Pacific Power |
Rocky Mountain Power
825 NE Multnomah, Suite 1600
Portland, Oregon 97232

April 19, 2021

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

RE: *PacifiCorp*
Updated Transmission System Loss Factor, Docket No. ER21-___-000

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 a proposed amendment to Schedule 10 of its Open Access Transmission Tariff ("OATT") to reflect an updated loss factor for Real Power Losses for use of PacifiCorp's Transmission System (the "Transmission System loss factor"). PacifiCorp respectfully requests that the amended Schedule 10 become effective June 1, 2021, to coincide with the effective date of PacifiCorp's 2021 Rate Year[4] and consistent with the settlement agreement in Docket No. ER11-3643 that implemented PacifiCorp's transmission formula rate, as described further below.[5]

I. Background and Reason for Filing

a. Requirement to update the Transmission System loss factor effective June 1.

On May 26, 2011, PacifiCorp submitted its transmission and ancillary service rate case filing in Docket No. ER11-3643, in which PacifiCorp sought to modify its transmission rates and adopt a formula transmission rate. PacifiCorp proposed employing a formula rate to calculate its rates for Point-to-Point Transmission Service and Network Integration Transmission Service, with such rates being updated annually pursuant to Formula Rate Implementation Protocols.

---

[1] 16 U.S.C. § 824d (2018)
[2] 18 C.F.R. Part 35 (2020).
[3] *Electronic Tariff Filings*, Order No. 714, 124 FERC ¶ 61,270 (2008).
[4] "Rate Year" is defined in Attachment H-2, Section I(2) as follows "The Formula Rate shall be applicable to service on and after June 1 of a given calendar year through May 31 of the subsequent calendar year"
[5] *PacifiCorp*, 143 FERC ¶ 61,162 (2013). The settlement agreement is referred to herein as the "Settlement Agreement".

PacifiCorp included in the Docket No. ER11-3643 rate case filing the following additions to its OATT: (1) Attachment H-1, which is the Formula; and (2) Attachment H-2, which are the Protocols. As noted earlier, a Settlement Agreement was reached in Docket No. ER113-3643 and was accepted by the Commission in a Letter Order dated May 23, 2013.

The Settlement Agreement reflected an amended OATT Schedule 10 that included an updated Transmission System loss factor of 4.26%.[6] In Section 3.6.9 of the Settlement Agreement, PacifiCorp agreed to file an adjusted Transmission System loss factor under Schedule 10 following completion of every two segments of its Energy Gateway Project (or substantially similar transmission segments or combination thereof), once the segments have been in commercial operation for at least one full calendar year.[7] The Settlement Agreement stipulates that the calculation for the Transmission System loss factor must be consistent with the spreadsheet calculation identified in Appendix 16 to the Settlement (the "Loss Factor Calculation") and be based on PacifiCorp's most recent FERC Form No. 1 data for the prior calendar year.[8] Furthermore, the Settlement Agreement includes a Loss Analysis Methodology in Appendix 17 to be used prospectively in calculating adjustments to PacifiCorp's transmission system loss factor. Finally, Section 3.6.9 requires PacifiCorp to request the Commission accept the updated Transmission System loss factor effective June 1 of the calendar year in which the filing is made.[9]

b. <u>Completion of Sigurd to Red Butte segment and the Wallula McNary transmission segment</u>.

PacifiCorp completed and placed in-service the Sigurd to Red Butte segment of the Energy Gateway Project in May 2015. Subsequently, PacifiCorp placed in-service the Wallula McNary transmission segment, which is similar to the Energy Gateway Project, in January 2019. As such, PacifiCorp has prepared this filing to update its Transmission System loss factor following the full calendar year of commercial operation for the Wallula McNary segment (*i.e.*, 2020).

c. <u>Timing of filing</u>.

---

[6] The updated Transmission System loss factor in OATT Schedule 10 also resulted in an update to the combination loss factor that is the sum of the transmission and distribution loss factors for uses of PacifiCorp's Transmission System and Distribution System, of 7.82%.
[7] The Energy Gateway transmission expansion program was originally announced in 2007. It is a multi-year, multi-billion dollar transmission expansion plan aimed at adding more than 2,000 megawatts of new transmission across the West. More information on the plan and associated transmission segments can be located at: http://www.pacificorp.com/tran/tp/eg.html.
[8] Section 3.6.9 also provides that, once triggered, PacifiCorp's update to its transmission system loss factor will be filed on or before April 1 following the full calendar year of commercial operation for the second of every two Energy Gateway Project segments (or substantially similar transmission segments or a combination thereof), with a request to the Commission that the updated transmission system loss factor be made effective June 1 of the calendar year in which the filing is made.
[9] PacifiCorp's first filing under Section 3.6.9 of the Settlement Agreement was submitted in Docket No. E15-1524.

Section 3.6.9 of the Settlement Agreement provides that, once triggered, PacifiCorp's update to its Transmission System loss factor would be filed on or before April 1 following the full calendar year of commercial operation for the second of every two Energy Gateway Project segments (or substantially similar transmission segments or a combination thereof). PacifiCorp acknowledges that is it making this filing after April 1 of the calendar year following the full calendar year of commercial operation of the Wallula McNary segment. However, as noted earlier the update filing is required to be based on PacifiCorp's most recent FERC Form No. 1 data for the prior calendar year. PacifiCorp filed its FERC Form No. 1 on April 14, 2021, which lead to the need to delay the timing of this filing to update the Transmission System loss factor.

PacifiCorp requested via electronic communication an exception from the Settlement Agreement from the Settling Parties – Bonneville Power Administration, Deseret Power, Utah Associated Municipal Power Systems, and Utah Municipal Power Agency -- to make this filing shortly after the filing of its 2020 FERC Form No. 1. PacifiCorp received no opposition provided that potential intervenors are afforded a typical time frame (i.e., 21 days) to review the filing. PacifiCorp agrees with the Settling Parties.

II. Summary of Proposed Changes and Loss Factor Methodology

a. Changes in loss factor.

This filing contains a proposed amendment to Schedule 10 of PacifiCorp's OATT to reflect: (1) a Transmission System loss factor of 3.75%, which is a decrease from the current Transmission System loss factor of 4.45%. In addition, Schedule 10 of PacifiCorp's OATT includes an amendment to reflect the resulting combination loss factor of 7.31%, which is the result of adding the updated Transmission System loss factor of 3.75% and the existing distribution loss factor of 3.56% for uses of PacifiCorp's Transmission and Distribution Systems.[10]

As described in detail below, PacifiCorp followed the loss calculation and methodology pursuant to Appendix 16 and Appendix 17 of the Settlement Agreement. Contributing factors to the decrease in the Transmission System loss factor based on 2020 FERC Form No. 1 data over 2014 FERC Form No. 1 data used for the loss factor include:

- a decrease in total energy losses from 4.6m megawatt hours in 2014 to 3.7m megawatt hours in 2020;
- a decrease in the proportion of transmission sales to ultimate customers from 14.1m megawatt hours in 2014 to 12.5m megawatt hours in 2020 relative to an increase in distribution sales to ultimate customers; and
- a decrease in off-system sales and purchases from 5.6m megawatt hours in 2014 to 3.2m megawatt hours in 2020.

[10] PacifiCorp is not proposing to update its loss factor for use of its Distribution System in this filing.

Each of these factors contributed to a decrease in the Transmission System loss factor and, in particular, given a decrease in total system resources of 70m megawatt hours in 2014 to approximately 61.5m megawatt hours in 2020.

b. Loss calculation and methodology.

PacifiCorp's calculations resulting in the updated Transmission System loss factor are demonstrated in the enclosed Loss Factor Calculation. The calculations in the Loss Factor Calculation are consistent with Appendix 16 of the Settlement Agreement.

To reinforce this and assist in the review of the calculation, PacifiCorp includes herewith as Enclosure 4 a matrix identifying the source materials, assumptions, and underlying calculations for each input of the Loss Factor Calculation. Consistent with the Settlement Agreement, PacifiCorp used the methodology outlined in the Loss Analysis Methodology in recalculating its Transmission System loss factor, using 2020 data from its FERC Form No. 1 and other settlement data.

The Loss Factor Calculation spreadsheet enclosed in this filing as Enclosure 3 is structured in the following components, which contribute to the calculation of the resulting Transmission System loss factor:

- **Input data from PacifiCorp's 2020 FERC Form No. 1 page 401a:** This includes the white-shaded section that summarizes data sourced directly from the FERC Form No. 1 and lists the total energy sources (received) and uses (delivered) on PacifiCorp's transmission system.

- **Recalculated and Adjusted Received and Delivered Energy:** This includes the green-shaded section that identifies the component and contract types of energy received including amount of energy received for losses as reported in the FERC Form No. 1. No adjustments were identified to the 2020 FERC Form No 1 data for modeling of the 2020 Loss Study.

- **Transmission and Distribution Losses Adjustments and Allocation:** This includes the yellow-shaded heading and following section that demonstrates the calculations and amounts used to complete the adjustments made to the received and delivered inputs in the green-shaded section described above under "Recalculated and Adjusted Received and Delivered Energy". This section also includes the allocation of losses between transmission and distribution.

The Loss Factor Calculation includes Attachments A through E that provide supporting documentation for the data used in the sections described above and as detailed in the matrix provided as Enclosure 4 to this filing. These attachments were included with the 2010 Loss Factor Calculation. For this Loss Factor Calculation, PacifiCorp has added as Attachment F an additional supporting workpaper titled "2020 Off-System

Sales/Purchases Summary". This attachment details the volume of PacifiCorp Energy's off-system transactions sourced from Company e-Tag data, which is deducted from 401a line 24, "Non-requirements Sales for Resale".

In addition to the Loss Factor Calculation spreadsheet, in Docket No. ER15-1524, intervenors raised concerns about the impact of E-Tag queries used by PacifiCorp and the impact on the resulting Transmission System Loss factor. In response to these concerns, PacifiCorp includes Enclosure 5 to this filing, which provides a high level explanation of the minor filter adjustments PacifiCorp made to the 2010 E-Tag query used in Docket No. ER11-3643.

c. <u>Adjustments to FERC Form No. 1 reporting practices and calculation methodology</u>.

