ELECTRICAL SYSTEMS	U1 GENERATOR CABLES/LEADS	$ 292,030	$ 292,030
2	3340030	1	33400	000444	CUTLER HYDROELE(	2/14/2008	AF	AF-ACCESSORY ELECTRICAL SYSTEMS	U2 GENERATOR CABLES/LEADS	407,542	407,542
3	3340260	14	33400	000444	CUTLER HYDROELE(	6/21/2017	CI	CI-CUTLER ACCESSORY ELECTRICAL EQUIPMENT	CANAL ELEVATION PROBES	1,928	
4	3340260	0	33400	000444	CUTLER HYDROELE(	12/31/1998	CI	CI-CUTLER ACCESSORY ELECTRICAL EQUIPMENT	CI-CUTLER ACCESSORY ELECTRICAL EQUIPMENT	-	
5	3340260	2	33400	000444	CUTLER HYDROELE(	10/23/2000	CI	CI-CUTLER ACCESSORY ELECTRICAL EQUIPMENT	CI-Cutler SCADA System - CISCA01	59,540	5,954
6	3340260	1	33400	000444	CUTLER HYDROELE(	12/31/1946	CI	CI-CUTLER ACCESSORY ELECTRICAL EQUIPMENT	CONTROLS AND INSTRUMENTATION	253	126
7	3340260	12	33400	000444	CUTLER HYDROELE(	4/21/2015	CI	CI-CUTLER ACCESSORY ELECTRICAL EQUIPMENT	CUTLER DAM WARNING SIRENS	50,267	
8	3340260	9	33400	000444	CUTLER HYDROELE(	12/24/2012	CI	CI-CUTLER ACCESSORY ELECTRICAL EQUIPMENT	CUTLER SECURITY - TAILRACE CAMERA	32,432	
9	3340260	13	33400	000444	CUTLER HYDROELE(	11/23/2015	CI	CI-CUTLER ACCESSORY ELECTRICAL EQUIPMENT	HYDRO SCADA CONTROL NETWORK EQUIPMENT	14,658	1,466
10	3340260	7	33400	000444	CUTLER HYDROELE(	5/5/2009	CI	CI-CUTLER ACCESSORY ELECTRICAL EQUIPMENT	JURISDICT LOAD SYS METER (JLS) L&G 2510	54,617	
11	3340260	8	33400	000444	CUTLER HYDROELE(	11/10/2011	CI	CI-CUTLER ACCESSORY ELECTRICAL EQUIPMENT	PLC CANAL LEVEL RADIO CONTROLS	2,765	
12	3340260	4	33400	000444	CUTLER HYDROELE(	12/20/2007	CI	CI-CUTLER ACCESSORY ELECTRICAL EQUIPMENT	RESERVOIR LEVEL TRANSMITTER REPLACEMENT	7,318	
13	3340260	10	33400	000444	CUTLER HYDROELE(	12/12/2014	CI	CI-CUTLER ACCESSORY ELECTRICAL EQUIPMENT	STREAMFLOW GAUGE ADCP MEASUREMENT EQUIPMENT	37,655	
14	3340260	6	33400	000444	CUTLER HYDROELE(	12/16/2008	CI	CI-CUTLER ACCESSORY ELECTRICAL EQUIPMENT	U1 PROTECTIVE RELAYS & PLANT CONTROLS	500,815	500,815
15	3340260	5	33400	000444	CUTLER HYDROELE(	2/14/2008	CI	CI-CUTLER ACCESSORY ELECTRICAL EQUIPMENT	U2 GENERATOR PROTECTIVE RELAYS	809,733	809,733
16	3340260	3	33400	000444	CUTLER HYDROELE(	5/5/2009	CI	CI-CUTLER ACCESSORY ELECTRICAL EQUIPMENT	JURISDICT LOAD SYS METER (JLS) L&G 2510	-	
17	3340400	19	33400	000444	CUTLER HYDROELE(	12/31/1992	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	AC CIRCUIT BREAKER, STATION SERVICE	5,943	1,486
18	3340400	14	33400	000444	CUTLER HYDROELE(	12/31/1979	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	ACCESS ELEC EQ, SYNCHO EQUIP, SVS TO SHOP/SWYD	109,608	10,961
19	3340400	9	33400	000444	CUTLER HYDROELE(	12/31/1964	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	ADDITIONS TO UNITS	13,767	
20	3340400	21	33400	000444	CUTLER HYDROELE(	3/7/2018	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	CUTLER DAM BACKUP EMERGENCY GENERATOR	261,109	-
21	3340400	1	33400	000444	CUTLER HYDROELE(	12/31/1927	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	CUTLER DEVEL., ELECTRICAL	44,042	11,010
22	3340400	0	33400	000444	CUTLER HYDROELE(	12/31/1998	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	-	
23	3340400	4	33400	000444	CUTLER HYDROELE(	12/31/1942	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	FREQUENCY CONTROL EQUIP	3,245	
24	3340400	2	33400	000444	CUTLER HYDROELE(	12/31/1928	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	FREQUENCY INDICATOR	121	
25	3340400	3	33400	000444	CUTLER HYDROELE(	12/31/1940	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	FREQUENCY RECORDER	532	
26	3340400	16	33400	000444	CUTLER HYDROELE(	12/31/1989	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	GEN JEM METERING, DAM MONITORING TELEMETRY	24,564	
27	3340400	11	33400	000444	CUTLER HYDROELE(	12/31/1967	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	IMPEDANCE GROUNDING AND SURGE PROTECTION	10,418	10,418
28	3340400	15	33400	000444	CUTLER HYDROELE(	12/31/1981	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	KW MODULES, LOAD METERING, DATA MODEMS - DISPATCH	11,188	
29	3340400	13	33400	000444	CUTLER HYDROELE(	12/31/1975	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	MEASUREMENT AND TRANSMISSION	9,772	
30	3340400	12	33400	000444	CUTLER HYDROELE(	12/31/1974	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	METERING MODIFICATION	4,026	
31	3340400	5	33400	000444	CUTLER HYDROELE(	12/31/1950	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	OCB (OIL CIRC BRKR) CABLES AND CONTROLS	30,778	7,695
32	3340400	20	33400	000444	CUTLER HYDROELE(	6/11/2007	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	PLANT BATTERY REPLACEMENT	116,074	23,215
33	3340400	18	33400	000444	CUTLER HYDROELE(	12/31/1992	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE BREAKERS	31,734	7,933
34	3340400	10	33400	000444	CUTLER HYDROELE(	12/31/1966	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	TELEMETERING FOR LOAD FREQ. CONTROL	1,671	
35	3340400	7	33400	000444	CUTLER HYDROELE(	12/31/1958	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	WATT VAR RECORDER	1,980	
36	3340400	6	33400	000444	CUTLER HYDROELE(	12/31/1954	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	WATT-VAR METER	269	
37	3340400	8	33400	000444	CUTLER HYDROELE(	12/31/1962	EM	EM-CUTLER OTHER ACCESSORY ELECTRICAL EQUIP	WATTHOUR METERS	1,142	
38	Total Cutler									2,953,535	2,090,384
39	3340260	17	33400	000455	ASHTON HE PLANT,	11/30/2016	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	ASHTON - UNIT 3 REVENUE METER	10,632	
40	3340260	15	33400	000455	ASHTON HE PLANT,	9/5/2014	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	ASHTON DAM SECURITY TAILRACE CAMERA SYSTEM	41,369	
41	3340260	13	33400	000455	ASHTON HE PLANT,	12/4/2008	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	ASHTON RESERVOIR LEVEL TRANSMITTER/MONITOR	6,700	
42	3340260	16	33400	000455	ASHTON HE PLANT,	11/7/2014	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	ASHTON RIVER ELEVATION PROBE REPLACEMENT	1,824	
43	3340260	0	33400	000455	ASHTON HE PLANT,	12/31/1998	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	-	
44	3340260	9	33400	000455	ASHTON HE PLANT,	12/31/1994	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	COMPUTER CONTROL EQUIPMENT, COMPUTER SYS	14,537	3,634
45	3340260	7	33400	000455	ASHTON HE PLANT,	12/31/1992	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	CONTROLS AND INST. CONTROL PANELS	182,960	45,740
46	3340260	12	33400	000455	ASHTON HE PLANT,	5/5/2009	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	JURISTICTIONAL LOAD METERS	11,449	
47	3340260	11	33400	000455	ASHTON HE PLANT,	4/9/2009	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	LOAD CONTROL, COMM/ALARM SYS EQUIPMENT	101,229	
48	3340260	14	33400	000455	ASHTON HE PLANT,	10/15/2013	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	PLANT METER COMMUN/MONITORING EQUIPMENT	5,842	
49	3340260	5	33400	000455	ASHTON HE PLANT,	12/31/1981	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	PLANT TRIPPING MODIFICATIONS	8,369	-
50	3340260	2	33400	000455	ASHTON HE PLANT,	12/31/1948	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	RELAY AND CURRENT TRANSFORMER	114	114
51	3340260	6	33400	000455	ASHTON HE PLANT,	12/31/1989	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	RELAY PROTECTION, LOAD CONTROL, PANELS	41,514	10,379
52	3340260	1	33400	000455	ASHTON HE PLANT,	12/31/1941	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	RELAYS ON #1 GENERATOR	721	721
53	3340260	10	33400	000455	ASHTON HE PLANT,	9/9/2008	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	WATT/VAR METER REPLACEMENT - FOR ENERGY MEASUREMNT	19,853	
54	3340260	8	33400	000455	ASHTON HE PLANT,	12/31/1992	CI	CI-ASHTON ACCESSORY ELECTRICAL EQUIPMENT	WIRE/CABLE, CONTROL & INSTRUMENTATION	111,312	27,828
55	3340400	14	33400	000455	ASHTON HE PLANT,	12/31/1995	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY BANK & CHARGER	17,749	3,550
56	3340400	17	33400	000455	ASHTON HE PLANT,	10/27/2015	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY BANK REPLACEMENT	68,889	13,778
57	3340400	13	33400	000455	ASHTON HE PLANT,	12/31/1982	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY CHARGER	3,315	663
58	3340400	15	33400	000455	ASHTON HE PLANT,	12/31/1989	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY CHARGER (XFERRED FROM COVE)	4,033	807
59	3340400	9	33400	000455	ASHTON HE PLANT,	12/31/1969	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	CABLE TO GENERATOR	4,317	4,317
60	3340400	3	33400	000455	ASHTON HE PLANT,	12/31/1926	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	CONDUIT	35	9
61	3340400	1	33400	000455	ASHTON HE PLANT,	12/31/1917	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT	1,591	398
62	3340400	2	33400	000455	ASHTON HE PLANT,	12/31/1925	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT	15,921	3,980
63	3340400	0	33400	000455	ASHTON HE PLANT,	12/31/1998	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	-	
64	3340400	10	33400	000455	ASHTON HE PLANT,	12/31/1988	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	NET GENERATION METERING	6,491	
65	3340400	7	33400	000455	ASHTON HE PLANT,	12/31/1960	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	RECORDING VOLTMETER	186	
66	3340400	6	33400	000455	ASHTON HE PLANT,	12/31/1959	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	RHEOSTATS, AND EXCITERS	910	910
67	3340400	11	33400	000455	ASHTON HE PLANT,	12/31/1989	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	SEMI-AUTOMATION EQUIP	334,586	
68	3340400	4	33400	000455	ASHTON HE PLANT,	12/31/1947	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE	822	206
69	3340400	8	33400	000455	ASHTON HE PLANT,	12/31/1965	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE PANEL	2,276	569
70	3340400	5	33400	000455	ASHTON HE PLANT,	12/31/1957	EM	EM-ASHTON OTHER ACCESSORY ELECTRICAL EQUIP	VOLTAGE REGULATORS	3,195	3,195
71	3340490	0	33400	000455	ASHTON HE PLANT,	12/31/1998	GE	GE-EXCITER SYSTEM, DC EXCITER	1998 BALANCE CONVERSION	-	

Primary Table Principles Followed:	Allocation to Real and Reactive Power Generation
1. Battery systems	20%
2. SCADA systems	10%
3. Emergency generator systems	0%
4. Station service equipment	25%
5. Electrical - miscellaneous	25%
6. Annunciators	10%
7. PLCs and RTUs	10%
8. Generator or exciter	100%

	Not sure to which category the item applies
???	Additional item

72	3340490 1	33400	000455	ASHTON HE PLANT,	12/31/1983	GE	GE-EXCITER SYSTEM, DC EXCITER	GENERATOR BREAKERS	187,887	187,887
73	3340490 2	33400	000455	ASHTON HE PLANT,	12/31/1982	GE	GE-EXCITER SYSTEM, DC EXCITER	GENERATOR, EXCITER	36,783	36,783
74	3340800 1	33400	000455	ASHTON HE PLANT,	12/31/1990	SM	SM-ASHTON STRUCTURES & IMPROVEMENTS	EMERG POWER UPGRADE (EPU) AND BUILDING	23,255	5,814
75	3340800 0	33400	000455	ASHTON HE PLANT,	12/31/1998	SM	SM-ASHTON STRUCTURES & IMPROVEMENTS	SM-ASHTON STRUCTURES & IMPROVEMENTS	-	
76	3347400 0	33470	000455	ASHTON HE PLANT,	12/31/1998	EM	EM-ELECTRIC EQUIPMENT, RTU	1998 BALANCE CONVERSION	-	
77	3347400 2	33470	000455	ASHTON HE PLANT,	9/22/2014	EM	EM-ELECTRIC EQUIPMENT, RTU	DAM MONITORING TELEMETRY	59,354	
				Total Ashton					1,330,021	351,281
78	3340260 31	33400	000457	GRACE HE PLANT,SI	10/14/2015	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	(2) ANNUNCIATOR PANELS FOR ALARM SYSTEM	7,339	734
79	3340260 14	33400	000457	GRACE HE PLANT,SI	4/15/1999	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	2 Each - 48 Point Annunciator	96,754	9,675
80	3340260 0	33400	000457	GRACE HE PLANT,SI	12/31/1998	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	-	
81	3340260 16	33400	000457	GRACE HE PLANT,SI	10/7/2003	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	CI-REPLACE SCADA WITH NEW L&N SYSTEM	55,587	5,559
82	3340260 8	33400	000457	GRACE HE PLANT,SI	12/31/1968	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	CONTROLS ADDTN, GRND/SURG PROTECT, RETD ANUNCIATOR	55,482	13,871
83	3340260 32	33400	000457	GRACE HE PLANT,SI	2/25/2019	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	COOLING WATER OIL CONTAMINATION NOTIFICATION/ALARM	31,628	
84	3340260 11	33400	000457	GRACE HE PLANT,SI	12/31/1981	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	DATA MODEMS FOR DISPATCH COMPUTER SYSTEM	1,192	
85	3340260 25	33400	000457	GRACE HE PLANT,SI	9/26/2011	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	ELEVATION FLOW PROBE/GAUGE AT WEIR	2,530	
86	3340260 20	33400	000457	GRACE HE PLANT,SI	7/11/2005	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	FLOW LINE LEAK MONITORING SYSTEM (COMMUN EQUIP)	155,687	
87	3340260 2	33400	000457	GRACE HE PLANT,SI	12/31/1922	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	GENERATOR PROTECTION RELAYS, FREQ METER	2,198	2,198
88	3340260 23	33400	000457	GRACE HE PLANT,SI	12/4/2008	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	GRACE RESERVOIR LEVEL TRANSMITTER	9,223	
89	3340260 29	33400	000457	GRACE HE PLANT,SI	11/23/2015	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	HYDRO SCADA CONTROL NETWORK EQUIPMENT	4,883	488
90	3340260 30	33400	000457	GRACE HE PLANT,SI	11/28/2017	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	ID NETWORK SCADA CONTROL EQUIPMENT	11,320	
91	3340260 24	33400	000457	GRACE HE PLANT,SI	11/10/2009	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	LOAD CONTROL, COMM/ALARM SYS EQUIPMENT	78,012	
92	3340260 3	33400	000457	GRACE HE PLANT,SI	12/31/1926	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	MASTER CLOCK AND TELECHRON	458	
93	3340260 9	33400	000457	GRACE HE PLANT,SI	12/31/1975	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	METERING MODIFIC, MEASUREMENT OF WATT/VAR	2,390	
94	3340260 10	33400	000457	GRACE HE PLANT,SI	12/31/1976	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	OVERVOLTAGE RELAYS	830	830
95	3340260 26	33400	000457	GRACE HE PLANT,SI	5/29/2012	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	RATE OF CHANGE ALARM / MONITOR FOR TAILRACE	22,296	
96	3340260 18	33400	000457	GRACE HE PLANT,SI	10/11/2004	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	RIVER GAUGES FLOW PHONE AND WEBSITE	17,251	
97	3340260 28	33400	000457	GRACE HE PLANT,SI	12/12/2014	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	STREAMFLOW GAUGE ADCP MEASUREMENT EQUIPMENT	37,655	
98	3340260 6	33400	000457	GRACE HE PLANT,SI	12/31/1958	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	WATTVAR RECORDER	1,031	
99	3340260 21	33400	000457	GRACE HE PLANT,SI	6/1/2007	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	JURISDICT LOAD SYS METER (JLS) L&G 2510	32,441	
100	3340260 27	33400	000457	GRACE HE PLANT,SI	6/20/2014	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	EIM METERING EQUIPMENT	57,672	
101	3340260 22	33400	000457	GRACE HE PLANT,SI	12/11/2008	CI	CI-GRACE INSTRUMENTATION & CONTROL EQUIPMENT	BR GAUGES, DATA LOGGERS, TELEMETRY, SEE LONG TEXT	141,065	
102	3340290 2	33400	000457	GRACE HE PLANT,SI	11/18/2015	CP	CP-GRACE CATHODIC PROTECTION	CATHODIC PROTECTION SYSTEM FOR PENSTOCKS	427,854	
103	3340290 3	33400	000457	GRACE HE PLANT,SI	11/20/2018	CP	CP-GRACE CATHODIC PROTECTION	CATHODIC PROTECTION - UPPER GROUNDBED REPLACEMENT	412,283	
104	3340290 1	33400	000457	GRACE HE PLANT,SI	10/11/2006	CP	CP-GRACE CATHODIC PROTECTION	CATHODIC PROTECTION ANODES FOR SURGE TANK GRNDBED	9,125	
105	3340400 10	33400	000457	GRACE HE PLANT,SI	12/31/1947	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	#4 BK. OF 130KV TRANS., RELAY FOR OIL CIRC BREAKER	1,528	1,528
106	3340400 23	33400	000457	GRACE HE PLANT,SI	4/9/2007	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	50DW MOBILE GENERATOR FOR EMERGENCY COMMAND CENTER	34,009	-
107	3340400 6	33400	000457	GRACE HE PLANT,SI	12/31/1924	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	6600V CABLE RECONSTRUCT, RELAYS, SWITCHES	29,713	29,713
108	3340400 2	33400	000457	GRACE HE PLANT,SI	12/31/1916	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	COVE DEVELOPMENT	6,178	
109	3340400 24	33400	000457	GRACE HE PLANT,SI	2/20/2009	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	DC BATTERY BANK, CHARGER, CONVERTER, DISTRIB PANEL	145,855	29,171
110	3340400 7	33400	000457	GRACE HE PLANT,SI	12/31/1930	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC IMPROVEMENTS TO 6600V BUS ROOM	5,167	1,292
111	3340400 21	33400	000457	GRACE HE PLANT,SI	12/31/1953	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	EM-EMERGENCY GENERATOR FROM YALE PLANT	4,877	-
112	3340400 0	33400	000457	GRACE HE PLANT,SI	12/31/1998	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	-	
113	3340400 17	33400	000457	GRACE HE PLANT,SI	12/31/1988	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	EM-NET GENERATION JEM 2	37,932	
114	3340400 18	33400	000457	GRACE HE PLANT,SI	12/31/1987	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	EM-REPLACE ANNUNCIATOR PANEL	22,400	2,240
115	3340400 25	33400	000457	GRACE HE PLANT,SI	2/20/2009	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	EMERGENCY GENERATOR	51,430	-
116	3340400 26	33400	000457	GRACE HE PLANT,SI	10/4/2016	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	EMERGENCY GENERATOR AT DAM INTAKE GATE REPLACE	113,086	
117	3340400 5	33400	000457	GRACE HE PLANT,SI	12/31/1923	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	GRACE - POCATELLO XFRMRS, GRCE SWCHYD SODA CONNECT	1,042	
118	3340400 1	33400	000457	GRACE HE PLANT,SI	12/31/1913	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	GRACE DEVELOPMENT, METERS	57,346	
119	3340400 4	33400	000457	GRACE HE PLANT,SI	12/31/1922	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	GRACE UNIT #5	33,259	33,259
120	3340400 14	33400	000457	GRACE HE PLANT,SI	12/31/1956	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	IMPROVE 6600 VOLT BUS ROOM	12,310	3,078
121	3340400 8	33400	000457	GRACE HE PLANT,SI	12/31/1941	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	INSTALL 161KV SUBSTATION	6,663	6,663
122	3340400 13	33400	000457	GRACE HE PLANT,SI	12/31/1953	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	INSULATE 6600 VOLT BUS BARS, WATTMETER, VOLTMETER	3,244	811
123	3340400 22	33400	000457	GRACE HE PLANT,SI	12/31/1988	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	LAST CHANCE REMOTE TERMINAL	3,745	
124	3340400 12	33400	000457	GRACE HE PLANT,SI	12/31/1952	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	REPAIRS TO STATION BUS	431	
125	3340400 9	33400	000457	GRACE HE PLANT,SI	12/31/1946	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	REPLACE POTENTIAL TRANSFORMER ON VOLTAGE REGULATOR	344	344
126	3340400 11	33400	000457	GRACE HE PLANT,SI	12/31/1949	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	REPLACE RELAY ON 6600V LOCAL SERVICE OCB	146	
127	3340400 27	33400	000457	GRACE HE PLANT,SI	1/7/2019	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE AUX TRANSFORMER REPLACEMENT	339,439	84,860
128	3340400 15	33400	000457	GRACE HE PLANT,SI	12/31/1983	EM	EM-GRACE OTHER ACCESSORY ELECTRICAL EQUIP	SUPERVISORY CONTROL AND DATA ACQUISITION EQUIPMENT	250,209	25,021
129	3340490 0	33400	000457	GRACE HE PLANT,SI	12/31/1998	GE	GE-EXCITER SYSTEM, DC EXCITER	1998 BALANCE CONVERSION	-	
130	3340490 1	33400	000457	GRACE HE PLANT,SI	12/31/1983	GE	GE-EXCITER SYSTEM, DC EXCITER	GENERATOR	22,702	22,702
131	3340490 2	33400	000457	GRACE HE PLANT,SI	12/31/1982	GE	GE-EXCITER SYSTEM, DC EXCITER	GENERATOR, EXCITER	34,541	34,541
132	3340490 3	33400	000457	GRACE HE PLANT,SI	12/31/1983	GE	GE-EXCITER SYSTEM, DC EXCITER	GENERATOR, EXCITER	81,824	81,824
133	3340820 1	33400	000457	GRACE HE PLANT,SI	12/31/1990	SP	SP - GRACE CAPITAL SPARES FERC 334	SP - GENERATOR BREAKER XFERD FR COVE, MM #6011002	45,351	45,351
134	3340820 2	33400	000457	GRACE HE PLANT,SI	12/31/1990	SP	SP - GRACE CAPITAL SPARES FERC 334	SP - PWR POTENTIAL TRANSFRMR XFR FR COVE, #6011003	75,584	75,584
135	3347400 0	33470	000457	GRACE HE PLANT,SI	12/31/1998	EM	EM-ELECTRIC EQUIPMENT, RTU	1998 BALANCE CONVERSION	-	
136	3347400 1	33470	000457	GRACE HE PLANT,SI	12/31/1992	EM	EM-ELECTRIC EQUIPMENT, RTU	EM-ALARM EQUIPMENT FOR LAST CHANCE	4,229	
137				Total Grace					3,098,769	511,336
138	3340030 2	33400	000459	ONEIDA HE PLANT /	6/4/2009	AF	AF - ACCESSORY ELECTRICAL EQUIPMENT	CABLE & CABLE TRAYS FROM GEN BUSS TO TRANSFORMER	479,411	479,411
139	3340030 1	33400	000459	ONEIDA HE PLANT /	12/17/2007	AF	AF - ACCESSORY ELECTRICAL EQUIPMENT	POWER CABLE FROM GENERATORS TO TRANSFORMERS	49,763	49,763
140	3340260 8	33400	000459	ONEIDA HE PLANT /	12/31/1964	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	ALARMS, RELAYS, PROTECTIVE DEVICES	12,924	3,231
141	3340260 23	33400	000459	ONEIDA HE PLANT /	8/5/2013	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	CAMPGROUND SIREN ALARM - RIVER LEVEL WARNING	28,157	
142	3340260 13	33400	000459	ONEIDA HE PLANT /	3/26/2002	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	CI-2002 SCADA SYSTEM - CISCA01	50,045	5,005
143	3340260 0	33400	000459	ONEIDA HE PLANT /	12/31/1998	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	-	
144	3340260 26	33400	000459	ONEIDA HE PLANT /	6/7/2018	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	COOLING WATER OIL CONTAMINATION NOTIFICATION/ALARM	103,487	
145	3340260 25	33400	000459	ONEIDA HE PLANT /	7/9/2014	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	DAM CONTROL PLC MODEM REPLACEMENT	964	
146	3340260 16	33400	000459	ONEIDA HE PLANT /	12/4/2008	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	DAM PLC PANEL LIGHTNING PROTECTION	5,082	
147	3340260 2	33400	000459	ONEIDA HE PLANT /	12/31/1929	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	DIFFERENTIAL RELAYS ON GENERATORS	296	296

148	3340260 3	33400	000459	ONEIDA HE PLANT A	12/31/1930	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	ELECTRIC IMPROVEMENTS	336	84
149	3340260 12	33400	000459	ONEIDA HE PLANT A	12/31/1994	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	GENERATOR DIFFERENTIAL RELAYS	15,333	15,333
150	3340260 9	33400	000459	ONEIDA HE PLANT A	12/31/1968	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	GROUNDING AND SURGE PROTECTION	15,696	15,696
151	3340260 14	33400	000459	ONEIDA HE PLANT A	5/19/2004	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	HYDROLABS (DATA LOGGERS) WATER QUALITY EQUIP	32,340	
152	3340260 6	33400	000459	ONEIDA HE PLANT A	12/31/1941	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	LOAD AND FREQUENCY CONTROL EQUIP	3,882	
153	3340260 18	33400	000459	ONEIDA HE PLANT A	12/4/2008	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	ONEIDA RESERVOIR LEVEL TRANSMITTER/MONITOR	4,585	
154	3340260 21	33400	000459	ONEIDA HE PLANT A	12/24/2012	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	ONEIDA SECURITY - TAILRACE CAMERA	23,166	
155	3340260 22	33400	000459	ONEIDA HE PLANT A	12/24/2012	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	ONEIDA SECURITY - WARNING SIREN	56,375	
156	3340260 4	33400	000459	ONEIDA HE PLANT A	12/31/1931	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	RELAYS	234	234
157	3340260 5	33400	000459	ONEIDA HE PLANT A	12/31/1938	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	RELAYS	272	272
158	3340260 17	33400	000459	ONEIDA HE PLANT A	12/11/2008	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	RESERVOIR ELEVATION MEASUREMENT EQUIPMENT	5,556	
159	3340260 7	33400	000459	ONEIDA HE PLANT A	12/31/1946	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	RHEOSTAT	77	77
160	3340260 19	33400	000459	ONEIDA HE PLANT A	12/13/2011	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	RTE OF CHNGE SENSORS, AUDIBLE ALARMS, SPILLWY ALRM	104,669	
161	3340260 11	33400	000459	ONEIDA HE PLANT A	12/31/1995	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	STATION CT'S	16,291	4,073
162	3340260 24	33400	000459	ONEIDA HE PLANT A	12/12/2014	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	STREAMFLOW GAUGE ADCP MEASUREMENT EQUIPMENT	37,655	
163	3340260 10	33400	000459	ONEIDA HE PLANT A	12/31/1984	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	SWITCH PANEL AND CONDUCTOR TO PANEL	16,198	
164	3340260 20	33400	000459	ONEIDA HE PLANT A	8/9/2012	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	U2 WATT-HOUR METER REPLACEMENT	5,074	
165	3340260 15	33400	000459	ONEIDA HE PLANT A	6/1/2007	CI	CI-ONEIDA ACCESSORY ELECTRICAL EQUIPMENT	JURISDICT LOAD SYS METER (JLS) L&G 2510	28,463	
166	3340290 1	33400	000459	ONEIDA HE PLANT A	10/25/2016	CP	CP-ONEIDA CATHODIC PROTECTION EQUIPMENT	CATHODIC PROTECTION TESTING STATIONS, MONITOR EQ	172,866	
167	3340400 22	33400	000459	ONEIDA HE PLANT A	12/31/1997	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	AC/DC LOAD CENTER, STATION SERVICE BREAKERS	68,900	17,225
168	3340400 20	33400	000459	ONEIDA HE PLANT A	12/31/1987	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	ANNUNCIATOR PANEL	37,957	3,796
169	3340400 9	33400	000459	ONEIDA HE PLANT A	12/31/1956	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	CD FREQUENCY RECORDER	547	
170	3340400 28	33400	000459	ONEIDA HE PLANT A	10/10/2017	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	CRITICAL AC EMERGENCY GENERATOR, CABLING, BACKUP	449,737	-
171	3340400 3	33400	000459	ONEIDA HE PLANT A	12/31/1918	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	CURRENT TRANSFORMER	10	11
172	3340400 19	33400	000459	ONEIDA HE PLANT A	12/31/1989	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	DAM MONITORING TELEMETRY	13,848	
173	3340400 27	33400	000459	ONEIDA HE PLANT A	12/27/2012	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	DC SYSTEM BATTERY BANK REPLACEMENT	102,751	20,550
174	3340400 0	33400	000459	ONEIDA HE PLANT A	12/31/1998	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	-	
175	3340400 23	33400	000459	ONEIDA HE PLANT A	2/20/2009	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	EMERGENCY GENERATOR FOR TURBINE ISO VALVES	66,126	
176	3340400 4	33400	000459	ONEIDA HE PLANT A	12/31/1923	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	IMPROVE DISCONNECT SWITCHES	121	
177	3340400 6	33400	000459	ONEIDA HE PLANT A	12/31/1947	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	LOCAL SERVICE OCB	93	
178	3340400 5	33400	000459	ONEIDA HE PLANT A	12/31/1926	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	MASTER CLOCK AND TELECHRON	470	
179	3340400 16	33400	000459	ONEIDA HE PLANT A	12/31/1982	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	METERING FOR STATE LOAD	15,429	
180	3340400 18	33400	000459	ONEIDA HE PLANT A	12/31/1988	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	NET GENERATION PROFILE METERING	22,902	
181	3340400 1	33400	000459	ONEIDA HE PLANT A	12/31/1915	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	ONEIDA DEVELOPMENT	75,628	
182	3340400 17	33400	000459	ONEIDA HE PLANT A	12/31/1985	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	ONEIDA DISASTER	11,532	
183	3340400 14	33400	000459	ONEIDA HE PLANT A	12/31/1980	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	PLANT TRIPPING MODIFICATION	20,213	5,053
184	3340400 7	33400	000459	ONEIDA HE PLANT A	12/31/1952	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	POTENTIAL TRANSFORMER #2, #3 UNITS	774	774
185	3340400 8	33400	000459	ONEIDA HE PLANT A	12/31/1953	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	RECORDING VOLTMETER, BUS BARS	436	109
186	3340400 15	33400	000459	ONEIDA HE PLANT A	12/31/1981	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	UNIT BREAKER REPLACEMENT	102,554	102,554
187	3340400 12	33400	000459	ONEIDA HE PLANT A	12/31/1974	EM	EM-ONEIDA OTHER ACCESSORY ELECTRICAL EQUIP	WATTHOUR METER INTRFCE, RELAYS	5,243	
188	3340490 0	33400	000459	ONEIDA HE PLANT A	12/31/1998	GE	GE-EXCITER SYSTEM, DC EXCITER	1998 BALANCE CONVERSION	-	
189	3340490 1	33400	000459	ONEIDA HE PLANT A	12/31/1981	GE	GE-EXCITER SYSTEM, DC EXCITER	EXCITER AND STATOR COILS ON #3 GENERATOR	17,182	17,182
190	3340490 3	33400	000459	ONEIDA HE PLANT A	12/31/1985	GE	GE-EXCITER SYSTEM, DC EXCITER	EXCITER ON #2 GENERATOR	63,616	63,616
191	3340490 2	33400	000459	ONEIDA HE PLANT A	12/31/1983	GE	GE-EXCITER SYSTEM, DC EXCITER	UNIT #1, STATOR COILS, EXCITER, VOLT REG	24,721	24,721
192			Total Oneida						2,369,988	829,066
193	3340030 1	33400	000461	SODA HE PLANT AN	5/10/2011	AF	AF-SODA OTHER ACCESSORY ELECTRICAL EQUIPMENT	GEN CURRENT XFORMERS & TEMP MONITORING	15,243	15,243
194	3340030 2	33400	000461	SODA HE PLANT AN	5/10/2011	AF	AF-SODA OTHER ACCESSORY ELECTRICAL EQUIPMENT	SODA GENERATOR CABLES	48,500	48,500
195	3340260 0	33400	000461	SODA HE PLANT AN	12/31/1998	CI	CI-SODA INSTRUMENTATION & CONTROL EQUIPMENT	CI-SODA INSTRUMENTATION & CONTROL EQUIPMENT	-	
196	3340260 3	33400	000461	SODA HE PLANT AN	2/19/2009	CI	CI-SODA INSTRUMENTATION & CONTROL EQUIPMENT	JURISTICTIONAL LOAD SYS METER (JLS) L&G 2510	30,610	
197	3340260 2	33400	000461	SODA HE PLANT AN	10/22/2008	CI	CI-SODA INSTRUMENTATION & CONTROL EQUIPMENT	LOAD CONTROL, COMM/ALARM SYS EQUIPMENT	170,138	
198	3340260 8	33400	000461	SODA HE PLANT AN	12/3/2012	CI	CI-SODA INSTRUMENTATION & CONTROL EQUIPMENT	REVENUE METER REMOTE CONTROL/MONITORING EQUIP	480	
199	3340260 6	33400	000461	SODA HE PLANT AN	5/10/2011	CI	CI-SODA INSTRUMENTATION & CONTROL EQUIPMENT	SODA GENERATOR PROTECTIVE RELAYS	5,543	5,543
200	3340260 4	33400	000461	SODA HE PLANT AN	12/4/2008	CI	CI-SODA INSTRUMENTATION & CONTROL EQUIPMENT	SODA RESERVOIR LEVEL TRANSMITTER	8,644	
201	3340260 7	33400	000461	SODA HE PLANT AN	12/24/2012	CI	CI-SODA INSTRUMENTATION & CONTROL EQUIPMENT	SODA SECURITY - TAILRACE CAMERA	23,166	
202	3340260 5	33400	000461	SODA HE PLANT AN	12/4/2008	CI	CI-SODA INSTRUMENTATION & CONTROL EQUIPMENT	SODA TAILRACE LEVEL TRANSMITTER	5,753	
203	3340260 10	33400	000461	SODA HE PLANT AN	12/12/2014	CI	CI-SODA INSTRUMENTATION & CONTROL EQUIPMENT	STREAMFLOW GAUGE ADCP MEASUREMENT EQUIPMENT	37,655	
204	3340260 9	33400	000461	SODA HE PLANT AN	8/20/2014	CI	CI-SODA INSTRUMENTATION & CONTROL EQUIPMENT	EIM METERING EQUIPMENT	25,688	
205	3340400 19	33400	000461	SODA HE PLANT AN	12/31/1970	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY CHARGER	1,596	319
206	3340400 1	33400	000461	SODA HE PLANT AN	12/31/1924	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT	120,441	30,110
207	3340400 0	33400	000461	SODA HE PLANT AN	12/31/1998	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	-	
208	3340400 16	33400	000461	SODA HE PLANT AN	12/31/1985	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	GENERATOR CABLE	32,542	32,542
209	3340400 8	33400	000461	SODA HE PLANT AN	12/31/1968	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	GROUNDING AND SURGE PROTECTION	12,279	12,279
210	3340400 11	33400	000461	SODA HE PLANT AN	12/31/1976	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	LENKURT DATA EQUIPMENT	363	
211	3340400 12	33400	000461	SODA HE PLANT AN	12/31/1977	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	LIGHTING PANEL AND WIRING	17,138	
212	3340400 6	33400	000461	SODA HE PLANT AN	12/31/1959	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	LOCAL SERVICE CABLE	1,896	
213	3340400 5	33400	000461	SODA HE PLANT AN	12/31/1950	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	LOCAL SERVICE TRANSFORMER	1,759	
214	3340400 10	33400	000461	SODA HE PLANT AN	12/31/1975	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	MEASURE AND TRANSMIT WATT/VAR	672	
215	3340400 13	33400	000461	SODA HE PLANT AN	12/31/1981	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	METERING FOR STATE LOAD, DATA MODEM DISPATCH COMPU	11,184	
216	3340400 9	33400	000461	SODA HE PLANT AN	12/31/1974	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	METERING MODIFICATIONS	2,911	
217	3340400 4	33400	000461	SODA HE PLANT AN	12/31/1931	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	METERS ON LOCAL SERVICE	41	
218	3340400 2	33400	000461	SODA HE PLANT AN	12/31/1925	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	PUSH BUTTON STATIONS	95	
219	3340400 7	33400	000461	SODA HE PLANT AN	12/31/1961	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	RELAYS ON #51 OIL SWITCH	1,079	
220	3340400 20	33400	000461	SODA HE PLANT AN	12/31/1987	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	STATION BATTERY	13,062	2,612
221	3340400 14	33400	000461	SODA HE PLANT AN	12/31/1982	EM	EM-SODA OTHER ACCESSORY ELECTRICAL EQUIP	SUPERVISORY CONTROL, DATA ACQUISITION	22,582	2,258
222	3340490 0	33400	000461	SODA HE PLANT AN	12/31/1998	GE	GE-EXCITER SYSTEM, DC EXCITER	1998 BALANCE CONVERSION	-	
223	3340490 2	33400	000461	SODA HE PLANT AN	10/10/2016	GE	GE-EXCITER SYSTEM, DC EXCITER	EXCITER BATTERY BANK 130Vdc & CHARGERS SYSTEM	28,071	28,071
224	3340490 1	33400	000461	SODA HE PLANT AN	12/31/1981	GE	GE-EXCITER SYSTEM, DC EXCITER	GENERATOR, EXCITER	156,814	156,814
225			Total Soda						795,944	334,292