In addition, in the Loss Analysis Methodology, PacifiCorp committed to make adjustments to its FERC Form No. 1 reporting practices and calculation methodology so that the data used would more closely tie to its FERC Form No. 1 on an ongoing basis. Specifically, PacifiCorp has made the following changes to its FERC Form No. 1 page 328 and Loss Factor Calculation consistent with the commitments outlined in the Loss Analysis Methodology:

- Page 328 includes an accrual variance entry to reflect calendar year amounts of energy received and delivered. The Loss Factor Calculation contains an itemization of the accrual amount in megawatt hours per the components used in the Loss Factor Calculation as shown on Attachment C, "Accrual Received".

- The Loss Factor Calculation on Attachment C and through items 16 and 17 separately specifies energy and loss amounts associated with Western Area Power Administration ("WAPA") rate schedules as reported in the Form 1, page 329, and page 401a, lines 16 and 17.

- Page 328 no longer includes accounting amounts related to WAPA rate schedule 262 tracking for water rights, which does not impact transmission energy delivered or received.

- The value of line 24 as reported in the FERC Form No. 1 page 401a, "Non-requirements Sales for Resale" is adjusted to remove 1) bus sales at locations where PacifiCorp transmission was not utilized with source data from either e-Tag records or Electric Quarterly Report entries as shown in the Loss Factor Calculation item 16 and 2) on-system sales to others for purposes of load service within PacifiCorp's Balancing Authority Area as shown in the Loss Factor Calculation item 15.

- The distribution loss factor, for purposes of calculating the amount of distribution losses on the system, was held constant at 4.64% based on the

2007 loss study and consistent with Appendix 16 of the Settlement Agreement.

- Retail customers taking service under transmission voltages do not include distribution losses as shown in the Loss Factor Calculation item 30.

III. Rate Impact to Customers and Statements BG/BH

PacifiCorp has calculated an estimated revenue impact of the revised Transmission System loss factor and the estimated impact to transmission customers. To determine the effect, PacifiCorp calculated the estimated change in annual revenue if the proposed Transmission System loss factor of 3.75% had been in effect in 2020 instead of the current Transmission System loss factor of 4.45%.

The estimated revenue impact of the proposed Transmission System loss factor is shown in Enclosure 1 to the filing: Statement BG (Revenue data to reflect changed rates) and Statement BH (Revenue data to reflect present rates). The billing determinants for the Statements BG/BH revenue calculation reflect the actual billing units of services provided to transmission customers in 2020. The estimated impact on revenue for 2020 resulting from the update is a decrease of approximately $902,213 or approximately 0.2% of total annual revenue for the 12-month period ending December 31, 2020.

IV. Enclosures

The following enclosures are included in this filing:

- Enclosure 1 – Statements BG and BH demonstrating the revenue impact of the proposed change to Schedule 10 of PacifiCorp's OATT;

- Enclosure 2 – Revised Schedule 10 of PacifiCorp's OATT (clean and redlined versions);

- Enclosure 3 – Loss Factor Calculation, consistent with Appendix 16 of the Settlement Agreement;

- Enclosure 4 – Matrix explaining the inputs, source material, and assumptions used in the Loss Factor Calculation, consistent with Appendix 17 of the Settlement Agreement; and

- Enclosure 5 – A high level explanation of the adjustments to filters made to the 2010 E-Tag query from Docket No. ER11-3643.

In addition to the items provided in the enclosures described above, the Loss Factor Calculation provided in Enclosure 3 has been made available in native format on PacifiCorp's OASIS website at the address listed in Section VII below.

V. Effective Date and Requests for Waiver

Pursuant to 18 C.F.R. § 35.11, PacifiCorp respectfully requests waiver of the Commission's notice requirement to permit an effective date for the amended OATT Schedule 10 of June 1, 2021. The Commission may provide that tariff revisions shall be effective as of a date prior to date they would otherwise become effective under the Commission's regulations, for good cause shown.[11] The Commission will ordinarily find good cause for granting waiver of the prior notice requirement if: (1) the filing reduces rates and charges; or (2) the filing increases rates and the rate change and effective date are prescribed by contract, such as annual rate revisions required by contract to become effective on a date specified in the contract.[12]

Good cause exists in this case because the Settlement Agreement required: (1) the updated loss factor to be based on PacifiCorp's 2020 FERC Form No. 1, which was filed on April 14, 2021 and, accordingly, impacted the timing of this filing, and (2) a June 1 effective date for the amended OATT Schedule 10, which coincides with the new transmission charges reflected in PacifiCorp's next annual update of its formula transmission rate, which will be effective June 1, 2021. Moreover, as noted above, the estimated impact on revenue resulting from this update is a decrease of approximately $902,213 or approximately 0.2% of total annual revenue for the 12-month period ending December 31, 2020.

To the extent necessary, PacifiCorp requests waiver of the full requirements of 18 C.F.R. § 35.13, as good cause exists for granting a waiver of the requirement to file the full range of information required by Section 35.13. The Commission has previously granted waiver of the requirement that utilities provide all of the cost of service information required by Section 35.13 in similar cases.[13] 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 revised Transmission System loss factor and combination loss factor to be accepted by FERC and made effective in the manner proposed herein.

VI. Communications

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

[11] 18 C.F.R. § 35.11.
[12] *See Central Hudson Gas & Elec. Corp.*, 60 FERC ¶ 61,106 at 61,338 (1992).
[13] *See, e.g., Westar Energy, Inc.*, 131 FERC ¶ 61,183 at P 21 (2010).

Matthew Loftus
Senior Counsel
PacifiCorp
825 NE Multnomah St., Suite 1600
Portland, OR 97232
Phone: (503) 813-6642
Matthew.Loftus@pacificorp.com

Rick Vail
Vice President, Transmission
PacifiCorp
825 NE Multnomah St., Suite 1600
Portland, OR 97232
Phone: (503) 813-6938
Richard.Vail@pacificorp.com

VII. Service

PacifiCorp is providing an electronic copy of this filing to all transmission customers pursuant to PacifiCorp's OATT, if such customers have provided PacifiCorp an e-mail contact address. To the extent that any such customers have not provided PacifiCorp a contact e-mail, PacifiCorp has served such customers with a hard copy of this filing to the last customer mailing address on file.

In addition, PacifiCorp posts this filing on its OASIS website: http://www.oatioasis.com/ppw/. The filing is centralized in the following folder on the OASIS site: "Transmission System Loss Factor 2021."[14] As indicated above, the posting includes not only the items included in this filing but also the Loss Factor Calculation in Enclosure 3 in native format.

For the foregoing reasons, PacifiCorp respectfully requests that the Commission accept PacifiCorp's this filing, effective June 1, 2021 as requested. If you have any questions, or if I can be of further assistance, please do not hesitate to contact me.

Respectfully Submitted,

<u>/s/ Matthew Loftus</u>
Matthew Loftus

Attorney for PacifiCorp

[14] See following folder location: PacifiCorp OASIS Tariff/Company Information/OATT Pricing/Transmission System Loss Factor 2021.

CERTIFICATE OF SERVICE

I hereby certify that I have on this day caused a copy of the foregoing document to be served via first-class mail or electronic mail upon each of the parties listed in the enclosed Service List.

Dated at Portland, Oregon this 19th day of April 2021.

__*/s/ Christian Marble*____
Christian Marble
Sr. Business Associate
PacifiCorp
825 NE Multnomah St
Suite 2000
Portland, OR 97232
(503) 813-6640
christian.marble@pacificorp.com

SCHEDULE 10

Real Power Losses

For Service Over the Transmission Provider’s Transmission System:

Any use of the Transmission Provider's Transmission System, excluding EIM participation, shall be assessed Real Power Losses in the following amounts:

Use of any portion of the Transmission System at a voltage of 46kV or greater	3.75%
Use of any portion of the Distribution System at a voltage 34.5 kV or less	3.56%
Use of a combination of the Transmission System and the Distribution System	7.31%

For Service on the PacifiCorp COI Segment:

Real Power Losses shall be calculated in accordance with Attachment S for Transmission Service on the PacifiCorp COI Segment.

Service Over PacifiCorp Facilities in Other Control Areas: For Transmission Service provided over PacifiCorp lines located in another control area, any Real Power Losses assessed to PacifiCorp by the adjacent control area associated with the Customer’s service will be passed through to the Transmission Customer. In instances where service is provided by PacifiCorp and an adjacent control area, any Real Power Losses assessed by the adjacent control area to PacifiCorp will be passed through to the Transmission Customer in addition to PacifiCorp Real Power Losses identified in this section.

Settlement of Transmission Losses: Unless Transmission Service is subject to Attachment S of the Tariff, a Transmission Customer taking Network Integration Transmission Service, Firm or Non-Firm Point-to-Point Transmission Service shall be responsible for Real Power Losses as provided for in Section 15.7 of the Tariff, this Schedule 10 and the Transmission Provider’s business practices posted on OASIS. A Transmission Customer shall have the option to settle Real Power Losses pursuant to section (a) (Financial Settlement) or section (b) (Physical Delivery) subject to the Transmission Provider’s business practices posted on OASIS.

(a) **Financial Settlement**.

(i) **Charges for Transmission Losses**. For each hour where the Transmission Provider provides loss service, the Transmission Customer shall compensate the Transmission Provider at a rate equal to the average hourly LAP price for the PACE and PACW BAAs, as established by the MO under Section 29.11(b)(3)(C) of the MO Tariff, multiplied by the energy for such hour based on a Transmission Customer's metered load actual amounts (for a Transmission Customer taking Network Integration Transmission Service) or actual amounts of power scheduled to be delivered at Point(s) of Delivery (for a Transmission Customer taking Point-to-Point Transmission Service).

A spreadsheet showing the average LAP prices for each hour of the previous month shall be accessible through the Transmission Provider's OASIS.

(b) **Physical Delivery**. Transmission Customers opting for physical delivery shall schedule losses to the Transmission Provider concurrently with transmission schedules. The Transmission Provider shall deliver to the Point(s) of Delivery the amount of power received from a Transmission Customer at Point(s) of Receipt, reduced for losses from the Point(s) of Receipt to the Point(s) of Delivery. The amount delivered to the Point(s) of Delivery shall be determined to be the amount of power received from a Transmission Customer at the Point(s) of Receipt divided by (1 + Real Power Losses rate) and the amount of losses shall be determined to be the amount of power received from a Transmission Customer at Point(s) of Receipt multiplied by (1 - 1/ (1 + Real Power Losses rate). Any hourly differences between the amounts of power scheduled to be delivered at Point(s) of Delivery (plus applicable Real Power Losses) and the actual amounts of energy received at Point(s) of Receipt shall be accounted for as Energy Imbalance subject to charges pursuant to Schedule 4.

Real Power Losses Updates: PacifiCorp shall update Schedule 10 factors for Real Power Losses following completion of every two Energy Gateway Project segments (or substantially similar transmission segments or combination thereof) which have been placed into commercial operation for at least one full calendar year. PacifiCorp's update to the Transmission System loss

factor shall be filed on or before April 1 following the full calendar year of commercial operation for the second of every two Energy Gateway Project segments (or substantially similar transmission segments or combination thereof) with a request to the Commission that the updated Transmission System loss factor be made effective June 1 of the calendar year in which the filing is made. Such filing shall be based on the most recent FERC Form No. 1 data for the prior calendar year. The update calculation shall be consistent with the methodology agreed upon in ER11-3643 and shall be based on annual sources and uses of energy from FERC Form No. 1, p. 401a, with adjustments to remove any energy source and corresponding energy use (i) which is not scheduled or otherwise transacted using PacifiCorp's transmission system, (ii) which is duplicative of, in part or whole, another energy source or energy use already represented in the data on FERC Form No. 1, p. 401a, and (iii) which represent financially settled losses (i.e., no actual physical losses).

SCHEDULE 10

Real Power Losses

For Service Over the Transmission Provider's Transmission System:

Any use of the Transmission Provider's Transmission System, excluding EIM participation, shall be assessed Real Power Losses in the following amounts:

Use of any portion of the Transmission System at a voltage of 46kV or greater	~~4.45%~~3.75%
Use of any portion of the Distribution System at a voltage 34.5 kV or less	3.56%
Use of a combination of the Transmission System and the Distribution System	~~8.01%~~7.31%

For Service on the PacifiCorp COI Segment:

Real Power Losses shall be calculated in accordance with Attachment S for Transmission Service on the PacifiCorp COI Segment.

Service Over PacifiCorp Facilities in Other Control Areas: For Transmission Service provided over PacifiCorp lines located in another control area, any Real Power Losses assessed to PacifiCorp by the adjacent control area associated with the Customer's service will be passed through to the Transmission Customer. In instances where service is provided by PacifiCorp and an adjacent control area, any Real Power Losses assessed by the adjacent control area to PacifiCorp will be passed through to the Transmission Customer in addition to PacifiCorp Real Power Losses identified in this section.

Settlement of Transmission Losses: Unless Transmission Service is subject to Attachment S of the Tariff, a Transmission Customer taking Network Integration Transmission Service, Firm or Non-Firm Point-to-Point Transmission Service shall be responsible for Real Power Losses as provided for in Section 15.7 of the Tariff, this Schedule 10 and the Transmission Provider's business practices posted on OASIS. A Transmission Customer shall have the option to settle Real Power Losses pursuant to section (a) (Financial Settlement) or section (b) (Physical Delivery) subject to the Transmission Provider’s business practices posted on OASIS.

(a) **Financial Settlement**.

(i) **Charges for Transmission Losses**. For each hour where the Transmission Provider provides loss service, the Transmission Customer shall compensate the Transmission Provider at a rate equal to the average hourly LAP price for the PACE and PACW BAAs, as established by the MO under Section 29.11(b)(3)(C) of the MO Tariff, multiplied by the energy for such hour based on a Transmission Customer’s metered load actual amounts (for a Transmission Customer taking Network Integration Transmission Service) or actual amounts of power scheduled to be delivered at Point(s) of Delivery (for a Transmission Customer taking Point-to-Point Transmission Service).

A spreadsheet showing the average LAP prices for each hour of the previous month shall be accessible through the Transmission Provider’s OASIS.

(b) **Physical Delivery**. Transmission Customers opting for physical delivery shall schedule losses to the Transmission Provider concurrently with transmission schedules. The Transmission Provider shall deliver to the Point(s) of Delivery the amount of power received from a Transmission Customer at Point(s) of Receipt, reduced for losses from the Point(s) of Receipt to the Point(s) of Delivery. The amount delivered to the Point(s) of Delivery shall be determined to be the amount of power received from a Transmission Customer at the Point(s) of Receipt divided by (1 + Real Power Losses rate) and the amount of losses shall be determined to be the amount of power received from a Transmission Customer at Point(s) of Receipt multiplied by (1 - 1/ (1 + Real Power Losses rate). Any hourly differences between the amounts of power scheduled to be delivered at Point(s) of Delivery (plus applicable Real Power Losses) and the actual amounts of energy received at Point(s) of Receipt shall be accounted for as Energy Imbalance subject to charges pursuant to Schedule 4.

Real Power Losses Updates: PacifiCorp shall update Schedule 10 factors for Real Power Losses following completion of every two Energy Gateway Project segments (or substantially similar transmission segments or combination thereof) which have been placed into commercial operation for at least one full calendar year. PacifiCorp's update to the Transmission System loss factor shall be filed on or before April 1 following the full calendar year of commercial operation for the second of every two Energy Gateway Project segments (or substantially similar transmission segments or combination thereof) with a request to the Commission that the updated Transmission System loss factor be made effective June 1 of the calendar year in which the filing is made. Such filing shall be based on the most recent FERC Form No. 1 data for the prior calendar year. The update calculation shall be consistent with the methodology agreed upon in ER11-3643 and shall be based on annual sources and uses of energy from FERC Form No. 1, p. 401a, with adjustments to remove any energy source and corresponding energy use (i) which is not scheduled or otherwise transacted using PacifiCorp's transmission system, (ii) which is duplicative of, in part or whole, another energy source or energy use already represented in the data on FERC Form No. 1, p. 401a, and (iii) which represent financially settled losses (i.e., no actual physical losses).

Enclosure 1

Statements BG and BH

PACIFICORP
ANNUAL COMPARISON
OATT PARTS II & III SERVICE AND LEGACY AGREEMENTS
2020

Line	Service/ Customer: Service Agreement ("SA") No.	**Present** (revenues under current loss system factor)	**Changed** (revenues under proposed loss system factor)	**Absolute difference** (changed *minus* present)	Percent difference	
	OATT Part II Long-Term Firm Point-to-Point Transmission Service					
1	PacifiCorp: multiple SAs	$ 84,867,053	$ 84,298,293	$ (568,760)	-0.67%	
2	Black Hills: SA 67	$ 1,696,586	$ 1,685,215	(11,370)	-0.67%	
3	BPA GS: SA 179	$ 610,771	$ 606,678	(4,093)	-0.67%	
4	BPA - Lost Creek: SA 656	$ 1,900,176	$ 1,887,441	(12,735)	-0.67%	
5	City of Roseville SA 881 [1]	$ 1,636,764	$ 1,636,764	-	0.00%	
6	Evergreen Bio SA 874	$ 339,317	$ 337,043	(2,274)	-0.67%	
7	Idaho Power: SA 212	$ 703,037	$ 698,326	(4,712)	-0.67%	
8	Avangrid Renewables, LLC: S.A. 895	$ 1,017,951	$ 1,011,129	(6,822)	-0.67%	
9	Thermo No. 1 (Cyrq Energy): SA 568	$ 373,249	$ 370,747	(2,501)	-0.67%	
10	Powerex: SA 169	$ 2,714,537	$ 2,696,345	(18,192)	-0.67%	
11	NextEra: SA 733	$ 3,092,085	$ 3,071,363	(20,722)	-0.67%	
12	Salt River Project: SA 809	$ 848,293	$ 842,608	(5,685)	-0.67%	
13	EWEB SA 605	$ 848,293	$ 842,608	(5,685)	-0.67%	
14	State of South Dakota: SA 779	$ 135,727	$ 134,817	(910)	-0.67%	
15	Sacramento MUD: SA 863	$ 644,703	$ 640,382	(4,321)	-0.67%	
16	Clatskanie Peoples Utility District: SA 899/900/901	$ 508,976	$ 505,565	(3,411)	-0.67%	
17	Powerex: SA 700 [1]	$ 3,273,528	$ 3,273,528	-	0.00%	
18	Powerex: SA 701 [1]	$ 3,273,528	$ 3,273,528	-	0.00%	
19	Powerex: SA 702 [1]	$ 3,273,528	$ 3,273,528	-	0.00%	
20	Powerex: SA 748 [1]	$ 1,636,764	$ 1,636,764	-	0.00%	
21	Powerex: SA 749 [1]	$ 4,910,292	$ 4,910,292	-	0.00%	
22	Garrett Solar: SA 966	$ 339,317	$ 337,043	(2,274)	-0.67%	
23	Airport Solar: SA 965	$ 1,696,586	$ 1,685,215	(11,370)	-0.67%	
24	Falls Creek: SA 868	$ 141,538	$ 140,590	(949)	-0.67%	
25	Subtotal	$ 120,482,597	$ 119,795,811	$ (686,785)	-0.57%	
	OATT Part III - Network Service (these loads already include losses)					
26	PacifiCorp: SA 66 [1]	$ 282,907,990	$ 282,907,990	$ -	0.00%	
27	BPA Yakama: SA 328	$ 175,847	$ 174,687	(1,159)	-0.66%	
28	BPA Gazely: SA 229	$ 106,588	$ 105,874	(714)	-0.67%	
29	BPA Clark: SA 735	$ 732,878	$ 727,967	(4,912)	-0.67%	
30	BPA Benton/Rimrock: SA 539	$ 22,604	$ 22,453	(151)	-0.67%	
31	BPA Ore Wind: SA 538	$ 5,172	$ 5,137	(35)	-0.67%	
32	BPA S. Idaho: SA 746	$ 7,101,084	$ 7,066,638	(34,446)	-0.49%	
33	BPA Idaho Falls SA 747	$ 3,082,348	$ 3,061,690	(20,658)	-0.67%	
34	Tri State: SA 628	$ 564,841	$ 564,638	(202)	-0.04%	
35	Calpine Energy Solutions: SA 299	$ 471,004	$ 467,848	(3,157)	-0.67%	
36	Basin: SA 505	$ 318,152	$ 316,020	(2,132)	-0.67%	
37	Black Hills: SA 347 [1]	$ 1,527,102	$ 1,527,102	-	0.00%	
38	USBR (Burbank): SA 506	$ 8,849	$ 8,790	(59)	-0.67%	
39	WAPA: SA 175	$ 43,340	$ 43,049	(290)	-0.67%	
40	Exelon Generation: SA 943	$ 35,283	$ 35,047	(236)	-0.67%	
41	Avangrid Renewables, LLC: SA 742	$ 1,084,701	$ 1,077,431	(7,269)	-0.67%	
42	BPA CEC SA 827	$ 1,507	$ 1,497	(10)	-0.67%	
43	BPA Airport Solar SA 865	$ 1,504	$ 1,494	(10)	-0.67%	
44	BPA WEID SA 975	$ 1,610	$ 1,599	(11)	-0.67%	
45	3 Phases Renewables Inc. SA 876	$ 8,108	$ 8,054	(54)	-0.67%	
46	NTUA SA 894	$ 77,905	$ 77,386	(520)	-0.67%	
47	Subtotal	$ 298,278,417	$ 298,202,391	$ (76,027)	-0.03%	
	Legacy Agreements (these loads already include losses)					
48	UAMPS: RS 297	$ 17,493,682	$ 17,399,406	$ (94,275)	-0.54%	
49	UMPA: RS 637	$ 2,635,708	$ 2,618,063	(17,645)	-0.67%	
50	DGT: RS 280	$ 4,480,620	$ 4,453,139	(27,480)	-0.61%	
51	WAPA OIS: RS 262/RS263	$ -	$ -	-	0.00%	N/A
52	Subtotal (Legacy Agreements)	$ 24,610,010	$ 24,470,609	$ (139,400)	-0.57%	
	Total	$ 443,371,024	$ 442,468,811	$ (902,213)	-0.20%	