226	3340030 9	33400	018000	JC BOYLE HYDRO PL	11/16/2004	AF	AF-Acessory Electrical Equipment	AF- U1& U2 GENERATOR BREAKER & CABLE LEADS	971,019	971,019	
227	3340030 6	33400	018000	JC BOYLE HYDRO PL	11/16/2004	AF	AF-Acessory Electrical Equipment	AF-BUS LEADS	157,652	157,652	
228	3340030 7	33400	018000	JC BOYLE HYDRO PL	11/16/2004	AF	AF-Acessory Electrical Equipment	AF-BUSS STRUCTURE	107,598	107,598	
229	3340030 0	33400	018000	JC BOYLE HYDRO PL	12/16/1999	AF	AF-Acessory Electrical Equipment	AF-GE U Type Bushing - AFTSFE30	3,428	3,428	
230	3340030 2	33400	018000	JC BOYLE HYDRO PL	11/16/2004	AF	AF-Acessory Electrical Equipment	AF-GENERATOR BUSS LEADS	16,762	16,762	
231	3340030 3	33400	018000	JC BOYLE HYDRO PL	11/16/2004	AF	AF-Acessory Electrical Equipment	AF-GENERATOR BUSS SUPPORTS	11,346	11,346	
232	3340030 5	33400	018000	JC BOYLE HYDRO PL	11/16/2004	AF	AF-Acessory Electrical Equipment	AF-GENERATOR CIRCUIT BREAKERS	47,276	47,276	
233	3340030 4	33400	018000	JC BOYLE HYDRO PL	11/16/2004	AF	AF-Acessory Electrical Equipment	AF-GENERATOR GROUNDING SYSTEM	2,689	2,689	
234	3340030 8	33400	018000	JC BOYLE HYDRO PL	11/16/2004	AF	AF-Acessory Electrical Equipment	AF-GROUNDING SYSTEM	23,200	23,200	
235	3340030 11	33400	018000	JC BOYLE HYDRO PL	12/30/2010	AF	AF-Acessory Electrical Equipment	GENERATOR BREAKER REBUILD	22,842	22,842	
236	3340030 10	33400	018000	JC BOYLE HYDRO PL	1/2/2007	AF	AF-Acessory Electrical Equipment	U1 GENERATOR CABLE LEADS	19,650	19,650	
237	3340260 32	33400	018000	JC BOYLE HYDRO PL	11/29/2010	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	ARC FLASH PROTECTION FOR U1&2 SWITCHGEAR	49,929	-	
238	3340260 7	33400	018000	JC BOYLE HYDRO PL	12/31/1990	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	AUTO SYNCHRONIZER/CONTROLS	99,216	24,804	
239	3340260 18	33400	018000	JC BOYLE HYDRO PL	12/31/1998	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	CI-CONTROLS AND INSTRUMENTATION UPGRADE (16263)	485,735	121,434	
240	3340260 16	33400	018000	JC BOYLE HYDRO PL	6/20/2002	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	CI-FLOWMETER - CICMPC0	157,346		
241	3340260 0	33400	018000	JC BOYLE HYDRO PL	12/31/1998	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	CI-JC BOYLE CONTROL & INSTRUMENTATION	-		
242	3340260 25	33400	018000	JC BOYLE HYDRO PL	3/17/2005	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	CI-PLC MONITORS	1,802		
243	3340260 19	33400	018000	JC BOYLE HYDRO PL	11/16/2004	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	CI-RELAY PANELS	251,779	62,945	
244	3340260 21	33400	018000	JC BOYLE HYDRO PL	11/16/2004	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	CI-RELAY PANELS	50,569	12,642	
245	3340260 24	33400	018000	JC BOYLE HYDRO PL	11/16/2004	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	CI-RELAY PROTECTION PANELS	505,314	505,314	
246	3340260 20	33400	018000	JC BOYLE HYDRO PL	11/16/2004	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	CI-RELAYS	104,865	104,865	
247	3340260 15	33400	018000	JC BOYLE HYDRO PL	12/17/1999	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	CONTROL/MONITOR EQUIP. CONTROL EQUIP - GE MASTER	390,693	97,673	
248	3340260 10	33400	018000	JC BOYLE HYDRO PL	12/31/1998	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	CONTROL/MONITOR EQUIP. CONTROL EQUIPMENT	18,583	4,646	
249	3340260 5	33400	018000	JC BOYLE HYDRO PL	12/31/1996	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	CONTROLS AND INSTRUMENTATION	59,175	14,794	
250	3340260 29	33400	018000	JC BOYLE HYDRO PL	2/20/2009	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	GEN PROTECTIVE RELAY SOFTWARE UPGRADE	56,617	56,617	
251	3340260 23	33400	018000	JC BOYLE HYDRO PL	11/3/2005	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	GENERATOR RELAY PROTECTION SYSTEM	279,980	279,980	
252	3340260 33	33400	018000	JC BOYLE HYDRO PL	7/13/2011	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	HEADGATE OPERATOR INTERFACE TERMINAL	3,561		
253	3340260 26	33400	018000	JC BOYLE HYDRO PL	7/18/2006	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	HEADGATE OPERATOR INTERFACE TERMINAL (OIT)	10,990		
254	3340260 37	33400	018000	JC BOYLE HYDRO PL	11/23/2015	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	HYDRO SCADA CONTROL NETWORK EQUIPMENT	9,766	977	
255	3340260 38	33400	018000	JC BOYLE HYDRO PL	11/28/2017	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	JC BOYLE NETWORK SCADA CONTROL EQUIPMENT	5,660	566	
256	3340260 35	33400	018000	JC BOYLE HYDRO PL	12/24/2012	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	JC BOYLE SECURITY - WARNING SIREN	36,883		
257	3340260 39	33400	018000	JC BOYLE HYDRO PL	3/24/2017	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	JC BOYLE SECURITY - WARNING SIREN @ CAMP BELOW DAM	35,790		
258	3340260 30	33400	018000	JC BOYLE HYDRO PL	9/27/2010	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	JCB STREAM GAUGES @ BYPASS REACH & SPENCER CREEK	31,354		
259	3340260 11	33400	018000	JC BOYLE HYDRO PL	12/31/1990	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	OTHER INST. & CONTROL, MINOR INSTRUMENTS	15,427		
260	3340260 40	33400	018000	JC BOYLE HYDRO PL	12/27/2017	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	PHASOR MEASUREMENT UNIT (PMU) - DATA, MONITORING	34,586	-	
261	3340260 9	33400	018000	JC BOYLE HYDRO PL	12/31/1990	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	PROGRAMMABLE LOGIC CONTROL, CONTROL INST	513,056	128,264	
262	3340260 13	33400	018000	JC BOYLE HYDRO PL	12/31/1990	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	RELAY PROTECTION, EVENT RECORDER	63,072	63,072	
263	3340260 27	33400	018000	JC BOYLE HYDRO PL	1/2/2007	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	RELAYS/CONTROLS GENERATOR TO STEP-UP PROTECTION	163,502	163,502	
264	3340260 14	33400	018000	JC BOYLE HYDRO PL	12/31/1990	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	SCADA SYSTEM, INTERFACE PANEL	169,432	16,943	
265	3340260 31	33400	018000	JC BOYLE HYDRO PL	12/30/2010	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	SPILLGATE POSITION SENSORS	5,484		
266	3340260 34	33400	018000	JC BOYLE HYDRO PL	12/30/2011	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	STREAM SENSORS, AUDIBLE ALARMS, SPILLWAY ALARMS	160,078		
267	3340260 36	33400	018000	JC BOYLE HYDRO PL	8/20/2014	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	EIM METERING EQUIPMENT	74,291		
268	3340260 28	33400	018000	JC BOYLE HYDRO PL	10/13/2008	CI	CI-JC BOYLE CONTROL & INSTRUMENTATION	KLAMATH RIVER CHART RECORDER UNDER KENO BRIDGE	907		
269	3340400 8	33400	018000	JC BOYLE HYDRO PL	12/31/1988	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY	3,125	625	
270	3340400 11	33400	018000	JC BOYLE HYDRO PL	6/28/1999	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	C107 dollars identified as 334	37,073	-	
271	3340400 9	33400	018000	JC BOYLE HYDRO PL	12/31/1990	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	D C SYSTEM, BATTERY BANK	40,870	8,174	
272	3340400 21	33400	018000	JC BOYLE HYDRO PL	12/22/2014	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	DAM POWER INVERTER AND UPS	8,794		
273	3340400 18	33400	018000	JC BOYLE HYDRO PL	9/7/2012	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	DC SYS DAM GROUND DETECTOR & LOCATOR @ DAM BLDG	3,397		
274	3340400 1	33400	018000	JC BOYLE HYDRO PL	12/31/1958	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT	37,122	9,280	
275	3340400 6	33400	018000	JC BOYLE HYDRO PL	12/31/1975	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT, ANNUNCIATOR	8,686	869	
276	3340400 0	33400	018000	JC BOYLE HYDRO PL	12/31/1998	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	-		
277	3340400 13	33400	018000	JC BOYLE HYDRO PL	12/31/1998	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	EM-REPLACE STATION SERVICE	69,161	17,290	
278	3340400 14	33400	018000	JC BOYLE HYDRO PL	7/30/2004	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	EM-TRANSFORMER CONTROL CABLE	79,699	79,699	
279	3340400 24	33400	018000	JC BOYLE HYDRO PL	10/16/2018	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	EMERGENCY GENERATOR AT CANAL HEADGATE	169,089		
280	3340400 15	33400	018000	JC BOYLE HYDRO PL	6/24/2005	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	FOREBAY BATTERY CHARGER	20,058		
281	3340400 3	33400	018000	JC BOYLE HYDRO PL	12/31/1971	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	INSULATORS, GROUNDING, LUMINAIRES	7,040		
282	3340400 2	33400	018000	JC BOYLE HYDRO PL	12/31/1962	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	JACK, INTAKE GATE STOP LOGS	163		
283	3340400 22	33400	018000	JC BOYLE HYDRO PL	10/15/2015	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	JCB DAM ELECTRIC SVS CABLE & MAIN CONTROL BREAKER	8,458		
284	3340400 19	33400	018000	JC BOYLE HYDRO PL	11/8/2012	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	LIGHTNING ARRESTORS REPLACEMENT	36,477		
285	3340400 16	33400	018000	JC BOYLE HYDRO PL	12/17/2007	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	MONITOR FOR PLANT BATTERY BANK	2,731	546	
286	3340400 17	33400	018000	JC BOYLE HYDRO PL	2/14/2008	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	REPLACE INVERTER FOR POWER SUPPLY BACKUP	3,878	969	
287	3340400 23	33400	018000	JC BOYLE HYDRO PL	1/31/2018	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE A/C PANEL BREAKER REPLACEMENT	9,455	2,364	
288	3340400 20	33400	018000	JC BOYLE HYDRO PL	12/9/2013	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE BATTERY BANK & CHARGER REPLACEMENT	47,332	11,833	
289	3340400 4	33400	018000	JC BOYLE HYDRO PL	12/31/1986	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE, CABLE, SWITCHES, CAPAC, BUS, ETC	112,612	28,153	
290	3340400 5	33400	018000	JC BOYLE HYDRO PL	12/31/1987	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	SURGE CAPACITOR STATION SERVICE	3,939	985	
291	3340400 10	33400	018000	JC BOYLE HYDRO PL	12/31/1987	EM	EM-JC BOYLE OTHER ACCESSORY ELECTRICAL EQUIP	TRANSFORMER FOR STATION SERVICE SYSTEM	1,095	274	
292	3340500 1	33400	018000	JC BOYLE HYDRO PL	7/8/2004	OH	OH-MISCPOWER PLANT EQUIPMENT	OH - COOLING PUMP/TRANSFORMER #2	15,205		
293	3340900 0	33400	018000	JC BOYLE HYDRO PL	12/31/1998	WC	WC-WATER CONVEYANCE SYSTEM	1998 BALANCE CONVERSION	-		
294	3340990 0	33400	018000	JC BOYLE HYDRO PL	12/31/1998	99	99-Non Unitized Assets (CAATS)	1998 BALANCE CONVERSION	-		
295	3347260 0	33470	018000	JC BOYLE HYDRO PL	12/31/1998	CI	CI-CONTROLS AND INSTRUMENTATION	1998 BALANCE CONVERSION	-		
296	3347260 1	33470	018000	JC BOYLE HYDRO PL	12/31/1990	CI	CI-CONTROLS AND INSTRUMENTATION	BATTERY BANK, SCADA SYSTEM	13,623	1,362	
297	3347260 3	33470	018000	JC BOYLE HYDRO PL	6/20/2002	CI	CI-CONTROLS AND INSTRUMENTATION	CI-SCADA SYSTEM, REMOTE TERMINAL UNIT - CISCA01	786,731	78,673	
298	3347260 2	33470	018000	JC BOYLE HYDRO PL	12/31/1990	CI	CI-CONTROLS AND INSTRUMENTATION	SCADA SYSTEM, REMOTE TERMINAL UNIT	106,100	10,610	
299			Total JC Boyle						6,860,818	3,294,206	

Principles Followed:	Allocation to Real and Reactive Power Generation
1. Battery systems	20%
2. SCADA systems	10%
3. Emergency generator systems	0%
4. Station service equipment	25%
5. Electrical - miscellaneous	25%
6. Annunciators	10%
7. PLCs and RTUs	10%
8. Generator or exciter	100%

300	3340030 1	33400	031000	PROSPECT #1 HYDR	2/11/2009	AF	AF - PROSPECT 1 ACCESSORY ELECTRICAL SYSTEMS	GENERATOR CABLES FROM GEN BREAKER TO XFORMER	69,904	69,904
301	3340260 0	33400	031000	PROSPECT #1 HYDR	12/31/1998	CI	CI-PROSPECT 1 ACCESSORY ELECTRICAL EQUIPMENT	CI-PROSPECT 1 ACCESSORY ELECTRICAL EQUIPMENT	-	
302	3340260 2	33400	031000	PROSPECT #1 HYDR	12/31/1960	CI	CI-PROSPECT 1 ACCESSORY ELECTRICAL EQUIPMENT	CONTROLS AND INSTRUMENTATION	20,276	
303	3340260 4	33400	031000	PROSPECT #1 HYDR	12/11/2012	CI	CI-PROSPECT 1 ACCESSORY ELECTRICAL EQUIPMENT	INSTREAM FLOW/AUTO - P1 PLANT CONTROL EQUIPMENT	781,035	
304	3340260 1	33400	031000	PROSPECT #1 HYDR	12/31/1911	CI	CI-PROSPECT 1 ACCESSORY ELECTRICAL EQUIPMENT	MAIN SWITCHBOARD, POWER CABLE, CONTROL CABLE	4,211	1,053
305	3340260 3	33400	031000	PROSPECT #1 HYDR	12/31/1965	CI	CI-PROSPECT 1 ACCESSORY ELECTRICAL EQUIPMENT	RELAYS	2,688	672
306	3340400 5	33400	031000	PROSPECT #1 HYDR	12/31/1986	EM	EM-PROSPECT 1 OTHER ACCESSORY ELECTRICAL EQUIP	BRACES, CROSS ARMS	830	
307	3340400 7	33400	031000	PROSPECT #1 HYDR	12/31/1988	EM	EM-PROSPECT 1 OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT	1,977	494
308	3340400 0	33400	031000	PROSPECT #1 HYDR	12/31/1998	EM	EM-PROSPECT 1 OTHER ACCESSORY ELECTRICAL EQUIP	EM-PROSPECT 1 OTHER ACCESSORY ELECTRICAL EQUIP	-	
309	3340400 2	33400	031000	PROSPECT #1 HYDR	12/31/1965	EM	EM-PROSPECT 1 OTHER ACCESSORY ELECTRICAL EQUIP	FLOOD DAMAGE REPAIR	5,984	
310	3340400 3	33400	031000	PROSPECT #1 HYDR	12/31/1966	EM	EM-PROSPECT 1 OTHER ACCESSORY ELECTRICAL EQUIP	INSTALL MISC. EQUIP	3,200	
311	3340400 4	33400	031000	PROSPECT #1 HYDR	12/31/1977	EM	EM-PROSPECT 1 OTHER ACCESSORY ELECTRICAL EQUIP	REGULATOR, VOLTAGE	2,307	2,307
312	3340400 1	33400	031000	PROSPECT #1 HYDR	12/31/1963	EM	EM-PROSPECT 1 OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE TRANSFORMERS	342	85
313	3340400 8	33400	031000	PROSPECT #1 HYDR	12/15/2008	EM	EM-PROSPECT 1 OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE XFORMERS & CABLES	12,724	3,181
314	3340400 6	33400	031000	PROSPECT #1 HYDR	12/31/1987	EM	EM-PROSPECT 1 OTHER ACCESSORY ELECTRICAL EQUIP	SURGE CAPACITOR	555	555
315	3340400 9	33400	031000	PROSPECT #1 HYDR	12/16/2010	EM	EM-PROSPECT 1 OTHER ACCESSORY ELECTRICAL EQUIP	TRANSFORMER COOLING WATER BASKET STRAINER	5,826	
316	3340260 3	33400	032000	PROSPECT #2 HYDR	12/31/1993	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	ANNUNCIATOR	20,661	5,165
317	3340260 8	33400	032000	PROSPECT #2 HYDR	12/31/1993	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	CABLE TRAY, CONTROL INSTRUMENTATION	10,859	2,715
318	3340260 18	33400	032000	PROSPECT #2 HYDR	7/30/2004	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	CI - RTU POWER SUPPLY	1,748	
319	3340260 17	33400	032000	PROSPECT #2 HYDR	1/7/2003	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	CI-LEVEL SWITCHES FOR P22 GOVERNOR	1,685	
320	3340260 16	33400	032000	PROSPECT #2 HYDR	7/10/2001	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	CI-P2C Spare MMI - CICMPc03	2,413	
321	3340260 0	33400	032000	PROSPECT #2 HYDR	12/31/1998	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	-	
322	3340260 7	33400	032000	PROSPECT #2 HYDR	12/31/1990	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	CONTROL INSTRUMENTATION, MINOR INSTR.	5,324	
323	3340260 11	33400	032000	PROSPECT #2 HYDR	12/31/1998	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	CONTROL/MONITOR EQUIP. CONTROL EQUIPMENT	19,080	
324	3340260 4	33400	032000	PROSPECT #2 HYDR	12/31/1990	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	CONTROLS AND INST. CONTROL PANELS	132,928	33,232
325	3340260 5	33400	032000	PROSPECT #2 HYDR	12/31/1993	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	CONTROLS AND INST. CONTROL PANELS	316,377	79,094
326	3340260 20	33400	032000	PROSPECT #2 HYDR	12/18/2008	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	GAGING SYS N FORK RIVER & ABOVE N FORK RESERVOIR	102,891	
327	3340260 24	33400	032000	PROSPECT #2 HYDR	12/11/2012	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	INSTREAM FLOW/AUTO - MIDDLE FORK DAM CONTROL EQ	198,040	
328	3340260 25	33400	032000	PROSPECT #2 HYDR	12/11/2012	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	INSTREAM FLOW/AUTO - N FORK DAM CONTROL EQUIP	133,510	
329	3340260 26	33400	032000	PROSPECT #2 HYDR	12/11/2012	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	INSTREAM FLOW/AUTO - P2 PLANT & FOREBAY CONTROL EQ	2,117,251	
330	3340260 28	33400	032000	PROSPECT #2 HYDR	12/11/2012	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	INSTREAM FLOW/AUTO - RED BLANKET DAM CONTROL EQUIP	161,632	
331	3340260 22	33400	032000	PROSPECT #2 HYDR	12/11/2012	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	INSTRM FLOW/AUTO - BARR CK CANAL GAUG STA CONTROLS	111,259	
332	3340260 23	33400	032000	PROSPECT #2 HYDR	12/11/2012	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	INSTRM FLOW/AUTO - MID FK CANAL GAUG STA CONTROLS	111,259	
333	3340260 27	33400	032000	PROSPECT #2 HYDR	12/11/2012	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	INSTRM FLOW/AUTO - RED BLKT CANL GAUG STA CONTROLS	55,629	
334	3340260 6	33400	032000	PROSPECT #2 HYDR	12/31/1990	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	METERING PANEL, CONTROL & INSTR.	105,455	
335	3340260 12	33400	032000	PROSPECT #2 HYDR	12/31/1993	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	METERING, OTHER INSTRUMENTATION & CONTRL	14,642	
336	3340260 29	33400	032000	PROSPECT #2 HYDR	6/15/2012	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	P2 GENERATION METER	4,815	
337	3340260 21	33400	032000	PROSPECT #2 HYDR	12/28/2011	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	P2 NORTH FORK DAM SPILLWAY ALARMS	52,519	
338	3340260 15	33400	032000	PROSPECT #2 HYDR	8/21/2001	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	Prospect - flume monitoring - CISCA01-	118,834	
339	3340260 30	33400	032000	PROSPECT #2 HYDR	3/7/2014	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	RED BLNKET & N FORK ANTENNA SG & CANAL GTE CONTROL	18,485	
340	3340260 14	33400	032000	PROSPECT #2 HYDR	12/31/1990	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	RELAY PROTECTION, EVENT RECORDER	89,557	89,557
341	3340260 13	33400	032000	PROSPECT #2 HYDR	12/31/1990	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	RELAY PROTECTION, RELAYS	212,024	212,024
342	3340260 19	33400	032000	PROSPECT #2 HYDR	11/13/2006	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	SERVER CABINET	8,620	
343	3340260 9	33400	032000	PROSPECT #2 HYDR	12/31/1990	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	WIRE/CABLE, CONTROL & INSTRUMENTATION	5,425	1,356
344	3340260 10	33400	032000	PROSPECT #2 HYDR	12/31/1993	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	WIRE/CABLE, CONTROL & INSTRUMENTATION	51,543	12,886
345	3340260 31	33400	032000	PROSPECT #2 HYDR	9/30/2013	CI	CI-PROSPECT 2 ACCESSORY ELECTRICAL EQUIPMENT	EIM METERING EQUIPMENT	285,498	
346	3340400 6	33400	032000	PROSPECT #2 HYDR	12/31/1976	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	CUTOUT	245	
347	3340400 2	33400	032000	PROSPECT #2 HYDR	12/31/1956	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	AERIAL CABLES, STATION SERVICE CIRCUITS	25,349	
348	3340400 10	33400	032000	PROSPECT #2 HYDR	12/31/1959	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	ANNUNCIATOR	1,772	443
349	3340400 13	33400	032000	PROSPECT #2 HYDR	6/28/1999	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	C107 DOLLARS	3,597	899
350	3340400 4	33400	032000	PROSPECT #2 HYDR	12/31/1963	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	CIRCUIT ON 5 POLES	177	
351	3340400 9	33400	032000	PROSPECT #2 HYDR	12/31/1990	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	COMPRESSOR	7,807	
352	3340400 7	33400	032000	PROSPECT #2 HYDR	12/31/1986	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	CONTROL CABLE, METER	32,053	
353	3340400 1	33400	032000	PROSPECT #2 HYDR	12/31/1928	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT	2,917	729
354	3340400 14	33400	032000	PROSPECT #2 HYDR	7/10/2001	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	EM-Install Lightning Arrestors - EMATFE19	4,513	
355	3340400 16	33400	032000	PROSPECT #2 HYDR	3/15/2005	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	EM-P2 FLOWLINE GROUNDING	38,843	
356	3340400 0	33400	032000	PROSPECT #2 HYDR	12/31/1998	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	-	
357	3340400 15	33400	032000	PROSPECT #2 HYDR	6/10/2002	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	EM-STATION SERVICE PANELS (REPLACE 4)	90,847	22,712
358	3340400 17	33400	032000	PROSPECT #2 HYDR	8/10/2011	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	P2 EMERGENCY GENERATOR	236,629	59,157
359	3340400 3	33400	032000	PROSPECT #2 HYDR	12/31/1958	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	PROTECTIVE EQUIP. ON GENERATORS	5,483	5,483
360	3340400 11	33400	032000	PROSPECT #2 HYDR	12/31/1996	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	STATION BATTERIES	25,930	6,483
361	3340400 12	33400	032000	PROSPECT #2 HYDR	12/31/1963	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE POWER SUPPLY	6,088	1,522
362	3340400 8	33400	032000	PROSPECT #2 HYDR	12/31/1987	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	SURGE CAPACITOR	2,467	2,467
363	3340400 5	33400	032000	PROSPECT #2 HYDR	12/31/1973	EM	EM-PROSPECT 2 OTHER ACCESSORY ELECTRICAL EQUIP	VOLTMETER	171	
364	3347260 0	33470	032000	PROSPECT #2 HYDR	12/31/1998	CI	CI-CONTROLS AND INSTRUMENTATION	1998 BALANCE CONVERSION	-	
365	3347260 1	33470	032000	PROSPECT #2 HYDR	12/31/1990	CI	CI-CONTROLS AND INSTRUMENTATION	SCADA SYSTEM, REMOTE TERMINAL UNIT	80,176	20,044
366	3340260 13	33400	033000	PROSPECT #3 HYDR	10/6/2004	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	CI - INVERTER	16,101	
367	3340260 12	33400	033000	PROSPECT #3 HYDR	12/31/1998	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	CI-ANNUNCIATOR SERV (W/O 16517)	232,725	58,181
368	3340260 11	33400	033000	PROSPECT #3 HYDR	12/21/2001	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	CI-CONTROL PANEL - CICMPC04	1,051	
369	3340260 0	33400	033000	PROSPECT #3 HYDR	12/31/1998	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	-	
370	3340260 14	33400	033000	PROSPECT #3 HYDR	12/23/2004	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	CI-SCADA NODE	3,038	760
371	3340260 16	33400	033000	PROSPECT #3 HYDR	11/12/2009	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	CONTROL NETWORK MODEM	2,451	
372	3340260 8	33400	033000	PROSPECT #3 HYDR	12/31/1994	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	CONTROL PANEL, CONTROL VALVE	90,527	
373	3340260 17	33400	033000	PROSPECT #3 HYDR	12/11/2012	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	INSTREAM FLOW/AUTO - P3 PLANT & FOREBAY CONTROL EQ	1,113,699	
374	3340260 18	33400	033000	PROSPECT #3 HYDR	12/11/2012	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	INSTREAM FLOW/AUTO - S FORK DAM CONTROL EQUIPMENT	330,438	
375	3340260 7	33400	033000	PROSPECT #3 HYDR	12/31/1990	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	KWH & KVAR METERS	4,078	
376	3340260 9	33400	033000	PROSPECT #3 HYDR	12/31/1994	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	LIGHTNING PROTECT., CONTROLS AND INSTR.	13,467	
377	3340260 3	33400	033000	PROSPECT #3 HYDR	12/31/1969	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	METERS, SYCHROSCOPE, RELAYS	3,585	
378	3340260 2	33400	033000	PROSPECT #3 HYDR	12/31/1965	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	RELAYS	13,834	3,458

379	3340260 4	33400	033000	PROSPECT #3 HYDR	12/31/1973	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	RELAYS	1,443	361
380	3340260 5	33400	033000	PROSPECT #3 HYDR	12/31/1982	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	RELAYS	1,590	397
381	3340260 15	33400	033000	PROSPECT #3 HYDR	6/5/2008	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	SIEMENS METER FOR DATA TO ENERGY MNMNT SYS	8,435	
382	3340260 6	33400	033000	PROSPECT #3 HYDR	12/31/1987	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	SURGE CAPACITOR	1,233	1,233
383	3340260 1	33400	033000	PROSPECT #3 HYDR	12/31/1934	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	SWITCHBOARD, CABLE	7,456	1,864
384	3340260 10	33400	033000	PROSPECT #3 HYDR	12/31/1994	CI	CI-PROSPECT 3 ACCESSORY ELECTRICAL EQUIPMENT	WIRE/CABLE, CONTROL & INSTRUMENTATION	8,492	2,123
385	3340400 6	33400	033000	PROSPECT #3 HYDR	12/31/1969	EM	EM-PROSPECT 3 OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY, RACK, BATTERY CHARGER	2,663	666
386	3340400 4	33400	033000	PROSPECT #3 HYDR	12/31/1969	EM	EM-PROSPECT 3 OTHER ACCESSORY ELECTRICAL EQUIP	CABLE/CONDUIT	623	156
387	3340400 1	33400	033000	PROSPECT #3 HYDR	12/31/1934	EM	EM-PROSPECT 3 OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT	13,617	3,404
388	3340400 2	33400	033000	PROSPECT #3 HYDR	12/31/1958	EM	EM-PROSPECT 3 OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT	345	86
389	3340400 7	33400	033000	PROSPECT #3 HYDR	11/19/2002	EM	EM-PROSPECT 3 OTHER ACCESSORY ELECTRICAL EQUIP	EM-ELECTRONIC METERS - MOIP JURISDICTIONAL LOAD	5,992	
390	3340400 0	33400	033000	PROSPECT #3 HYDR	12/31/1998	EM	EM-PROSPECT 3 OTHER ACCESSORY ELECTRICAL EQUIP	EM-PROSPECT 3 OTHER ACCESSORY ELECTRICAL EQUIP	-	
391	3340400 3	33400	033000	PROSPECT #3 HYDR	12/31/1959	EM	EM-PROSPECT 3 OTHER ACCESSORY ELECTRICAL EQUIP	POWER CABLE, GENERATOR PROTECTION	8,549	8,549
392	3340400 5	33400	033000	PROSPECT #3 HYDR	12/31/1971	EM	EM-PROSPECT 3 OTHER ACCESSORY ELECTRICAL EQUIP	RELAY, METER, XFORMER	1,371	343
393	3340990 0	33400	033000	PROSPECT #3 HYDR	12/31/1998	99	99-Non Unitized Assets (CAATS)	1998 BALANCE CONVERSION	-	
394	3340260 3	33400	034000	PROSPECT #4 HYDR	4/13/2009	CI	CI-PROSPECT 4 ACCESSORY ELECTRICAL EQUIPMENT	AC VOLT METER FOR P4 GENERATOR	799	799
395	3340260 0	33400	034000	PROSPECT #4 HYDR	12/31/1998	CI	CI-PROSPECT 4 ACCESSORY ELECTRICAL EQUIPMENT	CI-PROSPECT 4 ACCESSORY ELECTRICAL EQUIPMENT	-	
396	3340260 4	33400	034000	PROSPECT #4 HYDR	12/11/2012	CI	CI-PROSPECT 4 ACCESSORY ELECTRICAL EQUIPMENT	INSTREAM FLOW/AUTO - P4 PLANT CONTROL EQUIPMENT	669,777	
397	3340260 1	33400	034000	PROSPECT #4 HYDR	12/31/1944	CI	CI-PROSPECT 4 ACCESSORY ELECTRICAL EQUIPMENT	MAIN SWITCHBOARD, CABLE	9,515	2,379
398	3340260 2	33400	034000	PROSPECT #4 HYDR	12/31/1965	CI	CI-PROSPECT 4 ACCESSORY ELECTRICAL EQUIPMENT	RELAYS	1,803	1,803
399	3340400 0	33400	034000	PROSPECT #4 HYDR	12/31/1998	EM	EM-PROSPECT 4 OTHER ACCESSORY ELECTRICAL EQUIP	EM-PROSPECT 4 OTHER ACCESSORY ELECTRICAL EQUIP	-	
400	3340400 3	33400	034000	PROSPECT #4 HYDR	3/15/2005	EM	EM-PROSPECT 4 OTHER ACCESSORY ELECTRICAL EQUIP	EM-STATION SERVICE LOAD CENTER AC	17,034	4,258
401	3340400 1	33400	034000	PROSPECT #4 HYDR	12/31/1965	EM	EM-PROSPECT 4 OTHER ACCESSORY ELECTRICAL EQUIP	OCB, RELAYS	6,665	6,665
402	3340400 5	33400	034000	PROSPECT #4 HYDR	8/10/2011	EM	EM-PROSPECT 4 OTHER ACCESSORY ELECTRICAL EQUIP	P4 EMERGENCY GENERATOR	127,415	31,854
403	3340400 4	33400	034000	PROSPECT #4 HYDR	6/21/2011	EM	EM-PROSPECT 4 OTHER ACCESSORY ELECTRICAL EQUIP	P4 STATION SERVICE PH EXTERNAL POWER LINE CONNECTN	10,350	
404	3340400 2	33400	034000	PROSPECT #4 HYDR	12/31/1988	EM	EM-PROSPECT 4 OTHER ACCESSORY ELECTRICAL EQUIP	SURGE CAPACITOR	555	555
405				Total Prospect					8,677,601	764,114
406	3340260 7	33400	040000	LEMOLO #1 HYDRO	4/10/2003	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	CI-ELECTRIC VALVE ACTUATOR FOR BUTTERFLY VALVE	7,645	
407	3340260 0	33400	040000	LEMOLO #1 HYDRO	12/31/1998	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMENT	-	
408	3340260 5	33400	040000	LEMOLO #1 HYDRO	12/16/1999	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	CI-Lemolo 1 Purchase termination equip-CIMCOC09	1,960	
409	3340260 8	33400	040000	LEMOLO #1 HYDRO	12/31/1998	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	CONTROLS/INSTRUM, CRITICAL ACCESS ELEC (13999)	827,709	206,927
410	3340260 11	33400	040000	LEMOLO #1 HYDRO	5/8/2008	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	DCAF - RELAY PANEL FOR LM1 INTERCONNECT UPGRADE	26,854	
411	3340260 22	33400	040000	LEMOLO #1 HYDRO	6/27/2012	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	GENERATION METERING & CONTROL EQUIPMENT	511	
412	3340260 13	33400	040000	LEMOLO #1 HYDRO	2/18/2009	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	JURISTICTIONAL LOAD SYS METER (JLS) L&G 2510	5,280	
413	3340260 25	33400	040000	LEMOLO #1 HYDRO	11/23/2015	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	LEMELO 1 SUMP PUMP LEVEL CONTROLLER	8,246	
414	3340260 19	33400	040000	LEMOLO #1 HYDRO	2/7/2011	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	LM1 FOREBAY AUTOMATION PLC	64,583	
415	3340260 24	33400	040000	LEMOLO #1 HYDRO	11/15/2013	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	LM1 OH - PROTECTIVE RELAY EQUIPMENT	41,386	41,386
416	3340260 21	33400	040000	LEMOLO #1 HYDRO	9/26/2011	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	LM1 PENSTOCK WATER FLOW SENSORS	10,559	
417	3340260 12	33400	040000	LEMOLO #1 HYDRO	12/30/2008	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	LM1 PLC OPERATOR WORKSTATION/CONTROLS	3,603	
418	3340260 1	33400	040000	LEMOLO #1 HYDRO	12/31/1955	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	MAIN SWITCHBOARD, CABLE	89,482	22,370
419	3340260 9	33400	040000	LEMOLO #1 HYDRO	12/17/2007	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	METERING PANEL FOR STATION SERVICE & GEN METERING	20,422	
420	3340260 6	33400	040000	LEMOLO #1 HYDRO	10/25/2002	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	PLANT CONTROL EQUIP (PART OF GEN REWIND PROJ)	231,894	57,974
421	3340260 4	33400	040000	LEMOLO #1 HYDRO	12/31/1993	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	PRESSURE RELIEF VALVE CONTROL SYSTEM	218,978	
422	3340260 3	33400	040000	LEMOLO #1 HYDRO	12/31/1977	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	RELAYS	1,683	421
423	3340260 20	33400	040000	LEMOLO #1 HYDRO	9/8/2011	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	REMOTE START/STOP AUTO SYNC CONTROL EQUIPMENT	113,592	28,398
424	3340260 23	33400	040000	LEMOLO #1 HYDRO	7/24/2013	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	SECURITY SYS NETWORK SWITCH FOR REMOTE MONITORING	2,231	
425	3340260 2	33400	040000	LEMOLO #1 HYDRO	12/31/1966	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	SHELTER CONTROL CABINET	726	
426	3340260 16	33400	040000	LEMOLO #1 HYDRO	11/30/2009	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	WATER LEVEL INSTRUMENTS - CANAL	12,634	
427	3340260 17	33400	040000	LEMOLO #1 HYDRO	11/30/2009	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	WATER LEVEL INSTRUMENTS - POWER OUTLET VALVE (POV)	25,268	
428	3340260 15	33400	040000	LEMOLO #1 HYDRO	11/30/2009	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	WATER LEVEL INSTRUMENTS - TAILRACE	12,634	
429	3340260 14	33400	040000	LEMOLO #1 HYDRO	2/18/2009	CI	CI-LEMOLO 1 INSTRUMENTATION & CONTROL EQUIPMEN	JURISDICT LOAD SYS METER (JLS) L&G 2510	19,986	
430	3340290 1	33400	040000	LEMOLO #1 HYDRO	8/4/2006	CP	CP - CATHODIC PROTECTION	5.1FLOW RLSE CATHODIC PROTECT FOR LOW LEVEL OUTLET	23,303	
431	3340400 3	33400	040000	LEMOLO #1 HYDRO	12/31/1985	EM	EM-LEMOLO 1 OTHER ACCESSORY ELECTRICAL EQUIP	CABLE, CONNECTORS	9,916	2,479
432	3340400 1	33400	040000	LEMOLO #1 HYDRO	12/31/1955	EM	EM-LEMOLO 1 OTHER ACCESSORY ELECTRICAL EQUIP	CABLE, GROUNDING, TRANSFORMER, CONDUIT	4,242	1,061
433	3340400 14	33400	040000	LEMOLO #1 HYDRO	3/12/2008	EM	EM-LEMOLO 1 OTHER ACCESSORY ELECTRICAL EQUIP	DC BATTERY BANK & DC PANEL REPLACEMENT	83,404	16,681
434	3340400 15	33400	040000	LEMOLO #1 HYDRO	2/20/2009	EM	EM-LEMOLO 1 OTHER ACCESSORY ELECTRICAL EQUIP	DC BATTERY BANK, CHARGER, CONVERTER, AC/DSTR PANEL	85,297	8,530
435	3340400 12	33400	040000	LEMOLO #1 HYDRO	2/3/2004	EM	EM-LEMOLO 1 OTHER ACCESSORY ELECTRICAL EQUIP	EM-GENERATOR GROUNDING CABLES	1,082	1,082
436	3340400 0	33400	040000	LEMOLO #1 HYDRO	12/31/1998	EM	EM-LEMOLO 1 OTHER ACCESSORY ELECTRICAL EQUIP	EM-LEMOLO 1 OTHER ACCESSORY ELECTRICAL EQUIP	-	
437	3340400 19	33400	040000	LEMOLO #1 HYDRO	11/15/2016	EM	EM-LEMOLO 1 OTHER ACCESSORY ELECTRICAL EQUIP	LEMELO 1 PLANT EMERGENCY POWER LIGHTING	3,667	
438	3340400 17	33400	040000	LEMOLO #1 HYDRO	11/15/2013	EM	EM-LEMOLO 1 OTHER ACCESSORY ELECTRICAL EQUIP	LM1 OH - CRITICAL AC, W/ EMERGENCY GENERATOR	317,086	79,271
439	3340400 16	33400	040000	LEMOLO #1 HYDRO	11/15/2013	EM	EM-LEMOLO 1 OTHER ACCESSORY ELECTRICAL EQUIP	LM1 OH - STATION SERVICE SYS REPLACEMENT	362,131	90,533
440	3340400 2	33400	040000	LEMOLO #1 HYDRO	12/31/1982	EM	EM-LEMOLO 1 OTHER ACCESSORY ELECTRICAL EQUIP	TELEMETERING EQUIP RLF 66544 POTENTIOMETER	25,342	
441	3340400 18	33400	040000	LEMOLO #1 HYDRO	3/3/2015	EM	EM-LEMOLO 1 OTHER ACCESSORY ELECTRICAL EQUIP	UPS POWER MODULE REPLACEMENT	3,927	
442	3340990 0	33400	040000	LEMOLO #1 HYDRO	12/31/1998	99	99-Non Unitized Assets (CAATS)	1998 BALANCE CONVERSION	-	
443	3347400 0	33470	040000	LEMOLO #1 HYDRO	12/31/1998	EM	EM-ELECTRIC EQUIPMENT, RTU	1998 BALANCE CONVERSION	-	
444	3340030 1	33400	041000	LEMOLO #2 HYDRO	11/16/2009	AF	AF - LM2 ACCESSORY ELECTRICAL EQUIPMENT	LM2 OVERHAUL GENERATOR BREAKER, SWITCHGEAR	972,715	972,715
445	3340260 19	33400	041000	LEMOLO #2 HYDRO	12/12/2013	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	CANAL EMERG GENERATORS(PROP) FOR MONITORING SITE +	9,337	
446	3340260 17	33400	041000	LEMOLO #2 HYDRO	12/29/2009	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	CANAL SHUTOFF/DRAIN SYS CONTROLS @ MONITORING SITE	268,652	
447	3340260 5	33400	041000	LEMOLO #2 HYDRO	12/31/1995	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	CI-FIBER OPTIC CABLE	35,391	
448	3340260 0	33400	041000	LEMOLO #2 HYDRO	12/31/1998	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	-	
449	3340260 4	33400	041000	LEMOLO #2 HYDRO	12/31/1998	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	CI-SUPERVISORY CONTROL SYSTEMS (W/O 24989)	72,167	7,217
450	3340260 18	33400	041000	LEMOLO #2 HYDRO	6/27/2012	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	GENERATION METERING & CONTROL EQUIPMENT	950	
451	3340260 12	33400	041000	LEMOLO #2 HYDRO	11/16/2009	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	GENERATOR PROTECTIVE RELAYS, SWITCHES	879,440	879,440
452	3340260 20	33400	041000	LEMOLO #2 HYDRO	7/30/2015	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	HVAC COOLING SYS IN LM2 PLC CONTROL CABINET @ DECK	3,114	
453	3340260 8	33400	041000	LEMOLO #2 HYDRO	2/18/2009	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	JURISTICTIONAL LOAD SYS METERS (JLS) L&G 2510	5,387	
454	3340260 16	33400	041000	LEMOLO #2 HYDRO	11/30/2009	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	LM2 CONTROL / PLANT AUTOMATION SYSTEM	164,243	41,061
455	3340260 9	33400	041000	LEMOLO #2 HYDRO	3/9/2009	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	LM2 ELECTRONIC SECURITY HARDWARE & SOFTWARE	464,199	
456	3340260 6	33400	041000	LEMOLO #2 HYDRO	12/17/2007	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	METERING PANEL FOR STATION SERVICE & GEN METERING	12,942	