PACIFICORP
STATEMENT BH — REVENUE DATA TO REFLECT PRESENT RATES
OATT PARTS II & III SERVICE AND LEGACY AGREEMENTS
2020

Current Transmission Loss System Factor **4.45%**

Line	Service/ Customer: Service Agreement ("SA")/Rate Schedule ("RS") No.	January	February	March	April	May	June	July	August	September	October	November	December	Total
	OATT Part II Long-Term Firm Point-to-Point Transmission Service (we add on the losses %)													
1	PacifiCorp: multiple SAs	6,969,469	6,969,469	6,969,469	6,969,469	6,969,469	7,145,672	7,145,672	7,145,672	7,145,672	7,145,672	7,145,672	7,145,672	84,867,053
2	Black Hills: SA 67	142,467	142,467	142,467	142,467	142,467	140,607	140,607	140,607	140,607	140,607	140,607	140,607	1,696,586
3	BPA GS: SA 179	51,288	51,288	51,288	51,288	51,288	50,619	50,619	50,619	50,619	50,619	50,619	50,619	610,771
4	BPA - Lost Creek: SA 656	159,563	159,563	159,563	159,563	159,563	157,480	157,480	157,480	157,480	157,480	157,480	157,480	1,900,176
5	City of Roseville SA 881 [1]	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	1,636,764
6	Evergreen Bio SA 874	28,493	28,493	28,493	28,493	28,493	28,121	28,121	28,121	28,121	28,121	28,121	28,121	339,317
7	Idaho Power: SA 212	-	-	-	-	-	140,607	140,607	140,607	140,607	140,607	-	-	703,037
8	Avangrid Renewables, LLC: S.A. 895	85,480	85,480	85,480	85,480	85,480	84,364	84,364	84,364	84,364	84,364	84,364	84,364	1,017,951
9	Thermo No. 1 (Cyrq Energy): SA 568	31,343	31,343	31,343	31,343	31,343	30,934	30,934	30,934	30,934	30,934	30,934	30,934	373,249
10	Powerex: SA 169	227,947	227,947	227,947	227,947	227,947	224,972	224,972	224,972	224,972	224,972	224,972	224,972	2,714,537
11	NextEra: SA 733	282,084	282,084	282,084	282,084	282,084	224,972	224,972	224,972	224,972	224,972	278,403	278,403	3,092,085
12	Salt River Project: SA 809	71,233	71,233	71,233	71,233	71,233	70,304	70,304	70,304	70,304	70,304	70,304	70,304	848,293
13	EWEB SA 605	71,233	71,233	71,233	71,233	71,233	70,304	70,304	70,304	70,304	70,304	70,304	70,304	848,293
14	State of South Dakota: SA 779	11,397	11,397	11,397	11,397	11,397	11,249	11,249	11,249	11,249	11,249	11,249	11,249	135,727
15	Sacramento MUD: SA 863	54,137	54,137	54,137	54,137	54,137	53,431	53,431	53,431	53,431	53,431	53,431	53,431	644,703
16	Clatskanie Peoples Utility District: SA 899/900/901	42,740	42,740	42,740	42,740	42,740	42,182	42,182	42,182	42,182	42,182	42,182	42,182	508,976
17	Powerex: SA 700 [1]	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	3,273,528
18	Powerex: SA 701 [1]	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	3,273,528
19	Powerex: SA 702 [1]	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	3,273,528
20	Powerex: SA 748 [1]	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	1,636,764
21	Powerex: SA 749 [1]	409,191	409,191	409,191	409,191	409,191	409,191	409,191	409,191	409,191	409,191	409,191	409,191	4,910,292
22	Garrett Solar: SA 966	28,493	28,493	28,493	28,493	28,493	28,121	28,121	28,121	28,121	28,121	28,121	28,121	339,317
23	Airport Solar: SA 965	142,467	142,467	142,467	142,467	142,467	140,607	140,607	140,607	140,607	140,607	140,607	140,607	1,696,586
24	Falls Creek: SA 868	14,247	14,247	14,247	14,247	14,247	14,061	2,812	2,812	8,436	14,062	14,061	14,061	141,538
25	Subtotal	9,914,448	9,914,448	9,914,448	9,914,448	9,914,448	10,158,976	10,147,727	10,147,727	10,153,351	10,158,977	10,071,799	10,071,799	120,482,597
	OATT Part III - Network Service (these loads already include losses)													
26	PacifiCorp: SA 66 [1]	22,714,370	22,427,265	20,891,729	18,887,310	23,869,129	25,782,868	28,578,270	28,770,170	26,238,009	21,212,819	20,963,976	22,572,075	282,907,990
27	BPA Yakama: SA 328	20,320	19,570	15,874	14,084	11,981	11,200	13,812	15,080	13,367	15,403	13,308	11,846	175,847
28	BPA Gazely: SA 229	8,907	9,381	9,578	7,597	8,176	9,213	10,059	9,604	9,717	8,160	8,064	8,134	106,588
29	BPA Clark: SA 735	79,678	85,109	65,443	61,962	38,870	46,028	48,774	46,058	46,456	71,490	67,451	75,558	732,878
30	BPA Benton/Rimrock: SA 539	3,699	3,443	3,063	2,545	1,004	913	1,072	991	923	2,474	2,477	-	22,604
31	BPA Ore Wind: SA 538	-	-	-	142	450	1,074	-	956	-	1,026	-	1,524	5,172
32	BPA S. Idaho: SA 746	721,426	821,893	682,263	547,391	357,745	433,063	465,059	435,346	369,801	734,411	653,409	879,278	7,101,084
33	BPA Idaho Falls SA 747	264,220	287,157	286,330	180,791	234,900	227,166	284,082	296,289	269,046	223,117	254,698	274,551	3,082,348
34	Tri State: SA 628	57,470	57,756	54,196	55,053	32,045	42,919	41,855	41,982	36,441	54,057	44,168	46,901	564,841
35	Calpine Energy Solutions: SA 299	38,158	37,725	37,839	37,065	45,467	47,477	44,542	43,971	43,401	32,238	33,353	29,769	471,004
36	Basin: SA 505	29,143	29,249	28,253	24,554	20,473	26,751	25,997	28,964	25,332	26,285	24,853	28,296	318,152
37	Black Hills: SA 347 [1]	140,462	129,604	116,783	118,884	99,270	128,478	143,259	164,664	123,821	131,090	107,640	123,148	1,527,102
38	USBR (Burbank): SA 506	16	14	14	677	1,503	1,443	1,839	1,656	1,648	13	13	13	8,849
39	WAPA: SA 175	19	30	14	14	8,890	9,178	8,454	8,465	8,233	13	11	19	43,340
40	Exelon Generation: SA 943	3,162	2,894	2,984	2,862	2,960	3,368	3,244	3,005	3,239	2,493	2,175	2,897	35,283
41	Avangrid Renewables, LLC: SA 742	90,041	89,337	88,770	89,970	89,367	89,800	90,934	89,870	91,421	92,272	92,140	90,778	1,084,701
42	BPA CEC SA 827	456	128	-	-	-	-	-	-	-	-	433	490	1,507
43	BPA Airport Solar SA 865	480	325	-	120	-	38	-	-	-	-	269	272	1,504
44	BPA WEID SA 975	-	-	-	-	-	-	-	-	-	-	1,583	27	1,610
45	3 Phases Renewables Inc. SA 876	671	641	660	513	717	800	929	837	767	552	450	571	8,108
46	NTUA SA 894	7,166	6,970	6,078	5,314	5,816	5,977	7,207	7,242	6,672	6,101	6,322	7,040	77,905
47	Subtotal	24,179,863	24,008,491	22,289,872	20,036,848	24,828,763	26,867,755	29,769,389	29,965,149	27,288,293	22,614,015	22,276,793	24,153,187	298,278,417
	Legacy Agreements (these loads already include losses)													
48	UAMPS: RS 297	1,034,375	1,175,824	964,406	935,855	1,838,874	1,814,599	2,121,227	2,303,857	2,003,893	981,966	1,100,244	1,218,561	17,493,682
49	UMPA: RS 637	159,574	170,480	135,404	84,353	275,541	298,823	409,279	423,976	312,015	111,468	126,723	128,072	2,635,708
50	DGT: RS 280	245,310	243,403	178,765	320,124	422,749	423,449	402,324	646,679	602,624	339,943	327,852	327,399	4,480,620
51	WAPA OIS: RS 262/RS263 N/A	-	-	-	-	-	-	-	-	-	-	-	-	-
52	**Subtotal** (Legacy Agreements)	1,439,258	1,589,707	1,278,575	1,340,332	2,537,164	2,536,871	2,932,831	3,374,512	2,918,532	1,433,378	1,554,818	1,674,032	24,610,010
	Change													
53	Updated revenues with proposed loss factor (From Statement BG)	$ 35,459,770	$ 35,437,340	$ 33,410,969	$ 31,221,517	$ 37,206,625	$ 39,488,408	$ 42,770,002	$ 43,408,862	$ 40,280,945	$ 34,132,669	$ 33,828,492	$ 35,823,212	$ 442,468,811
54	Revenues with current loss factor	35,533,569	35,512,646	33,482,895	31,291,628	37,280,376	39,563,601	42,849,946	43,487,388	40,360,176	34,206,369	33,903,411	35,899,018	443,371,024
55	Absolute Difference (*proposed* minus *current*)	$ (73,799)	$ (75,306)	$ (71,926)	$ (70,111)	$ (73,751)	$ (75,193)	$ (79,944)	$ (78,526)	$ (79,231)	$ (73,700)	$ (74,919)	$ (75,806)	$ (902,213)
56	Percent Difference	-0.21%	-0.21%	-0.21%	-0.22%	-0.20%	-0.19%	-0.19%	-0.18%	-0.20%	-0.22%	-0.22%	-0.21%	-0.20%

Note [1] Per customers' contract agreements, no losses, or losses only applicable to certain load, are included in customers' billing determinants.
Note [2] A value of zero in a month (designated by "-") indicates that the customer did not take service for that month.

PACIFICORP
STATEMENT BG — REVENUE DATA TO REFLECT CHANGED RATES
OATT PARTS II & III SERVICE AND LEGACY AGREEMENTS
2020

Proposed Transmission Loss System Factor **3.75%**

Line	Service/ Customer: Service Agreement ("SA")/Rate Schedule ("RS") No.	January	February	March	April	May	June	July	August	September	October	November	December	Total
	OATT Part II Long-Term Firm Point-to-Point Transmission Service (we add on the losses %)													
1	PacifiCorp: multiple SAs	6,922,762	6,922,762	6,922,762	6,922,762	6,922,762	7,097,784	7,097,784	7,097,784	7,097,784	7,097,784	7,097,784	7,097,784	84,298,293
2	Black Hills: SA 67	141,512	141,512	141,512	141,512	141,512	139,665	139,665	139,665	139,665	139,665	139,665	139,665	1,685,215
3	BPA GS: SA 179	50,944	50,944	50,944	50,944	50,944	50,279	50,279	50,279	50,279	50,279	50,279	50,279	606,678
4	BPA - Lost Creek: SA 656	158,493	158,493	158,493	158,493	158,493	156,425	156,425	156,425	156,425	156,425	156,425	156,425	1,887,441
5	City of Roseville SA 881 [1]	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	1,636,764
6	Evergreen Bio SA 874	28,302	28,302	28,302	28,302	28,302	27,933	27,933	27,933	27,933	27,933	27,933	27,933	337,043
7	Idaho Power: SA 212	-	-	-	-	-	139,665	139,665	139,665	139,665	139,665	-	-	698,326
8	Avangrid Renewables, LLC: S.A. 895	84,907	84,907	84,907	84,907	84,907	83,799	83,799	83,799	83,799	83,799	83,799	83,799	1,011,129
9	Thermo No. 1 (Cyrq Energy): SA 568	31,133	31,133	31,133	31,133	31,133	30,726	30,726	30,726	30,726	30,726	30,726	30,726	370,747
10	Powerex: SA 169	226,419	226,419	226,419	226,419	226,419	223,464	223,464	223,464	223,464	223,464	223,464	223,464	2,696,345
11	NextEra: SA 733	280,194	280,194	280,194	280,194	280,194	223,464	223,464	223,464	223,464	223,464	276,537	276,537	3,071,363
12	Salt River Project: SA 809	70,756	70,756	70,756	70,756	70,756	69,833	69,833	69,833	69,833	69,833	69,833	69,833	842,608
13	EWEB SA 605	70,756	70,756	70,756	70,756	70,756	69,833	69,833	69,833	69,833	69,833	69,833	69,833	842,608
14	State of South Dakota: SA 779	11,321	11,321	11,321	11,321	11,321	11,173	11,173	11,173	11,173	11,173	11,173	11,173	134,817
15	Sacramento MUD: SA 863	53,775	53,775	53,775	53,775	53,775	53,073	53,073	53,073	53,073	53,073	53,073	53,073	640,382
16	Clatskanie Peoples Utility District: SA 899/900/901	42,454	42,454	42,454	42,454	42,454	41,900	41,900	41,900	41,900	41,900	41,900	41,900	505,565
17	Powerex: SA 700 [1]	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	3,273,528
18	Powerex: SA 701 [1]	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	3,273,528
19	Powerex: SA 702 [1]	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	272,794	3,273,528
20	Powerex: SA 748 [1]	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	136,397	1,636,764
21	Powerex: SA 749 [1]	409,191	409,191	409,191	409,191	409,191	409,191	409,191	409,191	409,191	409,191	409,191	409,191	4,910,292
22	Garrett Solar: SA 966	28,302	28,302	28,302	28,302	28,302	27,933	27,933	27,933	27,933	27,933	27,933	27,933	337,043
23	Airport Solar: SA 965	141,512	141,512	141,512	141,512	141,512	139,665	139,665	139,665	139,665	139,665	139,665	139,665	1,685,215
24	Falls Creek: SA 868	14,151	14,151	14,151	14,151	14,151	13,967	2,793	2,793	8,380	13,968	13,967	13,967	140,590
25	Subtotal	9,858,059	9,858,059	9,858,059	9,858,059	9,858,059	10,100,948	10,089,774	10,089,774	10,095,361	10,100,949	10,014,355	10,014,355	119,795,811
	OATT Part III - Network Service (these loads already include losses)													
26	PacifiCorp: SA 66 [1]	22,714,369.7	22,427,265.0	20,891,729.4	18,887,310.0	23,869,128.6	25,782,868.5	28,578,270.4	28,770,170.1	26,238,008.9	21,212,818.8	20,963,976.1	22,572,074.9	282,907,990.3
27	BPA Yakama: SA 328	20,186.8	19,442.0	15,770.2	13,991.6	11,902.0	11,127.4	13,720.2	14,980.2	13,278.6	15,300.6	13,219.4	11,768.2	174,687.2
28	BPA Gazely: SA 229	8,847.0	9,318.5	9,513.6	7,546.4	8,120.8	9,151.4	9,991.2	9,539.2	9,651.5	8,105.8	8,009.5	8,079.0	105,874.1
29	BPA Clark: SA 735	79,143.7	84,538.6	65,004.7	61,547.2	38,609.9	45,719.8	48,447.6	45,749.2	46,145.0	71,010.6	66,999.2	75,051.5	727,966.8
30	BPA Benton/Rimrock: SA 539	3,674.3	3,419.6	3,042.9	2,528.1	997.2	906.6	1,064.4	984.1	917.3	2,457.7	2,460.4	-	22,452.5
31	BPA Ore Wind: SA 538	-	-	-	140.9	447.1	1,067.0	-	949.4	-	1,018.9	-	1,513.7	5,137.0
32	BPA S. Idaho: SA 746	716,376.1	816,458.8	678,872.4	545,391.6	357,717.5	433,073.7	463,050.2	435,122.5	368,368.7	729,543.4	648,783.9	873,879.7	7,066,638.5
33	BPA Idaho Falls SA 747	262,449.7	285,233.4	284,409.6	179,577.6	233,326.2	225,645.0	282,178.8	294,305.1	267,241.7	221,622.7	252,991.1	272,709.8	3,061,690.5
34	Tri State: SA 628	57,087.6	57,505.0	54,196.0	54,834.3	31,832.3	42,773.2	41,577.8	43,877.1	36,311.6	53,830.6	44,132.8	46,679.8	564,638.2
35	Calpine Energy Solutions: SA 299	37,902.7	37,471.9	37,585.7	36,816.1	45,161.9	47,158.5	44,243.6	43,676.6	43,109.7	32,022.0	33,129.2	29,569.7	467,847.5
36	Basin: SA 505	28,947.3	29,053.0	28,063.9	24,389.6	20,336.0	26,571.8	25,823.0	28,770.1	25,162.5	26,109.2	24,686.4	28,106.9	316,019.6
37	Black Hills: SA 347 [1]	140,461.6	129,604.4	116,783.1	118,883.6	99,269.7	128,478.5	143,259.4	164,663.5	123,820.7	131,090.0	107,639.8	123,147.6	1,527,102.1
38	USBR (Burbank): SA 506	16.3	13.5	13.5	672.0	1,493.0	1,433.4	1,826.5	1,644.7	1,636.7	13.4	13.4	13.4	8,789.8
39	WAPA: SA 175	19.0	29.8	13.5	13.5	8,830.8	9,116.7	8,397.3	8,408.0	8,178.0	13.4	10.7	18.7	43,049.4
40	Exelon Generation: SA 943	3,140.5	2,874.9	2,964.4	2,842.4	2,940.0	3,345.5	3,222.5	2,984.5	3,217.2	2,476.4	2,160.8	2,877.5	35,046.8
41	Avangrid Renewables, LLC: SA 742	89,437.7	88,738.6	88,175.0	89,367.2	88,768.4	89,198.5	90,324.4	89,268.0	90,808.4	91,653.5	91,522.5	90,169.3	1,077,431.4
42	BPA CEC SA 827	452.5	127.4	-	-	-	-	-	-	-	-	430.6	486.7	1,497.2
43	BPA Airport Solar SA 865	476.9	322.4	-	119.2	-	37.4	-	-	-	-	267.4	270.1	1,493.5
44	BPA WEID SA 975	-	-	-	-	-	-	-	-	-	-	1,572.5	26.7	1,599.2
45	3 Phases Renewables Inc. SA 876	666.6	636.8	655.7	509.4	712.6	794.3	922.6	831.7	762.2	548.2	446.6	567.0	8,053.7
46	NTUA SA 894	7,119.9	6,923.5	6,036.9	5,278.6	5,775.0	5,936.6	7,158.9	7,193.9	6,628.5	6,060.5	6,278.5	6,994.7	77,385.7
47	Subtotal	24,170,775.8	23,998,977.1	22,282,830.6	20,031,759.4	24,825,369.0	26,864,403.9	29,763,478.7	29,963,117.9	27,283,247.1	22,605,695.6	22,268,730.8	24,144,004.9	298,202,390.8
	Legacy Agreements (these loads already include losses)													
48	UAMPS: RS 297	1,028,618.9	1,169,192.4	958,014.3	929,654.7	1,829,585.7	1,805,623.2	2,110,584.6	2,292,613.7	1,993,825.8	977,171.3	1,092,923.1	1,211,598.8	17,399,406.5
49	UMPA: RS 637	158,504.2	169,339.6	134,498.4	83,791.4	273,696.9	296,822.4	406,538.0	421,138.5	309,926.0	110,719.8	125,872.3	127,215.8	2,618,063.3
50	DGT: RS 280	243,812.4	241,771.9	177,567.1	318,252.4	419,914.5	420,610.8	399,626.7	642,217.3	598,585.3	338,133.7	326,610.5	326,037.0	4,453,139.5
51	WAPA OIS: RS 262/RS263 N/A	-	-	-	-	-	-	-	-	-	-	-	-	-
52	**Subtotal** (Legacy Agreements)	1,430,935.5	1,580,303.8	1,270,079.8	1,331,698.5	2,523,197.2	2,523,056.4	2,916,749.2	3,355,969.5	2,902,337.1	1,426,024.8	1,545,405.9	1,664,851.5	24,470,609.2
	Change													
53	Updated revenues with proposed loss factor	$ 35,459,770	$ 35,437,340	$ 33,410,969	$ 31,221,517	$ 37,206,625	$ 39,488,408	$ 42,770,002	$ 43,408,862	$ 40,280,945	$ 34,132,669	$ 33,828,492	$ 35,823,212	$ 442,468,811
54	Revenues with current loss factor (From Statement BH)	35,533,569	35,512,646	33,482,895	31,291,628	37,280,376	39,563,601	42,849,946	43,487,388	40,360,176	34,206,369	33,903,411	35,899,018	443,371,024
55	Absolute Difference (*proposed* minus *current*)	$ (73,799)	$ (75,306)	$ (71,926)	$ (70,111)	$ (73,751)	$ (75,193)	$ (79,944)	$ (78,526)	$ (79,231)	$ (73,700)	$ (74,919)	$ (75,806)	$ (902,213)
56	Percent Difference	-0.21%	-0.21%	-0.21%	-0.22%	-0.20%	-0.19%	-0.19%	-0.18%	-0.20%	-0.22%	-0.22%	-0.21%	-0.20%