457	3340260 14	33400	041000	LEMOLO #2 HYDRO	11/30/2009	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	NERC/CIPS ELECTRONIC SECURITY HARDWARE & SOFTWARE	147,694		
458	3340260 21	33400	041000	LEMOLO #2 HYDRO	4/16/2015	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	OPERATOR INTERFACE TERMINAL	4,452		
459	3340260 11	33400	041000	LEMOLO #2 HYDRO	11/16/2009	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	PLC AUTOMATION & PLANT CONTROL EQUIPMENT	724,091	72,409	
460	3340260 15	33400	041000	LEMOLO #2 HYDRO	11/30/2009	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	WATER LEVEL INSTRUMENTS - CANAL	12,634		
461	3340260 10	33400	041000	LEMOLO #2 HYDRO	2/18/2009	CI	CI-LEMOLO 2 CONTROL & INSTRUMENTATION	JURISDICT LOAD SYS METER (JLS) L&G 2510	28,342		
462	3340290 1	33400	041000	LEMOLO #2 HYDRO	3/15/2006	CP	CP - CATHODIC PROTECTION	5.1 INSTRM FLOW CATHODIC PROTECT FOR FLOWMTR VAULT	54,751		
463	3340400 5	33400	041000	LEMOLO #2 HYDRO	12/31/1970	EM	EM-LEMOLO 2 OTHER ACCESSORY ELECTRICAL EQUIP	30' POLES W/CROSSARMS & INSULATORS	1,252		
464	3340400 7	33400	041000	LEMOLO #2 HYDRO	12/31/1987	EM	EM-LEMOLO 2 OTHER ACCESSORY ELECTRICAL EQUIP	BASE RADIO, ENCLOSR W/RACK, SOLAR PNL, ANTNN, FLW	16,667		
465	3340400 15	33400	041000	LEMOLO #2 HYDRO	7/5/2007	EM	EM-LEMOLO 2 OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY BANK FOR DAM FOREBAY	13,168		
466	3340400 19	33400	041000	LEMOLO #2 HYDRO	3/3/2015	EM	EM-LEMOLO 2 OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY BANK REPLACEMENT @ CANAL SITE #4	5,449		
467	3340400 16	33400	041000	LEMOLO #2 HYDRO	11/16/2009	EM	EM-LEMOLO 2 OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY BANK, RACK, CHARGER, INVERTER	161,641		
468	3340400 14	33400	041000	LEMOLO #2 HYDRO	2/3/2004	EM	EM-LEMOLO 2 OTHER ACCESSORY ELECTRICAL EQUIP	EM-GENERATOR GROUNDING CABLES	290	290	
469	3340400 0	33400	041000	LEMOLO #2 HYDRO	12/31/1998	EM	EM-LEMOLO 2 OTHER ACCESSORY ELECTRICAL EQUIP	EM-LEMOLO 2 OTHER ACCESSORY ELECTRICAL EQUIP	-		
470	3340400 21	33400	041000	LEMOLO #2 HYDRO	9/23/2016	EM	EM-LEMOLO 2 OTHER ACCESSORY ELECTRICAL EQUIP	LEMOLO 2 CANAL SITE 1 BATTERY	4,657		
471	3340400 18	33400	041000	LEMOLO #2 HYDRO	12/10/2015	EM	EM-LEMOLO 2 OTHER ACCESSORY ELECTRICAL EQUIP	POWER CABLE PLANT TO FOREBAY, AUX TRANSFORMERS	105,592		
472	3340400 20	33400	041000	LEMOLO #2 HYDRO	11/15/2016	EM	EM-LEMOLO 2 OTHER ACCESSORY ELECTRICAL EQUIP	SWITCHGEAR - REMOTE BREAKER RACKING DEVICE	24,560	24,560	
473	3340990 0	33400	041000	LEMOLO #2 HYDRO	12/31/1998	99	99-Non Unitized Assets (CAATS)	1998 BALANCE CONVERSION	-		
474	3347400 0	33470	041000	LEMOLO #2 HYDRO	12/31/1998	EM	EM-ELECTRIC EQUIPMENT, RTU	1998 BALANCE CONVERSION	-		
475				Total Lemolo					6,861,037	2,554,803	
476	3340260 11	33400	042000	CLEARWATER #1 H\	7/21/2015	CI	CI-CLEARWATER 1 ACCESSORY ELECTRICAL EQUIPMENT	BYPASS REACH - RITTMEYER FLOW SENSORS	11,865		
477	3340260 0	33400	042000	CLEARWATER #1 H\	12/31/1998	CI	CI-CLEARWATER 1 ACCESSORY ELECTRICAL EQUIPMENT	CI-CLEARWATER 1 ACCESSORY ELECTRICAL EQUIPMENT	-		
478	3340260 4	33400	042000	CLEARWATER #1 H\	12/31/1995	CI	CI-CLEARWATER 1 ACCESSORY ELECTRICAL EQUIPMENT	CI-FIBER OPTIC CABLE	29,003		
479	3340260 2	33400	042000	CLEARWATER #1 H\	12/31/1957	CI	CI-CLEARWATER 1 ACCESSORY ELECTRICAL EQUIPMENT	CONTROL CABINET SHELTER	153		
480	3340260 8	33400	042000	CLEARWATER #1 H\	1/9/2012	CI	CI-CLEARWATER 1 ACCESSORY ELECTRICAL EQUIPMENT	CW1 ETHERNET SWITCHES/METERING	5,801		
481	3340260 10	33400	042000	CLEARWATER #1 H\	1/28/2016	CI	CI-CLEARWATER 1 ACCESSORY ELECTRICAL EQUIPMENT	FIBER OPTIC CONTROL CABLE PLANT TO FOREBAY	56,804		
482	3340260 6	33400	042000	CLEARWATER #1 H\	2/18/2009	CI	CI-CLEARWATER 1 ACCESSORY ELECTRICAL EQUIPMENT	JURISTICTIONAL LOAD SYS METER (JLS) L&G 2510	26,364		
483	3340260 1	33400	042000	CLEARWATER #1 H\	12/31/1953	CI	CI-CLEARWATER 1 ACCESSORY ELECTRICAL EQUIPMENT	MAIN SWITCHBOARD, CONTROLS, MONITORING	109,414	27,354	
484	3340260 5	33400	042000	CLEARWATER #1 H\	12/17/2007	CI	CI-CLEARWATER 1 ACCESSORY ELECTRICAL EQUIPMENT	METERING PANEL FOR STATION SERVICE & GEN METERING	19,825		
485	3340260 7	33400	042000	CLEARWATER #1 H\	5/22/2009	CI	CI-CLEARWATER 1 ACCESSORY ELECTRICAL EQUIPMENT	PROGRAMMABLE LOGIC CONTROLLER (PLC)	58,940	5,894	
486	3340260 3	33400	042000	CLEARWATER #1 H\	12/31/1978	CI	CI-CLEARWATER 1 ACCESSORY ELECTRICAL EQUIPMENT	RELAY, SHUNT	1,212	1,212	
487	3340260 9	33400	042000	CLEARWATER #1 H\	9/12/2013	CI	CI-CLEARWATER 1 ACCESSORY ELECTRICAL EQUIPMENT	SPEED CONTROL SENSOR EQUIP - OVERSPEED PROTECTION	5,738		
488	3340400 15	33400	042000	CLEARWATER #1 H\	8/18/2009	EM	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	BACKUP GENERATOR, PANEL, SWITCH FOR LADDER PUMP	3,946	-	
489	3340400 8	33400	042000	CLEARWATER #1 H\	12/31/1987	EM	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	CAPACITOR, SURGE	648	648	
490	3340400 14	33400	042000	CLEARWATER #1 H\	2/20/2009	EM	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	DC BATTERY BANK, CHARGER, CONVERTER, DISTRIB PANEL	76,807	15,361	
491	3340400 0	33400	042000	CLEARWATER #1 H\	12/31/1998	EM	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	-		
492	3340400 11	33400	042000	CLEARWATER #1 H\	2/3/2004	EM	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	EM-GENERATOR GROUNDING CABLES	1,050	1,050	
493	3340400 12	33400	042000	CLEARWATER #1 H\	2/20/2006	EM	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	EM-HI-PRESS PLANT AIR COMPRESSOR	6,387		
494	3340400 17	33400	042000	CLEARWATER #1 H\	12/31/2015	EM	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	FOREBAY BATTERY BANK, CHARGER, DC PANEL	55,978		
495	3340400 1	33400	042000	CLEARWATER #1 H\	12/31/1953	EM	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	METAL CONDUIT, COPPER & TUBE WORK	1,491	373	
496	3340400 6	33400	042000	CLEARWATER #1 H\	12/31/1978	EM	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	POLE 30'	423		
497	3340400 5	33400	042000	CLEARWATER #1 H\	12/31/1971	EM	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	POLE, 35'	677		
498	3340400 2	33400	042000	CLEARWATER #1 H\	12/31/1958	EM	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	POLES, CONTROL WIRE 25'& 30'53 EA W/ACCESS	2,068		
499	3340400 4	33400	042000	CLEARWATER #1 H\	12/31/1966	EM	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	SHELTER, CONTROL CABINET	349		
500	3340400 16	33400	042000	CLEARWATER #1 H\	5/15/2013	EM	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE BREAKER FOR FEED TO WATSON RIDGE	8,311	-	
501	3340400 7	33400	042000	CLEARWATER #1 H\	12/31/1986	EM	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	STATION TRANSFORMERS	7,207	1,802	
502	3340400 3	33400	042000	CLEARWATER #1 H\	12/31/1965	EM	EM-CLEARWATER 1 OTHER ACCESSORY ELECTRICAL EQUIP	TELEMETERING	4,380		
503	3340990 0	33400	042000	CLEARWATER #1 H\	12/31/1998	99	99-Non Unitized Assets (CAATS)	1998 BALANCE CONVERSION	-		
504	3347260 0	33470	042000	CLEARWATER #1 H\	12/31/1998	CI	CI-CONTROLS AND INSTRUMENTATION	1998 BALANCE CONVERSION	-		
505	3347260 1	33470	042000	CLEARWATER #1 H\	12/31/1992	CI	CI-CONTROLS AND INSTRUMENTATION	SCADA SYSTEM, REMOTE TERMINAL UNIT	21,510	2,151	
506	3340030 1	33400	043000	CLEARWATER #2 H\	12/31/1996	AF	AF-CW2 ACCESSORY ELECTRICAL EQUIPMENT	ACCESSORY ELECTRIC EQUIP. - GENERATOR BUSS	13,221	13,221	
507	3340030 0	33400	043000	CLEARWATER #2 H\	12/31/1998	AF	AF-CW2 ACCESSORY ELECTRICAL EQUIPMENT	AF-CW2 ACCESSORY ELECTRICAL EQUIPMENT	-		
508	3340030 3	33400	043000	CLEARWATER #2 H\	9/26/2012	AF	AF-CW2 ACCESSORY ELECTRICAL EQUIPMENT	SURGE ARRESTOR & BUS SECTION	5,636	5,636	
509	3340030 2	33400	043000	CLEARWATER #2 H\	10/18/2000	AF	AF-CW2 ACCESSORY ELECTRICAL EQUIPMENT	Surge Capacitor -AFBUS03-	1,159	1,159	
510	3340260 0	33400	043000	CLEARWATER #2 H\	12/31/1998	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	-		
511	3340260 7	33400	043000	CLEARWATER #2 H\	12/31/1995	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	CI-FIBER OPTIC CABLE	35,992		
512	3340260 18	33400	043000	CLEARWATER #2 H\	12/10/2015	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	CONTROL CABLES BTWN FOREBAY & DIVERSION DAM	45,333		
513	3340260 11	33400	043000	CLEARWATER #2 H\	5/11/2009	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	CONTROLS/FO @ MONITORING SITE FOR CANAL GATES & HG	154,149		
514	3340260 15	33400	043000	CLEARWATER #2 H\	5/30/2012	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	CW2 FOREBAY ELEVATION CONTROLS/MONITOR EQUIP	4,149		
515	3340260 12	33400	043000	CLEARWATER #2 H\	11/22/2011	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	GAUGE STATION @ CLEARWATER 2 CANAL	10,659		
516	3340260 1	33400	043000	CLEARWATER #2 H\	12/31/1953	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	MAIN SWITCHBOARD, CONTROLS, MONITORING	84,946	21,236	
517	3340260 8	33400	043000	CLEARWATER #2 H\	12/17/2007	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	METERING PANEL FOR STATION SERVICE & GEN METERING	13,640		
518	3340260 13	33400	043000	CLEARWATER #2 H\	2/9/2012	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	MV-90 METER TO MEASURE 6.9KV FEED TO CW VILLAGE	37,682		
519	3340260 16	33400	043000	CLEARWATER #2 H\	6/26/2013	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	PLANT TRIP CONTROLS - LUBE OIL FLOW SWITCH	2,262		
520	3340260 17	33400	043000	CLEARWATER #2 H\	12/3/2014	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	PLC ENCLOSURES FOR CANAL EMERGENCY DUMP STATIONS	24,339	-	
521	3340260 14	33400	043000	CLEARWATER #2 H\	2/20/2012	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	PLC VOLTAGE CONTROL RELAY TRANSDUCER	1,717	172	
522	3340260 4	33400	043000	CLEARWATER #2 H\	12/31/1968	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	RELAYS	1,638	409	
523	3340260 6	33400	043000	CLEARWATER #2 H\	12/31/1978	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	RELAYS	1,103	276	
524	3340260 3	33400	043000	CLEARWATER #2 H\	12/31/1957	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	SHELTER, METAL SWT GEAR, FENCE	1,786		
525	3340260 5	33400	043000	CLEARWATER #2 H\	12/31/1976	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	TRANSFORMER, RESISTOR, RELAY, CONDUIT	3,854	964	
526	3340260 10	33400	043000	CLEARWATER #2 H\	2/18/2009	CI	CI-CLEARWATER 2 ACCESSORY ELECTRICAL EQUIPMENT	JURISDICT LOAD SYS METER (JLS) L&G 2510	25,683		
527	3340400 15	33400	043000	CLEARWATER #2 H\	7/20/2010	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	CW SHOP DC CABINET, FOR CONTROL PILOT WIRES	5,579		
528	3340400 14	33400	043000	CLEARWATER #2 H\	5/17/2010	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY BANK, CHARGER, PANEL REPLACEMENT	123,252	24,650	
529	3340400 5	33400	043000	CLEARWATER #2 H\	12/31/1979	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	BUS, SWITCHGR, POTENTL XFORMER, LIGHTNING ARREST	10,304	10,304	
530	3340400 2	33400	043000	CLEARWATER #2 H\	12/31/1962	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	CONTROL CIRCUIT	2,940	735	
531	3340400 10	33400	043000	CLEARWATER #2 H\	12/31/1987	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT, RTU	6,525	653	

Principles Followed:	Allocation to Real and Reactive Power Generation
1. Battery systems	20%
2. SCADA systems	10%
3. Emergency generator systems	0%
4. Station service equipment	25%
5. Electrical - miscellaneous	25%
6. Annunciators	10%
7. PLCs and RTUs	10%
8. Generator or exciter	100%

532	3340400 0	33400	043000	CLEARWATER #2 H\	12/31/1998	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	-	
533	3340400 11	33400	043000	CLEARWATER #2 H\	2/3/2004	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	EM-GENERATOR GROUNDING CABLES	808	808
534	3340400 18	33400	043000	CLEARWATER #2 H\	10/17/2013	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	EMERGENCY GENERATORS @ CANAL EMERG DRAIN SYS LOCS	38,857	
535	3340400 16	33400	043000	CLEARWATER #2 H\	9/19/2012	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	FOREBAY BATTERY BANK, CHARGER, DC PANEL REPLACMENT	86,957	
536	3340400 3	33400	043000	CLEARWATER #2 H\	12/31/1967	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	POLE, CROSSARM, SHUNT, ANCHOR	173	
537	3340400 20	33400	043000	CLEARWATER #2 H\	11/21/2014	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	POTENTIAL TRANSFORMERS TO MEASURE GENERATOR OUTPUT	6,945	
538	3340400 19	33400	043000	CLEARWATER #2 H\	8/26/2015	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	POWER CABLE BETWEEN PLANT AND FOREBAY	163,160	
539	3340400 4	33400	043000	CLEARWATER #2 H\	12/31/1978	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	SHUNT	91	
540	3340400 17	33400	043000	CLEARWATER #2 H\	9/4/2013	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	SOLAR BATTERIES @ CANAL DUMP/DRAIN SITE	4,132	
541	3340400 6	33400	043000	CLEARWATER #2 H\	12/31/1986	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	TRANSFORMERS, CONTROL VALVE	9,188	
542	3340400 1	33400	043000	CLEARWATER #2 H\	12/31/1953	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	WIRE CONTROL, GROUNDING, CONDUIT	23,318	5,829
543	3340400 7	33400	043000	CLEARWATER #2 H\	12/31/1987	EM	EM-CLEARWATER 2 OTHER ACCESSORY ELECTRICAL EQUIP	XMITTER, H2O SENSOR, PWR SUPPLY, SURGE CAPACITOR	5,191	
544	3347400 0	33470	043000	CLEARWATER #2 H\	12/31/1998	EM	EM-ELECTRIC EQUIPMENT, RTU	1998 BALANCE CONVERSION	-	
545	3347400 1	33470	043000	CLEARWATER #2 H\	12/31/1988	EM	EM-ELECTRIC EQUIPMENT, RTU	ELECTRIC EQUIPMENT, RTU	24,575	2,457
546	3347400 2	33470	043000	CLEARWATER #2 H\	12/31/1995	EM	EM-ELECTRIC EQUIPMENT, RTU	EM-L&G SCADA RTU	8,941	2,235
547				Total Clearwater					1,506,236	146,590
548	3340260 25	33400	044000	TOKETEE HYDRO PL	5/28/2014	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	86T LOCKOUT RELAY	5,925	5,925
549	3340260 7	33400	044000	TOKETEE HYDRO PL	12/31/1992	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	ANNUNCIATOR	6,314	631
550	3340260 12	33400	044000	TOKETEE HYDRO PL	12/31/1995	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	CI FIBER OPTIC CABLING	205,357	
551	3340260 0	33400	044000	TOKETEE HYDRO PL	12/31/1998	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	-	
552	3340260 8	33400	044000	TOKETEE HYDRO PL	12/31/1992	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	CONTROLS AND INST. CONTROL PANELS	80,624	20,156
553	3340260 20	33400	044000	TOKETEE HYDRO PL	11/22/2011	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	GAUGE STATION @ TOKETEE BYPASS REACH	10,659	
554	3340260 21	33400	044000	TOKETEE HYDRO PL	6/27/2012	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	GENERATION METERING & CONTROL EQUIPMENT	1,648	
555	3340260 18	33400	044000	TOKETEE HYDRO PL	2/23/2011	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	GENERATOR PROTECTIVE GROUND RELAY	3,808	3,808
556	3340260 29	33400	044000	TOKETEE HYDRO PL	11/23/2015	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	HYDRO SCADA CONTROL NETWORK EQUIPMENT	4,883	488
557	3340260 19	33400	044000	TOKETEE HYDRO PL	2/10/2011	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	LOAD MONITORING PANEL METER IN CONTROL ROOM	1,018	
558	3340260 13	33400	044000	TOKETEE HYDRO PL	12/17/2007	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	METERING PANEL FOR STATION SERVICE & GEN METERING	25,916	
559	3340260 10	33400	044000	TOKETEE HYDRO PL	12/31/1992	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	OTHER INST. & CONTROL, MINOR INSTRUMENTS	6,804	
560	3340260 11	33400	044000	TOKETEE HYDRO PL	3/24/2006	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	PROGAM LOGIC CONTROLLER HW/SW FOR ALARM FUNCTIONS	24,539	
561	3340260 16	33400	044000	TOKETEE HYDRO PL	10/5/2010	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	PROTECTIVE GENERATOR LOCKOUT RELAY	3,355	3,355
562	3340260 22	33400	044000	TOKETEE HYDRO PL	12/19/2012	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	PROTECTIVE GENERATOR LOCKOUT RELAY	1,673	1,673
563	3340260 17	33400	044000	TOKETEE HYDRO PL	9/27/2010	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	PROTECTIVE GENERATOR/TRANSFORMER LOCKOUT RELAY	3,324	3,324
564	3340260 27	33400	044000	TOKETEE HYDRO PL	10/27/2015	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	PROTECTIVE RELAY REPLACEMENTS	255,171	255,171
565	3340260 28	33400	044000	TOKETEE HYDRO PL	12/28/2015	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	PROTECTIVE RELAY REPLACEMENTS	243,913	243,913
566	3340260 30	33400	044000	TOKETEE HYDRO PL	11/4/2016	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	PROTECTIVE RELAY REPLACEMENTS	405,566	405,566
567	3340260 1	33400	044000	TOKETEE HYDRO PL	12/31/1950	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	SWITCHBOARD, CONTROL, MOTOR GEN, ETC	85,348	21,337
568	3340260 31	33400	044000	TOKETEE HYDRO PL	12/12/2017	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	TCC DVR'S FOR VIDEO SURVEILLANCE SYSTEM	18,350	
569	3340260 23	33400	044000	TOKETEE HYDRO PL	12/6/2013	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	TCC SCADA CONTROL NETWORK GPS TIMEKEEPER	22,907	
570	3340260 32	33400	044000	TOKETEE HYDRO PL	11/18/2015	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	TOKETEE 3 PLANT LOCAL PANEL MEGAWATT METER	802	
571	3340260 33	33400	044000	TOKETEE HYDRO PL	12/15/2016	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	TOKETEE UNDERGROUND OPTIC FIBER TO CONTROL CENTER	31,697	
572	3340260 26	33400	044000	TOKETEE HYDRO PL	10/1/2014	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	TURBINE VALVE CONTROL CIRCUIT BREAKERS	2,519	
573	3340260 9	33400	044000	TOKETEE HYDRO PL	12/31/1992	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	WIRE/CABLE, CONTROL & INSTRUMENTATION	26,053	26,053
574	3340260 15	33400	044000	TOKETEE HYDRO PL	2/18/2009	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	JURISDICT LOAD SYS METER (JLS) L&G 2510	76,814	
575	3340260 24	33400	044000	TOKETEE HYDRO PL	8/12/2014	CI	CI-TOKETEE ACCESSORY ELECTRICAL EQUIPMENT	EIM METERING EQUIPMENT	26,779	
576	3340400 5	33400	044000	TOKETEE HYDRO PL	12/31/1965	EM	EM-TOKETEE OTHER ACCESSORY ELECTRICAL EQUIP	ANCHOR	42	
577	3340400 15	33400	044000	TOKETEE HYDRO PL	8/22/2013	EM	EM-TOKETEE OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY BANK REPLACEMENT	103,374	20,675
578	3340400 6	33400	044000	TOKETEE HYDRO PL	12/31/1968	EM	EM-TOKETEE OTHER ACCESSORY ELECTRICAL EQUIP	CABINET, LOAD CONTROL	6,847	
579	3340400 1	33400	044000	TOKETEE HYDRO PL	12/31/1950	EM	EM-TOKETEE OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT	62,040	15,510
580	3340400 0	33400	044000	TOKETEE HYDRO PL	12/31/1998	EM	EM-TOKETEE OTHER ACCESSORY ELECTRICAL EQUIP	EM-TOKETEE OTHER ACCESSORY ELECTRICAL EQUIP	-	
581	3340400 3	33400	044000	TOKETEE HYDRO PL	12/31/1957	EM	EM-TOKETEE OTHER ACCESSORY ELECTRICAL EQUIP	FUEL TANK FOR AUXIL. DIESEL GENER UNIT	1,422	
582	3340400 4	33400	044000	TOKETEE HYDRO PL	12/31/1961	EM	EM-TOKETEE OTHER ACCESSORY ELECTRICAL EQUIP	REMOTE CONTROL	20,885	
583	3340400 9	33400	044000	TOKETEE HYDRO PL	12/31/1988	EM	EM-TOKETEE OTHER ACCESSORY ELECTRICAL EQUIP	SURGE CAPACITOR	1,264	1,264
584	3340400 10	33400	044000	TOKETEE HYDRO PL	12/31/1989	EM	EM-TOKETEE OTHER ACCESSORY ELECTRICAL EQUIP	TELEMETERING PACKAGE	8,505	
585	3340400 17	33400	044000	TOKETEE HYDRO PL	8/20/2019	EM	EM-TOKETEE OTHER ACCESSORY ELECTRICAL EQUIP	TOKETEE CONTROL CENTER EMERGENCY GENERATOR REPLACE	380,458	
586	3340400 14	33400	044000	TOKETEE HYDRO PL	12/16/2008	EM	EM-TOKETEE OTHER ACCESSORY ELECTRICAL EQUIP	TOKETEE STATION SERVICE REWIRE	13,010	3,252
587	3347400 0	33470	044000	TOKETEE HYDRO PL	12/31/1998	EM	EM-ELECTRIC EQUIPMENT, RTU	1998 BALANCE CONVERSION	-	
588	3347400 3	33470	044000	TOKETEE HYDRO PL	12/31/1973	EM	EM-ELECTRIC EQUIPMENT, RTU	ELECTRIC EQUIPMENT, RTU	22,018	2,202
589	3347400 4	33470	044000	TOKETEE HYDRO PL	12/31/1995	EM	EM-ELECTRIC EQUIPMENT, RTU	EM-L&G SCADA RTU	26,630	2,663
590				Total Toketee					2,228,261	1,036,967
591	3340030 0	33400	045000	FISH CREEK HYDRO	12/31/1998	AF	AF-ACCESSORY ELECTRIC EQUIP. - GENERATOR BUSS	1998 BALANCE CONVERSION	-	
592	3340030 1	33400	045000	FISH CREEK HYDRO	12/31/1996	AF	AF-ACCESSORY ELECTRIC EQUIP. - GENERATOR BUSS	ACCESSORY ELECTRIC EQUIP. - GENERATOR BUSS	14,107	14,107
593	3340260 6	33400	045000	FISH CREEK HYDRO	12/31/1978	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	CABLE & WIRE	5,186	1,296
594	3340260 13	33400	045000	FISH CREEK HYDRO	7/30/2009	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	CANAL DRAIN SYS - H2O LEVEL /DUMP CNTRL/MONITORING	414,083	
595	3340260 15	33400	045000	FISH CREEK HYDRO	5/30/2012	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	CANAL DRAIN SYS ADDED FO COMMUN / CONTROLS	59,418	
596	3340260 9	33400	045000	FISH CREEK HYDRO	12/31/1996	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	CI-FIBER OPTIC CABLE	19,856	
597	3340260 0	33400	045000	FISH CREEK HYDRO	12/31/1998	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	-	
598	3340260 18	33400	045000	FISH CREEK HYDRO	7/25/2014	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	FC CANAL FLOW DATA LOGGER REPLACEMENT	2,410	
599	3340260 22	33400	045000	FISH CREEK HYDRO	12/10/2015	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	FC CONTROL CABLE BTWN FOREBAY & FC PLANT	41,954	
600	3340260 21	33400	045000	FISH CREEK HYDRO	12/1/2015	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	FISH DIVERSION & CANAL DRAIN CONTROL, PWR, COMM, +	991,066	
601	3340260 14	33400	045000	FISH CREEK HYDRO	2/9/2012	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	FOREBAY PRESSURE TRANSMITTERS FOR TRASH RACK	3,589	
602	3340260 16	33400	045000	FISH CREEK HYDRO	6/27/2012	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	GENERATION METERING & CONTROL EQUIPMENT	10,456	
603	3340260 20	33400	045000	FISH CREEK HYDRO	11/10/2014	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	GENERATOR LOCKOUT RELAY REPLACEMENT	4,339	4,339
604	3340260 11	33400	045000	FISH CREEK HYDRO	2/18/2009	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	JURISTICTIONAL LOAD SYS METER (JLS) L&G 2510	27,547	
605	3340260 12	33400	045000	FISH CREEK HYDRO	2/18/2009	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	JURISTICTIONAL LOAD SYS METER (JLS) L&G 2510	5,387	
606	3340260 1	33400	045000	FISH CREEK HYDRO	12/31/1952	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	MAIN SWITCHBOARD, CONTROLS, MONITORING	54,453	13,613
607	3340260 10	33400	045000	FISH CREEK HYDRO	5/9/2008	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	METERING PANEL FOR STATION SERVICE & GEN METERING	25,224	
608	3340260 19	33400	045000	FISH CREEK HYDRO	6/30/2014	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	PENSTOCK HEADGATE CONTROLS/INDICATION REPLACEMENT	4,070	