Note [1] Per customers' contract agreements, no losses, or losses only applicable to certain load, are included in customers' billing determinants.
Note [2] A value of zero in a month (designated by "-") indicates that the customer did not take service for that month.

Enclosure 2
(Clean and Redline Versions)

Schedule 10 of PacifiCorp's OATT

SCHEDULE 10

Real Power Losses

<u>For Service Over the Transmission Provider’s Transmission System</u>:

Any use of the Transmission Provider's Transmission System, excluding EIM participation, shall be assessed Real Power Losses in the following amounts:

Use of any portion of the Transmission System at a voltage of 46kV or greater	3.75%
Use of any portion of the Distribution System at a voltage 34.5 kV or less	3.56%
Use of a combination of the Transmission System and the Distribution System	7.31%

<u>For Service on the PacifiCorp COI Segment</u>:

Real Power Losses shall be calculated in accordance with Attachment S for Transmission Service on the PacifiCorp COI Segment.

<u>Service Over PacifiCorp Facilities in Other Control Areas</u>: For Transmission Service provided over PacifiCorp lines located in another control area, any Real Power Losses assessed to PacifiCorp by the adjacent control area associated with the Customer’s service will be passed through to the Transmission Customer. In instances where service is provided by PacifiCorp and an adjacent control area, any Real Power Losses assessed by the adjacent control area to PacifiCorp will be passed through to the Transmission Customer in addition to PacifiCorp Real Power Losses identified in this section.

<u>Settlement of Transmission Losses</u>: Unless Transmission Service is subject to Attachment S of the Tariff, a Transmission Customer taking Network Integration Transmission Service, Firm or Non-Firm Point-to-Point Transmission Service shall be responsible for Real Power Losses as provided for in Section 15.7 of the Tariff, this Schedule 10 and the Transmission Provider’s business practices posted on OASIS. A Transmission Customer shall have the option to settle Real Power Losses pursuant to section (a) (Financial Settlement) or section (b) (Physical Delivery) subject to the Transmission Provider’s business practices posted on OASIS.

(a) **Financial Settlement**.

(i) **Charges for Transmission Losses**. For each hour where the Transmission Provider provides loss service, the Transmission Customer shall compensate the Transmission Provider at a rate equal to the average hourly LAP price for the PACE and PACW BAAs, as established by the MO under Section 29.11(b)(3)(C) of the MO Tariff, multiplied by the energy for such hour based on a Transmission Customer's metered load actual amounts (for a Transmission Customer taking Network Integration Transmission Service) or actual amounts of power scheduled to be delivered at Point(s) of Delivery (for a Transmission Customer taking Point-to-Point Transmission Service).

A spreadsheet showing the average LAP prices for each hour of the previous month shall be accessible through the Transmission Provider's OASIS.

(b) **Physical Delivery**. Transmission Customers opting for physical delivery shall schedule losses to the Transmission Provider concurrently with transmission schedules. The Transmission Provider shall deliver to the Point(s) of Delivery the amount of power received from a Transmission Customer at Point(s) of Receipt, reduced for losses from the Point(s) of Receipt to the Point(s) of Delivery. The amount delivered to the Point(s) of Delivery shall be determined to be the amount of power received from a Transmission Customer at the Point(s) of Receipt divided by (1 + Real Power Losses rate) and the amount of losses shall be determined to be the amount of power received from a Transmission Customer at Point(s) of Receipt multiplied by (1 - 1/ (1 + Real Power Losses rate). Any hourly differences between the amounts of power scheduled to be delivered at Point(s) of Delivery (plus applicable Real Power Losses) and the actual amounts of energy received at Point(s) of Receipt shall be accounted for as Energy Imbalance subject to charges pursuant to Schedule 4.

Real Power Losses Updates: PacifiCorp shall update Schedule 10 factors for Real Power Losses following completion of every two Energy Gateway Project segments (or substantially similar transmission segments or combination thereof) which have been placed into commercial operation for at least one full calendar year. PacifiCorp's update to the Transmission System loss

factor shall be filed on or before April 1 following the full calendar year of commercial operation for the second of every two Energy Gateway Project segments (or substantially similar transmission segments or combination thereof) with a request to the Commission that the updated Transmission System loss factor be made effective June 1 of the calendar year in which the filing is made. Such filing shall be based on the most recent FERC Form No. 1 data for the prior calendar year. The update calculation shall be consistent with the methodology agreed upon in ER11-3643 and shall be based on annual sources and uses of energy from FERC Form No. 1, p. 401a, with adjustments to remove any energy source and corresponding energy use (i) which is not scheduled or otherwise transacted using PacifiCorp’s transmission system, (ii) which is duplicative of, in part or whole, another energy source or energy use already represented in the data on FERC Form No. 1, p. 401a, and (iii) which represent financially settled losses (i.e., no actual physical losses).

SCHEDULE 10

Real Power Losses

For Service Over the Transmission Provider's Transmission System:

Any use of the Transmission Provider's Transmission System, excluding EIM participation, shall be assessed Real Power Losses in the following amounts:

Use of any portion of the Transmission System at a voltage of 46kV or greater	~~4.45~~3.75%
Use of any portion of the Distribution System at a voltage 34.5 kV or less	3.56%
Use of a combination of the Transmission System and the Distribution System	~~8.01~~7.31%

For Service on the PacifiCorp COI Segment:

Real Power Losses shall be calculated in accordance with Attachment S for Transmission Service on the PacifiCorp COI Segment.

Service Over PacifiCorp Facilities in Other Control Areas: For Transmission Service provided over PacifiCorp lines located in another control area, any Real Power Losses assessed to PacifiCorp by the adjacent control area associated with the Customer's service will be passed through to the Transmission Customer. In instances where service is provided by PacifiCorp and an adjacent control area, any Real Power Losses assessed by the adjacent control area to PacifiCorp will be passed through to the Transmission Customer in addition to PacifiCorp Real Power Losses identified in this section.

Settlement of Transmission Losses: Unless Transmission Service is subject to Attachment S of the Tariff, a Transmission Customer taking Network Integration Transmission Service, Firm or Non-Firm Point-to-Point Transmission Service shall be responsible for Real Power Losses as provided for in Section 15.7 of the Tariff, this Schedule 10 and the Transmission Provider's business practices posted on OASIS. A Transmission Customer shall have the option to settle Real Power Losses pursuant to section (a) (Financial Settlement) or section (b) (Physical Delivery) subject to the Transmission Provider's business practices posted on OASIS.

(a) **Financial Settlement**.

(i) **Charges for Transmission Losses**. For each hour where the Transmission Provider provides loss service, the Transmission Customer shall compensate the Transmission Provider at a rate equal to the average hourly LAP price for the PACE and PACW BAAs, as established by the MO under Section 29.11(b)(3)(C) of the MO Tariff, multiplied by the energy for such hour based on a Transmission Customer's metered load actual amounts (for a Transmission Customer taking Network Integration Transmission Service) or actual amounts of power scheduled to be delivered at Point(s) of Delivery (for a Transmission Customer taking Point-to-Point Transmission Service).

A spreadsheet showing the average LAP prices for each hour of the previous month shall be accessible through the Transmission Provider's OASIS.