609	3340260 3	33400	045000	FISH CREEK HYDRO	12/31/1964	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	POLE, CONTROL CIRCUIT	169	
610	3340260 17	33400	045000	FISH CREEK HYDRO	9/19/2013	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	POSITION TRANSMITTER ON DIVERSION SLUICE GATE	2,576	
611	3340260 4	33400	045000	FISH CREEK HYDRO	12/31/1968	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	RELAYS	1,458	365
612	3340260 8	33400	045000	FISH CREEK HYDRO	12/31/1988	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	RELAYS	4,541	1,135
613	3340260 5	33400	045000	FISH CREEK HYDRO	12/31/1977	CI	CI-FISH CREEK ACCESSORY ELECTRICAL EQUIPMENT	SHUNTS	1,771	443
614	3340400 6	33400	045000	FISH CREEK HYDRO	7/5/2007	EM	EM-FISH CREEK OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY BANK FOR FOREBAY	14,011	
615	3340400 9	33400	045000	FISH CREEK HYDRO	11/22/2010	EM	EM-FISH CREEK OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY REPLACEMENTS ALONG CANAL, FOR DRAINAGE SYS	33,894	
616	3340400 3	33400	045000	FISH CREEK HYDRO	12/31/1987	EM	EM-FISH CREEK OTHER ACCESSORY ELECTRICAL EQUIP	CAPACITOR, SURGE	1,892	1,892
617	3340400 1	33400	045000	FISH CREEK HYDRO	12/31/1952	EM	EM-FISH CREEK OTHER ACCESSORY ELECTRICAL EQUIP	CONDUIT, GROUNDING SYSTEM	128	128
618	3340400 7	33400	045000	FISH CREEK HYDRO	3/12/2008	EM	EM-FISH CREEK OTHER ACCESSORY ELECTRICAL EQUIP	DC BATTERY BANK & DC PANEL REPLACEMENT	80,606	16,121
619	3340400 0	33400	045000	FISH CREEK HYDRO	12/31/1998	EM	EM-FISH CREEK OTHER ACCESSORY ELECTRICAL EQUIP	EM-FISH CREEK OTHER ACCESSORY ELECTRICAL EQUIP	-	
620	3340400 5	33400	045000	FISH CREEK HYDRO	9/11/2002	EM	EM-FISH CREEK OTHER ACCESSORY ELECTRICAL EQUIP	EM-SEISMIC BATTERY RACK	14,311	2,862
621	3340400 8	33400	045000	FISH CREEK HYDRO	9/27/2010	EM	EM-FISH CREEK OTHER ACCESSORY ELECTRICAL EQUIP	TRANSFER SWITCH AT HEAD (INTAKE) WORKS, FROM GEN	5,625	
622				Total Fish Creek					1,844,126	56,301
623	3340260 21	33400	046000	SODA SPRINGS HYD	1/27/2015	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	4.1 FISH PASSAGE CONTROL UPGRADE FOR GATES/VALVES	279,687	
624	3340260 19	33400	046000	SODA SPRINGS HYD	4/2/2014	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	4.1.1/4.1.2 LIMIT SWITCH REPLACE FISH SCREEN CLEAN	2,636	
625	3340260 15	33400	046000	SODA SPRINGS HYD	3/11/2010	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	CABLE RACEWAY REPLACEMENT - ROCKFALL DAMAGE	13,390	3,347
626	3340260 11	33400	046000	SODA SPRINGS HYD	12/31/1997	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	CI-CONTROLS AND PLANT PROTECTION (W/O 16275)	207,495	51,874
627	3340260 12	33400	046000	SODA SPRINGS HYD	12/31/1995	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	CI-FIBER OPTIC CABLE	22,005	
628	3340260 10	33400	046000	SODA SPRINGS HYD	4/12/2002	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	CI-REPLACE MANUAL SPEED SWITCHES WITH ELECTRONIC	19,090	
629	3340260 0	33400	046000	SODA SPRINGS HYD	12/31/1998	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	-	
630	3340260 18	33400	046000	SODA SPRINGS HYD	10/23/2013	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	DAM FLOOD PROTECT - TELEMETRY CONTROLS, BATT BCKUP	167,122	
631	3340260 20	33400	046000	SODA SPRINGS HYD	7/25/2014	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	FISH PASSAGE SCREEN DIFFERENTIAL LEVEL PROBE	1,687	
632	3340260 22	33400	046000	SODA SPRINGS HYD	9/8/2014	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	FISH PASSAGE SCREEN DIFFERENTIAL LEVEL PROBE	2,251	
633	3340260 16	33400	046000	SODA SPRINGS HYD	6/27/2012	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	GENERATION METERING & CONTROL EQUIPMENT	768	
634	3340260 14	33400	046000	SODA SPRINGS HYD	6/2/2009	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	KVM SWITCH FOR PLANT AUTOMATION CONTROLS	2,661	665
635	3340260 1	33400	046000	SODA SPRINGS HYD	12/31/1952	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	MAIN SWITCHBOARD, CABLE, CONTROL WIRE	70,496	17,624
636	3340260 17	33400	046000	SODA SPRINGS HYD	11/9/2012	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	PLC ETHERNET MODULE FOR PLANT CONTROL	2,107	211
637	3340260 8	33400	046000	SODA SPRINGS HYD	12/31/1979	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	RELAY, SHUNT	1,281	1,281
638	3340260 9	33400	046000	SODA SPRINGS HYD	12/31/1988	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	RELAYS	6,003	1,501
639	3340260 7	33400	046000	SODA SPRINGS HYD	12/31/1976	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	RESISTOR, RELAYS, CABLE, WIRING	2,836	709
640	3340260 13	33400	046000	SODA SPRINGS HYD	12/18/2008	CI	CI-SODA SPRINGS ACCESSORY ELECTRICAL EQUIPMENT	SODA SPRINGS RESERVOIR LEVEL MONITOR	7,866	
641	3340400 18	33400	046000	SODA SPRINGS HYD	7/13/2007	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY BANK FOR FOREBAY	14,631	
642	3340400 8	33400	046000	SODA SPRINGS HYD	12/31/1987	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	CAPACITOR SURGE	746	746
643	3340400 15	33400	046000	SODA SPRINGS HYD	9/28/2005	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	EM - 150 kVA TRANSFORMER	47,160	11,790
644	3340400 16	33400	046000	SODA SPRINGS HYD	9/28/2005	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	EM - 15kV #2 POWER CABLE	286,362	71,590
645	3340400 17	33400	046000	SODA SPRINGS HYD	3/15/2005	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	EM-125VDC BATTERY BANK	17,106	3,421
646	3340400 13	33400	046000	SODA SPRINGS HYD	7/18/2002	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	EM-BATTERY CHARGER, 125VDC	2,125	425
647	3340400 12	33400	046000	SODA SPRINGS HYD	7/10/2001	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	EM-SDS Replace UPS Batteries - EMDCSE01	2,755	689
648	3340400 0	33400	046000	SODA SPRINGS HYD	12/31/1998	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	-	
649	3340400 10	33400	046000	SODA SPRINGS HYD	12/31/1994	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	EMERGENCY POWER, CRITICAL AC SYSTEM	52,972	13,243
650	3340400 3	33400	046000	SODA SPRINGS HYD	12/31/1958	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	INSTALL 12 POLES - CONTR CIRCUIT	753	
651	3340400 6	33400	046000	SODA SPRINGS HYD	12/31/1981	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	POLE 35' & ANCHOR	354	
652	3340400 4	33400	046000	SODA SPRINGS HYD	12/31/1971	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	POLES 30', 35', 50'	3,394	
653	3340400 11	33400	046000	SODA SPRINGS HYD	12/31/1986	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE SYSTEM	9,569	2,392
654	3340400 2	33400	046000	SODA SPRINGS HYD	12/31/1955	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	TRANSDUCER, WATT 120V 5A	446	
655	3340400 5	33400	046000	SODA SPRINGS HYD	12/31/1976	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	TRANSFORMER 25 KVA 7200 120/240V	975	
656	3340400 7	33400	046000	SODA SPRINGS HYD	12/31/1985	EM	EM-SODA SPRINGS OTHER ACCESSORY ELECTRICAL EQUIP	TRANSMITTERS, METER, POSIT INDIC, LOOP ISOLATOR	10,706	
657	3340990 0	33400	046000	SODA SPRINGS HYD	12/31/1998	99	99-Non Unitized Assets (CAATS)	1998 BALANCE CONVERSION	-	
658	3347400 0	33470	046000	SODA SPRINGS HYD	12/31/1998	EM	EM-ELECTRIC EQUIPMENT, RTU	1998 BALANCE CONVERSION	-	
659	3347400 1	33470	046000	SODA SPRINGS HYD	12/31/1985	EM	EM-ELECTRIC EQUIPMENT, RTU	ELECTRIC EQUIPMENT, RTU	29,536	2,954
660	3347400 2	33470	046000	SODA SPRINGS HYD	12/31/1995	EM	EM-ELECTRIC EQUIPMENT, RTU	EM-SCADA RTU	5,185	519
661				Total Soda Springs					1,294,157	184,981
662	3340030 1	33400	047000	SLIDE CREEK HYDRC	12/19/2011	AF	AF-SLIDE CREEK ACCESSORY ELECTRIC EQUIPMENT	SLIDE CK OH - GENERATOR CIRCUIT BREAKER	1,729,491	1,729,491
663	3340030 2	33400	047000	SLIDE CREEK HYDRC	3/31/2015	AF	AF-SLIDE CREEK ACCESSORY ELECTRIC EQUIPMENT	SUDDEN PRESSURE DEVICE REPLACEMENT GEN XFORMER	5,580	5,580
664	3340260 18	33400	047000	SLIDE CREEK HYDRC	7/25/2014	CI	CI-SLIDE CREEK ACCESSORY ELECTRICAL EQUIPMENT	BYPASS REACH DATA LOGGER REPLACEMENT	2,720	
665	3340260 10	33400	047000	SLIDE CREEK HYDRC	12/31/1995	CI	CI-SLIDE CREEK ACCESSORY ELECTRICAL EQUIPMENT	CI-FIBER OPTIC CABLE	52,974	
666	3340260 0	33400	047000	SLIDE CREEK HYDRC	12/31/1998	CI	CI-SLIDE CREEK ACCESSORY ELECTRICAL EQUIPMENT	CI-SLIDE CREEK ACCESSORY ELECTRICAL EQUIPMENT	-	
667	3340260 9	33400	047000	SLIDE CREEK HYDRC	12/31/1998	CI	CI-SLIDE CREEK ACCESSORY ELECTRICAL EQUIPMENT	CI-SLIDE CREEK CONTROLS	267,035	66,759
668	3340260 14	33400	047000	SLIDE CREEK HYDRC	11/22/2011	CI	CI-SLIDE CREEK ACCESSORY ELECTRICAL EQUIPMENT	GAUGE STATION @ SLIDE CK BYPASS REACH	8,295	
669	3340260 21	33400	047000	SLIDE CREEK HYDRC	9/30/2015	CI	CI-SLIDE CREEK ACCESSORY ELECTRICAL EQUIPMENT	GOVERNOR SUMP LEVEL TRANSMITTER	2,454	
670	3340260 1	33400	047000	SLIDE CREEK HYDRC	12/31/1951	CI	CI-SLIDE CREEK ACCESSORY ELECTRICAL EQUIPMENT	MAIN SWITCHBOARD, CONTROLS, MONITORING	48,821	12,205
671	3340260 15	33400	047000	SLIDE CREEK HYDRC	12/19/2011	CI	CI-SLIDE CREEK ACCESSORY ELECTRICAL EQUIPMENT	SLIDE CK OH - PLANT CONTROLS	217,971	54,493
672	3340260 16	33400	047000	SLIDE CREEK HYDRC	12/19/2011	CI	CI-SLIDE CREEK ACCESSORY ELECTRICAL EQUIPMENT	SLIDE CK OH - PROTECTIVE RELAYS	572,277	572,277
673	3340260 19	33400	047000	SLIDE CREEK HYDRC	9/3/2015	CI	CI-SLIDE CREEK ACCESSORY ELECTRICAL EQUIPMENT	SLIDE CREEK - CAMP FEED POWER METER	8,546	
674	3340260 20	33400	047000	SLIDE CREEK HYDRC	7/10/2015	CI	CI-SLIDE CREEK ACCESSORY ELECTRICAL EQUIPMENT	SLIDE CREEK GRAPHICS TERMINAL (CONTROL SPILL GATES	4,048	
675	3340260 22	33400	047000	SLIDE CREEK HYDRC	4/26/2016	CI	CI-SLIDE CREEK ACCESSORY ELECTRICAL EQUIPMENT	SLIDE CREEK WASTE WATER SUMP LEVEL CONTROL	5,163	
676	3340260 13	33400	047000	SLIDE CREEK HYDRC	2/18/2009	CI	CI-SLIDE CREEK ACCESSORY ELECTRICAL EQUIPMENT	JURISDICT LOAD SYS METER (JLS) L&G 2510	24,319	
677	3340400 6	33400	047000	SLIDE CREEK HYDRC	12/31/1962	EM	EM-SLIDE CREEK OTHER ACCESSORY ELECTRICAL EQUIP	12 POLES & 1 ANCHOR	1,202	
678	3340400 0	33400	047000	SLIDE CREEK HYDRC	12/31/1998	EM	EM-SLIDE CREEK OTHER ACCESSORY ELECTRICAL EQUIP	EM-SLIDE CREEK OTHER ACCESSORY ELECTRICAL EQUIP	-	
679	3340400 5	33400	047000	SLIDE CREEK HYDRC	12/31/1961	EM	EM-SLIDE CREEK OTHER ACCESSORY ELECTRICAL EQUIP	OHD REMOTE CONTROL	1,946	
680	3340400 8	33400	047000	SLIDE CREEK HYDRC	12/31/1965	EM	EM-SLIDE CREEK OTHER ACCESSORY ELECTRICAL EQUIP	POLE 40' CONTROL CIRCUIT	124	
681	3340400 9	33400	047000	SLIDE CREEK HYDRC	12/31/1972	EM	EM-SLIDE CREEK OTHER ACCESSORY ELECTRICAL EQUIP	POLES, ANCHORS	2,704	
682	3340400 17	33400	047000	SLIDE CREEK HYDRC	12/19/2011	EM	EM-SLIDE CREEK OTHER ACCESSORY ELECTRICAL EQUIP	SLIDE CK OH - DC SYS BATTERY BANK, CHARGER, PANEL	227,054	45,411

Principles Followed:	Allocation to Real and Reactive Power Generation
1. Battery systems	20%
2. SCADA systems	10%
3. Emergency generator systems	0%
4. Station service equipment	25%
5. Electrical - miscellaneous	25%
6. Annunciators	10%
7. PLCs and RTUs	10%
8. Generator or exciter	100%

683	3340400 10	33400	047000	SLIDE CREEK HYDRC	12/31/1986	EM	EM-SLIDE CREEK OTHER ACCESSORY ELECTRICAL EQUIP	TRANSFORMER STATION SERVICE	8,000	2,000
684	3340990 0	33400	047000	SLIDE CREEK HYDRC	12/31/1998	99	99-Non Unitized Assets (CAATS)	1998 BALANCE CONVERSION	-	
685	3347260 0	33470	047000	SLIDE CREEK HYDRC	12/31/1998	CI	CI-CONTROLS AND INSTRUMENTATION	1998 BALANCE CONVERSION	-	
686	3347260 2	33470	047000	SLIDE CREEK HYDRC	12/31/1995	CI	CI-CONTROLS AND INSTRUMENTATION	CI-SCADA RTU	7,031	703
687	3347260 1	33470	047000	SLIDE CREEK HYDRC	12/31/1994	CI	CI-CONTROLS AND INSTRUMENTATION	SCADA SYSTEM, REMOTE TERMINAL UNIT	59,213	5,921
688				Total Slide Creek					3,256,965	2,494,839
689	3340032 2	33400	215000	MERWIN HYDRO PL	7/19/2000	AF	AF-ACCESSORY ELECTRIC EQUIP. - GENERATOR BUSS	AF-115KV GEN BRKRS W/F8 - AFPCBE05	1,198	1,198
690	3340032 0	33400	215000	MERWIN HYDRO PL	12/14/1999	AF	AF-ACCESSORY ELECTRIC EQUIP. - GENERATOR BUSS	Cables, circuit controls 12c #10 awg	20,995	5,249
691	3340032 4	33400	215000	MERWIN HYDRO PL	8/11/2010	AF	AF-ACCESSORY ELECTRIC EQUIP. - GENERATOR BUSS	EMERGENCY GENERATOR BREAKER	12,126	-
692	3340032 5	33400	215000	MERWIN HYDRO PL	11/12/2012	AF	AF-ACCESSORY ELECTRIC EQUIP. - GENERATOR BUSS	U3 GENERATOR BUSS REFURBISHMENT	11,485	11,485
693	3340032 1	33400	215000	MERWIN HYDRO PL	1/13/2000	AF	AF-ACCESSORY ELECTRIC EQUIP. - GENERATOR BUSS	Unit 3 Transformer Bushing Replacement AFTSFE30	-	
694	3340262 20	33400	215000	MERWIN HYDRO PL	12/31/1977	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	AUTO SHUTDOWN EQUIP. RELAYS & OTHER APPARATUS	24,776	6,194
695	3340262 12	33400	215000	MERWIN HYDRO PL	12/31/1982	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	CABLE UGD, 5141', SURGE CAPACITORS	14,082	3,521
696	3340262 13	33400	215000	MERWIN HYDRO PL	12/31/1986	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	CABLE, PWR 5KV (4200') 20966.28 & 6 - CUTOUTS 100A	22,757	5,689
697	3340262 40	33400	215000	MERWIN HYDRO PL	12/31/1997	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	CI-1997 AUTO SYNC, EQUIPMENT UNIT #1	411,581	102,895
698	3340262 42	33400	215000	MERWIN HYDRO PL	12/31/1997	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	CI-1997 CONTROL WIRE AND CABLES UNIT #1	85,780	21,445
699	3340262 43	33400	215000	MERWIN HYDRO PL	12/31/1998	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	CI-1998 CONTROL WIRE AND CABLES UNIT #1	18,922	4,730
700	3340262 47	33400	215000	MERWIN HYDRO PL	3/29/2004	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	CI-HYDRO DATA HISTORIAN INTERFACE	56,266	
701	3340262 0	33400	215000	MERWIN HYDRO PL	12/31/1998	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	-	
702	3340262 26	33400	215000	MERWIN HYDRO PL	5/20/1999	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	COMMUNICATION EQUIP UPGRADE MERWIN TO PDX	286,170	
703	3340262 27	33400	215000	MERWIN HYDRO PL	5/20/1999	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	Communication equipment	27,747	
704	3340262 58	33400	215000	MERWIN HYDRO PL	10/27/2011	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	CONTROLS, METERING, RELAY REPLACEMENTS	1,525,407	381,352
705	3340262 64	33400	215000	MERWIN HYDRO PL	10/27/2015	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	FLOW CONTROLS - AUXILIARY PLC'S & CONTROL SYSTEM	202,455	
706	3340262 61	33400	215000	MERWIN HYDRO PL	10/27/2015	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	FLOW CONTROLS - GENERATOR 1 PLC & CONTROL SYS	337,492	
707	3340262 62	33400	215000	MERWIN HYDRO PL	10/27/2015	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	FLOW CONTROLS - GENERATOR 2 PLC & CONTROL SYS	337,492	
708	3340262 63	33400	215000	MERWIN HYDRO PL	10/27/2015	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	FLOW CONTROLS - GENERATOR 3 PLC & CONTROL SYS	337,289	
709	3340262 65	33400	215000	MERWIN HYDRO PL	10/27/2015	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	FLOW CONTROLS - SCADA SYS & NETWORK EQUIPMENT	202,455	50,614
710	3340262 19	33400	215000	MERWIN HYDRO PL	12/31/1958	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	GEN. LEADS, CABLE, PWR/CTRL. CONDUIT, MAIN SWTCHBD	89,091	89,091
711	3340262 66	33400	215000	MERWIN HYDRO PL	11/23/2015	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	HYDRO SCADA CONTROL NETWORK EQUIPMENT	14,658	1,466
712	3340262 53	33400	215000	MERWIN HYDRO PL	2/18/2009	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	JURISTICTIONAL LOAD SYS METERS (JLS) L&G 2510	27,559	
713	3340262 30	33400	215000	MERWIN HYDRO PL	4/30/1999	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	L.R. HQ area radio/repeater CIMCOC13	13,203	
714	3340262 55	33400	215000	MERWIN HYDRO PL	12/16/2010	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	MERWIN DAM FIBER OPTIC MONITORING CABLE	5,479	
715	3340262 51	33400	215000	MERWIN HYDRO PL	12/20/2007	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	METERS (SIEMENS) FOR GEN INFO FOR C&T	24,374	
716	3340262 67	33400	215000	MERWIN HYDRO PL	12/27/2017	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	PHASOR MEASUREMENT UNIT (PMU) - DATA, MONITORING	46,074	
717	3340262 23	33400	215000	MERWIN HYDRO PL	12/31/1995	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	POTENTIAL RELAYS	61,542	61,542
718	3340262 49	33400	215000	MERWIN HYDRO PL	11/7/2006	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	PROGRAMMABLE LOGIC CONTROLLER (PLC)	10,229	1,023
719	3340262 57	33400	215000	MERWIN HYDRO PL	5/25/2011	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	STATION SERVICE SYS PROTECTIVE RELAYS	-	
720	3340262 59	33400	215000	MERWIN HYDRO PL	5/25/2011	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	STATION SERVICE SYS PROTECTIVE RELAYS	2,577	644
721	3340262 6	33400	215000	MERWIN HYDRO PL	12/31/1969	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	SURGE CAPACITOR	1,043	1,043
722	3340262 16	33400	215000	MERWIN HYDRO PL	12/31/1933	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	SWITCH GR, CNTR. WIRING, LD CNTR., BATTRY, ST SERV	77,852	19,463
723	3340262 52	33400	215000	MERWIN HYDRO PL	7/21/2008	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	TURB AUTO WITH CABLES & LIMIT SWITCHES FOR ISO VLV	11,842	
724	3340262 15	33400	215000	MERWIN HYDRO PL	12/31/1988	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	VOLTAGE REGULATOR	14,085	14,085
725	3340262 60	33400	215000	MERWIN HYDRO PL	2/23/2015	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	WATER LEVEL MONITOR @ DRAINAGE GALLERY FLUME	3,708	
726	3340262 68	33400	215000	MERWIN HYDRO PL	12/10/2018	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	WATER QUALITY MONITOR EQUIP, SONDE, MS5, GAS PROBE	227,670	
727	3340262 54	33400	215000	MERWIN HYDRO PL	2/18/2009	CI	CI-MERWIN ACCESSORY ELECTRICAL EQUIPMENT	JURISDICT LOAD SYS METER (JLS) L&G 2510	60,655	
728	3340402 8	33400	215000	MERWIN HYDRO PL	12/31/1995	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	AC CIRCUIT BREAKER, STATION SERVICE	63,394	15,848
729	3340402 5	33400	215000	MERWIN HYDRO PL	12/31/1990	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	BATTERY BANK AND CHARGER	44,613	8,923
730	3340402 22	33400	215000	MERWIN HYDRO PL	5/16/2013	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	CONDUCTOR FROM #2 STATION SERVICE TO SWITCHGEAR	26,275	6,569
731	3340402 6	33400	215000	MERWIN HYDRO PL	12/31/1992	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	D C SYSTEM, BATTERY BANK	29,108	5,822
732	3340402 7	33400	215000	MERWIN HYDRO PL	12/31/1995	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	D C SYSTEM, CIRCUIT BREAKER	42,615	8,523
733	3340402 21	33400	215000	MERWIN HYDRO PL	4/16/2012	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	DC BATTERY BANK DISCONNECT SWITCH	7,592	1,518
734	3340402 16	33400	215000	MERWIN HYDRO PL	6/10/2002	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	EM-125VDC INVERTER (EMCRTE15)	56,617	11,323
735	3340402 14	33400	215000	MERWIN HYDRO PL	2/4/2002	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	EM-2400 VOLT SWITCHGEAR (REDUNDANCY) EMSSTE21	886,634	221,659
736	3340402 15	33400	215000	MERWIN HYDRO PL	2/4/2002	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	EM-480 VOLT MOTOR CONTROL CTR (REDUNDANCY)EMSSTE21	200,794	50,198
737	3340402 11	33400	215000	MERWIN HYDRO PL	2/8/2000	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	EM-CONTROLS,ELECTRICAL	34,661	8,665
738	3340402 13	33400	215000	MERWIN HYDRO PL	4/12/2001	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	EM-EMERGENCY GENERATOR EMCRTE12	617,308	-
739	3340402 12	33400	215000	MERWIN HYDRO PL	1/18/2002	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	EM-LIGHTING PANEL REPLACEMENT - ENSSTE16	15,833	
740	3340402 0	33400	215000	MERWIN HYDRO PL	12/31/1998	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	-	
741	3340402 23	33400	215000	MERWIN HYDRO PL	9/22/2014	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	EMERG GENERATOR LOAD BREAKERS FOR BACKUP PWR +	84,898	-
742	3340402 24	33400	215000	MERWIN HYDRO PL	6/9/2017	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	MARBLE CREEK EMERGENCY POWER EQUIP REPLACEMENT	68,688	
743	3340402 18	33400	215000	MERWIN HYDRO PL	12/4/2008	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	MERWIN PARK DRY TYPE AUX TRANSFORMER	28,209	
744	3340402 20	33400	215000	MERWIN HYDRO PL	12/21/2011	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	STATION SERVICE GROUND/CONDUCTOR FR SWITCHGEAR	161,419	40,355
745	3340402 19	33400	215000	MERWIN HYDRO PL	12/8/2009	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	STATION SERVICE RELAY - IMPROVE LOAD SWITCHING	-	
746	3340402 9	33400	215000	MERWIN HYDRO PL	12/31/1995	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	TRANSFORMER, STATION SERVICE	169,221	42,305
747	3340402 17	33400	215000	MERWIN HYDRO PL	12/20/2007	EM	EM-MERWIN OTHER ACCESSORY ELECTRICAL EQUIPMENT	UPS FOR INTAKE SUB CONTROL PANEL (POWER TO DAM/PLT	55,274	
748	3340992 0	33400	215000	MERWIN HYDRO PL	12/31/1998	99	99-Non Unitized Assets (CAATS)	1998 BALANCE CONVERSION	-	
749	3347262 0	33470	215000	MERWIN HYDRO PL	12/31/1998	CI	CI-CONTROLS AND INSTRUMENTATION	1998 BALANCE CONVERSION	-	
750	3347262 6	33470	215000	MERWIN HYDRO PL	11/7/2002	CI	CI-CONTROLS AND INSTRUMENTATION	CI-Pi Software and Supporting Hardware	31,698	
751	3347262 5	33470	215000	MERWIN HYDRO PL	8/26/2002	CI	CI-CONTROLS AND INSTRUMENTATION	CI-TELEMETRY UPGRADE	20,837	
752	3347262 3	33470	215000	MERWIN HYDRO PL	6/21/1999	CI	CI-CONTROLS AND INSTRUMENTATION	Pump & Tank Level Controls, Water Storage Tank	10,331	
753	3347262 7	33470	215000	MERWIN HYDRO PL	12/20/2007	CI	CI-CONTROLS AND INSTRUMENTATION	SCADA RADIO NETWORK - MONITOR RIVER @ MERWIN DAM	34,971	3,497
754	3347402 0	33470	215000	MERWIN HYDRO PL	12/31/1998	EM	EM-ELECTRIC EQUIPMENT, RTU	1998 BALANCE CONVERSION	-	
755				Total Merwin					7,319,103	1,207,933
756	3340032 5	33400	218000	SWIFT HYDRO #1 Pl	10/25/2012	AF	AF-ACCESSORY ELECTRIC EQUIP. - GENERATOR BUSS	GENERATOR BREAKERS - SOURCE OF STATION SERVICE	3,015,131	753,783

Principles Followed:	Allocation to Real and Reactive Power Generation

757	3340032 1	33400	218000	SWIFT HYDRO #1 Pl	3/12/1999	AF	AF-ACCESSORY ELECTRIC EQUIP. - GENERATOR BUSS	Replace Swift #12 transformer (T-2100) Bushings	45,837	45,837	
758	3340032 0	33400	218000	SWIFT HYDRO #1 Pl	6/28/1999	AF	AF-ACCESSORY ELECTRIC EQUIP. - GENERATOR BUSS	STEP UP TRANSFORMER AFTSFE30	-		
759	3340262 22	33400	218000	SWIFT HYDRO #1 Pl	12/24/2008	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	SWIFT 1 ELECTRONIC SECURITY HARDWARE & SOFTWARE	113,397		
760	3340262 3	33400	218000	SWIFT HYDRO #1 Pl	12/31/1995	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	ANNUNCIATOR PANEL	57,570	5,757	
761	3340262 4	33400	218000	SWIFT HYDRO #1 Pl	12/31/1994	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	AUTO SYNCHRONIZERS FOR UNITS 1, 2, 3	29,149	7,287	
762	3340262 28	33400	218000	SWIFT HYDRO #1 Pl	12/5/2011	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	CANAL DRAIN FLOW MONITOR/ANALYZER	20,032		
763	3340262 10	33400	218000	SWIFT HYDRO #1 Pl	2/8/2000	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	CI-Swift #1 Flow Annunciator - CIANNC10	-		
764	3340262 11	33400	218000	SWIFT HYDRO #1 Pl	2/8/2000	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	CI-Swift #1 Flow annunciators - ciann01	-		
765	3340262 12	33400	218000	SWIFT HYDRO #1 Pl	8/12/2004	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	CI-SWIFT #1 GENERATOR PROTECTIVE RELAYS 3420	209,372	209,372	
766	3340262 0	33400	218000	SWIFT HYDRO #1 Pl	12/31/1998	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	-		
767	3340262 8	33400	218000	SWIFT HYDRO #1 Pl	5/14/1999	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	Closed Circuit TV Sys, Cameras, Video Cable	5,785		
768	3340262 9	33400	218000	SWIFT HYDRO #1 Pl	5/17/1999	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	Control & Indication to Power Circuit Breaker 9P13	13,335		
769	3340262 2	33400	218000	SWIFT HYDRO #1 Pl	12/31/1967	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	CONTROL RELAY & ACCESSORIES	1,505	376	
770	3340262 14	33400	218000	SWIFT HYDRO #1 Pl	9/7/2004	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	DIGITAL CONTROLS (PLC)	1,947,714	194,771	
771	3340262 33	33400	218000	SWIFT HYDRO #1 Pl	12/18/2014	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	EAP RADIO WARNING SYS BELOW SWIFT DAM	86,575		
772	3340262 34	33400	218000	SWIFT HYDRO #1 Pl	12/11/2014	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	FIBER OPTIC CONTROL CABLE PH TO MW BLDG	15,369		
773	3340262 25	33400	218000	SWIFT HYDRO #1 Pl	12/2/2009	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	FIREWALL FOR SW1 TO SW2 CONTROL FIBER SYS	7,360		
774	3340262 36	33400	218000	SWIFT HYDRO #1 Pl	12/20/2016	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	GENERATOR POWER METERS & STATION SVS METER REPLACE	66,985		
775	3340262 6	33400	218000	SWIFT HYDRO #1 Pl	12/31/1996	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	GENERATOR RELAY PROTECTION	82,205	82,205	
776	3340262 18	33400	218000	SWIFT HYDRO #1 Pl	9/25/2006	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	HUMAN/MACHINE INTERFACE (HMI) CONTROL COMPUTERS	16,477		
777	3340262 35	33400	218000	SWIFT HYDRO #1 Pl	11/23/2015	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	HYDRO SCADA CONTROL NETWORK EQUIPMENT	4,883	488	
778	3340262 7	33400	218000	SWIFT HYDRO #1 Pl	12/31/1997	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	MICROPROCESSOR AND PROTECTIVE RELAYS	36,862	36,862	
779	3340262 23	33400	218000	SWIFT HYDRO #1 Pl	11/30/2009	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	NERC/CIPS ELECTRONIC SECURITY HARDWARE & SOFTWARE	18,863		
780	3340262 37	33400	218000	SWIFT HYDRO #1 Pl	12/27/2017	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	PHASOR MEASUREMENT UNIT (PMU) - DATA, MONITORING	38,137		
781	3340262 20	33400	218000	SWIFT HYDRO #1 Pl	5/31/2007	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	PHONE LINE FOR GENERATION METERS	1,200		
782	3340262 19	33400	218000	SWIFT HYDRO #1 Pl	3/9/2007	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	PLC (PROG LOGIC CNTRL) U11 ETHERNET COMMUN MODULE	2,813	281	
783	3340262 21	33400	218000	SWIFT HYDRO #1 Pl	7/21/2008	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	PLC NETWORK INTERFACE MODULES	9,796	980	
784	3340262 24	33400	218000	SWIFT HYDRO #1 Pl	12/2/2009	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	PROGRAMMABLE LOGIC CONTROLLER (PLC)	31,199	3,120	
785	3340262 32	33400	218000	SWIFT HYDRO #1 Pl	7/8/2014	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	SENSOR REPLACEMENT IN DAM LEAK MEASUREMENT WEIR	5,566		
786	3340262 30	33400	218000	SWIFT HYDRO #1 Pl	10/4/2013	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	SWIFT FISH COLLECTR WATER QUALITY MONITORING PROBE	5,723		
787	3340262 29	33400	218000	SWIFT HYDRO #1 Pl	12/24/2012	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	SWIFT SECURITY - WARNING SIRENS	130,081		
788	3340262 27	33400	218000	SWIFT HYDRO #1 Pl	8/23/2010	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	TAILRACE MONITORING EQUIPMENT	6,289		
789	3340262 26	33400	218000	SWIFT HYDRO #1 Pl	3/30/2010	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	WEATHER STA WIND TURBINE @ SWIFT CAMP	1,414		
790	3340262 31	33400	218000	SWIFT HYDRO #1 Pl	9/15/2014	CI	CI-SWIFT 1 ACCESSORY ELECTRICAL EQUIPMENT	EIM METERING EQUIPMENT	158,128		
791	3340402 10	33400	218000	SWIFT HYDRO #1 Pl	12/31/1958	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	MICROWAVE SYSTEM	81,608		
792	3340402 13	33400	218000	SWIFT HYDRO #1 Pl	12/31/1998	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	AC station electrical service panel --EMSSTE21--	17,068	4,267	
793	3340402 9	33400	218000	SWIFT HYDRO #1 Pl	12/31/1984	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY CHARGER	234	47	
794	3340402 8	33400	218000	SWIFT HYDRO #1 Pl	12/31/1958	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY CHARGERS	4,922	984	
795	3340402 11	33400	218000	SWIFT HYDRO #1 Pl	12/31/1995	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	DC SYSTEM BATTERY BANK	41,836	8,367	
796	3340402 1	33400	218000	SWIFT HYDRO #1 Pl	12/31/1958	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT	380,367	95,092	
797	3340402 15	33400	218000	SWIFT HYDRO #1 Pl	12/31/1998	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	EM-S#1 -UNIT 2 REPLACE GE U-TYPE BUSHINGS	41,744	41,744	
798	3340402 0	33400	218000	SWIFT HYDRO #1 Pl	12/31/1998	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	-		
799	3340402 14	33400	218000	SWIFT HYDRO #1 Pl	9/17/2002	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	EM-SWIFT#1 ELECT EQUIP FOR STATIC EXCITER	107,537	107,537	
800	3340402 4	33400	218000	SWIFT HYDRO #1 Pl	12/31/1976	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	FS TONE SIGNALING ASSY	1,894		
801	3340402 3	33400	218000	SWIFT HYDRO #1 Pl	12/31/1966	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	METER I2R, ELECTRIC MAGNETIC COUNTER	1,843		
802	3340402 2	33400	218000	SWIFT HYDRO #1 Pl	12/31/1961	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	RELAY	1,484	371	
803	3340402 7	33400	218000	SWIFT HYDRO #1 Pl	12/31/1990	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	REPLACE VOLTAGE RECORDER	3,609		
804	3340402 18	33400	218000	SWIFT HYDRO #1 Pl	12/9/2011	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	STAND-BY EMERGENCY GENERATOR FOR BLACK START	506,063	-	
805	3340402 19	33400	218000	SWIFT HYDRO #1 Pl	10/8/2012	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE BREAKER	30,234	7,559	
806	3340402 20	33400	218000	SWIFT HYDRO #1 Pl	10/10/2013	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE BREAKER REFURBISHMENT	8,121	2,030	
807	3340402 23	33400	218000	SWIFT HYDRO #1 Pl	1/18/2019	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE POWER CABLE SURGE TANK TO PH	122,844	30,711	
808	3340402 16	33400	218000	SWIFT HYDRO #1 Pl	5/27/2009	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE REPLACEMENT	29,642	7,411	
809	3340402 5	33400	218000	SWIFT HYDRO #1 Pl	12/31/1982	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	STRUCTURAL STEEL & MISC FITTINGS	11,396		
810	3340402 6	33400	218000	SWIFT HYDRO #1 Pl	12/31/1987	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	SURGE CAPACITORS	5,123	5,123	
811	3340402 22	33400	218000	SWIFT HYDRO #1 Pl	9/21/2015	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	SWIFT FLOATING SURFACE COLLECTOR SURGE PROTECTORS	4,716		
812	3340402 21	33400	218000	SWIFT HYDRO #1 Pl	12/19/2013	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	SWIFT STATION SERVICE BREAKER CONTROLS	46,363	11,591	
813	3340402 12	33400	218000	SWIFT HYDRO #1 Pl	12/31/1987	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	TRANSFORMERS STATION SVC, GENERATOR NEUTRAL	88,608	22,152	
814	3340402 17	33400	218000	SWIFT HYDRO #1 Pl	12/22/2009	EM	EM-SWIFT 1 OTHER ACCESSORY ELECTRICAL EQUIP	SPEELYAI HATCHERY EMERGENCY GENERATOR	-		
815	3340502 1	33400	218000	SWIFT HYDRO #1 Pl	4/11/2003	OH	OH-MISCPOWER PLANT EQUIPMENT	OH-AIR COMPRESSOR	29,544		
816	3340992 0	33400	218000	SWIFT HYDRO #1 Pl	12/31/1998	99	99-Non Unitized Assets (CAATS)	1998 BALANCE CONVERSION	-		
817	3347262 0	33470	218000	SWIFT HYDRO #1 Pl	12/31/1998	CI	CI-SWIFT 1 CONTROLS AND INSTRUMENTATION	CI-SWIFT 1 CONTROLS AND INSTRUMENTATION	-		
818	3347262 2	33470	218000	SWIFT HYDRO #1 Pl	5/14/1999	CI	CI-SWIFT 1 CONTROLS AND INSTRUMENTATION	Motor Operators for Disconnect Switches on SCADA	47,409	4,741	
819	3347262 1	33470	218000	SWIFT HYDRO #1 Pl	12/31/1981	CI	CI-SWIFT 1 CONTROLS AND INSTRUMENTATION	REMOTE RFL, RELAYS, TAP CHANGER, CABLE, ETC	195,541	48,885	
820	3347402 0	33470	218000	SWIFT HYDRO #1 Pl	12/31/1998	EM	EM-ELECTRIC EQUIPMENT, RTU	1998 BALANCE CONVERSION	-		
821	3347402 1	33470	218000	SWIFT HYDRO #1 Pl	12/31/1990	EM	EM-ELECTRIC EQUIPMENT, RTU	ELECTRIC EQUIPMENT, RTU SUPERVISORY REMOTE	85,124	8,512	
822				Total Swift					8,079,631	1,748,245	
823	3340032 7	33400	219000	YALE HYDRO PLANT	1/13/2005	AF	AF-YALE ACCESSORY ELECTRIC SYSTEM	AF-GROUND GRID CONNECTIONS	46,090	11,523	
824	3340032 6	33400	219000	YALE HYDRO PLANT	12/22/2003	AF	AF-YALE ACCESSORY ELECTRIC SYSTEM	AF-GSU B-PFASE OIL PUMP	12,101		
825	3340032 4	33400	219000	YALE HYDRO PLANT	10/7/2003	AF	AF-YALE ACCESSORY ELECTRIC SYSTEM	AF-REPLACE GENERATOR CIRCUIT BREAKERS	266,972	266,972	
826	3340032 0	33400	219000	YALE HYDRO PLANT	12/31/1998	AF	AF-YALE ACCESSORY ELECTRIC SYSTEM	AF-YALE ACCESSORY ELECTRIC SYSTEM	-		
827	3340032 2	33400	219000	YALE HYDRO PLANT	12/31/1992	AF	AF-YALE ACCESSORY ELECTRIC SYSTEM	CURRENT TRANSFORMERS	1,829	1,829	
828	3340032 9	33400	219000	YALE HYDRO PLANT	11/6/2015	AF	AF-YALE ACCESSORY ELECTRIC SYSTEM	GENERATOR BREAKER REBUILDS	117,227	117,227	
829	3340032 10	33400	219000	YALE HYDRO PLANT	3/24/2017	AF	AF-YALE ACCESSORY ELECTRIC SYSTEM	GENERATOR BUSS WORK - (2) VENTILATION FANS	2,600	2,600	
830	3340032 3	33400	219000	YALE HYDRO PLANT	12/31/1992	AF	AF-YALE ACCESSORY ELECTRIC SYSTEM	WIRE/CABLE FOR GENERATOR CIRCUIT BREAKER	3,414	3,414	
831	3340032 8	33400	219000	YALE HYDRO PLANT	4/13/2006	AF	AF-YALE ACCESSORY ELECTRIC SYSTEM	SPARE GENERATOR BREAKER (AFPCB) MM #7889882	60,191	60,191	
832	3340262 3	33400	219000	YALE HYDRO PLANT	12/31/1964	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	AUTO LOAD CONTROL EQUIP	13,665		
833	3340262 7	33400	219000	YALE HYDRO PLANT	12/31/1992	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	AUTO SYNCHRONIZERS	30,148	7,537	
834	3340262 12	33400	219000	YALE HYDRO PLANT	2/16/2001	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	Beckwith Transformer Protection Relay - CIRLY01	101,187	101,187	

1. Battery systems	20%
2. SCADA systems	10%
3. Emergency generator systems	0%
4. Station service equipment	25%
5. Electrical - miscellaneous	25%
6. Annunciators	10%
7. PLCs and RTUs	10%
8. Generator or exciter	100%

835	3340262 9	33400	219000	YALE HYDRO PLANT	12/31/1997	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	CABLE FIBER OPTIC EXTENSION PLANT TO COMM. SITE	123,192	
836	3340262 17	33400	219000	YALE HYDRO PLANT	7/19/2000	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	CI-AUTOMATION & CONTROLS UPGRADE (MODICON PLC)	802,842	80,284
837	3340262 16	33400	219000	YALE HYDRO PLANT	8/5/2002	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	CI-DISSOLVED GAS ANALYZER - CIMCOC05	18,884	
838	3340262 14	33400	219000	YALE HYDRO PLANT	5/17/1999	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	CI-Microwave site battery charger - CIMCOE02	3,075	
839	3340262 0	33400	219000	YALE HYDRO PLANT	12/31/1998	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	-	
840	3340262 13	33400	219000	YALE HYDRO PLANT	5/16/2001	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	CI-YLC CT's on both units - CIATSE31	30,481	30,481
841	3340262 4	33400	219000	YALE HYDRO PLANT	12/31/1970	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	CONTROL CABLE 19 GA. 2190'	3,080	770
842	3340262 8	33400	219000	YALE HYDRO PLANT	12/31/1953	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	CONTROL PANELS, WIRING, SWTCHGR, SWTCHBRD	207,997	51,999
843	3340262 1	33400	219000	YALE HYDRO PLANT	12/31/1953	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	CONTROLS AND INSTRUMENTATION	114,252	28,563
844	3340262 23	33400	219000	YALE HYDRO PLANT	6/15/2012	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	GENERATION METER	24,133	
845	3340262 20	33400	219000	YALE HYDRO PLANT	12/31/1998	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	GENERATOR RELAY PROTECTION	44,649	44,649
846	3340262 21	33400	219000	YALE HYDRO PLANT	11/15/2006	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	HUMAN/MACHINE INTERFACE (HMI) CONTROL COMPUTERS	18,894	
847	3340262 5	33400	219000	YALE HYDRO PLANT	12/31/1986	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	LTC CONTROLLERS, BACKUPS, TIMING RELAYS	3,991	
848	3340262 29	33400	219000	YALE HYDRO PLANT	12/27/2017	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	PHASOR MEASUREMENT UNIT (PMU) - DATA, MONITORING	40,326	
849	3340262 22	33400	219000	YALE HYDRO PLANT	10/3/2008	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	PLC CONTROLLER ETHERNET CARDS	4,641	464
850	3340262 25	33400	219000	YALE HYDRO PLANT	11/22/2013	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	PROTECTIVE RELAY EQUIPMENT - ANNUNCIATOR	4,896	490
851	3340262 19	33400	219000	YALE HYDRO PLANT	10/9/2003	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	SADDLE DAM FAILURE NOTIFICATION SYS - HI H2O SENSR	25,758	
852	3340262 2	33400	219000	YALE HYDRO PLANT	12/31/1963	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	THERMAL CONVERTERS, TELEMETER TRANSMITTERS	3,763	
853	3340262 28	33400	219000	YALE HYDRO PLANT	12/8/2015	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	VIBRATION MONITORING SYSTEM (TURBINE)	53,988	
854	3340262 11	33400	219000	YALE HYDRO PLANT	12/31/1996	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	WEATHER MONITORING EQUIPMENT	19,930	
855	3340262 27	33400	219000	YALE HYDRO PLANT	5/8/2015	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	YALE DAM WARNING SIRENS	52,947	
856	3340262 10	33400	219000	YALE HYDRO PLANT	12/31/1996	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	YALE SECURITY/VIDEO EQUIPMENT	4,707	
857	3340262 24	33400	219000	YALE HYDRO PLANT	10/4/2013	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	YALE TAILRACE WATER QUALITY MONITORING PROBE	5,723	
858	3340262 26	33400	219000	YALE HYDRO PLANT	4/28/2014	CI	CI-YALE ACCESSORY ELECTRICAL EQUIPMENT	EIM METERING EQUIPMENT	70,631	
859	3340402 14	33400	219000	YALE HYDRO PLANT	4/6/2012	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY BANK DISCONNECTS - TO ALLOW TESTING	6,354	1,271
860	3340402 15	33400	219000	YALE HYDRO PLANT	4/6/2012	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY CHARGERS FOR BACKUP DC POWER BATTERIES	15,856	3,171
861	3340402 8	33400	219000	YALE HYDRO PLANT	5/17/1999	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	Cable and Raceway	4,176	1,044
862	3340402 16	33400	219000	YALE HYDRO PLANT	6/9/2017	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	CAMP CREEK EMERGENCY POWER EQUIP REPLACEMENT	72,645	
863	3340402 5	33400	219000	YALE HYDRO PLANT	12/31/1995	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	D C SYSTEM, BATTERY BANK	40,732	8,146
864	3340402 7	33400	219000	YALE HYDRO PLANT	5/17/1999	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	DC Station Service Panel	1,706	426
865	3340402 1	33400	219000	YALE HYDRO PLANT	12/31/1953	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT	204,437	51,109
866	3340402 9	33400	219000	YALE HYDRO PLANT	2/8/2000	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	EM-Merwin Arrester,srg,115kv,96kv - EMSSTE19	5,445	5,445
867	3340402 10	33400	219000	YALE HYDRO PLANT	12/31/1998	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	EM-SET UP TRANSFORMER HEAT EXCHANGER (W/O 25011)	28,952	28,952
868	3340402 0	33400	219000	YALE HYDRO PLANT	12/31/1998	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	-	
869	3340402 3	33400	219000	YALE HYDRO PLANT	12/31/1992	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	EMERGENCY GENERATOR, CRITICAL AC SYSTEM	6,996	-
870	3340402 2	33400	219000	YALE HYDRO PLANT	12/31/1991	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	GENERATOR VOLTAGE REGULATOR	1,692	1,692
871	3340402 17	33400	219000	YALE HYDRO PLANT	12/27/2017	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	POWER CABLE REPLACEMENT FROM INTAKE TO MW BUILDING	185,008	
872	3340402 13	33400	219000	YALE HYDRO PLANT	10/29/2010	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	SPILLWAY MOTOR CONTROL CENTER (MCC) BREAKERS	1,600	
873	3340402 12	33400	219000	YALE HYDRO PLANT	2/11/2008	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	SUMP PUMP CONTROLS - STOP PUMP WHEN OIL DETECTED	2,089	
874	3340402 4	33400	219000	YALE HYDRO PLANT	12/31/1996	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	UNINTERRUPTIBLE POWER SYS. DC SYSTEM	8,384	
875	3340402 11	33400	219000	YALE HYDRO PLANT	12/6/2006	EM	EM-YALE OTHER ACCESSORY ELECTRICAL EQUIP	UNINTERUPTIBLE POWER SUPPLY (UPS)	10,395	
876	3340492 0	33400	219000	YALE HYDRO PLANT	12/31/1998	GE	GE-EXCITER SYSTEM, DC EXCITER	1998 BALANCE CONVERSION	-	
877	3340492 1	33400	219000	YALE HYDRO PLANT	12/31/1996	GE	GE-EXCITER SYSTEM, DC EXCITER	DC EXCITERS, TRANSFORMERS	97,581	97,581
878	3340492 3	33400	219000	YALE HYDRO PLANT	12/31/1996	GE	GE-EXCITER SYSTEM, DC EXCITER	DC EXCITERS, UNIT 1 AND 2	588,125	588,125
879	3340492 2	33400	219000	YALE HYDRO PLANT	12/31/1996	GE	GE-EXCITER SYSTEM, DC EXCITER	DC EXCITERS, WIRE AND CABLE	97,581	97,581
880	3340492 4	33400	219000	YALE HYDRO PLANT	9/9/2016	GE	GE-EXCITER SYSTEM, DC EXCITER	YALE UNITS 1 & 2 EXCITER BRUSHES AND RIGGINGS	26,653	26,653
881	3340992 0	33400	219000	YALE HYDRO PLANT	12/31/1998	99	99-Non Unitized Assets (CAATS)	1998 BALANCE CONVERSION	-	
882	3347402 0	33470	219000	YALE HYDRO PLANT	12/31/1998	EM	EM-ELECTRIC EQUIPMENT, RTU	1998 BALANCE CONVERSION	-	
883	3347402 1	33470	219000	YALE HYDRO PLANT	12/31/1987	EM	EM-ELECTRIC EQUIPMENT, RTU	MASTER TERMINAL, REMOTE TERMINAL, LANDIS & GYR	110,528	11,053
884				Total Yale					3,855,140	1,732,428
885	3340036 1	33400	610000	IRON GATE HYDRO	2/11/2009	AF	AF-ACCESSORY ELECTRIC EQUIPMENT	GEN GROUNDING BREAKER FOR WESTINGHOUSE SWITCHGEAR	15,862	3,966
886	3340266 0	33400	610000	IRON GATE HYDRO	12/31/1998	CI	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMEN	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMENT	-	
887	3340266 4	33400	610000	IRON GATE HYDRO	12/23/2004	CI	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMEN	CI-SCADA NODE	2,679	268
888	3340266 3	33400	610000	IRON GATE HYDRO	12/31/1998	CI	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMEN	CONTROL/MONITOR EQUIP. CONTROL EQUIPMENT	12,162	3,041
889	3340266 8	33400	610000	IRON GATE HYDRO	2/11/2009	CI	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMEN	FLOW INDICATION - ACUSONIC INSTRUMENTS @ GOVERNOR	4,532	
890	3340266 18	33400	610000	IRON GATE HYDRO	10/15/2015	CI	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMEN	IG RESERVOIR LEVEL INSTRUMENTATION	4,444	
891	3340266 17	33400	610000	IRON GATE HYDRO	11/28/2017	CI	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMEN	IRONGATE NETWORK SCADA CONTROL EQUIPMENT	5,660	566
892	3340266 5	33400	610000	IRON GATE HYDRO	5/31/2007	CI	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMEN	JURISDICT LOAD SYS METER (JLS) L&G 2510	4,290	
893	3340266 13	33400	610000	IRON GATE HYDRO	9/10/2013	CI	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMEN	METEOROLOGICAL STA & WATER QUALITY INSTRUMENTS	54,864	
894	3340266 14	33400	610000	IRON GATE HYDRO	10/1/2014	CI	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMEN	PENSTOCK LEVEL TRANSMITTERS AT TRASH RACK	3,132	
895	3340266 9	33400	610000	IRON GATE HYDRO	8/31/2011	CI	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMEN	PH H2O QUALITY MONITORING - SONDE TELEMETRY	26,650	
896	3340266 16	33400	610000	IRON GATE HYDRO	10/31/2017	CI	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMEN	PROTECTIVE RELAYS FOR GENERATOR & XFORMER	113,308	113,308
897	3340266 11	33400	610000	IRON GATE HYDRO	12/30/2011	CI	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMEN	RATE OF CHANGE STREAM SENSORS, AUDIBLE ALARMS	144,477	
898	3340266 10	33400	610000	IRON GATE HYDRO	2/17/2011	CI	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMEN	REMOTE MONITORING/CONTROL FOR DAM - VIDEO	64,941	
899	3340266 1	33400	610000	IRON GATE HYDRO	12/31/1962	CI	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMEN	SWITCHBOARD, CONDUIT, GROUNDS, RELAYS,	135,932	33,983
900	3340266 15	33400	610000	IRON GATE HYDRO	6/27/2016	CI	CI-IRON GATE INSTRUMENTATION & CONTROL EQUIPMEN	WATER QUALITY MONITORING EQUIP (TEMP, SONDE, SNSOR	98,278	
901	3340406 6	33400	610000	IRON GATE HYDRO	12/31/1992	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	ADD SUPPORT TO BATTERY BANK	2,756	551
902	3340406 15	33400	610000	IRON GATE HYDRO	12/22/2014	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	BREAKER FOR STATION SVS AUX TRANSFORMER	10,042	2,510
903	3340406 2	33400	610000	IRON GATE HYDRO	12/31/1967	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	CABLE, GROUND	2,514	629
904	3340406 16	33400	610000	IRON GATE HYDRO	1/28/2016	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	DC SYSTEM BATTERY BANK, CHARGER, PANEL REPLACEMENT	53,404	10,681
905	3340406 1	33400	610000	IRON GATE HYDRO	12/31/1963	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT	532	133
906	3340406 8	33400	610000	IRON GATE HYDRO	12/14/2005	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	EM-BATTERY BANK	2,128	426
907	3340406 9	33400	610000	IRON GATE HYDRO	12/14/2005	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	EM-BATTERY CHARGER	4,321	864
908	3340406 7	33400	610000	IRON GATE HYDRO	10/26/2001	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	EM-Iron Gate UPS Batteries and Rack - EMDCSE01	1,398	280
909	3340406 0	33400	610000	IRON GATE HYDRO	12/31/1998	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	-	

Principles Followed:	Allocation to Real and Reactive Power Generation
1. Battery systems	20%
2. SCADA systems	10%
3. Emergency generator systems	0%
4. Station service equipment	25%
5. Electrical - miscellaneous	25%
6. Annunciators	10%
7. PLCs and RTUs	10%
8. Generator or exciter	100%

910	3340406 14	33400	610000	IRON GATE HYDRO	12/21/2011	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	EMERGENCY GENERATOR FOR IG HATCHERY	49,958		
911	3340406 3	33400	610000	IRON GATE HYDRO	12/31/1970	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	FLOODLIGHT	107		
912	3340406 13	33400	610000	IRON GATE HYDRO	4/11/2011	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	IG HATCHERY ELECTRICAL PANEL	6,813		
913	3340406 10	33400	610000	IRON GATE HYDRO	8/14/2009	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	REPLACE 3 PHASE ELECTRIC PANEL	2,986	746	
914	3340406 5	33400	610000	IRON GATE HYDRO	12/31/1962	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	STATION BATTERY AND CHARGER	3,937	787	
915	3340406 11	33400	610000	IRON GATE HYDRO	5/19/2011	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE - GANG SWITCH ON POLE P-562	4,470	1,118	
916	3340406 12	33400	610000	IRON GATE HYDRO	5/19/2011	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE - POLE #512 & AUX TRANSFORMER	20,560	5,140	
917	3340406 4	33400	610000	IRON GATE HYDRO	12/31/1986	EM	EM-IRONGATE OTHER ACCESSORY ELECTRICAL EQUIP	TRANSFORMER, NEUTRAL GROUNDING 10 KVA	501	501	
918	3340526 0	33400	610000	IRON GATE HYDRO	12/31/1998	GV	GV-GOVERNOR	1998 BALANCE CONVERSION	-		
919	3340526 1	33400	610000	IRON GATE HYDRO	12/31/1963	GV	GV-GOVERNOR	GOVERNOR	765		
920	3347266 0	33470	610000	IRON GATE HYDRO	12/31/1998	CI	CI-CONTROLS AND INSTRUMENTATION	1998 BALANCE CONVERSION	-		
921	3347266 1	33470	610000	IRON GATE HYDRO	12/31/1991	CI	CI-CONTROLS AND INSTRUMENTATION	SCADA SYSTEM, REMOTE TERMINAL UNIT	36,543	3,654	
922	3347406 0	33470	610000	IRON GATE HYDRO	12/31/1998	EM	EM-ELECTRIC EQUIPMENT, RTU	1998 BALANCE CONVERSION	-		
923	3347406 1	33470	610000	IRON GATE HYDRO	12/31/1988	EM	EM-ELECTRIC EQUIPMENT, RTU	ELECTRIC EQUIPMENT, RTU	16,468	1,647	
924				Total Irongate					911,415	184,798	
925	3340266 14	33400	611000	COPCO #1 HYDRO F	12/31/1996	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	ANNUNCIATOR, CONTROL PANEL	18,746	1,875	
926	3340266 15	33400	611000	COPCO #1 HYDRO F	12/31/1996	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	ANNUNCIATOR, PLC	30,660	3,066	
927	3340266 13	33400	611000	COPCO #1 HYDRO F	12/31/1996	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	ANNUNCIATOR, PLC CPU	16,582	1,658	
928	3340266 16	33400	611000	COPCO #1 HYDRO F	12/31/1996	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	ANNUNCIATOR, UPS	28,042	2,804	
929	3340266 17	33400	611000	COPCO #1 HYDRO F	12/31/1996	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	ANNUNCIATOR, WIRE AND CABLE	33,649	3,365	
930	3340266 18	33400	611000	COPCO #1 HYDRO F	12/31/1994	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	AUTO SYNCHRONIZER	61,670	15,418	
931	3340266 0	33400	611000	COPCO #1 HYDRO F	12/31/1998	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	CI-COPCO 1 CONTROL & INSTRUMENTATION	-		
932	3340266 1	33400	611000	COPCO #1 HYDRO F	12/31/1918	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	CONTROL CABLE UNIT #1	11,324	2,831	
933	3340266 32	33400	611000	COPCO #1 HYDRO F	1/31/2018	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	CONTROL PLC & RTU EQUIP - GENERATOR CONTROL SYS	86,319	8,632	
934	3340266 8	33400	611000	COPCO #1 HYDRO F	12/31/1957	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	CONTROL WIRING	9,334	2,333	
935	3340266 22	33400	611000	COPCO #1 HYDRO F	12/31/1997	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	CONTROLS AND INSTRUMENTATION	110,835	27,709	
936	3340266 24	33400	611000	COPCO #1 HYDRO F	3/9/2009	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	COPCO 1 ELECTRONIC SECURITY HARDWARE & SOFTWARE	390,466		
937	3340266 23	33400	611000	COPCO #1 HYDRO F	10/13/2008	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	COPCO LAKE ELEVATION PROBE	926		
938	3340266 31	33400	611000	COPCO #1 HYDRO F	11/23/2015	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	HYDRO SCADA CONTROL NETWORK EQUIPMENT	9,766	977	
939	3340266 10	33400	611000	COPCO #1 HYDRO F	12/31/1967	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	LOAD CONTROL, STARTER	6,491		
940	3340266 19	33400	611000	COPCO #1 HYDRO F	12/31/1918	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	MAIN SWITCHBOARD	19,532	4,883	
941	3340266 12	33400	611000	COPCO #1 HYDRO F	12/31/1990	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	METERS	10,342		
942	3340266 11	33400	611000	COPCO #1 HYDRO F	12/31/1988	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	METERS, WIRING, RELAYS, TRANSDUCERS	25,101		
943	3340266 25	33400	611000	COPCO #1 HYDRO F	11/30/2009	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	NERC/CIPS ELECTRONIC SECURITY HARDWARE & SOFTWARE	129,953		
944	3340266 33	33400	611000	COPCO #1 HYDRO F	1/31/2018	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	PROTECTIVE RELAYS FOR GENERATOR	44,467	44,467	
945	3340266 27	33400	611000	COPCO #1 HYDRO F	12/30/2011	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	RATE OF CHANGE STREAM SENSORS, AUDIBLE ALARMS	30,996		
946	3340266 9	33400	611000	COPCO #1 HYDRO F	12/31/1966	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	RELAYS, CNTRL EQ, PANELS, CONDUIT, SWTCHCONVRS UNI	91,147	22,787	
947	3340266 30	33400	611000	COPCO #1 HYDRO F	11/19/2014	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	RESERVOIR WATER LEVEL TRANSMITTER	791		
948	3340266 34	33400	611000	COPCO #1 HYDRO F	11/30/2016	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	REVENUE METERS FOR MONITORING, RECORDING, REPORTS	45,058		
949	3340266 28	33400	611000	COPCO #1 HYDRO F	9/9/2013	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	SCADA CONTROL RTU EQUIP - FROM HCC	21,055	2,106	
950	3340266 26	33400	611000	COPCO #1 HYDRO F	12/30/2010	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	SPILLGATE POSITION SENSORS	5,054		
951	3340266 20	33400	611000	COPCO #1 HYDRO F	12/31/1991	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	STATIC EXCITERS AND RELATED EQUIP	108,990	108,990	
952	3340266 21	33400	611000	COPCO #1 HYDRO F	12/31/1991	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	STATIC EXCITERS AND RELATED EQUIP	64,235	64,235	
953	3340266 35	33400	611000	COPCO #1 HYDRO F	12/20/2017	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	TRASH RACK DIFFERENTIAL LEVEL REMOTE INSTRUMENTS	8,088		
954	3340266 2	33400	611000	COPCO #1 HYDRO F	12/31/1923	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	UNIT 1A MAIN SWITCHBOARD & CONTROL CABLE	52,658	13,164	
955	3340266 29	33400	611000	COPCO #1 HYDRO F	10/1/2014	CI	CI-COPCO 1 CONTROL & INSTRUMENTATION	EIM METERS	106,155		
956	3340396 0	33400	611000	COPCO #1 HYDRO F	12/31/1998	DW	DW-DAMS	1998 BALANCE CONVERSION	-		
957	3340396 2	33400	611000	COPCO #1 HYDRO F	12/31/1962	DW	DW-DAMS	TRANSFORMER, LINE AND SERVICE LEAD TO HEADGATE	628		
958	3340396 1	33400	611000	COPCO #1 HYDRO F	12/31/1961	DW	DW-DAMS	TRANSFORMERS AT HEADGATE	555		
959	3340406 13	33400	611000	COPCO #1 HYDRO F	12/31/1991	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	FLASHOVER PROTECTION	11,950		
960	3340406 16	33400	611000	COPCO #1 HYDRO F	12/31/1993	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	ADDITION TO BATTERY BANK SUPPORT	3,458	692	
961	3340406 23	33400	611000	COPCO #1 HYDRO F	12/12/2018	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY BANK & CHARGER REPLACEMENT	35,273	7,055	
962	3340406 17	33400	611000	COPCO #1 HYDRO F	12/31/1994	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY BANK AND RACK	19,687	3,937	
963	3340406 18	33400	611000	COPCO #1 HYDRO F	12/31/1994	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY CHARGER	5,877	1,175	
964	3340406 14	33400	611000	COPCO #1 HYDRO F	12/31/1966	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY, RACK, BATTERY CHARGER	2,228	446	
965	3340406 10	33400	611000	COPCO #1 HYDRO F	12/31/1984	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	CABLE AL TRIPLEX, 45' POLE, XARMS, WIRE, INSULATOR	5,009		
966	3340406 8	33400	611000	COPCO #1 HYDRO F	12/31/1971	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	CHARGER, BATTERY C & D	727	145	
967	3340406 9	33400	611000	COPCO #1 HYDRO F	12/31/1975	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	CIRCUIT BREAKERS, INSULATORS, XARMS, WIRE	10,976	2,744	
968	3340406 11	33400	611000	COPCO #1 HYDRO F	12/31/1988	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	CONTROL CABLE #19 1500'	6,127	1,532	
969	3340406 3	33400	611000	COPCO #1 HYDRO F	12/31/1961	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT	660	165	
970	3340406 6	33400	611000	COPCO #1 HYDRO F	12/31/1966	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT	14,079	3,520	
971	3340406 7	33400	611000	COPCO #1 HYDRO F	12/31/1969	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	ELECTRIC EQUIPMENT	6,874	1,718	
972	3340406 0	33400	611000	COPCO #1 HYDRO F	12/31/1998	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	-		
973	3340406 21	33400	611000	COPCO #1 HYDRO F	9/2/2010	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	EMERGENCY GENERATOR BREAKER	1,848	-	
974	3340406 2	33400	611000	COPCO #1 HYDRO F	12/31/1959	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	GENERATOR BUSSES W/SWITCHES, RELAYS	22,161	22,161	
975	3340406 15	33400	611000	COPCO #1 HYDRO F	12/31/1969	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	STATION BATTERY W/RACK, CHARGER STATION BATTERY	6,877	1,375	
976	3340406 19	33400	611000	COPCO #1 HYDRO F	12/31/1961	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE SYSTEM	6,179	1,545	
977	3340406 4	33400	611000	COPCO #1 HYDRO F	12/31/1964	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	TELEMETERING EQUIPMENT	12,663		
978	3340406 22	33400	611000	COPCO #1 HYDRO F	12/16/2010	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	TRANSFORMER COOLING WATER BASKET STRAINER	-		
979	3340406 12	33400	611000	COPCO #1 HYDRO F	12/31/1989	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	TRANSFORMER, 69/2.4KV G.E	103,645	103,645	
980	3340406 1	33400	611000	COPCO #1 HYDRO F	12/31/1958	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	XFORMERS - 2 EACH ON GEN, PILOT WIRE LINE1600' W/R	5,449	5,449	
981	3340406 20	33400	611000	COPCO #1 HYDRO F	2/13/2006	EM	EM-COPCO 1 OTHER ACCESSORY ELECTRICAL EQUIP	EMERGENCY GENERATOR RADIATOR	2,073	-	
982	3340996 0	33400	611000	COPCO #1 HYDRO F	12/31/1998	99	99-Non Unitized Assets (CAATS)	1998 BALANCE CONVERSION	-		
983	3347266 0	33470	611000	COPCO #1 HYDRO F	12/31/1998	CI	CI-CONTROLS AND INSTRUMENTATION	1998 BALANCE CONVERSION	-		
984	3347266 1	33470	611000	COPCO #1 HYDRO F	12/31/1991	CI	CI-CONTROLS AND INSTRUMENTATION	SCADA SYSTEM, INTERFACE PANEL	17,579	1,758	
985	3347406 0	33470	611000	COPCO #1 HYDRO F	12/31/1998	EM	EM-ELECTRIC EQUIPMENT, RTU	1998 BALANCE CONVERSION	-		
986	3347406 1	33470	611000	COPCO #1 HYDRO F	12/31/1988	EM	EM-ELECTRIC EQUIPMENT, RTU	ELECTRIC EQUIPMENT, RTU	41,457	4,146	
987	3340036 3	33400	612000	COPCO #2 HYDRO F	2/14/2008	AF	AF - COPCO 2 ACCESSORY ELECTRICAL EQUIPMENT	GENERATOR CIRCUIT BREAKER REPLACEMENTS	2,096,125	2,096,125	

988	3340036 2	33400	612000	COPCO #2 HYDRO F	2/14/2008	AF	AF - COPCO 2 ACCESSORY ELECTRICAL EQUIPMENT	GENERATOR LEADS RACEWAY GENERATOR TO TRANSFORMER	558,196	558,196
989	3340036 1	33400	612000	COPCO #2 HYDRO F	2/14/2008	AF	AF - COPCO 2 ACCESSORY ELECTRICAL EQUIPMENT	GENERATOR LEADS REPLACEMENT	1,139,368	1,139,368
990	3340266 0	33400	612000	COPCO #2 HYDRO F	12/31/1998	CI	CI-COPCO 2 ACCESSORY ELECTRICAL EQUIPMENT	CI-COPCO 2 ACCESSORY ELECTRICAL EQUIPMENT	-	
991	3340266 20	33400	612000	COPCO #2 HYDRO F	2/14/2008	CI	CI-COPCO 2 ACCESSORY ELECTRICAL EQUIPMENT	CONTROL & MONITORING INSTRUM - GENERATOR/TRANSFORM	761,055	190,264
992	3340266 21	33400	612000	COPCO #2 HYDRO F	2/14/2008	CI	CI-COPCO 2 ACCESSORY ELECTRICAL EQUIPMENT	GENERATOR/TRANSFORMER RELAYS	996,966	996,966
993	3340266 16	33400	612000	COPCO #2 HYDRO F	12/31/1994	CI	CI-COPCO 2 ACCESSORY ELECTRICAL EQUIPMENT	HEAD LEVEL CONTROL MONITORING	46,318	
994	3340266 24	33400	612000	COPCO #2 HYDRO F	11/30/2016	CI	CI-COPCO 2 ACCESSORY ELECTRICAL EQUIPMENT	REVENUE METERS FOR MONITORING, RECORDING, REPORTS	27,241	
995	3340266 22	33400	612000	COPCO #2 HYDRO F	9/9/2013	CI	CI-COPCO 2 ACCESSORY ELECTRICAL EQUIPMENT	SCADA CONTROL RTU EQUIP - FROM HCC	10,528	1,053
996	3340266 17	33400	612000	COPCO #2 HYDRO F	12/31/1994	CI	CI-COPCO 2 ACCESSORY ELECTRICAL EQUIPMENT	TEMPERATURE AND PRECIPITATION MONITORS	6,315	
997	3340266 23	33400	612000	COPCO #2 HYDRO F	12/9/2014	CI	CI-COPCO 2 ACCESSORY ELECTRICAL EQUIPMENT	WARNING SIREN BELOW CC2 POWERHOUSE	54,451	
998	3340406 33	33400	612000	COPCO #2 HYDRO F	1/17/2017	EM	EM-COPCO 2 OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY BANK & CHARGER REPLACEMENT	57,154	11,431
999	3340406 32	33400	612000	COPCO #2 HYDRO F	12/22/2014	EM	EM-COPCO 2 OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY BANK BUS BAR CONNECTION REPLACEMENTS	8,004	1,601
1000	3340406 30	33400	612000	COPCO #2 HYDRO F	12/19/2014	EM	EM-COPCO 2 OTHER ACCESSORY ELECTRICAL EQUIP	BATTERY CHARGER REPLACEMENT	12,482	2,496
1001	3340406 34	33400	612000	COPCO #2 HYDRO F	12/12/2018	EM	EM-COPCO 2 OTHER ACCESSORY ELECTRICAL EQUIP	CC2 BACKUP GENERATOR REPLACEMENT	32,472	
1002	3340406 0	33400	612000	COPCO #2 HYDRO F	12/31/1998	EM	EM-COPCO 2 OTHER ACCESSORY ELECTRICAL EQUIP	EM-COPCO 2 OTHER ACCESSORY ELECTRICAL EQUIP	-	
1003	3340406 25	33400	612000	COPCO #2 HYDRO F	11/5/2002	EM	EM-COPCO 2 OTHER ACCESSORY ELECTRICAL EQUIP	EM-GENERATOR BREAKER OPERATORS	52,309	52,309
1004	3340406 31	33400	612000	COPCO #2 HYDRO F	12/22/2014	EM	EM-COPCO 2 OTHER ACCESSORY ELECTRICAL EQUIP	EMERGENCY GENERATOR TRANSFER SWITCH	2,969	-
1005	3340406 29	33400	612000	COPCO #2 HYDRO F	12/31/1987	EM	EM-COPCO 2 OTHER ACCESSORY ELECTRICAL EQUIP	STANDBY GENERATOR & 280 GALLON FUEL TANK	11,264	-
1006	3340406 28	33400	612000	COPCO #2 HYDRO F	2/14/2008	EM	EM-COPCO 2 OTHER ACCESSORY ELECTRICAL EQUIP	STATION SERVICE UPGRADE	802,861	200,715
1007	3347266 0	33470	612000	COPCO #2 HYDRO F	12/31/1998	CI	CI-CONTROLS AND INSTRUMENTATION	1998 BALANCE CONVERSION	-	
1008	3347266 1	33470	612000	COPCO #2 HYDRO F	12/31/1992	CI	CI-CONTROLS AND INSTRUMENTATION	MINOR INSTRUMENTS, SCADA SYSTEM	45,150	4,515
1009	3347266 2	33470	612000	COPCO #2 HYDRO F	12/31/1992	CI	CI-CONTROLS AND INSTRUMENTATION	SCADA SYSTEM, REMOTE TERMINAL UNIT	70,741	7,074
1010	3347406 0	33470	612000	COPCO #2 HYDRO F	12/31/1998	EM	EM-ELECTRIC EQUIPMENT, RTU	1998 BALANCE CONVERSION	-	
1011	3347406 3	33470	612000	COPCO #2 HYDRO F	12/31/1987	EM	EM-ELECTRIC EQUIPMENT, RTU	ELECTRIC EQUIPMENT, RTU	104,555	10,456
1012	3347406 4	33470	612000	COPCO #2 HYDRO F	12/31/1988	EM	EM-ELECTRIC EQUIPMENT, RTU	ELECTRIC EQUIPMENT, RTU	27,198	2,720
1013	3347406 5	33470	612000	COPCO #2 HYDRO F	12/31/1992	EM	EM-ELECTRIC EQUIPMENT, RTU	ELECTRIC EQUIPMENT, RTU	11,775	1,178
1014				Total Copco					8,857,966	5,770,972

		Asset	SNo.	Cap.date	Asset description	Amount
1		40074888	0	5/31/2008	CAPACITOR BANK 34.5KV 16.8MVAR	50,000
2		40074888	1	5/31/2008	CAPACITOR BANK 34.5KV 16.8MVAR INSTALL COSTS	144,959
3		40074889	0	5/31/2008	CAPACITOR BANK 34.5KV 16.8MVAR	50,000
4		40074889	1	5/31/2008	CAPACITOR BANK 34.5KV 16.8MVAR INSTALL COSTS	144,959
5	*	Asset Class	35311	Capacitor Bank		389,918
6	**	Location	205200	GOODNOE HILLS WIND PLANT UNIT 1		389,918
7		40072325	0	10/30/2007	CAPACITOR BANK 11.6MVAR 34.5KV	45,000
8		40072325	1	10/30/2007	CAPACITOR BANK INSTALL COSTS	55,978
9		40072326	0	10/30/2007	CAPACITOR BANK 11.6MVAR 34.5KV	45,000
10		40072326	1	10/30/2007	INSTALL CAPACITOR BANK - 11.6MVA 34.5KV	55,978
11		40072327	0	10/30/2007	CAPACITOR BANK	45,000
12		40072327	1	10/30/2007	INSTALL CAPACITOR BANK	55,978
13		40072328	0	10/30/2007	CAPACITOR BANK	45,000
14		40072328	1	10/30/2007	INSTALL CAPACITOR BANK	55,978
15	*	Asset Class	35311	Capacitor Bank		403,913
16	**	Location	240016	MARENGO UNIT 1 SUBSTATION		403,913
17		40075775	0	6/26/2008	CAPACITOR BANK 9MVAR 34.5KV CAP #1	38,000
18		40075775	1	6/26/2008	CAPACITOR BANK 9MVAR 34.5KV CAP #1 INSTALL COSTS	40,078
19		40075776	0	6/26/2008	CAPACITOR BANK 9MVAR 34.5KV CAP #2	38,000
20		40075776	1	6/26/2008	CAPACITOR BANK 9MVAR 34.5KV CAP #2 INSTALL COSTS	40,078
21	*	Asset Class	35311	Capacitor Bank		156,157
22	**	Location	240017	MARENGO UNIT 2 SUBSTATION		156,157
23		40084582	0	10/1/2010	CAPACITOR BANK EQ# 10088588 C11 / COOPER 34.5	33,000
24		40084582	1	10/1/2010	INSTALL CAPACITOR BANK EQ# 10088588 C11	11,849
25		40084583	0	10/1/2010	CAPACITOR BANK EQ# 10088590 C12	33,000
26		40084583	1	10/1/2010	INSTALL CAPACITOR BANK EQ# 10088590 C12	11,849
27	*	Asset Class	35311	Capacitor Bank		89,698
28	**	Location	509100	DUNLAP WIND PLANT COMMON		89,698
29		40079534	0	7/17/2009	CAPACITOR BANK 34.5KV 5MVAR	20,000
30		40079534	2	7/17/2009	CAPACITOR BANK 34.5KV 5MVAR INSTALL COSTS	12,634
31	*	Asset Class	35311	Capacitor Bank		32,634
32	**	Location	510100	HIGH PLAINS - MCFADDEN WIND PLANT COMM		32,634
33	***	Company Code	1000	PacifiCorp		1,072,321

PacifiCorp
Reactive Power
Repowered Wind Generating Facility
Dunlap
2019

	Asset Category	Amount	Percentage	Allocated Investment	Total Investment	FERC Account
1	Turbine foundations	$ -	0.00%	$ -	$ -	343
2	Turbines - nacelle w/o generators	45,968,800	40.09%	6,013,553	51,982,353	343
3	Turbine blades	37,014,800	32.28%	4,842,207	41,857,007	343
4	Turbine tower	-	0.00%	-	-	343
5	Generators	8,880,000	7.74%	1,161,665	10,041,665	344
6	Collector system		0.00%	-	-	
7	Individual step-up transformers	-	0.00%	-	-	345
8	Grounding transformers	-	0.00%	-	-	
9	Fiber optic control cable	-	0.00%	-	-	345
10	Power cable from turbines to substation	-	0.00%	-	-	345
11	Operations building	-	0.00%	-	-	341
12	Access roads	-	0.00%	-	-	341
13	Meteorlogical equipment	-	0.00%	-	-	346
14	DTA - Control Box	11,100,000	9.68%	1,452,081	12,552,081	343
15	Hub	11,699,400	10.20%	1,530,494	13,229,894	343
16	Other 3	-	0.00%	-	-	
17	Subtotal	114,663,000	100.00%	$ 15,000,000	$ 129,663,000	
	Allocated Costs					
18	Project management	5,000,000				
19	AFUDC	10,000,000				
20	Other 1	-				
21	Other 2	-				
22	Other 3	-				
23	Subtotal	15,000,000				
24	Total Generation	129,663,000		Depreciation	$ 4,322,100	
	Substation					
25	GSU	-				353
26	Capacitors	-				353
27	Other 1	-				353
28	Other 2	-				353
29	Transmission Lines	-				
30	Total Project	$ 129,663,000				

PacifiCorp
Reactive Power
Repowered Wind Generating Facility
Foote Creek I - Repower Costs
2019