(b) **Physical Delivery**. Transmission Customers opting for physical delivery shall schedule losses to the Transmission Provider concurrently with transmission schedules. The Transmission Provider shall deliver to the Point(s) of Delivery the amount of power received from a Transmission Customer at Point(s) of Receipt, reduced for losses from the Point(s) of Receipt to the Point(s) of Delivery. The amount delivered to the Point(s) of Delivery shall be determined to be the amount of power received from a Transmission Customer at the Point(s) of Receipt divided by (1 + Real Power Losses rate) and the amount of losses shall be determined to be the amount of power received from a Transmission Customer at Point(s) of Receipt multiplied by (1 - 1/ (1 + Real Power Losses rate). Any hourly differences between the amounts of power scheduled to be delivered at Point(s) of Delivery (plus applicable Real Power Losses) and the actual amounts of energy received at Point(s) of Receipt shall be accounted for as Energy Imbalance subject to charges pursuant to Schedule 4.

Real Power Losses Updates: PacifiCorp shall update Schedule 10 factors for Real Power Losses following completion of every two Energy Gateway Project segments (or substantially similar transmission segments or combination thereof) which have been placed into commercial operation for at least one full calendar year. PacifiCorp's update to the Transmission System loss

factor shall be filed on or before April 1 following the full calendar year of commercial operation for the second of every two Energy Gateway Project segments (or substantially similar transmission segments or combination thereof) with a request to the Commission that the updated Transmission System loss factor be made effective June 1 of the calendar year in which the filing is made. Such filing shall be based on the most recent FERC Form No. 1 data for the prior calendar year. The update calculation shall be consistent with the methodology agreed upon in ER11-3643 and shall be based on annual sources and uses of energy from FERC Form No. 1, p. 401a, with adjustments to remove any energy source and corresponding energy use (i) which is not scheduled or otherwise transacted using PacifiCorp’s transmission system, (ii) which is duplicative of, in part or whole, another energy source or energy use already represented in the data on FERC Form No. 1, p. 401a, and (iii) which represent financially settled losses (i.e., no actual physical losses).

Enclosure 3

Loss Factor Calculation

Amounts in thousands of MWh

Input Data from 2020 FERC Form No.1, Page 401a

SOURCES		USES	
Net Generation, Ln 9	49,661	Sales to Ultimate Consumers, Ln 22	54,560
Purchases, Ln 10	11,928	Requirements Sales for Resale, Ln 23	267
	61,588	Energy Furnished Without Charge, Ln 25	129
Net Exchanges, Ln 14	2,286	Non-requirements Sales for Resale, Ln 24	4,982
		Energy Used by the Company, Ln 26	-
Received, Ln 16	16,923	Total Energy Losses, Ln 27	3,794
Delivered, Ln 17	(16,817)		
Transmission By Others Losses, Ln 19	(249)		
Total	**63,732**	Total	**63,732**

Recalculated and Adjusted Received and Delivered Energy

REF	Sources				Uses		REF
1	Generation, 401a lines 9,10			61,588	Sales to Ultimate Consumers, 401a line 22	54,560	18
2	Net exchange, 401a line 14			2,286	Requirements Sales for Resale, 401a line 23	267	19
3	Transmission by Others Losses, 401a line 19			(249)			
				63,626			
4	Reconciliation of Transmission Received (401a line 16):				On-system non-requirements sales for resale subject to losses	1,343	20
5	Pt-to-Pt transmission received - losses ***financially*** settled	Att. A	4,449				
6	Network transmission received - losses ***financially*** settled	Att. B	2,983				
7	WAPA RS 262 delivered	Att. C	1,628		Company sales, 401a line 26	-	21
8	WAPA RS 263 delivered	Att. C	43				
9	WAPA losses received	Att. C	107				
10	Black Hills transmission received - losses ***financially*** settled	Att. D	382				
11	Transmission received - losses p***hysically*** settled	Att. D	295				
12	Transmission received -- supplied losses - network customers	Att. C	7,037				
13	Total Transmission Received:			16,923	Transmission delivered without losses	16,172	22
14	**Gross Received**			**80,549**			
15	Less third-party sales on-system (reported in Energy Received (duplicate transactions))			(130)			
16	Less off-system sales/purchases w/o losses	Att. F		(3,243)			
17	**Net on-system received**			**77,176**	**Total delivered with on-system losses**	**72,342**	23
					Total system delivered loss rate including off-system	6.7%	24

Total losses (Sources-Uses)	**4,834**	25
Distribution losses / Fixed 4.64% Loss Rate (see page 2)	2,042	26
Transmission losses (total losses - distribution losses)	2,792	27
Transmission deliveries = Total delivered (Uses) + Distribution losses =	74,384	28
Transmission loss rate @ delivery =	**3.75%**	29

Amounts in thousands of MWh

Transmission and Distribution Losses Adjustments and Allocation

REF					Current Tran Loss Factor 4.45%		Distribution Loss Factor 4.64%	2007 Distribution Loss Study
REF	**Schedule 10 loss factor (prior to update)**							
				FERC # w/ Current Loss Factor	**Trans Loss embedded in current #s**	**Adjusted to remove current Loss Factor (total delivered)**	**Retail Load w/ Dist. Loss**	**Dist. Loss**
				A	**C =A-B**	**B**		
30	TRANSMISSION: Sales to ultimate consumers transmission (including interdepartmental sales)			12,592		12,592	12,592	
31	DISTRIBUTION: Sales to ultimate consumers distribution (including interdepartmental sales)			41,968		41,968	44,010	2,042
32	Requirements sales for resale			267		267		
	Adjustments:							
33	Non-requirements sales for resale, 401a line 24		4,982					
	Adjustments to remove financial transactions, duplicate transactions and off-system activity:							
34	Less losses included paid by Black Hills		(11)					
35	Less Pt-to-Pt, network, and OS losses - financially settled	Att. E	(254)					
36	Off system sales/purchases w/o losses	Att. F	(3,243)					
37	Third party sales on-system (reported in Energy Received (duplicate transactions))		(130)					
38	Total on-system non-requirements sales for resale subject to losses			1,343		1,343		
39	Energy used by the company (electric dept only, excluding station use, 401a line 26)			-		-	-	-
	Transmission received/delivered (adjusted 401a lines 16 & 17):							
40	Transmission received - losses ***financially*** settled	Att. A, B		*7,432*	*316*	*7,116*		
41	WAPA adjustments (losses and RS 262 & 263 adj.)	Att. C		*1,777*	*107*	*1,671*		
42	Transmission pt-to-pt Black Hills - losses ***financially*** settled	Att. D		*382*	*17*	*365*		
43	Transmission other - losses ***physically*** settled	Att. C		*295*	*12*	*283*		
44	Transmission received - supplied losses	Att. C		*7,037*	*300*	*6,737*		
45	Total Transmission:			16,923	752	16,172		
46	**Total**			**73,094**	**752**	**72,342**	**44,010**	**2,042**