	Asset Category	Amount	Percentage	Allocated Investment	Total Investment	FERC Account
1	Turbine foundations	$ 4,840,864	7.36%	$ 981,475	$ 5,822,339	343
2	Turbines - nacelle w/o generators	24,751,146	37.65%	5,018,243	29,769,388	343
3	Turbine blades	13,750,636	20.92%	2,787,913	16,538,549	343
4	Turbine tower	11,000,509	16.73%	2,230,330	13,230,839	343
5	Generators	4,400,204	6.69%	892,132	5,292,336	344
6	Collector system	-	0.00%	-	-	
7	Individual step-up transformers (In tower)	1,100,051	1.67%	223,033	1,323,084	345
8	Grounding transformers	-	0.00%	-	-	
9	Fiber optic control cable	194,363	0.30%	39,407	233,770	345
10	Power cable from turbines to substation	2,552,806	3.88%	517,576	3,070,382	345
11	Operations building	-	0.00%	-	-	341
12	Access roads	2,512,913	3.82%	509,488	3,022,401	341
13	Meteorlogical equipment	631,627	0.96%	128,061	759,688	346
14	Other 1	-	0.00%	-	-	
15	Other 2	-	0.00%	-	-	
16	Other 3	-	0.00%	-	-	
17	Subtotal	65,735,119	100.00%	$ 13,327,657	$ 79,062,776	
	Allocated Costs					
18	Project management	992,485				
19	AFUDC	3,043,161				
20	Engineering	1,571,488				
21	Permiting	843,549				
22	Land Rights - Lease Purchase - Property Tax	6,876,973				
23	Subtotal	13,327,657				
24	Total Generation	79,062,776		Depreciation	$ 2,635,426	
	Substation					
25	GSU	-				353
26	Capacitors	-				353
27	Switchgear Building	3,519,671				353
28	Other 2	-				353
29	Transmission Lines	-				
30	Total Project	$ 82,582,448				

PacifiCorp
Reactive Power
New Wind Generating Facility
Cedar Springs II
2019

		Turbogen Accounts 343&344	AEE Account 345	GSU	Total Gen & GSU		
1	Expected purchase price				$ 266,300,000		
2	PAC Internal Costs				4,100,000		
3	Total Costs	232,898,450	25,806,123	2,793,553	270,400,000	Depreciation	$ 9,013,333
4	Ekola Flats	274,302,787	37,203,627	2,930,546	323,999,710		
5	TB Flats	494,105,856	42,625,403	7,286,972	555,380,727		
6	Proyor Mountain	333,535,589	42,271,004	3,000,000	400,000,000		
7	Total	1,101,944,233	122,100,033	13,217,518	1,279,380,437		
8	Percentages	86.1%	9.5%	1.0%	96.7%		

	Asset Category	Amount	Percentage	Allocated Investment	Total Investment	FERC Account
1	Turbine foundations	$ 12,141,342	5.05%	$ 4,057,124	$ 16,198,466	343
2	Turbines - nacelle including generators	182,903,794	76.00%	61,118,732	244,022,526	343
3	Turbine blades		0.00%	-	-	343
4	Turbine tower		0.00%	-	-	343
5	Generators	-	0.00%	-	-	344
6	Collector system		0.00%	-	-	345
7	Individual step-up transformers	-	0.00%	-	-	345
8	Grounding transformers	596,720	0.25%	199,399	796,119	345
9	Fiber optic control cable	754,513	0.31%	252,126	1,006,639	345
10	Power cable from turbines to substation	25,789,244	10.72%	8,617,677	34,406,921	345
11	Operations building	1,576,319	0.66%	526,739	2,103,058	341
12	Access roads	4,287,782	1.78%	1,432,796	5,720,578	341
13	Meteorlogical equipment	1,303,529	0.54%	435,584	1,739,113	346
14	WTG Erection	10,554,820	4.39%	3,526,976	14,081,796	343
15	Aircraft Detection Lighting	745,000	0.31%	248,948	993,948	345
16	Subtotal	240,653,063	100.00%	$ 80,416,101	$ 321,069,164	
	Allocated Costs					
17	Project management	5,000,000				
18	AFUDC	18,435,910				
19	Engineering	11,643,466				
20	Environmental Studies / Permits	1,432,573				
21	LGIA	2,760,000				
22	Development Fee	24,397,667				
23	Landowner Fees	1,689,616				
24	Estimated Taxes	12,298,208				
25	Insurance contingency	124,434				
26	Capitalized Spare Parts	2,634,227				
27	Subtotal	80,416,101				
28	Total Generation	321,069,164		Depreciation	$ 10,799,990	
	Substation					
29	GSU	2,930,546				353
30	Capacitors	-				353
31	Telecommunications	250,000				353
32	Substation	6,407,495				353
33	Transmission Lines	1,077,660				
34	Total Project	$ 331,734,865				

PacifiCorp
Reactive Power
New Wind Generating Facility
TB Flats
2019

	Asset Category	Amount	Percentage	Allocated Investment	Total Investment	FERC Account
1	Turbine foundations	$ 19,462,593	4.54%	$ 5,425,293	$ 24,887,886	343
2	Turbines - nacelle including generators	192,464,649	44.90%	53,650,461	246,115,111	343
3	Turbine blades	87,483,932	20.41%	24,386,573	111,870,505	343
4	Turbine tower	69,987,145	16.33%	19,509,259	89,496,404	343
5	Generators	-	0.00%	-	-	344
6	Collector system					
7	Individual step-up transformers	-	0.00%	-	-	345
8	Grounding transformers	-	0.00%	-	-	345
9	Fiber optic control cable	1,139,558	0.27%	317,657	1,457,215	345
10	Power cable from turbines to substation	31,448,963	7.34%	8,766,552	40,215,515	345
11	Operations building	1,859,556	0.43%	518,360	2,377,916	341
12	Access roads	4,587,201	1.07%	1,278,705	5,865,906	341
13	Meteorlogical equipment	2,438,836	0.57%	679,837	3,118,673	346
14	WTG Erection	16,997,746	3.97%	4,738,205	21,735,951	343
15	Aircraft Detection Lighting	745,000	0.17%	207,672	952,672	345
16	Subtotal	428,615,179	100.00%	$ 119,478,576	$ 548,093,755	
	Allocated Costs					
17	Project management	5,000,000				
18	AFUDC	10,000,000				
19	Environmental Studies / Permints	1,178,000				
20	LGIA	3,753,804				
21	Development Fee	50,686,667				
22	Landowner Fees	1,999,490				
23	Estimated Taxes	21,648,638				
24	Other (insurance, contingency, estaimated change ord	22,507,401				
25	Capitalize Spare Parts	2,704,576				
26	Engineering / Mob Demob	4,340,565				
27	Subtotal	119,478,576				
28	Total Generation	548,093,755		Depreciation	$ 18,512,691	
	Substation					
29	GSU	7,286,972				353
30	Capacitors	-	Included in collector substatincost			353
31	Telecommunications	399,448				353
32	Collector substations	15,431,943				353
33	Transmission Lines	9,586,394				
34	Total Project	$ 580,798,512				

PacifiCorp
Reactive Power
New Wind Generating Facility
Pryor Mountain Project
2019

	Asset Category	Amount	Percentage	Allocated Investment	Total Investment	FERC Account
1	Turbine foundations	$ 22,000,000	6.42%	$ 3,478,413	$ 25,478,413	343
2	Turbines - nacelle including generators and blades	230,000,000	67.09%	36,365,228	266,365,228	343
3	Turbine Erection	30,000,000	8.75%	4,743,291	34,743,291	343
4	Crane Pads; walks and breakdown	3,500,000	1.02%	553,384	4,053,384	343
5	Engineering	2,500,000	0.73%	395,274	2,895,274	344
6	Collector system	23,000,000	6.71%	3,636,523	26,636,523	345
7	Mob/Demob; G&A; Insurance;	7,000,000	2.04%	1,106,768	8,106,768	345
8	Grounding transformers	-	0.00%	-	-	345
9	Fiber optic control cable	-	0.00%	-	-	345
10	Power cable from turbines to substation	-	0.00%	-	-	345
11	Operations building	3,000,000	0.88%	474,329	3,474,329	341
12	Access roads	14,000,000	4.08%	2,213,536	16,213,536	341
13	Meteorological equipment	1,300,000	0.38%	205,543	1,505,543	346
14	Collector Substation	6,500,000	1.90%	1,027,713	7,527,713	345
15	Subtotal	342,800,000	100.00%	$ 54,200,000	$ 397,000,000	
	Allocated Costs					
16	Project management	4,000,000				
17	AFUDC & Cap Surch	18,000,000				
18	Legal Cost	1,500,000				
19	Land & Property	3,500,000				
20	Development Asset Purchase	15,000,000				
21	Property tax and County Impact fees	7,700,000				
22	Utilities, IT, communications	1,500,000				
23	Operations Spare Parts, Tooling and Equip	1,000,000				
24	Interconnection	2,000,000				
25	Subtotal	54,200,000				
26	Total Generation	397,000,000		Depreciation	$ 13,333,333	
	Substation					
27	GSU	3,000,000				353
28	Capacitors	1,000,000				353
29	DVAR	4,000,000				353
30	Other 2	-				353
31	Transmission Lines	1,000,000				
32	Total Project	$ 406,000,000				

	I. Allocators			FERC Form 1 or Line # Reference
	a. Wage Allocator			
1	Total O&M Wages	$	362,000,992	354.28b
2	Less: A&G Wages		42,795,683	354.27b
3	O&M Wages Less A&G Wages		319,205,309	(Line 1 - Line 2)
4	Production Wages		143,501,344	354.20b
5	Wage Allocator		44.96%	(Line 4 / Line 3)
	b. Gross Plant Allocator			
6	Production Plant	$	12,370,876,824	205.46g footnote
7	Total Utility Plant		28,448,313,270	205.104g footnote
8	Gross Plant Allocator		43.49%	(Line 6 / Line 7)

	II. A&G Expenses			
9	Amount	$	123,136,603	323.197b
10	Wage Allocator		44.96%	(Line 5)
11	A&G Allocated to Production		55,357,062	(Line 9 * Line 10)
12	Production Investment		12,370,876,824	(Line 6)
13	A&G Allocation Percent		0.45%	(Line 11 / Line 12)

	III. Other Taxes			
	Wage Related			
14	FICA	-	263.3i	Treated as labor adder
15	Federal Umployment	-	263.4i	Treated as labor adder
16	State Unemployment Taxes	-	Various	Treated as labor adder
17	Total	-		
18	Wage Allocator	44.96%	(Line 5)	
19	FICA and Unemployment Allocated to Production	-	(Line 17 * Line 18)	
	Property Related			
20	Arizona	2,694,681	263.11i	
21	California	2,087,104	263.16i	
22	Colorado	2,978,742	263.24i	
23	Idaho	6,121,555	263.29i	
24	Montana	5,149,080	263.1.2i	
25	New Mexico	21,147	263.1.14i	
26	Oregon	24,808,302	263.1.19i	
27	Utah	79,123,372	263.2.2i	
28	Washington	8,502,236	263.2.9i	
29	Wyoming	16,805,340	263.2.21i	
30	Possessory - Goshute	29,054	263.2.30i	
31	Possessory - Sho-Ban	271,335	263.2.31i	
32	Possessory - Navajo	14,993	263.2.32i	
33	Possessory - Ute	40,695	263.2.33i	
34	Possessory - Crow	72,000	263.2.34i	
35	Possessory - Umatilla	69,751	263.2.35i	
36	Annual Report - Wyoming	76,984	263.2.26i	
30	Total	148,866,371	(Sum 20 to 29)	
31	Gross Plant Allocator	43.49%	(Line 8)	
32	Property Taxes Allocated to Production	64,735,210	(Line 30 * Line 31)	
33	Total FICA and Unemplyment and Property Taxes	64,735,210	(Line 19 + 32)	
34	Production Investment	12,370,876,824	(Line 6)	
35	FICA/Unemplyment and Property Taxes Allocation Percent	0.52%	(Line 33 / Line 34)	

	IV. General and Intangible Property		
36	General Plant	1,287,632,918	207.99g footnote
37	Intangible Plant	1,015,882,796	205.5g
38	Total General and Intangible Plant	2,303,515,714	
39	Rate of Return	7.55%	(Line 74)
40	Income Taxes	1.67%	(Line 95)
41	Return and Income Taxes	9.22%	(Line 39 + 40)
42	G&I Return	212,476,267	(Line 38 * Line 41)
43	General Depreciation Expense	43,110,635	336.10b+d
44	Intangible Amortization Expense	48,671,914	336.1d
45	Total G&I Revenue Requirement	304,258,816	(Line 42 + 43 + 44)
46	Wage Allocator	44.96%	(Line 5)
47	G&I Revenue Requirement Allcoated to Production	136,782,026	(Line 45 * Line 46)
48	Production Plant	12,370,876,824	(Line 6)
49	G&I Allocation Percent	1.11%	(Line 47 / Line 48)

	V. Prepayments		
50	Amount	62,585,511	111.57c
51	Rate of Return	7.55%	(Line 74)
52	Income Taxes	1.67%	(Line 95)
53	Return and Income Taxes	9.22%	(Line 51 + 52)
54	Prepayment Revenue Requirement	5,772,887	111.57c
55	Total Utility Plant	28,448,313,270	(Line 7)
56	Prepayment Allocation Percent	0.02%	(Line 54 / Line 55)

	VI. Materials and Supplies		
57	Production Plant	67,226,405	227.7c
58	Assigned to Construction	162,913,741	227.5.c
59	Gross Plant Allocator	43.49%	(Line 8)
60	Allocated to Production	70,843,772	(Line 58 * Line 59)
61	Total Production Materials and Supplies	138,070,177	(Line 57 + 60)
62	Rate of Return	7.55%	(Line 74)
63	Income Taxes	1.67%	(Line 95)
64	Return and Income Taxes	9.22%	(Line 62 + 63)
65	Materials and Supplies Revenue Requirement	12,735,592	(Line 60 * Line 64)
66	Production Plant	12,370,876,824	(Line 6)
67	Materials and Supplies Allocation Percent	0.10%	(Line 65 / Line 66)

	VII. Rate of Return						
68	Common Equity	8,437,788,931		112.16c			
69	Less: Preferred Stock	2,397,600		(Line 86)			
70	Less; Accumulated Comprehensive Income	(15,916,633)		112.15c	Capitalization Percent	Cost Rate	Weighted Cost
71	Adjusted Commonn Equity		8,451,307,964		52.34%	9.80%	5.13%
72	Preferred Stock		2,397,600	(Line 86)	0.01%	8.0%	0.00%
73	Long-term Debt		7,691,854,707	(Line 87)	47.64%	5.08%	2.42%
74	Total Capitalization / Rate of Return		16,145,560,271	(Line 71 + 72 + 73)	100.00%		7.55%
75	Cost of Long-term Debt						
76	Long-term Debt Expense	$ 369,853,259		117.62c			
77	Amort. Of Debt Discount and Expense	3,892,240		117.63c			
78	Amort. Of Loss on Reacquired Debt	583,695		117.64c			
79	Amort. Of Gain on Reacquired Debt	(11,026)		117.65.c			
80	Total Interest Expense	374,318,168					
81	Long-term Debt - Beginning of Year	7,044,517,215		112.24d			
82	Long-term Debt - End of Year	7,691,854,707		112.24c			
83	Average	7,368,185,961		(AVG Line 81 and Line 82)			
84	Cost of Debt	5.08%		(Line 80 / Line 83)			
85	Preferred Stock Dividends	191,902		118.29c			
86	Preferred Stock (same beginning and end of year)	2,397,600		112.3c			
87	Cost of Preferred	8.00%		(Line 85 / Line 86)			

	VIII. Income Taxes			For ADIT Calculations Prior to 2018
88	Federal Tax Rate	21.00%	Transmission Formula Rate	35.00%
89	State Weighted Average Tax Rate	4.54%	Transmission Formula Rate	4.54%
90	Composite Income Tax Rate	24.59%	(Line 88 + (Line 89 * (1 - Line 88))	37.95%
91	Tax Rate/(1-Tax Rate)	32.60%	(Line 90 / (1- Line 90)	61.16%
92	Weighted Cost of Equity	5.13%	(Line 71)	5.13%
93	Weighted Cost of Preferred	0.00%	(Line 72)	0.00%
94	Total Equity Return	5.13%	(Line 92 + 93)	5.13%
95	Income Taxes on Equity Return	1.67%	(Line 94 * Line 95)	3.14%

	OPP=Other Power Production	FERC Account	500/546	501/547	502	503	504	505/548	506/549	507/550	508	509	510/551	511/552	512	513/553	514/554	515			
			Operations S&E	Fuel	Steam	Steam Other	Steam Trf	Electric Expense	Misc. Steam/Other Power	Rents	Operations Supplies	Allowances	Maintenance S&E	Maintenance Structures	Maintenance of Boiler	Maintenance of Electric	Maintenance of Misc.	Maintenance of Steam	Total Steam/OPP	Excluded - 501, 509, 510, 512, 513, 547	Net Steam/OPP O&M
	Generating Facility	Type																			
1	Blundell	Steam	43,503	-	-	265,042	4,836,772	-	1,739,757	8,964	-	-	-	352,874	294,801	194,104	47,548	-	7,783,365	488,905	7,294,460
2	Chehalis	Combined Cycle (OPP)	192,912	64,982,881	-	-	-	1,934,664	878,661	-	-	-	-	28,915	-	1,693,967	-	-	69,712,000	64,982,881	4,729,119
3	Cholla	Steam - Coal	2,307,136	41,486,521	6,114,697	-	-	309,411	2,052,900	-	-	-	2,359,677	4,086,250	4,854,765	1,055,833	1,277,890	-	65,905,080	49,756,796	16,148,284
4	Colstrip	Steam - Coal	30,468	17,091,647	986,660	-	-	51,410	1,906,865	10,042	-	-	253,117	389,383	2,564,639	8,127	344,140	-	23,636,498	19,917,530	3,718,968
5	Currant Creek	Combined Cycle (OPP)	60,872	64,056,541	-	-	-	1,747,075	1,021,373	-	-	-	-	420,484	-	920,033	68,252	-	68,294,630	64,056,541	4,238,089
6	Dave Johnston	Steam - Coal	15,843	49,807,479	2,024,824	-	-	-	16,810,355	86,157	-	-	-	4,307,318	14,838,235	11,731,602	1,386,180	-	101,007,993	76,377,316	24,630,677
7	Gadsby	Combustion Turbine and	34,410	6,669,026	144,257	-	-	-	3,691,399	-	-	-	-	128,946	906,130	1,166,287	445,056		13,185,511	6,669,026	6,516,485
8	Gadsby Peakers	GT	-	1,160,580	-	-	-	734,954	-	-	-	-	-	58,078	-	307,244	123,631	-	2,384,487	1,160,580	1,223,907
9	Total Gadsby	(OPP)	34,410	7,829,606	144,257	-	-	734,954	3,691,399	-	-	-	-	187,024	906,130	1,473,531	568,687	-	15,569,998	7,829,606	7,740,392
10	Hermiston	Combined Cycle (OPP)	-	29,285,582	-	-	-	7,137,888	-										36,423,470	29,285,582	7,137,888
11	Hunter	Steam - Coal	-	136,014,783	-	23,514,207	-	(32,315)	370,645	-	-	-	-	3,412,789	16,730,239	5,029,984	1,250,108	-	186,290,440	157,775,006	28,515,434
12	Huntington	Steam - Coal	15,087	104,571,495	13,205,769	-	-	-	9,848,321	25,964	-	-	1,598,911	2,477,961	13,595,055	7,992,089	822,980	-	154,153,632	127,757,550	26,396,082
13	Jim Bridger	Steam - Coal	14,234,340	252,682,285	19,568,003	-	-	-	(21,036,522)	331,946	-	-	580,006	10,304,164	23,037,622	7,389,583	2,295,209	-	309,386,636	283,689,496	25,697,140
14	Lake Side	Combined Cycle	47,328	64,738,243	-	-	-	2,341,763	496,509	-	-	-	-	909,310	-	1,256,397	14,715	-	69,804,265	64,738,243	5,066,022
15	Lake Side	Combined Cycle	54,696	55,984,255	-	-	-	3,127,779	574,681	-	-	-	-	957,626	-	378,560	15,451		61,093,048	55,984,255	5,108,793
16	Total Lake Side	(OPP)	102,024	120,722,498	-	-	-	5,469,542	1,071,190	-	-	-	-	1,866,936	-	1,634,957	30,166	-	130,897,313	120,722,498	10,174,815
17	Naughton	Steam - Coal	299,356	86,682,877	7,913,360	-	-	1,865	6,252,984	14,350	-	-	1,498,176	1,031,530	4,834,856	2,952,761	826,583	-	112,308,698	95,968,670	16,340,028
18	Craig	Steam - Coal	422,593	23,520,484	2,037,591	-	-	808,542	1,112,827	-	-	-	792,998	564,248	3,715,128	604,437	884,870	-	34,463,718	28,633,047	5,830,671
19	Hayden	Steam - Coal	145,370	12,051,841	1,179,420	-	-	393,609	492,771	-	-	-	210,597	319,054	689,291	208,446	216,206	-	15,906,605	13,160,175	2,746,430
20	Wyodak	Steam - Coal	9,495	22,490,477	3,295,495	-	-	3,800,445	15,043	-	-	-		240,210	2,978,981	1,175,767	134,621	-	34,140,534	26,645,225	7,495,309

		FERC Account	535 Operations S&E	536 Water for Power	537 Hydraulic	538 Electric	539 Misc. Hydraulic	540 Rents	541 Maintenance S&E	542 Maintenance Structures	543 Maintenance of Dams	544 Maintenance of Electric	545 Maintenance of Misc.	Total Hydro	Excluded - 544	Net Hydro O&M
21	Merwin	Hydro	1,689,541	3,618	788,143	-	562,242	96,619	-	36,479	32,091	137,630	500,907	3,847,270	137,630	3,709,640
22	Yale	Hydro	1,576,354	3,564	776,553	-	486,488	95,182	-	24,888	75,687	84,677	478,730	3,602,123	84,677	3,517,446
23	Swift 1	Hydro	2,948,946	6,384	1,636,070	-	404,476	170,475	-	32,253	114,965	175,100	854,965	6,343,634	175,100	6,168,534
24	Lemolo	Hydro	35,738	721	73,720	-	710,190	132,424	-	77,412	6,840	70,001	155,188	1,262,234	70,001	1,192,233
25	Lemolo	Hydro	43,011	868	88,722	-	643,546	159,372	-	56,821	152,722	15,261	185,851	1,346,174	15,261	1,330,913
26	Total Lemelo													2,608,408	85,262	2,523,146
27	Toketee	Hydro	71,088	958	97,942	-	736,778	175,933	-	67,843	12,989	117,837	205,165	1,486,533	117,837	1,368,696
28	Slide Creek	Hydro	24,905	406	41,480	-	351,691	74,512	-	28,288	20,519	89,618	86,891	718,310	89,618	628,692
29	Soda Springs	Hydro	12,289	248	112,090	-	435,622	45,535	-	16,506	87,988	105,167	61,413	876,858	105,167	771,691
30	Clearwater	Hydro	21,753	338	34,567	-	326,338	62,093	-	21,528	7,297	54,360	72,409	600,683	54,360	546,323
31	Clearwater	Hydro	29,046	586	59,916	-	456,212	107,628	-	37,586	10,946	7,042	125,599	834,561	7,042	827,519
32	Total Clearwater													1,435,244	61,402	1,373,842
33	Fish Creek	Hydro	12,289	248	25,349	-	261,016	45,535	-	16,389	5,999	4,474	53,100	424,399	4,474	419,925
34	Prospect	Hydro	394,402	12,490	1,626	512,455	712,142	40,113	260	64,842	200,591	422,443	438,020	2,799,384	422,443	2,376,941
35	Copco	Hydro	21,216	-	1,048	-	1,077,576	120,695	-	2,787	12,324	101,694	15,424	1,352,764	101,694	1,251,070
36	Copco	Hydro	28,641	-	1,414	-	1,243,258	162,938	-	3,395	898	6,866	20,823	1,468,233	6,866	1,461,367
37	Total Copco		49,857	-	2,462	-	2,320,834	283,633	-	6,182	13,222	108,560	36,247	2,820,997	108,560	2,712,437
38	JC Boyle	Hydro	166,463	-	4,979	-	1,023,745	2,305	-	88,225	23,609	214,540	131,211	1,655,077	214,540	1,440,537
39	Irongate	Hydro	1,310,374	-	943	-	1,072,544	108,626	-	3,282	8,566	120,412	13,882	2,638,629	120,412	2,518,217
40	Ashton	Hydro				454,176						149,232		603,408	149,232	454,176
41	Soda	Hydro	42,220	-	15,975	-	466,712	5,077	-	60	3,591	30,637	27,047	591,319	30,637	560,682
42	Grace	Hydro	125,312	-	37,655	-	1,567,742	12,477	-	17,856	91,128	124,958	86,818	2,063,946	124,958	1,938,988
43	Oneida	Hydro	90,472	-	34,232	-	849,267	10,751	-	-	7,436	77,027	57,958	1,127,143	77,027	1,050,116
44	Cutler	Hydro	129,376	-	114,728	-	1,428,546	18,011	-	-	5,682	16,407	334,104	2,046,854	16,407	2,030,447

		FERC Account	546-550 Operations	551-555 Maintenance	Total Wind	Excluded - None	Net Wind
45	Glenrock I	Wind	191,664	740,767	932,431	-	932,431
46	Glenrock II	Wind	78,135	382,682	460,817	-	460,817
47	Total Glenrock						1,393,248
48	Rolling Hills	Wind	192,248	1,247,565	1,439,813	-	1,439,813
49	Seven Mile Hill 1	Wind	791,847	551,715	1,343,562	-	1,343,562
50	Seven Mike Hill 2	Wind	54,683	105,554	160,237	-	160,237
51	Total Seven Mile Hill						1,503,799
52	High Plains	Wind	1,014,346	814,274	1,828,620	-	1,828,620
53	McFadden Ridge	Wind	290,190	289,526	579,716	-	579,716
54	Total HP/MR						2,408,336
55	Goodnoe Hills	Wind	958,589	484,223	1,442,812	-	1,442,812
56	Leaning Juniper	Wind	1,133,720	272,243	1,405,963	-	1,405,963
57	Marengo I	Wind	737,176	893,869	1,631,045	-	1,631,045
58	Marengo II	Wind	465,922	445,604	911,526	-	911,526
59	Total Marengo						2,542,571
60	Dunlap	Wind			1,610,606	-	1,610,606
61	Foote Creek	Wind			790,038	-	790,038
62	Cedar Springs II	Wind			3,891,443	-	3,891,443
63	Ekola Flats	Wind			2,707,237	-	2,707,237
64	TB Flats I	Wind			6,279,326	-	6,279,326
65	Pryor Mountain	Wind			3,442,324	-	3,442,324

2021 estimated data for Dunlap, Foote Creek, Cedar Springs II, Ekola Flats, TB Flats and Pryor Mountain

	CoCd	Location	Location Description	2018 Gross Plant	2019 Gross Plant	2019 Depr Exp	Depr Exp - Based on Composite
1	1000	018000	JC BOYLE HYDRO PLANT	$ 36,220,901	$ 36,310,120	$ (3,901,166)	$ (4,632,618)
2	1000	610000	IRON GATE HYDRO PLANT	29,675,220	30,042,629	(14,592,016)	(3,814,230)
3	1000	611000	COPCO #1 HYDRO PLANT	10,982,868	11,365,714	1,465,199	(1,427,423)
4	1000	612000	COPCO #2 HYDRO PLANT	16,463,544	16,757,525	5,031,854	(2,121,858)
				93,342,532	94,475,988	(11,996,129)	(11,996,129)
5				Avg Gross Plant	93,909,260		
6				Composite Rate	12.77%		

	Plant	Stipulated Life 2002 Depr Study Effective 4/1/2003	Stipulated Life 2007 Depr Study Effective 1/1/2008	Stipulated Life 2012 Depr Study Effective 1/1/2014	Book Life To Use in RP RR 2019
	Steam				
1	Cholla	44.0	61.0	61.0	60.0
2	Colstrip	44.0	61.0	61.0	60.0
3	Craig	44.0	54.0	54.0	60.0
4	Dave Johnston	54.0	61.0	61.0	60.0
5	Hayden	54.0	60.0	60.0	60.0
6	Hunter	44.0	61.0	61.0	60.0
7	Huntington	44.0	61.0	61.0	60.0
8	Jim Bridger	44.0	61.0	61.0	60.0
9	Naughton	54.0	61.0	61.0	60.0
10	Wyodak	44.0	61.0	61.0	60.0
11	Blundell	30.0	49.0	46.0	45.0
	Gas				
12	Chehalis	-	40.0	40.0	40.0
13	Currant Creek (CCCT)	-	40.0	40.0	40.0
14	Gadsby (Rankine)	54.0	64.0	79.0	
15	Gadsby (CT)	25.0	30.0	30.0	40.0
16	Hermiston (CCCT)	35.0	40.0	40.0	40.0
17	Lake side	-	40.0	40.0	40.0
	Hydro				
18	Ashton	118.0	117.0	117.0	100.0
19	Cutler	97.0	97.0	97.0	100.0
20	Grace	123.0	125.0	125.0	100.0
21	Oneida	116.0	118.0	118.0	100.0
22	Soda	107.0	109.0	109.0	100.0
23	Merwin	105.0	115.0	127.0	100.0
24	Swift	78.0	88.0	100.0	100.0
25	Yale	83.0	93.0	105.0	100.0
26	Lemolo #1	85.0	83.0	83.0	
27	Lemolo #2	84.0	82.0	82.0	100.0
28	Clearwater #1	87.0	85.0	85.0	
29	Clearwater #2	87.0	85.0	85.0	100.0
30	Toketee	91.0	89.0	89.0	100.0
31	Fish Creek	88.0	86.0	86.0	100.0
32	Soda Springs	88.0	86.0	86.0	100.0
33	Slide Creek	89.0	87.0	87.0	100.0
34	Prospect #1	123.0	125.0	126.0	
35	Prospect #2	107.0	109.0	110.0	
36	Prospect #3	87.0	86.0	86.0	
37	Prospect #4	91.0	93.0	94.0	100.0
38	J. C. Boyle	78.0	88.0	61.0	100.0
39	Iron Gate	74.0	84.0	57.0	100.0
40	COPCO #1	118.0	128.0	101.0	
41	COPCO #2	100.0	121.0	94.0	100.0
	Wind				
42	Glenrock/Rolling Hills	-	25.0	30.0	30.0
43	Seven Mile Hill	-	25.0	30.0	30.0
44	High Plains/McFadden Ridge	-	25.0	30.0	30.0
45	Goodnoe Hills	-	25.0	30.0	30.0
46	Leaning Juniper	-	25.0	30.0	30.0
47	Marengo	-	25.0	30.0	30.0
48	Dunlap	-	25.0	30.0	30.0
49	Foote Creek	25.0	25.0	30.0	30.0
50	Cedar Springs	-	-	-	30.0
51	Ekola Flats	-	-	-	30.0
52	TB Flats	-	-	-	30.0
53	Pryor Mountain	-	-	-	30.0

Year	Solar and Wind Five-Year	Nuclear and GT 15 Year	Steam Including Combined Cycle Hydroelectric All Other 20 Year
1	20.000%	5.000%	3.750%
2	32.000%	9.500%	7.219%
3	19.200%	8.550%	6.677%
4	11.520%	7.700%	6.177%
5	11.520%	6.930%	5.713%
6	5.760%	6.230%	5.285%
7		5.900%	4.888%
8		5.900%	4.522%
9		5.910%	4.462%
10		5.900%	4.461%
11		5.910%	4.462%
12		5.900%	4.461%
13		5.910%	4.462%
14		5.900%	4.461%
15		5.910%	4.462%
16		2.950%	4.461%
17			4.462%
18			4.461%
19			4.462%
20			4.461%
21			2.231%
	100.000%	100.000%	100.000%

Electric, Gas, Water & Steam, Utility Services note
Class I MACRS

21	Electric Utility Hydraulic Production Plant	50	20
22	Electric Utility Nuclear Production Plant	20	15
23	Electric Utility Nuclear Fuel Assemblies	5	5
24	Electric Utility Steam Production Plant	28	20

Includes assets used in the steam power production of electricity for sale, combustion turbines operated in a combined cycle with a conventional steam unit and related land improvements.
Also includes package boilers, electric generators and related assets such as electricity and steam distribution systems as used by a waste reduction and resource recovery plant if the steam or electricity is normally for sale to others.

25	Electric Utility Transmission & Distribution Plant	30	20
26	Electric Utility Combustion Turbine Production Plant	20	15

Includes assets used in the production of electricity for sale by the use of such prime movers as jet engines, combustion turbines, diesel engines, gasoline engines, and other internal combustion engines,
their associated power turbines and/or generators, and related land improvements. Does not include combustion turbines operated in a combined cycle with a conventional steam unit.

OATT (Part III - Network Service net of Self-Supply) - PROJECTED (3-year average)

	Column			e	f1	f2	f3	f4	f5	f6	f7	f8	f9	f10	f11	f12	f13	f14	f15	f16	f17	f18	f19	f20	
	Customer			PacifiCorp	BPA Yakama	BPA Gazley	BPA Clarke PUD	BPA: Benton REA	BPA Oregon Wind	BPA CEC	Tri-State	Calpine Energy	Basin Electric	Black Hills	USBR	WAPA	Avangrid Rer	Exelon	BPA South East Ida	BPA Idaho Falls	3 Phases Renewabl	NTUA	BPA Airport Solar		
	Class			NFS	FNO	FNO	FNO	FNO	FNO	FNO	FNO	FNO	FNO	FNO	FNO	FNO	FNO	FNO	FNO	FNO	FNO	FNO	FNO	Total FNO	
	RS / SA			(see note)	SA 328	SA 229	SA 735	SA 539	SA 538	SA 827	SA 628	SA 299	SA 505	SA 347	SA 506	SA 175	SA 742	SA 943	SA 746	SA 747	SA 876	SA 894	SA 836		
					(net of self-supply)	(net of self-supply)	(net of self-supply)	(net of self-supply)	(net of self-supply)	(net of self-supply)									(net of self-supply)	(net of self-supply)					
1	Jan	2	9:00	8,233.30	6.64	3.47	27.75	1.29	0.29	-	19.78	15.45	10.47	45.55	0.01	0.01	30.81	0.75	280.50	97.00	0.01	2.64		542.43	
2	Feb	7	8:00	8,603.86	7.36	3.41	34.14	1.30	0.48	0.02	18.86	16.14	11.81	55.25	0.01	0.01	31.82	0.79	229.98	96.00	0.06	2.42		509.86	
3	March	4	8:00	8,217.50	6.38	2.82	30.59	1.32	0.10	0.02	21.94	14.33	11.13	54.20	0.01	0.01	31.63	0.77	212.72	94.35	0.05	2.34		484.69	
4	April	10	8:00	7,167.34	2.59	1.45	8.70	0.50	-	-	16.23	13.71	8.54	37.79	0.24	0.01	31.21	0.70	80.40	68.05	0.07	1.87		272.03	
5	May	13	18:00	7,310.85	-	-	-	-	-	-	11.21	15.44	6.69	32.18	0.54	1.99	32.06	0.79	-	95.29	0.08	1.77		198.03	
6	Jun	28	18:00	8,681.42	0.44	0.34	1.17	0.04	-	-	14.36	15.40	9.62	44.89	0.55	3.20	31.97	0.87	13.02	96.09	0.11	1.93		234.00	
7	Jul	22	17:00	10,333.54	-	-	-	-	-	-	12.68	17.43	11.28	53.47	0.61	3.09	32.04	0.72	-	122.05	0.14	2.61		256.12	
8	Aug	5	17:00	10,220.49	0.03	0.02	0.09	0.00	-	-	13.95	17.57	10.90	50.13	0.63	2.93	32.27	0.34	0.66	106.80	0.18	2.42		238.92	
9	Sept	5	17:00	9,721.67	-	-	-	-	-	-	16.11	17.35	10.95	51.58	0.50	3.17	31.80	0.71	-	83.61	0.14	2.11		218.02	
10	Oct	30	8:00	8,274.42	6.06	3.23	24.49	1.17	0.34	0.12	18.17	14.16	11.60	48.47	0.01	0.01	32.06	0.78	238.73	92.90	0.07	2.49		494.83	
11	Nov	26	18:00	8,081.40	4.20	3.17	23.89	1.10	-	0.17	17.03	13.84	11.06	43.68	0.01	0.01	32.27	0.55	203.97	78.49	0.07	2.16		435.68	
12	Dec	17	18:00	8,498.13	4.50	2.97	22.87	0.84	-	0.17	17.09	13.91	9.79	43.64	0.01	0.01	32.61	0.72	236.82	65.63	0.08	2.65	0.24	454.28	
13	Total			103,343.93	38.20	20.88	173.68	7.56	1.22	0.50	197.39	184.71	123.83	560.83	3.09	14.44	382.54	8.48	1,496.79	1,096.26	1.06	27.44	0.24	4,338.88	
14	Ave 12CP			8,611.99	3.18	1.74	14.47	0.63	0.10	0.04	16.45	15.39	10.32	46.74	0.26	1.20	31.88	0.71	124.73	91.36	0.09	2.29	0.02	361.57	

Other Service - PROJECTED

	j1	j2	j3	j4	j5	f20+j5
	UAMPS	UMPA	Deseret	Western Area Power Administration	Total OS	
	OS	OS	OS	OS		
	RS 297	RS 637	RS 280	RS 262/263		
	(net of self-supply)	(net of self-supply)	(net of self-supply)			
1	270.69	38.42	-	324.00	633.11	
2	207.71	36.00	-	340.00	583.71	
3	173.69	-	-	320.00	493.69	
4	287.39	-	-	290.00	577.39	
5	259.46	-	-	295.00	554.46	
6	418.14	-	173.38	317.00	908.52	
7	582.81	-	212.50	318.00	1,113.32	
8	608.40	-	-	318.00	926.40	
9	561.43	9.87	-	288.00	859.30	
10	317.32	-	-	334.00	651.32	
11	227.47	-	-	299.00	526.47	
12	255.84	-	-	314.00	569.84	
13	4,170.35	84.29	385.88	3,757.00	8,397.52	12,736.40
14	347.53	7.02	32.16	313.08	699.79	1,061.37

OATT Part II Long-Term Firm Point-to-Point Transmission Service

	Column			g1	g2	g3	g4	g5	g6	g6	g7	g8	g9	g10	g11	g12	g13	g14	g15	g16	g17	g18	g19	g20	g21	g22	g22	g23	g24	g25	g26
	Customer			PacifiCorp	Avangrid	Black Hills, Inc.	BPA	BPA	City of Roseville	Clatskanie Peoples UI	Clatskanie Peo	Clatskanie Pec	Evergreen Bi	Idaho Power	Thermo No 1 (CR	Powerex	Powerex	Powerex	Powerex	Powerex	Powerex	Powerex	NextEra:	State of SD	Sacramento Mu	Salt River P	EWEB	Garrrett Sc	Obsidian	Obsidian	Losses	
	Class			LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	LTP	Total LTP
	RS / SA	Day	Time	Various	SA 895	SA 67	SA 179	SA 656	SA 881	SA 899	SA 900	SA 901	SA 874	SA 212	SA 568	SA 169	SA 700	SA 701	SA 702	SA 748	SA 749	SA 733	SA 779	SA 863	SA 809	SA 605	SA 966	SA 880	SA 836		
	Jan	2	18:00	2,446.00	30.00	50.00	13.11	40.49	50.00	13.00	3.00	2.00	10.00	-	11.00	80.00	100.00	100.00	100.00	50.00	150.00	99.00	4.00	19.00	25.00	-	-	-		127.54	3,523.14
15	Feb	23	8:00	2,446.00	30.00	50.00	12.62	40.49	50.00	13.00	3.00	2.00	10.00	-	11.00	80.00	100.00	100.00	100.00	50.00	150.00	99.00	4.00	19.00	25.00	-	-	-		127.54	3,522.65
16	March	6	8:00	2,446.00	30.00	50.00	5.81	5.49	50.00	13.00	3.00	2.00	10.00	-	11.00	80.00	100.00	100.00	100.00	50.00	150.00	99.00	4.00	19.00	25.00	-	-	-		127.54	3,480.84
17	April	3	8:00	2,446.00	30.00	50.00	5.79	6.49	50.00	13.00	3.00	2.00	10.00	-	11.00	80.00	100.00	100.00	100.00	50.00	150.00	99.00	4.00	19.00	25.00	25.00	-	-		128.65	3,507.93
18	May	24	17:00	2,446.00	30.00	50.00	10.97	25.49	50.00	13.00	3.00	2.00	10.00	-	11.00	80.00	100.00	100.00	100.00	50.00	150.00	99.00	4.00	19.00	25.00	25.00	-	-		128.65	3,532.11
19	Jun	27	17:00	2,541.00	30.00	50.00	8.37	-	50.00	13.00	3.00	2.00	10.00	50.00	11.00	80.00	100.00	100.00	100.00	50.00	150.00	80.00	4.00	19.00	25.00	25.00	-	-		134.26	3,635.63
20	Jul	16	17:00	2,541.00	30.00	50.00	10.31	10.49	50.00	13.00	3.00	2.00	10.00	50.00	11.00	80.00	100.00	100.00	100.00	50.00	150.00	80.00	4.00	19.00	25.00	25.00	-	-		134.26	3,648.06
21	Aug	9	16:00	2,541.00	30.00	50.00	10.68	26.49	50.00	13.00	3.00	2.00	10.00	50.00	11.00	80.00	100.00	100.00	100.00	50.00	150.00	80.00	4.00	19.00	25.00	25.00	-	-		134.26	3,664.43
22	Sept	7	17:00	2,541.00	30.00	50.00	13.88	25.49	50.00	13.00	3.00	2.00	10.00	50.00	11.00	80.00	100.00	100.00	100.00	50.00	150.00	80.00	4.00	19.00	25.00	25.00	-	-		134.26	3,666.63
23	Oct	2	13:00	2,541.00	30.00	50.00	18.80	37.49	50.00	13.00	-	2.00	10.00	50.00	11.00	80.00	100.00	100.00	100.00	50.00	150.00	80.00	4.00	19.00	25.00	25.00	-	10.00		134.57	3,690.86
24	Nov	20	8:00	2,446.00	30.00	50.00	-	53.48	50.00	13.00	-	2.00	10.00	-	11.00	80.00	100.00	100.00	100.00	50.00	150.00	99.00	4.00	19.00	25.00	25.00		10.00	50.00	131.19	3,608.67
25	Dec	6	18:00	2,446.00	30.00	50.00	18.80	38.49	50.00	13.00	-	2.00	10.00	-	11.00	80.00	100.00	100.00	100.00	50.00	150.00	99.00	4.00	19.00	25.00	25.00	10.00	-	50.00	131.19	3,612.48
26	Total			29,827.00	360.00	600.00	129.13	310.40	600.00	156.00	27.00	24.00	120.00	250.00	132.00	960.00	1,200.00	1,200.00	1,200.00	600.00	1,800.00	1,093.00	48.00	228.00	300.00	225.00	10.00	20.00	100.00	1,573.91	43,093.43
27	Avg 12CP			2,485.58	30.00	50.00	10.76	25.87	50.00	13.00	2.25	2.00	10.00	20.83	11.00	80.00	100.00	100.00	100.00	50.00	150.00	91.08	4.00	19.00	25.00	18.75	0.83	1.67	8.33	131.16	3,591.12

		Total Network & OS	Behind-the Meter	Total Network Load	Divisor Network + OS + LTP
	Jan	9,409	237	9,646	13,169
28	Feb	9,697	186	9,883	13,406
29	March	9,196	192	9,388	12,869
30	April	8,017	196	8,213	11,721
31	May	8,063	185	8,249	11,781
32	Jun	9,824	197	10,021	13,657
33	Jul	11,703	103	11,806	15,454
34	Aug	11,386	93	11,479	15,144
35	Sept	10,799	180	10,979	14,645
36	Oct	9,421	191	9,612	13,302
37	Nov	9,044	234	9,278	12,887
38	Dec	9,522	236	9,758	13,370
39	Total	116,080	2,230	118,310	161,404
40	Avg 12CP	9,673	186	9,859	13,450

	Generating Facility	Unit No.	Amount	
1	Blundell	1	$ -	Zero fuel costs
2	Blundell	2	-	Zero fuel costs
3	Total		-	
4	Chehalis	NA	-	Not in the PAC BAA
5	Cholla	NA	-	Not in the PAC BAA
6	Colstrip	NA	-	Not in the PAC BAA
7	Currant Creek	CT1	1,521	
8	Currant Creek	CT2	1,456	
9	Currant Creek	STG	10,020	
10	Total		12,996	
11	Dave Johnston	1	593	
12	Dave Johnston	2	633	
13	Dave Johnston	3	2,342	
14	Dave Johnston	4	1,093	
15	Total		4,662	
16	Gadsby	1	176	
17	Gadsby	2	220	
18	Gadsby	3	2,023	
19	Gadsby	4	-	Not calculated
20	Gadsby	5	-	Not calculated
20	Gadsby	6	-	Not calculated
21	Total		2,419	
22	Hermiston	NA	-	Not in the PAC BAA
23	Hunter	1	7,251	
24	Hunter	2	4,698	
25	Hunter	3	7,881	
26	Total		19,830	
27	Huntington	1	4,085	
28	Huntington	2	8,420	
29	Total		12,505	
30	Jim Bridger	1	17,096	
31	Jim Bridger	2	15,880	
32	Jim Bridger	3	14,843	
33	Jim Bridger	4	15,715	
34	Total		63,535	
35	Lake Side	CT11	1,713	
36	Lake Side	CT12	2,181	
37	Lake Side	STG10	5,145	
38	Lake Side	CT21	1,612	
39	Lake Side	CT22	1,386	
39	Lake Side	STG20	4,471	
40	Total		16,508	
41	Naughton	1	4,028	
42	Naughton	2	9,823	
43	Naughton	3	1,223	
43	Total		15,074	
44	Craig	NA	-	Not in the PAC BAA
45	Hayden	NA	-	Not in the PAC BAA
46	Wyodak	1	3,587	
47	Total		$ 151,115	

The following are PacifiCorp percent ownership of generating facilities where ownership is less than 100%.
The revenue requirements in this reactive power analyses reflect only the PacifiCorp ownership share.

Colstrip 3 and 4	10.00%
Craig 1 and 2	19.28%
Hayden 1	24.50%
Hayden 2	12.60%
Hunter 1	93.75%
Hunter 2	60.31%
Jim Bridger 1-4	66.67%
Wyodak	80.00%
Hermiston	50.00%

PacifiCorp
Reactive Power
Blundell 1 Heating Losses
2019

	Thermal Generating Facility	Blundell		1	Source		
	Transformer Losses						
1	Load Loss @85C (watts)	43,534	watts		Transformer Test Report		
2	Transformer Rating	25	MVA		PTT Transformer Test Report		
3	Transformer Voltage	12	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	1,157.48			(Line 2*1000)/(SQRT 3*Line 3)		
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.01083			Line 1/(3*(Line 4^2))		
6	Ibase @avg power factor	1,178.45			(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9822
7	Ibase @ pf 1	1,157			Line 4	in 2019	
8	Incremental Transformer Heating Losses	1,592	watts		3*(Line 6^2 - Line 7^2)*Line 5		
9	Incremental Transformer Heating Losses	0.002	MWs		Line 8/1000000		
	Generator Losses						
10	Generator Rating	30.7	MVA				
11	Generator Voltage	12.47	kV				
12	Stray loss factor	1.24			EPRI paper		
13	Ra=stator electrical resistance	0.00958	ohms		Generator data sheet		
14	Rf=rotor electrical resistance	0.48000	ohms		Generator data sheet		
15	If@ APF = rated excitation current with reactive power (A)	340.00			Generator vee curve		
16	If@unity pf = rated excitation current at unity (A)	320.00			Generator vee curve		
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	1,447.14			((Line 10/APF)*1000)/(SQRT 3 * Line 11)		
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	1,421.38			((Line 10/1.0)*1000)/(SQRT 3 * Line 11)		
19	Incremental generator heating losses	10,490	watts		(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)		
20	Incremental generator heating losses	0.010	MWs		Line 19/1000000		
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.002	MWs		Line 9		
22	Incremental generator heating losses	0.010	MWs		Line 20+Line 21		
23	Total Incremental Losses	0.012	MWs		Line 21+Line 22		
	Hours of operation						
24	2018	8,501			Actual operating hours		
25	2019	8,588			Actual operating hours		
26	Two year average	8,545			Average of Line 24 and Line 25		
27	Total Incremental Losses	103	MWh		Line 26*Line23		
28	Fuel Costs per MWh	-			Line 33		
29	Cost of Heating Losses	$ -			Line 27*Line 28		

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	-	223,051	FF1, page 402
31	2019 Fuel Costs and Net Generation		115,179	FF1, page 403
32	Total	-	338,230	
33	Average Cost per MWh	$ -		

	Thermal Generating Facility	Blundell 2					
	Transformer Losses						
1	Load Loss @85C (watts)	57,000	watts	Transformer Test Report			
2	Transformer Rating	15	MVA	PTT Transformer Test Report			
3	Transformer Voltage	12	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	694.49		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.03939		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	695.18		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.999	
7	Ibase @ pf 1	694		Line 4	in 2019		
8	Incremental Transformer Heating Losses	114	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.000	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	14.118	MVA				
11	Generator Voltage	12.47	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.03500	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.04570	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	340.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	320.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	654.31		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	653.65		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	859	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.001	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.000	MWs	Line 9			
22	Incremental generator heating losses	0.001	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.001	MWs	Line 21+Line 22			
	Hours of operation						
24	2017	8,484		Actual operating hours			
25	2018	7,908		Actual operating hours			
26	Two year average	8,196		Average of Line 24 and Line 25			
27	Total Incremental Losses	8	MWh	Line 26*Line23			
28	Fuel Costs per MWh	-		Line 33			
29	Cost of Heating Losses	$ -		Line 27*Line 28			

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	-	223,051	FF1, page 402
31	2019 Fuel Costs and Net Generation	-	115,179	FF1, page 403
32	Total	-	338,230	
33	Average Cost per MWh	$ -		

	Thermal Generating Facility	Currant Creek	CT1			
	Transformer Losses					
1	Load Loss @85C (watts)	383,077	watts	Transformer Test Report		
2	Transformer Rating	190	MVA	PTT Transformer Test Report		
3	Transformer Voltage	18	kV			
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	6,094.25		(Line 2*1000)/(SQRT 3*Line 3)		
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00344		Line 1/(3*(Line 4^2))		
6	Ibase @avg power factor	6,102.19		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9987
7	Ibase @ pf 1	6,094		Line 4	in 2019	
8	Incremental Transformer Heating Losses	998	watts	3*(Line 6^2 - Line 7^2)*Line 5		
9	Incremental Transformer Heating Losses	0.001	MWs	Line 8/1000000		
	Generator Losses					
10	Generator Rating	172	MVA			
11	Generator Voltage	18	kV			
12	Stray loss factor	1.24		EPRI paper		
13	Ra=stator electrical resistance	0.00754	ohms	Generator data sheet		
14	Rf=rotor electrical resistance	0.17900	ohms	Generator data sheet		
15	If@ APF = rated excitation current with reactive power (A)	1,350.00		Generator vee curve		
16	If@unity pf = rated excitation current at unity (A)	1,340.00		Generator vee curve		
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	5,524.08		((Line 10/APF)*1000)/(SQRT 3 * Line 11)		
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	5,516.90		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)		
19	Incremental generator heating losses	8,193	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)		
20	Incremental generator heating losses	0.008	MWs	Line 19/1000000		
	Cost of Heating Losses					
21	Incremental Transformer Heating Losses	0.001	MWs	Line 9		
22	Incremental generator heating losses	0.008	MWs	Line 20+Line 21		
23	Total Incremental Losses	0.009	MWs	Line 21+Line 22		
	Hours of operation					
24	2018	6,614		Actual operating hours		
25	2019	7,676		Actual operating hours		
26	Two year average	7,145		Average of Line 24 and Line 25		
27	Total Incremental Losses	66	MWh	Line 26*Line23		
28	Fuel Costs per MWh	$ 23.16		Line 33		
29	Cost of Heating Losses	**$ 1,521**		Line 27*Line 28		

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	$ 59,493,080	2,418,275	FF1, page 420
31	2019 Fuel Costs and Net Generation	64,056,541	2,917,279	FF1, page 421
32	Total	123,549,621	5,335,554	
33	Average Cost per MWh	**$ 23.16**		

	Thermal Generating Facility	Currant Creek	CT2			
	Transformer Losses					
1	Load Loss @85C (watts)	382,593	watts	Transformer Test Report		
2	Transformer Rating	190	MVA	PTT Transformer Test Report		
3	Transformer Voltage	18	kV			
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	6,094.25		(Line 2*1000)/(SQRT 3*Line 3)		
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00343		Line 1/(3*(Line 4^2))		
6	Ibase @avg power factor	6,100.96		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9989
7	Ibase @ pf 1	6,094		Line 4	in 2019	
8	Incremental Transformer Heating Losses	843	watts	3*(Line 6^2 - Line 7^2)*Line 5		
9	Incremental Transformer Heating Losses	0.001	MWs	Line 8/1000000		
	Generator Losses					
10	Generator Rating	172	MVA			
11	Generator Voltage	18	kV			
12	Stray loss factor	1.24		EPRI paper		
13	Ra=stator electrical resistance	0.00754	ohms	Generator data sheet		
14	Rf=rotor electrical resistance	0.17900	ohms	Generator data sheet		
15	If@ APF = rated excitation current with reactive power (A)	1,350.00		Generator vee curve		
16	If@unity pf = rated excitation current at unity (A)	1,340.00		Generator vee curve		
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	5,522.98		((Line 10/APF)*1000)/(SQRT 3 * Line 11)		
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	5,516.90		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)		
19	Incremental generator heating losses	7,851	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)		
20	Incremental generator heating losses	0.008	MWs	Line 19/1000000		
	Cost of Heating Losses					
21	Incremental Transformer Heating Losses	0.001	MWs	Line 9		
22	Incremental generator heating losses	0.008	MWs	Line 20+Line 21		
23	Total Incremental Losses	0.009	MWs	Line 21+Line 22		
	Hours of operation					
24	2018	6,602		Actual operating hours		
25	2019	7,859		Actual operating hours		
26	Two year average	7,231		Average of Line 24 and Line 25		
27	Total Incremental Losses	63	MWh	Line 26*Line23		
28	Fuel Costs per MWh	$ 23.16		Line 33		
29	Cost of Heating Losses	**$ 1,456**		Line 27*Line 28		

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	59,493,080	2,418,275	FF1, page 402
31	2019 Fuel Costs and Net Generation	64,056,541	2,917,279	FF1, page 403
32	Total	123,549,621	5,335,554	
33	Average Cost per MWh	**$ 23.16**		

	Thermal Generating Facility	Currant Creek	STG			
	Transformer Losses					
1	Load Loss @85C (watts)	451,301	watts	Transformer Test Report		
2	Transformer Rating	270	MVA	PTT Transformer Test Report		
3	Transformer Voltage	18	kV			
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	8,660.25		(Line 2*1000)/(SQRT 3*Line 3)		
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00201		Line 1/(3*(Line 4^2))		
6	Ibase @avg power factor	8,681.96		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9975
7	Ibase @ pf 1	8,660		Line 4	in 2019	
8	Incremental Transformer Heating Losses	2,265	watts	3*(Line 6^2 - Line 7^2)*Line 5		
9	Incremental Transformer Heating Losses	0.002	MWs	Line 8/1000000		
	Generator Losses					
10	Generator Rating	305	MVA			
11	Generator Voltage	18	kV			
12	Stray loss factor	1.24		EPRI paper		
13	Ra=stator electrical resistance	0.01282	ohms	Generator data sheet		
14	Rf=rotor electrical resistance	0.17900	ohms	Generator data sheet		
15	If@ APF = rated excitation current with reactive power (A)	1,375.00		Generator vee curve		
16	If@unity pf = rated excitation current at unity (A)	1,325.00		Generator vee curve		
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	9,807.40		((Line 10/APF)*1000)/(SQRT 3 * Line 11)		
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	9,782.88		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)		
19	Incremental generator heating losses	52,870	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)		
20	Incremental generator heating losses	0.053	MWs	Line 19/1000000		
	Cost of Heating Losses					
21	Incremental Transformer Heating Losses	0.002	MWs	Line 9		
22	Incremental generator heating losses	0.053	MWs	Line 20+Line 21		
23	Total Incremental Losses	0.055	MWs	Line 21+Line 22		
	Hours of operation					
24	2018	7,123		Actual operating hours		
25	2019	8,574		Actual operating hours		
26	Two year average	7,849		Average of Line 24 and Line 25		
27	Total Incremental Losses	433	MWh	Line 26*Line23		
28	Fuel Costs per MWh	$ 23.16		Line 33		
29	Cost of Heating Losses	**$ 10,020**		Line 27*Line 28		

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	59,493,080	2,418,275	FF1, page 402
31	2019 Fuel Costs and Net Generation	64,056,541	2,917,279	FF1, page 403
32	Total	123,549,621	5,335,554	
33	Average Cost per MWh	**$ 23.16**		

Thermal Generating Facility | Dave Johnston | 1

	Transformer Losses						
1	Load Loss @85C (watts)	34,730	watts	Transformer Test Report			
2	Transformer Rating	120	MVA	PTT Transformer Test Report			
3	Transformer Voltage	14	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	5,020.44		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00046		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	5,043.13		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9955	
7	Ibase @ pf 1	5,020		Line 4	in 2019		
8	Incremental Transformer Heating Losses	315	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.000	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	133.689	MVA				
11	Generator Voltage	13.8	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00157	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.42500	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	505.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	495.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	5,618.43		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	5,593.14		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	6,922	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.007	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.000	MWs	Line 9			
22	Incremental generator heating losses	0.007	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.007	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	6,546		Actual operating hours			
25	2019	8,353		Actual operating hours			
26	Two year average	7,450		Average of Line 24 and Line 25			
27	Total Incremental Losses	54	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 11.00		Line 33			
29	Cost of Heating Losses	**$ 593**		Line 27*Line 28			

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	54,519,018	4,800,371	FF1, Page 403
31	2019 Fuel Costs and Net Generation	49,807,479	4,686,381	FF1, Page 404
32	Total	104,326,497	9,486,752	
33	Average Cost per MWh	**$ 11.00**		

	Thermal Generating Facility	Dave Johnston		2			
	Transformer Losses						
1	Load Loss @85C (watts)	34,730	watts	Transformer Test Report			
2	Transformer Rating	120	MVA	PTT Transformer Test Report			
3	Transformer Voltage	14	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	5,020.44		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00046		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	5,043.13		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9955	
7	Ibase @ pf 1	5,020		Line 4	in 2019		
8	Incremental Transformer Heating Losses	315	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.000	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	133.689	MVA				
11	Generator Voltage	13.8	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00157	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.42500	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	505.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	495.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	5,618.43		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	5,593.14		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	6,922	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.007	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.000	MWs	Line 9			
22	Incremental generator heating losses	0.007	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.007	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	7,371		Actual operating hours			
25	2019	8,544		Actual operating hours			
26	Two year average	7,958		Average of Line 24 and Line 25			
27	Total Incremental Losses	58	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 11.00		Line 33			
29	Cost of Heating Losses	**$ 633**		Line 27*Line 28			

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	54,519,018	4,800,371	FF1, Page 403
31	2019 Fuel Costs and Net Generation	49,807,479	4,686,381	FF1, Page 404
32	Total	104,326,497	9,486,752	
33	Average Cost per MWh	**$ 11.00**		

	Thermal Generating Facility	Dave Johnston		3			
	Transformer Losses						
1	Load Loss @85C (watts)	598,761	watts	Transformer Test Report			
2	Transformer Rating	235	MVA	PTT Transformer Test Report			
3	Transformer Voltage	13	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	10,278.58		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00189		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	10,309.51		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.997	
7	Ibase @ pf 1	10,279		Line 4	in 2019		
8	Incremental Transformer Heating Losses	3,609	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.004	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	255	MVA				
11	Generator Voltage	13.8	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00224	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.22900	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	1,160.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	1,130.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	10,700.53		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	10,668.43		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	25,227	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.025	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.004	MWs	Line 9			
22	Incremental generator heating losses	0.025	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.029	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	8,232		Actual operating hours			
25	2019	6,539		Actual operating hours			
26	Two year average	7,386		Average of Line 24 and Line 25			
27	Total Incremental Losses	213	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 11.00		Line 33			
29	Cost of Heating Losses	**$ 2,342**		Line 27*Line 28			

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	54,519,018	4,800,371	FF1, Page 403
31	2019 Fuel Costs and Net Generation	49,807,479	4,686,381	FF1, Page 404
32	Total	104,326,497	9,486,752	
33	Average Cost per MWh	**$ 11.00**		

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Reactive Power
Dave Johnston 4 Heating Losses
2019

	Thermal Generating Facility	Dave Johnston		4			
	Transformer Losses						
1	Load Loss @85C (watts)	652,400	watts	Transformer Test Report			
2	Transformer Rating	400	MVA	PTT Transformer Test Report			
3	Transformer Voltage	22	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	10,497.28		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00197		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	10,507.79		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.999	
7	Ibase @ pf 1	10,497		Line 4	in 2019		
8	Incremental Transformer Heating Losses	1,307	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.001	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	400	MVA				
11	Generator Voltage	22	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00484	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.14800	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	1,950.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	1,940.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	10,507.79		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	10,497.28		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	11,113	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.011	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.001	MWs	Line 9			
22	Incremental generator heating losses	0.011	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.012	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	8,055		Actual operating hours			
25	2019	7,956		Actual operating hours			
26	Two year average	8,006		Average of Line 24 and Line 25			
27	Total Incremental Losses	99	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 11.00		Line 33			
29	Cost of Heating Losses	**$ 1,093**		Line 27*Line 28			

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	54,519,018	4,800,371	FF1, Page 403
31	2019 Fuel Costs and Net Generation	49,807,479	4,686,381	FF1, Page 404
32	Total	104,326,497	9,486,752	
33	Average Cost per MWh	**$ 11.00**		

Thermal Generating Facility: Gadsby 1

	Transformer Losses						
1	Load Loss @85C (watts)	254,770	watts	Transformer Test Report			
2	Transformer Rating	75	MVA	PTT Transformer Test Report			
3	Transformer Voltage	13	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	3,280.40		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00789		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	3,291.59		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9966	
7	Ibase @ pf 1	3,280		Line 4	in 2019		
8	Incremental Transformer Heating Losses	1,741	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.002	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	81.176	MVA				
11	Generator Voltage	13.8	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00125	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.13880	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	620.00		Estimated values			
16	If@unity pf = rated excitation current at unity (A)	600.00		Estimated values			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	3,407.74		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	3,396.16		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	4,565	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.005	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.002	MWs	Line 9			
22	Incremental generator heating losses	0.005	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.006	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	408		Actual operating hours			
25	2019	530		Actual operating hours			
26	Two year average	469		Average of Line 24 and Line 25			
27	Total Incremental Losses	3	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 59.53		Line 33			
29	Cost of Heating Losses	**$ 176**		Line 27*Line 28			

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	3,248,365	51,636	FF1, Page 403.2
31	2019 Fuel Costs and Net Generation	6,669,026	114,952	FF1, Page 403.3
32	Total	9,917,391	166,588	
33	Average Cost per MWh	**$ 59.53**		

	Thermal Generating Facility	Gadsby		2			
	Transformer Losses						
1	Load Loss @85C (watts)	257,350	watts	Transformer Test Report			
2	Transformer Rating	75	MVA	PTT Transformer Test Report			
3	Transformer Voltage	13	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	3,280.40		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00797		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	3,285.66		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9984	
7	Ibase @ pf 1	3,280		Line 4	in 2019		
8	Incremental Transformer Heating Losses	826	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.001	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	86.25	MVA				
11	Generator Voltage	13.8	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00125	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.13880	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	635.00		Estimated values			
16	If@unity pf = rated excitation current at unity (A)	620.00		Estimated values			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	3,614.22		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	3,608.44		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	3,433	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.003	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.001	MWs	Line 9			
22	Incremental generator heating losses	0.003	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.004	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	558		Actual operating hours			
25	2019	1,174		Actual operating hours			
26	Two year average	866		Average of Line 24 and Line 25			
27	Total Incremental Losses	4	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 59.53		Line 33			
29	Cost of Heating Losses	**$ 220**		Line 27*Line 28			

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	3,248,365	51,636	FF1, Page 403.2
31	2019 Fuel Costs and Net Generation	6,669,026	114,952	FF1, Page 403.3
32	Total	9,917,391	166,588	
33	Average Cost per MWh	**$ 59.53**		

	Thermal Generating Facility	Gadsby		3			
	Transformer Losses						
1	Load Loss @85C (watts)	506,190	watts	Transformer Test Report			
2	Transformer Rating	125	MVA	PTT Transformer Test Report			
3	Transformer Voltage	13	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	5,467.33		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00564		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	5,501.99		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9937	
7	Ibase @ pf 1	5,467		Line 4	in 2019		
8	Incremental Transformer Heating Losses	6,439	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.006	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	133.689	MVA				
11	Generator Voltage	13.8	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00557	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.18240	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	890.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	870.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	5,628.60		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	5,593.14		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	16,212	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.016	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.006	MWs	Line 9			
22	Incremental generator heating losses	0.016	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.023	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	738		Actual operating hours			
25	2019	2,263		Actual operating hours			
26	Two year average	1,501		Average of Line 24 and Line 25			
27	Total Incremental Losses	34	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 59.53		Line 33			
29	Cost of Heating Losses	**$ 2,023**		Line 27*Line 28			

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	3,248,365	51,636	FF1, Page 403.2
31	2019 Fuel Costs and Net Generation	6,669,026	114,952	FF1, Page 403.3
32	Total	9,917,391	166,588	
33	Average Cost per MWh	**$ 59.53**		

	Thermal Generating Facility	Hunter		1			
	Transformer Losses						
1	Load Loss @85C (watts)	1,004,289	watts	Transformer Test Report			
2	Transformer Rating	612	MVA	PTT Transformer Test Report			
3	Transformer Voltage	24	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	14,722.43		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00154		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	14,731.27		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9994	
7	Ibase @ pf 1	14,722		Line 4	in 2019		
8	Incremental Transformer Heating Losses	1,206	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.001	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	525	MVA				
11	Generator Voltage	24	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00176	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.16200	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	2,500.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	2,450.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	12,637.12		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	12,629.54		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	50,969	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.051	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.001	MWs	Line 9			
22	Incremental generator heating losses	0.051	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.052	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	7,130		Actual operating hours			
25	2019	8,481		Actual operating hours			
26	Two year average	7,806		Average of Line 24 and Line 25			
27	Total Incremental Losses	407	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 18.99		Line 35			
29	Cost of Heating Losses	7,734		Line 27*Line 28			
30	PAC Ownership	93.75%		Att 15 - Heating Losses			
31	PAC Cost of Heating Losses	**$ 7,251**		Line 29*Line 30			

		Fuel Costs	Net Generation MWHs	
32	2018 Fuel Costs and Net Generation	46,389,882	2,356,979	FF1, page 402.1
33	2019 Fuel Costs and Net Generation	50,679,932	2,754,327	FF1, page 402.1
34	Total	97,069,814	5,111,306	
35	Average Cost per MWh	**$ 18.99**		

	Thermal Generating Facility	Hunter		2		
	Transformer Losses					
1	Load Loss @85C (watts)	1,012,014	watts	Transformer Test Report		
2	Transformer Rating	580	MVA	PTT Transformer Test Report		
3	Transformer Voltage	23	kV			
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	14,559.27		(Line 2*1000)/(SQRT 3*Line 3)		
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00159		Line 1/(3*(Line 4^2))		
6	Ibase @avg power factor	14,569.47		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9993
7	Ibase @ pf 1	14,559		Line 4	in 2019	
8	Incremental Transformer Heating Losses	1,418	watts	3*(Line 6^2 - Line 7^2)*Line 5		
9	Incremental Transformer Heating Losses	0.001	MWs	Line 8/1000000		
	Generator Losses					
10	Generator Rating	525	MVA			
11	Generator Voltage	24	kV			
12	Stray loss factor	1.24		EPRI paper		
13	Ra=stator electrical resistance	0.00176	ohms	Generator data sheet		
14	Rf=rotor electrical resistance	0.16200	ohms	Generator data sheet		
15	If@ APF = rated excitation current with reactive power (A)	2,500.00		Generator vee curve		
16	If@unity pf = rated excitation current at unity (A)	2,450.00		Generator vee curve		
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	12,638.38		((Line 10/APF)*1000)/(SQRT 3 * Line 11)		
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	12,629.54		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)		
19	Incremental generator heating losses	51,178	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)		
20	Incremental generator heating losses	0.051	MWs	Line 19/1000000		
	Cost of Heating Losses					
21	Incremental Transformer Heating Losses	0.001	MWs	Line 9		
22	Incremental generator heating losses	0.051	MWs	Line 20+Line 21		
23	Total Incremental Losses	0.053	MWs	Line 21+Line 22		
	Hours of operation					
24	2018	8,204		Actual operating hours		
25	2019	7,840		Actual operating hours		
26	Two year average	8,022		Average of Line 24 and Line 25		
27	Total Incremental Losses	422	MWh	Line 26*Line23		
28	Fuel Costs per MWh	$ 18.46		Line 35		
29	Cost of Heating Losses	7,789		Line 27*Line 28		
30	PAC Ownership	60.31%		Att 15 - Heating Losses		
31	PAC Cost of Heating Losses	**$ 4,698**		Line 29*Line 30		

		Fuel Costs	Net Generation MWHs	
32	2018 Fuel Costs and Net Generation	34,186,040	1,810,269	FF1, Page 402.1
33	2019 Fuel Costs and Net Generation	32,508,552	1,802,519	FF1, Page 402.2
34	Total	66,694,592	3,612,788	
35	Average Cost per MWh	**$ 18.46**		

	Thermal Generating Facility	Hunter		3			
	Transformer Losses						
1	Load Loss @85C (watts)	1,084,000	watts	Transformer Test Report			
2	Transformer Rating	540	MVA	PTT Transformer Test Report			
3	Transformer Voltage	22	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	14,171.32		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00180		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	14,185.51		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.999	
7	Ibase @ pf 1	14,171		Line 4	in 2019		
8	Incremental Transformer Heating Losses	2,171	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.002	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	527.223	MVA				
11	Generator Voltage	22	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00239	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.14200	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	2,550.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	2,500.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	13,849.87		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	13,836.02		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	47,866	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.048	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.002	MWs	Line 9			
22	Incremental generator heating losses	0.048	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.050	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	8,416		Actual operating hours			
25	2019	8,327		Actual operating hours			
26	Two year average	8,372		Average of Line 24 and Line 25			
27	Total Incremental Losses	419	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 18.81		Line 33			
29	Cost of Heating Losses	**$ 7,881**		Line 27*Line 28			

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	57,000,166	2,954,132	FF1 Page 403.1
31	2019 Fuel Costs and Net Generation	52,826,299	2,883,126	FF1 Page 403.2
32	Total	109,826,465	5,837,258	
33	Average Cost per MWh	**$ 18.81**		

	Thermal Generating Facility	Huntington		1			
	Transformer Losses						
1	Load Loss @85C (watts)	1,278,245	watts	Transformer Test Report			
2	Transformer Rating	559	MVA	PTT Transformer Test Report			
3	Transformer Voltage	21	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	15,368.51		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00180		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	15,379.28		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9993	
7	Ibase @ pf 1	15,369		Line 4	in 2019		
8	Incremental Transformer Heating Losses	1,791	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.002	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	541.305	MVA				
11	Generator Voltage	22	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00393	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.14110	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	2,320.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	2,300.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	14,215.52		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	14,205.57		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	20,305	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.020	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.002	MWs	Line 9			
22	Incremental generator heating losses	0.020	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.022	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	7,447		Actual operating hours			
25	2019	8,581		Actual operating hours			
26	Two year average	8,014		Average of Line 24 and Line 25			
27	Total Incremental Losses	177	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 23.07		Line 33			
29	Cost of Heating Losses	$ 4,085		Line 27*Line 28			

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	125,760,156	5,087,824	FF1, Page 403.1
31	2019 Fuel Costs and Net Generation	104,571,495	4,897,541	FF1, Page 403.2
32	Total	230,331,651	9,985,365	
33	Average Cost per MWh	**$ 23.07**		

	Thermal Generating Facility	Huntington		2			
	Transformer Losses						
1	Load Loss @85C (watts)	1,272,909	watts	Transformer Test Report			
2	Transformer Rating	552	MVA	PTT Transformer Test Report			
3	Transformer Voltage	21	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	15,176.06		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00184		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	15,206.48		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.998	
7	Ibase @ pf 1	15,176		Line 4	in 2019		
8	Incremental Transformer Heating Losses	5,107	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.005	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	575	MVA				
11	Generator Voltage	22	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00393	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.14110	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	2,720.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	2,690.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	15,120.08		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	15,089.84		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	41,765	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.042	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.005	MWs	Line 9			
22	Incremental generator heating losses	0.042	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.047	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	8,282		Actual operating hours			
25	2019	7,294		Actual operating hours			
26	Two year average	7,788		Average of Line 24 and Line 25			
27	Total Incremental Losses	365	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 23.07		Line 33			
29	Cost of Heating Losses	**$ 8,420**		Line 27*Line 28			

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	125,760,156	5,087,824	FF1, Page 403.1
31	2019 Fuel Costs and Net Generation	104,571,495	4,897,541	FF1, Page 403.2
32	Total	230,331,651	9,985,365	-
33	Average Cost per MWh	**$ 23.07**		

	Thermal Generating Facility	Jim Bridger		1			
	Transformer Losses						
1	Load Loss @85C (watts)	871,133	watts	Transformer Test Report			
2	Transformer Rating	575	MVA	PTT Transformer Test Report			
3	Transformer Voltage	22	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	15,089.84		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00128		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	15,158.05		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9955	
7	Ibase @ pf 1	15,090		Line 4	in 2019		
8	Incremental Transformer Heating Losses	7,893	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.008	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	608.29	MVA				
11	Generator Voltage	22	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00955	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.14220	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	2,825.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	2,800.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	16,035.63		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	15,963.47		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	106,828	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.107	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.008	MWs	Line 9			
22	Incremental generator heating losses	0.107	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.115	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	6,930		Actual operating hours			
25	2019	8,518		Actual operating hours			
26	Two year average	7,724		Average of Line 24 and Line 25			
27	Total Incremental Losses	886	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 28.94		Line 35			
29	Cost of Heating Losses	25,643		Line 27*Line 28			
30	PAC Ownership	66.67%		Att 15 - Heating Losses			
31	PAC Cost of Heating Losses	**$ 17,096**		Line 29*Line 30			

		Fuel Costs	Net Generation MWHs	
32	2018 Fuel Costs and Net Generation	252,789,422	8,454,799	FF1, Page 402.2
33	2019 Fuel Costs and Net Generation	252,682,285	9,012,300	FF1, Page 402.2
34	Total	505,471,707	17,467,099	
35	Average Cost per MWh	**$ 28.94**		

	Thermal Generating Facility	Jim Bridger		2			
	Transformer Losses						
1	Load Loss @85C (watts)	1,068,250	watts	Transformer Test Report			
2	Transformer Rating	580	MVA	Transformer Test Report			
3	Transformer Voltage	22	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	15,221.05		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00154		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	15,272.98		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9966	
7	Ibase @ pf 1	15,221		Line 4	in 2019		
8	Incremental Transformer Heating Losses	7,301	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.007	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	617	MVA				
11	Generator Voltage	22	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00955	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.14220	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	2,825.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	2,800.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	16,247.29		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	16,192.05		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	88,458	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.088	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.007	MWs	Line 9			
22	Incremental generator heating losses	0.088	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.096	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	8,615		Actual operating hours			
25	2019	8,576		Actual operating hours			
26	Two year average	8,596		Average of Line 24 and Line 25			
27	Total Incremental Losses	823	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 28.94		Line 35			
29	Cost of Heating Losses	23,819		Line 27*Line 28			
30	PAC Ownership	66.67%		Att 15 - Heating Losses			
31	PAC Cost of Heating Losses	**$ 15,880**		Line 29*Line 30			

		Fuel Costs	Net Generation MWHs	
32	2018 Fuel Costs and Net Generation	252,789,422	8,454,799	FF1, Page 402.2
33	2019 Fuel Costs and Net Generation	252,682,285	9,012,300	FF1, Page 402.2
34	Total	505,471,707	17,467,099	
35	Average Cost per MWh	**$ 28.94**		

	Thermal Generating Facility	Jim Bridger		3			
	Transformer Losses						
1	Load Loss @85C (watts)	1,370,100	watts	Transformer Test Report			
2	Transformer Rating	561	MVA	Transformer Test Report			
3	Transformer Voltage	22	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	14,722.43		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00211		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	14,772.66		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9966	
7	Ibase @ pf 1	14,722		Line 4	in 2019		
8	Incremental Transformer Heating Losses	9,364	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.009	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	608.29	MVA				
11	Generator Voltage	22	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00955	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.14220	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	2,825.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	2,800.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	16,017.93		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	15,963.47		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	86,673	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.087	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.009	MWs	Line 9			
22	Incremental generator heating losses	0.087	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.096	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	8,470		Actual operating hours			
25	2019	7,552		Actual operating hours			
26	Two year average	8,011		Average of Line 24 and Line 25			
27	Total Incremental Losses	769	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 28.94		Line 35			
29	Cost of Heating Losses	22,264		Line 27*Line 28			
30	PAC Ownership	66.67%		Att 15 - Heating Losses			
31	PAC Cost of Heating Losses	**$ 14,843**		Line 29*Line 30			

		Fuel Costs	Net Generation MWHs	
32	2018 Fuel Costs and Net Generation	252,789,422	8,454,799	FF1, Page 402.2
33	2019 Fuel Costs and Net Generation	252,682,285	9,012,300	FF1, Page 402.2
34	Total	505,471,707	17,467,099	
35	Average Cost per MWh	**$ 28.94**		

	Thermal Generating Facility	Jim Bridger		4			
	Transformer Losses						
1	Load Loss @85C (watts)	1,348,550	watts	Transformer Test Report			
2	Transformer Rating	561	MVA	Transformer Test Report			
3	Transformer Voltage	22	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	14,722.43		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00207		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	14,772.66		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9966	
7	Ibase @ pf 1	14,722		Line 4	in 2019		
8	Incremental Transformer Heating Losses	9,217	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.009	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	608.29	MVA				
11	Generator Voltage	22	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00955	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.14220	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	2,825.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	2,800.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	16,017.93		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	15,963.47		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	86,673	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.087	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.009	MWs	Line 9			
22	Incremental generator heating losses	0.087	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.096	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	8,369		Actual operating hours			
25	2019	8,620		Actual operating hours			
26	Two year average	8,495		Average of Line 24 and Line 25			
27	Total Incremental Losses	815	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 28.94		Line 35			
29	Cost of Heating Losses	23,572		Line 27*Line 28			
30	PAC Ownership	66.67%		Att 15 - Heating Losses			
31	PAC Cost of Heating Losses	**$ 15,715**		Line 29*Line 30			

		Fuel Costs	Net Generation MWHs	
32	2018 Fuel Costs and Net Generation	252,789,422	8,454,799	FF1, Page 402.2
33	2019 Fuel Costs and Net Generation	252,682,285	9,012,300	FF1, Page 402.2
34	Total	505,471,707	17,467,099	
35	Average Cost per MWh	**$ 28.94**		

PacifiCorp
Reactive Power
Lake Side CT11 Heating Losses
2019

	Thermal Generating Facility	Lake Side	CT11			
	Transformer Losses					
1	Load Loss @85C (watts)	529,723	watts	PTT Transformer Test Report		
2	Transformer Rating	225	MVA	PTT Transformer Test Report		
3	Transformer Voltage	17	kV			
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	7,872.96		(Line 2*1000)/(SQRT 3*Line 3)		
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00285		Line 1/(3*(Line 4^2))		
6	Ibase @avg power factor	7,881.63		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9989
7	Ibase @ pf 1	7,873		Line 4	in 2019	
8	Incremental Transformer Heating Losses	1,167	watts	3*(Line 6^2 - Line 7^2)*Line 5		
9	Incremental Transformer Heating Losses	0.001	MWs	Line 8/1000000		
	Generator Losses					
10	Generator Rating	203	MVA			
11	Generator Voltage	16.5	kV			
12	Stray loss factor	1.24		EPRI paper		
13	Ra=stator electrical resistance	0.00536	ohms	Generator data sheet		
14	Rf=rotor electrical resistance	0.17600	ohms	Generator data sheet		
15	If@ APF = rated excitation current with reactive power (A)	980.00		Generator vee curve		
16	If@unity pf = rated excitation current at unity (A)	960.00		Generator vee curve		
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	7,110.98		((Line 10/APF)*1000)/(SQRT 3 * Line 11)		
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	7,103.16		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)		
19	Incremental generator heating losses	10,686	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)		
20	Incremental generator heating losses	0.011	MWs	Line 19/1000000		
	Cost of Heating Losses					
21	Incremental Transformer Heating Losses	0.001	MWs	Line 9		
22	Incremental generator heating losses	0.011	MWs	Line 20+Line 21		
23	Total Incremental Losses	0.012	MWs	Line 21+Line 22		
	Hours of operation					
24	2018	4,371		Actual operating hours		
25	2019	7,423		Actual operating hours		
26	Two year average	5,897		Average of Line 24 and Line 25		
27	Total Incremental Losses	70	MWh	Line 26*Line23		
28	Fuel Costs per MWh	$ 24.50		Line 33		
29	Cost of Heating Losses	**$ 1,713**		Line 27*Line 28		

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	48,493,424	1,839,453	FF1, Page 403.3
31	2019 Fuel Costs and Net Generation	64,738,243	2,781,914	FF1, Page 403.3
32	Total	113,231,667	4,621,367	
33	Average Cost per MWh	**$ 24.50**		

PacifiCorp
Reactive Power
Lake Side CT12 Heating Losses
2019

	Thermal Generating Facility	Lake Side	CT12			
	Transformer Losses					
1	Load Loss @85C (watts)	599,874	watts	PTT Transformer Test Report		
2	Transformer Rating	225	MVA	PTT Transformer Test Report		
3	Transformer Voltage	17	kV			
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	7,872.96		(Line 2*1000)/(SQRT 3*Line 3)		
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00323		Line 1/(3*(Line 4^2))		
6	Ibase @avg power factor	7,889.53		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9979
7	Ibase @ pf 1	7,873		Line 4	in 2019	
8	Incremental Transformer Heating Losses	2,527	watts	3*(Line 6^2 - Line 7^2)*Line 5		
9	Incremental Transformer Heating Losses	0.003	MWs	Line 8/1000000		
	Generator Losses					
10	Generator Rating	203	MVA			
11	Generator Voltage	16.5	kV			
12	Stray loss factor	1.24		EPRI paper		
13	Ra=stator electrical resistance	0.00536	ohms	Generator data sheet		
14	Rf=rotor electrical resistance	0.17600	ohms	Generator data sheet		
15	If@ APF = rated excitation current with reactive power (A)	980.00		Generator vee curve		
16	If@unity pf = rated excitation current at unity (A)	960.00		Generator vee curve		
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	7,118.11		((Line 10/APF)*1000)/(SQRT 3 * Line 11)		
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	7,103.16		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)		
19	Incremental generator heating losses	12,710	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)		
20	Incremental generator heating losses	0.013	MWs	Line 19/1000000		
	Cost of Heating Losses					
21	Incremental Transformer Heating Losses	0.003	MWs	Line 9		
22	Incremental generator heating losses	0.013	MWs	Line 20+Line 21		
23	Total Incremental Losses	0.015	MWs	Line 21+Line 22		
	Hours of operation					
24	2018	5,118		Actual operating hours		
25	2019	6,564		Actual operating hours		
26	Two year average	5,841		Average of Line 24 and Line 25		
27	Total Incremental Losses	89	MWh	Line 26*Line23		
28	Fuel Costs per MWh	$ 24.50		Line 33		
29	Cost of Heating Losses	**$ 2,181**		Line 27*Line 28		

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	48,493,424	1,839,453	FF1, Page 403.3
31	2019 Fuel Costs and Net Generation	64,738,243	2,781,914	FF1, Page 403.3
32	Total	113,231,667	4,621,367	
33	Average Cost per MWh	**$ 24.50**		

	Thermal Generating Facility	Lake Side	STG10			
	Transformer Losses					
1	Load Loss @85C (watts)	772,831	watts	PTT Transformer Test Report		
2	Transformer Rating	295	MVA	PTT Transformer Test Report		
3	Transformer Voltage	17	kV			
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	10,322.32		(Line 2*1000)/(SQRT 3*Line 3)		
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00242		Line 1/(3*(Line 4^2))		
6	Ibase @avg power factor	10,353.38		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.997
7	Ibase @ pf 1	10,322		Line 4	in 2019	
8	Incremental Transformer Heating Losses	4,658	watts	3*(Line 6^2 - Line 7^2)*Line 5		
9	Incremental Transformer Heating Losses	0.005	MWs	Line 8/1000000		
	Generator Losses					
10	Generator Rating	251	MVA			
11	Generator Voltage	16.5	kV			
12	Stray loss factor	1.24		EPRI paper		
13	Ra=stator electrical resistance	0.00759	ohms	Generator data sheet		
14	Rf=rotor electrical resistance	0.17600	ohms	Generator data sheet		
15	If@ APF = rated excitation current with reactive power (A)	1,150.00		Generator vee curve		
16	If@unity pf = rated excitation current at unity (A)	1,125.00		Generator vee curve		
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	8,809.15		((Line 10/APF)*1000)/(SQRT 3 * Line 11)		
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	8,782.72		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)		
19	Incremental generator heating losses	25,544	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)		
20	Incremental generator heating losses	0.026	MWs	Line 19/1000000		
	Cost of Heating Losses					
21	Incremental Transformer Heating Losses	0.005	MWs	Line 9		
22	Incremental generator heating losses	0.026	MWs	Line 20+Line 21		
23	Total Incremental Losses	0.030	MWs	Line 21+Line 22		
	Hours of operation					
	2018	5,816		Actual operating hours		
1	2019	8,090		Actual operating hours		
2	Two year average	6,953		Average of Line 24 and Line 25		
3	Total Incremental Losses	210	MWh	Line 26*Line23		
4	Fuel Costs per MWh	$ 24.50		Line 33		
5	Cost of Heating Losses	**$ 5,145**		Line 27*Line 28		

		Fuel Costs	Net Generation MWHs	
6	2018 Fuel Costs and Net Generation	48,493,424	1,839,453	FF1, Page 403.3
7	2019 Fuel Costs and Net Generation	64,738,243	2,781,914	FF1, Page 403.3
8	Total	113,231,667	4,621,367	
9	Average Cost per MWh	**$ 24.50**		

Thermal Generating Facility	Lake Side	CT21			
Transformer Losses					
Load Loss @85C (watts)	504,660	watts	PTT Transformer Test Report		
Transformer Rating	254	MVA	PTT Transformer Test Report		
Transformer Voltage	17	kV			
Ibase = (MVA*1000)/SQRT 3 * low side voltage	8,887.70		(Line 2*1000)/(SQRT 3*Line 3)		
Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00213		Line 1/(3*(Line 4^2))		
Ibase @avg power factor	8,896.59		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.999
Ibase @ pf 1	8,888		Line 4	in 2019	
Incremental Transformer Heating Losses	1,011	watts	3*(Line 6^2 - Line 7^2)*Line 5		
Incremental Transformer Heating Losses	0.001	MWs	Line 8/1000000		
Generator Losses					
Generator Rating	206	MVA			
Generator Voltage	16.5	kV			
Stray loss factor	1.24		EPRI paper		
Ra=stator electrical resistance	0.00264	ohms	Generator data sheet		
Rf=rotor electrical resistance	0.15200	ohms	Generator data sheet		
If@ APF = rated excitation current with reactive power (A)	1,065.00		Generator vee curve		
If@unity pf = rated excitation current at unity (A)	1,045.00		Generator vee curve		
Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	7,215.35		((Line 10/APF)*1000)/(SQRT 3 * Line 11)		
Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	7,208.13		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)		
Incremental generator heating losses	8,976	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)		
Incremental generator heating losses	0.009	MWs	Line 19/1000000		
Cost of Heating Losses					
Incremental Transformer Heating Losses	0.001	MWs	Line 9		
Incremental generator heating losses	0.009	MWs	Line 20+Line 21		
Total Incremental Losses	0.010	MWs	Line 21+Line 22		
Hours of operation					
2018	7,014		Actual operating hours		
2019	6,132		Actual operating hours		
Two year average	6,573		Average of Line 24 and Line 25		
Total Incremental Losses	66	MWh	Line 26*Line23		
Fuel Costs per MWh	$ 24.56		Line 33		
Cost of Heating Losses	**$ 1,612**		Line 27*Line 28		

	Fuel Costs	Net Generation MWHs	
2018 Fuel Costs and Net Generation	55,984,255	2,281,902	FF1, Page 402.4
2019 Fuel Costs and Net Generation	74,274,535	3,021,716	FF1, Page 402.4
Total	130,258,790	5,303,618	
Average Cost per MWh	**$ 24.56**		

	Thermal Generating Facility	Lake Side	CT22			
	Transformer Losses					
1	Load Loss @85C (watts)	623,120	watts	PTT Transformer Test Report		
2	Transformer Rating	254	MVA	PTT Transformer Test Report		
3	Transformer Voltage	17	kV			
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	8,887.70		(Line 2*1000)/(SQRT 3*Line 3)		
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00263		Line 1/(3*(Line 4^2))		
6	Ibase @avg power factor	8,897.48		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9989
7	Ibase @ pf 1	8,888		Line 4	in 2019	
8	Incremental Transformer Heating Losses	1,373	watts	3*(Line 6^2 - Line 7^2)*Line 5		
9	Incremental Transformer Heating Losses	0.001	MWs	Line 8/1000000		
	Generator Losses					
10	Generator Rating	206	MVA			
11	Generator Voltage	16.5	kV			
12	Stray loss factor	1.24		EPRI paper		
13	Ra=stator electrical resistance	0.00264	ohms	Generator data sheet		
14	Rf=rotor electrical resistance	0.15200	ohms	Generator data sheet		
15	If@ APF = rated excitation current with reactive power (A)	1,065.00		Generator vee curve		
16	If@unity pf = rated excitation current at unity (A)	1,045.00		Generator vee curve		
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	7,216.07		((Line 10/APF)*1000)/(SQRT 3 * Line 11)		
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	7,208.13		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)		
19	Incremental generator heating losses	9,078	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)		
20	Incremental generator heating losses	0.009	MWs	Line 19/1000000		
	Cost of Heating Losses					
21	Incremental Transformer Heating Losses	0.001	MWs	Line 9		
22	Incremental generator heating losses	0.009	MWs	Line 20+Line 21		
23	Total Incremental Losses	0.010	MWs	Line 21+Line 22		
	Hours of operation					
24	2018	6,333		Actual operating hours		
25	2019	4,463		Actual operating hours		
26	Two year average	5,398		Average of Line 24 and Line 25		
27	Total Incremental Losses	56	MWh	Line 26*Line23		
28	Fuel Costs per MWh	$ 24.56		Line 33		
29	Cost of Heating Losses	**$ 1,386**		Line 27*Line 28		

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	55,984,255	2,281,902	FF1, Page 402.4
31	2019 Fuel Costs and Net Generation	74,274,535	3,021,716	FF1, Page 402.4
32	Total	130,258,790	5,303,618	
33	Average Cost per MWh	**$ 24.56**		

	Thermal Generating Facility	Lake Side	STG20			
	Transformer Losses					
1	Load Loss @85C (watts)	634,490	watts	PTT Transformer Test Report		
2	Transformer Rating	390	MVA	PTT Transformer Test Report		
3	Transformer Voltage	18	kV			
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	12,509.26		(Line 2*1000)/(SQRT 3*Line 3)		
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00135		Line 1/(3*(Line 4^2))		
6	Ibase @avg power factor	12,560.75		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9959
7	Ibase @ pf 1	12,509		Line 4	in 2019	
8	Incremental Transformer Heating Losses	5,235	watts	3*(Line 6^2 - Line 7^2)*Line 5		
9	Incremental Transformer Heating Losses	0.005	MWs	Line 8/1000000		
	Generator Losses					
10	Generator Rating	316	MVA			
11	Generator Voltage	18	kV			
12	Stray loss factor	1.24		EPRI paper		
13	Ra=stator electrical resistance	0.00308	ohms	Generator data sheet		
14	Rf=rotor electrical resistance	0.16430	ohms	Generator data sheet		
15	If@ APF = rated excitation current with reactive power (A)	1,365.00		Generator vee curve		
16	If@unity pf = rated excitation current at unity (A)	1,340.00		Generator vee curve		
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	10,177.43		((Line 10/APF)*1000)/(SQRT 3 * Line 11)		
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	10,135.70		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)		
19	Incremental generator heating losses	23,476	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)		
20	Incremental generator heating losses	0.023	MWs	Line 19/1000000		
	Cost of Heating Losses					
21	Incremental Transformer Heating Losses	0.005	MWs	Line 9		
22	Incremental generator heating losses	0.023	MWs	Line 20+Line 21		
23	Total Incremental Losses	0.029	MWs	Line 21+Line 22		
	Hours of operation					
24	2018	7,292		Actual operating hours		
25	2019	5,389		Actual operating hours		
26	Two year average	6,341		Average of Line 24 and Line 25		
27	Total Incremental Losses	182	MWh	Line 26*Line23		
28	Fuel Costs per MWh	$ 24.56		Line 33		
29	Cost of Heating Losses	**$ 4,471**		Line 27*Line 28		

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	55,984,255	2,281,902	FF1, Page 402.4
31	2019 Fuel Costs and Net Generation	74,274,535	3,021,716	FF1, Page 402.4
32	Total	130,258,790	5,303,618	
33	Average Cost per MWh	**$ 24.56**		

	Thermal Generating Facility	Naughton		1			
	Transformer Losses						
1	Load Loss @85C (watts)	614,000	watts	PTT Transformer Test Report			
2	Transformer Rating	175	MVA	PTT Transformer Test Report			
3	Transformer Voltage	17	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	5,943.31		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00579		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	5,955.22		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.998	
7	Ibase @ pf 1	5,943		Line 4	in 2019		
8	Incremental Transformer Heating Losses	2,463	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.002	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	192	MVA				
11	Generator Voltage	18	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00675	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.27250	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	860.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	840.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	6,170.74		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	6,158.40		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	15,309	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.015	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.002	MWs	Line 9			
22	Incremental generator heating losses	0.015	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.018	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	8,603		Actual operating hours			
25	2019	8,410		Actual operating hours			
26	Two year average	8,507		Average of Line 24 and Line 25			
27	Total Incremental Losses	151	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 26.64		Line 33			
29	Cost of Heating Losses	**$ 4,028**		Line 27*Line 28			

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	115,283,027	4,740,078	FF1, Page 402.2
31	2019 Fuel Costs and Net Generation	86,682,877	2,840,374	FF1, Page 402.2
32	Total	201,965,904	7,580,452	
33	Average Cost per MWh	**$ 26.64**		

Thermal Generating Facility Naughton 2

	Transformer Losses						
1	Load Loss @85C (watts)	660,000	watts	PTT Transformer Test Report			
2	Transformer Rating	250	MVA	PTT Transformer Test Report			
3	Transformer Voltage	19	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	7,596.71		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00381		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	7,650.27		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.993	
7	Ibase @ pf 1	7,597		Line 4	in 2019		
8	Incremental Transformer Heating Losses	9,338	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.009	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	256	MVA				
11	Generator Voltage	20	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00328	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.10400	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	2,000.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	1,950.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	7,442.18		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	7,390.08		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	34,903	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.035	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.009	MWs	Line 9			
22	Incremental generator heating losses	0.035	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.044	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	8,495		Actual operating hours			
25	2019	8,172		Actual operating hours			
26	Two year average	8,334		Average of Line 24 and Line 25			
27	Total Incremental Losses	369	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 26.64		Line 33			
29	Cost of Heating Losses	$ 9,823		Line 27*Line 28			

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	115,283,027	4,740,078	FF1, Page 402.2
31	2019 Fuel Costs and Net Generation	86,682,877	2,840,374	FF1, Page 402.2
32	Total	201,965,904	7,580,452	
33	Average Cost per MWh	**$ 26.64**		

	Thermal Generating Facility	Naughton		3			
	Transformer Losses						
1	Load Loss @85C (watts)	928,600	watts	PTT Transformer Test Report			
2	Transformer Rating	350	MVA	PTT Transformer Test Report			
3	Transformer Voltage	23	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	8,785.76		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00401		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	8,812.20		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.997	
7	Ibase @ pf 1	8,786		Line 4	in 2019		
8	Incremental Transformer Heating Losses	5,597	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.006	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	384	MVA				
11	Generator Voltage	24	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00240	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.13500	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	-		Generator vee curve - not available			
16	If@unity pf = rated excitation current at unity (A)	-		Generator vee curve - not available			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	9,265.40		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	9,237.60		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	4,592	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.005	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.006	MWs	Line 9			
22	Incremental generator heating losses	0.005	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.010	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	8,080		Actual operating hours			
25	2019	929		Actual operating hours			
26	Two year average	4,505		Average of Line 24 and Line 25			
27	Total Incremental Losses	46	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 26.64		Line 33			
29	Cost of Heating Losses	$ 1,223		Line 27*Line 28			

		Fuel Costs	Net Generation MWHs	
30	2018 Fuel Costs and Net Generation	115,283,027	4,740,078	FF1, Page 402.2
31	2019 Fuel Costs and Net Generation	86,682,877	2,840,374	FF1, Page 402.2
32	Total	201,965,904	7,580,452	
33	Average Cost per MWh	**$ 26.64**		

	Thermal Generating Facility	Wyodak		1			
	Transformer Losses						
1	Load Loss @85C (watts)	456,700	watts	PTT Transformer Test Report			
2	Transformer Rating	360	MVA	PTT Transformer Test Report			
3	Transformer Voltage	22	kV				
4	Ibase = (MVA*1000)/SQRT 3 * low side voltage	9,447.55		(Line 2*1000)/(SQRT 3*Line 3)			
5	Transformer Resistance (RTr) = watt loss/3*Ibase^2)	0.00171		Line 1/(3*(Line 4^2))			
6	Ibase @avg power factor	9,469.33		(Line 2/(APF*1000))/(SQRT 3*Line 4)	Average Power Factor (APF)	0.9977	
7	Ibase @ pf 1	9,448		Line 4	in 2019		
8	Incremental Transformer Heating Losses	2,108	watts	3*(Line 6^2 - Line 7^2)*Line 5			
9	Incremental Transformer Heating Losses	0.002	MWs	Line 8/1000000			
	Generator Losses						
10	Generator Rating	402.3	MVA				
11	Generator Voltage	22	kV				
12	Stray loss factor	1.24		EPRI paper			
13	Ra=stator electrical resistance	0.00662	ohms	Generator data sheet			
14	Rf=rotor electrical resistance	0.16100	ohms	Generator data sheet			
15	If@ APF = rated excitation current with reactive power (A)	2,155.00		Generator vee curve			
16	If@unity pf = rated excitation current at unity (A)	2,130.00		Generator vee curve			
17	Ia@ pf = APF (A)=(MVA/pf/1000)/(SQRT 3*kV)	10,581.98		((Line 10/APF)*1000)/(SQRT 3 * Line 11)			
18	Ia@ pf = 1 (A)=(MVA/pf/1000)/(SQRT 3*kV)	10,557.64		((Line 10/1.0)*1000)/(SQRT 3 * Line 11)			
19	Incremental generator heating losses	34,061	watts	(Line 12*(3*(Line 17^2-Line18^2)*Line 13+(Line 15^2-Line16^2)*Line 14)			
20	Incremental generator heating losses	0.034	MWs	Line 19/1000000			
	Cost of Heating Losses						
21	Incremental Transformer Heating Losses	0.002	MWs	Line 9			
22	Incremental generator heating losses	0.034	MWs	Line 20+Line 21			
23	Total Incremental Losses	0.036	MWs	Line 21+Line 22			
	Hours of operation						
24	2018	8,202		Actual operating hours			
25	2019	7,607		Actual operating hours			
26	Two year average	7,905		Average of Line 24 and Line 25			
27	Total Incremental Losses	286	MWh	Line 26*Line23			
28	Fuel Costs per MWh	$ 15.68		Line 33			
29	Cost of Heating Losses	4,484		Line 27*Line 28			
30	PAC Ownership	80.00%		Att 15 - Heating Losses			
31	PAC Cost of Heating Losses	**$ 3,587**		Line 29*Line 30			

		Fuel Costs	Net Generation MWHs	
32	2018 Fuel Costs and Net Generation	27,048,098	1,741,620	FF1, Page 403.2
33	2019 Fuel Costs and Net Generation	22,490,477	1,417,217	FF1, Page 403.2
34	Total	49,538,575	3,158,837	
35	Average Cost per MWh	**$ 15.68**		

Attachment F

Model Protective Agreement

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp	)	**Docket No. ER21-__-000**

PROTECTIVE AGREEMENT

1. Participants in this proceeding(s) may exchange documents or materials that are deemed to contain Privileged Material and/or Critical Energy/Electric Infrastructure Information (CEII), as those terms are defined herein.

2. The Commission's regulations and its policy governing the labelling of controlled unclassified information (CUI), establish and distinguish the respective designations of Privileged Material and CEII. As to these designations, this Protective Agreement provides that a Participant:

   A. may designate as Privileged Material any material which customarily is treated by that Participant as commercially sensitive or proprietary or material subject to a legal privilege, which is not otherwise available to the public, and which, if disclosed, would subject that Participant or its customers to risk of competitive disadvantage or other business injury; and

   B. must designate as CEII, any material that meets the definition of that term as provided by 18 C.F.R. §§ 388.113(a), (c).

3. For the purposes of this Protective Agreement, the listed terms are defined as follows:

   A. Participant(s): As defined at 18 C.F.R. § 385.102(b).

   B. Privileged Material:

      i. Material (including depositions) provided by a Participant in response to discovery requests or filed with the Commission, and that is designated as Privileged Material by such Participant;

      ii. Material that is privileged under federal, state, or foreign law, such as work- product privilege, attorney-client privilege, or governmental privilege, and that is designated as Privileged Material by such Participant;

      iii. Any information contained in or obtained from such designated material;

      iv. Any other material which is made subject to this Protective Agreement by the Federal Energy Regulatory Commission (Commission), any court, or other body having appropriate authority, or by agreement of the Participants (subject to approval by the relevant authority);

v. Notes of Privileged Material (memoranda, handwritten notes, or any other form of information (including electronic form) which copies or discloses Privileged Material); or

vi. Copies of Privileged Material.

vii. Privileged Material does not include:

a. Any information or document that has been filed with and accepted into the public files of the Commission, or contained in the public files of any other federal or state agency, or any federal or state court, unless the information or document has been determined to be privileged by such agency or court;

b. Information that is public knowledge, or which becomes public knowledge, other than through disclosure in violation of this Protective Agreement; or

c. Any information or document labeled as "Non-Internet Public" by a Participant, in accordance with Paragraph 30 of FERC Order No. 630.

C. Critical Energy/Electric Infrastructure Information (CEII): As defined at 18 C.F.R. §§ 388.113(a), (c).

D. Non-Disclosure Certificate: The certificate attached to this Protective Agreement, by which Participants granted access to Privileged Material and/or CEII must certify their understanding that such access to such material is provided pursuant to the terms and restrictions of this Protective Agreement, and that such Participants have read the Protective Agreement and agree to be bound by it. All executed Non-Disclosure Certificates must be served on all Participants on the official service list maintained by the Secretary of the Commission for this proceeding.

E. Reviewing Representative: A person who has signed a Non-Disclosure Certificate and who is:

i. Commission Trial Staff designated as such in this proceeding;

ii. An attorney who has made an appearance in this proceeding for a Participant;

iii. Attorneys, paralegals, and other employees associated for purposes of this case with an attorney who has made an appearance in this proceeding on behalf of a Participant;

iv. An expert or an employee of an expert retained by a Participant for the purpose of advising, preparing for, submitting evidence or testifying in this proceeding;

v. A person designated as a Reviewing Representative by order of the Commission; or

vi. Employees or other representatives of Participants appearing in this proceeding with significant responsibility for this docket.

4. Privileged Material and/or CEII shall be made available under the terms of this Protective Agreement only to Participants and only to their Reviewing Representatives as provided in Paragraphs 6-10 of this Protective Agreement. The contents of Privileged Material, CEII or any other form of information that copies or discloses such materials shall not be disclosed to anyone other than in accordance with this Protective Agreement and shall be used only in connection with this specific proceeding.

5. All Privileged Material and/or CEII must be maintained in a secure place. Access to those materials must be limited to Reviewing Representatives specifically authorized pursuant to Paragraphs 7-9 of this Protective Agreement.

6. Privileged Material and/or CEII must be handled by each Participant and by each Reviewing Representative in accordance with the Non-Disclosure Certificate executed pursuant to Paragraph 9 of this Protective Agreement. Privileged Material and/or CEII shall not be used except as necessary for the conduct of this proceeding, nor shall they (or the substance of their contents) be disclosed in any manner to any person except a Reviewing Representative who is engaged in this proceeding and who needs to know the information in order to carry out that person's responsibilities in this proceeding. Reviewing Representatives may make copies of Privileged Material and/or CEII, but such copies automatically become Privileged Material and/or CEII. Reviewing Representatives may make notes of Privileged Material, which shall be treated as Notes of Privileged Material if they reflect the contents of Privileged Material.

7. If a Reviewing Representative's scope of employment includes any of the activities listed under this Paragraph 7, such Reviewing Representative may not use information contained in any Privileged Material and/or CEII obtained in this proceeding for a commercial purpose (*e.g.*, to give a Participant or competitor of any Participant a commercial advantage):

A. Energy marketing;

B. Direct supervision of any employee or employees whose duties include energy marketing; or

C. The provision of consulting services to any person whose duties include energy marketing.

8. In the event that a Participant wishes to designate a person not described in Paragraph 3.E above as a Reviewing Representative, the Participant must seek agreement from the Participant providing the Privileged Material and/or CEII. If an agreement is reached, the designee shall be a Reviewing Representative pursuant to Paragraph 3.D of this Protective Agreement with respect to those materials. If no agreement is reached, the matter must be submitted to the Presiding Judge for resolution.

9. A Reviewing Representative shall not be permitted to inspect, participate in discussions regarding, or otherwise be permitted access to Privileged Material and/or CEII pursuant to this Protective Agreement until three business days after that Reviewing Representative first has executed and served a Non-Disclosure Certificate. However, if an attorney qualified as a Reviewing Representative has executed a Non-Disclosure Certificate, any participating paralegal, secretarial and clerical personnel under the attorney's instruction, supervision or control need not do so. Attorneys designated Reviewing Representatives are responsible for ensuring that persons under their supervision or control comply with this Protective Agreement, and must take all reasonable precautions to ensure that Privileged Material and/or CEII are not disclosed to unauthorized persons. All executed Non-Disclosure Certificates must be served on all Participants on the official service list maintained by the Secretary of the Commission for the proceeding.

10. Any Reviewing Representative may disclose Privileged Material and/or CEII to any other Reviewing Representative as long as both Reviewing Representatives have executed a Non- Disclosure Certificate. In the event any Reviewing Representative to whom Privileged Material and/or CEII are disclosed ceases to participate in this proceeding, or becomes employed or retained for a position that renders him or her ineligible to be a Reviewing Representative under Paragraph 3.D of this Protective Agreement, access to such materials by that person shall be terminated. Even if no longer engaged in this proceeding, every person who has executed a Non-Disclosure Certificate shall continue to be bound by the provisions of this Protective Agreement and the Non-Disclosure Certificate for as long as the Protective Agreement is in effect.

11. All Privileged Material and/or CEII in this proceeding filed with the Commission, submitted to the Presiding Judge, or submitted to any Commission personnel, must comply with the Commission's Notice of Document Labelling Guidance for Documents Submitted to or Filed with the Commission or Commission Staff. Consistent with those requirements:

    A. Documents that contain Privileged Material must include a top center header on each page of the document with the following text: CUI//PRIV. Any corresponding electronic files must also include this text in the file name.

    B. Documents that contain CEII must include a top center header on each page of the document with the following text: CUI//CEII. Any corresponding electronic files must also include this text in the file name.

C. Documents that contain both Privileged Material and CEII must include a top center header on each page of the document with the following text: CUI//CEII/PRIV. Any corresponding electronic files must also include this text in the file name.

D. The specific content on each page of the document that constitutes Privileged Material and/or CEII must also be clearly identified. For example, lines or individual words or numbers that include both Privileged Material and CEII shall be prefaced and end with "BEGIN CUI//CEII/PRIV" and "END CUI//CEII/PRIV".

12. The Secretary shall place any Privileged Material and/or CEII filed with the Commission in a non-public file. By placing such documents in a non-public file, the Commission is not making a determination concerning any claim of privilege or CEII status. The Commission retains the right to make determinations with regard to any privilege or CEII claim, as well as the discretion to release information necessary to carry out its jurisdictional responsibilities. For documents submitted to Commission Trial Staff, the notification procedures specified at 18 C.F.R. § 388.112 must be followed before making public any Privileged Material.

13. If any Participant desires to include, utilize, or refer to Privileged Material or information derived from Privileged Material in testimony or other exhibits during the hearing in this proceeding in a manner that might require disclosure of such materials to persons other than Reviewing Representatives, that Participant first must notify both counsel for the disclosing Participant and the Presiding Judge, and identify all such Privileged Material. Thereafter, use of such Privileged Material will be governed by procedures determined by the Presiding Judge.

14. Nothing in this Protective Agreement shall be construed as precluding any Participant from objecting to the production or use of Privileged Material and/or CEII on any appropriate ground.

15. Nothing in this Protective Agreement shall preclude any Participant from requesting the Commission, or any other body having appropriate authority, to find this Protective Agreement should not apply to all or any materials previously designated Privileged Material pursuant to this Protective Agreement. The Commission, or any other body having appropriate authority may alter or amend this Protective Agreement as circumstances warrant at any time during the course of this proceeding.

16. Each Participant governed by this Protective Agreement has the right to seek changes in it as appropriate from the Commission, or any other body having appropriate authority.

17. Subject to Paragraph 18, the Commission shall resolve any disputes arising under this Protective Agreement pertaining to Privileged Material according to the following procedures. Prior to presenting any such dispute to the Commission, the Participants to the dispute shall employ good faith best efforts to resolve it.

A. Any Participant that contests the designation of material as Privileged Material shall notify the Participant that provided the Privileged Material by specifying in writing the material for which the designation is contested.

B. In any challenge to the designation of material as Privileged Material, the burden of proof shall be on the Participant seeking protection. If the Commission finds that the material at issue is not entitled to the designation, the procedures of Paragraph 18 shall apply.

C. The procedures described above shall not apply to material designated by a Participant as CEII. Material so designated shall remain subject to the provisions of this Protective Agreement, unless a Participant requests and obtains a determination from the Commission's CEII Coordinator that such material need not retain that designation.

18. .The designator will have five (5) days in which to respond to any pleading requesting disclosure of Privileged Material. Should the Commission, as appropriate, determine that the information should be made public, the Commission will provide notice to the designator no less than five (5) days prior to the date on which the material will become public. This Protective Agreement shall automatically cease to apply to such material on the sixth (6th) calendar day after the notification is made unless the designator files a motion with the Commission, with supporting affidavits, demonstrating why the material should continue to be privileged. Should such a motion be filed, the material will remain confidential until such time as the motion has been addressed by the Motions Commissioner or Commission, as provided in the Commission's regulations, 18 C.F.R. §§ 385.714, .715. No Participant waives its rights to seek additional administrative or judicial remedies after the Commission's denial of any appeal thereof. The provisions of 18 C.F.R. §§ 388.112 and 388.113 shall apply to any requests under the Freedom of Information Act (5 U.S.C. § 552) for Privileged Material and/or CEII in the files of the Commission.

19. Privileged Material and/or CEII shall remain available to Participants until the later of 1) the date an order terminating this proceeding no longer is subject to judicial review, or 2) the date any other Commission proceeding relating to the Privileged Material and/or CEII is concluded and no longer subject to judicial review. After this time, the Participant that produced the Privileged Material and/or CEII may request (in writing) that all other Participants return or destroy the Privileged Material and/or CEII. This request must be satisfied with within fifteen (15) days of the date the request is made. However, copies of filings, official transcripts and exhibits in this proceeding containing Privileged Material, or Notes of Privileged Material, may be retained if they are maintained in accordance with Paragraph 5 of this Protective Agreement. If requested, each Participant also must submit to the Participant making the request an affidavit stating that to the best of its knowledge it has satisfied the request to return or destroy the Privileged Material and/or CEII. To the extent Privileged Material and/or CEII are not returned or destroyed, they shall remain subject to this Protective Agreement.

20. Regardless of any order terminating this proceeding, this Protective Agreement shall remain in effect until specifically modified or terminated by the Commission. All CEII designations shall be subject to the "[d]uration of the CEII designation" provisions of 18 C.F.R. § 388.113(e).

21. Any violation of this Protective Agreement and of any Non-Disclosure Certificate executed hereunder shall constitute a violation of an order of the Commission.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp	)	**Docket No. ER21-__-000**

NON-DISCLOSURE CERTIFICATE

I hereby certify my understanding that access to Privileged Material and/or Critical Energy/Electric Infrastructure Information (CEII) is provided to me pursuant to the terms and restrictions of the Protective Agreement in this proceeding, that I have been given a copy of and have read the Protective Agreement, and that I agree to be bound by it. I understand that the contents of Privileged Material and/or CEII, any notes or other memoranda, or any other form of information that copies or discloses such materials, shall not be disclosed to anyone other than in accordance with the Protective Agreement. I acknowledge that a violation of this certificate constitutes a violation of an order of the Federal Energy Regulatory Commission.

By: _____

Printed Name: _____

Title: _____

Representing: _____

Date: _____