Attachment A

FF1 2020 328 MWH RECEIVED/DELIVERED
TRANSMISSION MWH FINANCIAL SETTLEMENT of LOSSES

Page	Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	StatisticalClassification(d)	FERC Rate Schedule of Tariff Number (e)	MegaWatt Hours
328	Line 3	Airport Solar LLC	LFP	SA 965	99,052
328	Line 5	Avangrid Renewables, LLC	NF	SA 121	199,751
328	Line 6	Avangrid Renewables, LLC	AD	SA 121	18,003
328	Line 7	Avangrid Renewables, LLC	SFP	SA 122	83,526
328	Line 8	Avangrid Renewables, LLC	AD	SA 122	3,507
328	Line 11	Avangrid Renewables, LLC	LFP	SA 895	69,867
328	Line 12	Avangrid Renewables, LLC	AD	SA 895	6,306
328	Line 17	Basin Electric Power Cooperative, Inc.	NF	SA 607	23,631
328	Line 18	Basin Electric Power Cooperative, Inc.	AD	SA 607	2,587
328	Line 19	Basin Electric Power Cooperative, Inc.	SFP	SA 606	4,523
328.1	Line 20	Bonneville Power Administration	NF	SA 44	240,859
328.1	Line 28	Brookfield Renewable Trading	NF	SA 941	147,967
328.1	Line 29	Brookfield Renewable Trading	AD	SA 941	12,696
328.1	Line 30	Brookfield Renewable Trading	SFP	SA 941	366
328.2	Line 2	Clatskanie People's Utility Dist	LFP	SA 899	72,634
328.2	Line 3	Clatskanie People's Utility Dist	AD	SA 899	8,251
328.2	Line 4	Clatskanie People's Utility Dist	LFP	SA 901	10,853
328.2	Line 5	Clatskanie People's Utility Dist	AD	SA 901	1,233
328.2	Line 7	CP Energy Marketing (US) Inc.	NF	SA 968	386
328.2	Line 11	Deseret Gen and Trans	NF	SA 156	11,360
328.2	Line 12	Deseret Gen and Trans	AD	SA 156	9,739
328.2	Line 13	Eagle Energy Partners I LP	NF	SA 569	2,754
328.2	Line 14	Eagle Energy Partners I LP	AD	SA 569	2,105
328.2	Line 15	Enel Trading North America, LLC	NF	SA 962	5,480
328.2	Line 16	Energy Keepers, Inc.	NF	SA 814	9,988
328.2	Line 17	Energy Keepers, Inc.	SFP	SA 815	13,256
328.2	Line 19	Evergreen Biopower LLC	LFP	SA 874	42,571
328.2	Line 20	Evergreen Biopower LLC	AD	SA 874	4,820
328.2	Line 23	Exelon Generation Company, LLC	NF	SA 759	2,193
328.2	Line 24	Exelon Generation Company, LLC	AD	SA 759	90
328.2	Line 25	Falls Creek H.P.	LFP	SA 868	14,126
328.2	Line 28	Guzman Energy LLC	NF	SA 786	16,107
328.2	Line 29	Guzman Energy LLC	SFP	SA 785	11,946
328.2	Line 30	Idaho Power Company	LFP	SA 212	400
328.2	Line 32	Idaho Power Company	SFP	SA 726	2,807
328.2	Line 33	Idaho Power Company	NF	SA 725	15,713
328.2	Line 34	Garrett Solar LLC	LFP	SA 966	22,713
328.3	Line 1	Garrett Solar LLC	AD	SA 966	300
328.3	Line 2	Macquarie Energy LLC	NF	SA 755	28,123
328.3	Line 3	Macquarie Energy LLC	AD	SA 755	4,104
328.3	Line 4	Macquarie Energy LLC	SFP	SA 754	1,969
328.3	Line 5	MAG Energy Solutions, Inc.	NF	SA 903	3,393
328.3	Line 6	Mercuria Energy America LLC	NF	SA 998	4,739
328.3	Line 9	Morgan Stanley Capital Group, Inc.	NF	SA 157	502,525
328.3	Line 10	Morgan Stanley Capital Group, Inc.	AD	SA 157	6,044
328.3	Line 11	Morgan Stanley Capital Group, Inc.	SFP	SA 160	6,136
328.3	Line 12	Morgan Stanley Capital Group, Inc.	AD	SA 160	72
328.3	Line 15	NextEra Energy Resources, LLC	LFP	SA 733	274,929
328.3	Line 16	NextEra Energy Resources, LLC	AD	SA 733	7,651
328.3	Line 17	NextEra Energy Resources, LLC	NF	SA 236	31
328.3	Line 18	NextEra Energy Resources, LLC	AD	SA 236	17
328.3	Line 19	NextEra Energy Resources, LLC	SFP	SA 237	13
328.3	Line 20	NextEra Energy Resources, LLC	AD	SA 237	58
328.3	Line 23	Pacific Gas & Electric Company	NF	SA 338	793
328.3	Line 26	Portland General Electric Company	SFP	SA 248	432
328.3	Line 27	Portland General Electric Company	AD	SA 248	50
328.3	Line 28	Powerex Corporation	LFP	SA 169	346,233
328.3	Line 29	Powerex Corporation	AD	SA 169	28,141
328.4	Line 6	Powerex Corporation	NF	SA 47	286,663
328.4	Line 7	Powerex Corporation	AD	SA 47	13,245
328.4	Line 8	Powerex Corporation	SFP	SA 151	35,813
328.4	Line 11	Rainbow Energy Marketing Corporation	NF	SA 316	72,287
328.4	Line 12	Rainbow Energy Marketing Corporation	AD	SA 316	117
328.4	Line 14	Sacramento Municipal Utility Dist	LFP	SA 863	122,840
328.4	Line 15	Sacramento Municipal Utility Dist	AD	SA 863	14,003
328.4	Line 16	Salt River Project	LFP	SA 809	124,010
328.4	Line 17	Salt River Project	AD	SA 809	14,892
328.4	Line 18	Salt River Project	NF	SA 557	1,416
328.4	Line 19	Salt River Project	SFP	SA 557	795
328.4	Line 20	Shell Energy North America (US), L.P.	LFP	SA 791	10,298
328.4	Line 21	Shell Energy North America (US), L.P.	AD	SA 791	682
328.4	Line 22	Shell Energy North America (US), L.P.	NF	SA 23	720,420
328.4	Line 23	Shell Energy North America (US), L.P.	AD	SA 23	35,105
328.4	Line 24	Shell Energy North America (US), L.P.	SFP	SA 162	17,892
328.4	Line 25	Shell Energy North America (US), L.P.	AD	SA 162	600
328.4	Line 29	Southern California Edison Company	NF	SA 642	292,116
328.4	Line 30	Southern California Edison Company	AD	SA 642	21,878
328.4	Line 31	Southern California Public Power Authority	NF	SA 629	56
328.4	Line 34	Tenaska Power Services Co.	NF	SA 125	28,615
328.5	Line 1	Tenaska Power Services Co.	AD	SA 125	777
328.5	Line 2	Tenaska Power Services Co.	SFP	SA 126	9
328.5	Line 3	Tenaska Power Services Co.	AD	SA 126	857
328.5	Line 4	The Energy Authority, Inc.	NF	SA 310	4,961
328.5	Line 5	The Energy Authority, Inc.	AD	SA 310	1,041
328.5	Line 6	Thermo No. 1 BE-01, LLC	LFP	SA 568	54,806
328.5	Line 7	Thermo No. 1 BE-01, LLC	AD	SA 568	5,814
328.5	Line 8	TransAlta Energy Marketing (U.S.) Inc.	NF	SA 127	114,719
328.5	Line 9	TransAlta Energy Marketing (U.S.) Inc.	AD	SA 127	5,728
328.5	Line 10	TransAlta Energy Marketing (U.S.) Inc.	SFP	SA 128	7,920
328.5	Line 13	Tri-State Gen and Trans	NF	SA 33	3,290
328.5	Line 23	Utah Municipal Power Agency	NF	SA 20	13,092
328.5	Line 33	Western Area Power Adm CO River	NF	SA 132	294
328.5	Line 34	Western Area Power Adm CO MO	NF	SA 137	5,522
328.6	Line 1	Western Area Power Adm CO MO	SFP	SA 724	700

Total MWh	4,443,192
Accrual Adjustment	6,005
Total point-to-point schedules subject to losses (as reported on FERC Form No. 1, page 329)	4,449,197
REF	5

FF1 2020 328 MWH RECEIVED/DELIVERED
TRANSMISSION MWH FINANCIAL SETTLEMENT of LOSSES - Network customers

Page	Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	StatisticalClassification(d)	FERC Rate Schedule of Tariff Number (e)	MegaWatt Hours
328	Line 1	3 Phase Renewables, LLC	FNO	SA 876	1,522
328	Line 2	3 Phase Renewables, LLC	AD	SA 876	44
328	Line 13	Avangrid Renewables, LLC	FNO	SA 742	264,562
328	Line 14	Avangrid Renewables, LLC	AD	SA 742	23,949
328	Line 15	Basin Electric Power Cooperative, Inc.	FNO	SA 505	64,671
328	Line 16	Basin Electric Power Cooperative, Inc.	AD	SA 505	6,974
328.1	Line 4	Bonneville Power Administration	FNO	SA 229	21,787
328.1	Line 5	Bonneville Power Administration	AD	SA 229	2,353
328.1	Line 6	Bonneville Power Administration	FNO	SA 539	5,230
328.1	Line 7	Bonneville Power Administration	AD	SA 539	781
328.1	Line 8	Bonneville Power Administration	FNO	SA 538	708
328.1	Line 9	Bonneville Power Administration	AD	SA 538	78
328.1	Line 14	Bonneville Power Administration	FNO	SA 328	31,957
328.1	Line 15	Bonneville Power Administration	AD	SA 328	3,473
328.1	Line 16	Bonneville Power Administration	FNO	SA 827	673
328.1	Line 17	Bonneville Power Administration	AD	SA 827	88
328.1	Line 18	Bonneville Power Administration	FNO	SA 746	1,296,983
328.1	Line 19	Bonneville Power Administration	AD	SA 746	166,916
328.1	Line 21	Bonneville Power Administration	FNO	SA 747	635,122
328.1	Line 22	Bonneville Power Administration	AD	SA 747	65,048
328.1	Line 23	Bonneville Power Administration	FNO	SA 735	118,020
328.1	Line 24	Bonneville Power Administration	AD	SA 735	14,654
328.1	Line 25	Bonneville Power Administration	FNO	SA 865	746
328.1	Line 26	Bonneville Power Administration	AD	SA 865	91
328.1	Line 27	Bonneville Power Administration	FNO	SA 975	426
328.1	Line 31	Calpine Energy Solutions, LLC	FNO	SA 299	102,193
328.1	Line 32	Calpine Energy Solutions, LLC	AD	SA 299	9,190
328.2	Line 21	Exelon Generation Company, LLC	FNO	SA 943	7,270
328.2	Line 22	Exelon Generation Company, LLC	AD	SA 943	440
328.3	Line 13	Navajo Tribal Utility Authority	FNO	SA 894	14,383
328.3	Line 14	Navajo Tribal Utility Authority	AD	SA 894	1,627
328.5	Line 11	Tri-State Gen and Trans	FNO	SA 628	117,826
328.5	Line 12	Tri-State Gen and Trans	AD	SA 628	12,548
328.5	Line 14	U.S. Bureau of Reclamation	FNO	SA 506	2,473
328.5	Line 15	U.S. Bureau of Reclamation	AD	SA 506	4
328.5	Line 31	Western Area Power Administration	FNO	SA 175	9,184
328.5	Line 32	Western Area Power Administration	AD	SA 175	5

Total MWh	3,003,999
Accrual Adjustment	(20,915)
Total	2,983,084
REF	6

Western Area Power Administration Total Received/Delivered & Total Received Per FF1 2018 328 and 401a Summary
2020

Amounts in MWh	Western Rec./Del. Reconciliation						REF Loss Factor Clauclation Worksheet
		RS 262	RS 263	Subtotal	Energy Return (Variation)	Net	
	Energy Received	1,731,607	45,805	1,777,412	-	***1,777,412***	
	Losses	(103,894)	(2,718)	(106,612)		(106,612)	9
	Energy Delivered	1,627,713	43,087	1,670,800	-	***1,670,800***	
	Details:						
	Total Received: Reported						
	OS Reported	1,566,627	41,694	1,608,321	-	1,608,321	
	AD Reported	163,190	4,111	167,301	-	167,301	
	Accrual Adjustment (included in total Accrual)	1,790	-	1,790	-	1,790	
	Total Received	1,731,607	45,805	1,777,412	-	1,777,412	
	Total Delivered: Reported						
	OS Reported	1,472,633	39,218	1,511,851		1,511,851	
	AD Reported	153,398	3,866	157,264		157,264	
	Accrual Adjustment (included in total Accrual)	1,682	3	1,685		1,685	
	Total Delivered	1,627,713	43,087	1,670,800		1,670,800	7, 8

Total Received per 328 and 401a-lines 16/17 as reported

	Received per 328	Accrual Received FF1 Pg 328.6	Total Received Per 401a	
Total point-to-point schedules subject to losses - as reported on 328 (financial settlement)	4,443,192	6,005	4,449,197	5
Total network schedules ***financially*** settled - subst of total report on 328	3,003,999	(20,915)	2,983,084	6
Western RS 262 Received reported on page 328	1,729,817	1,790	1,731,607	see above
Western RS 263 Received reported on page 328	45,805	-	45,805	see above
Black Hills (losses paid financially to PacifiCorp Energy)	382,108	(457)	381,651	10
Physical Losses Received (See Attachment D)	299,954	(4,875)	295,079	11
Network/OS/and other rate schedules [1]	7,000,406	36,490	7,036,896	12
Total Received per 401a Line 16	16,905,281	18,038	16,923,319	

2020 328 MWH RECEIVED/DELIVERED
PT-TO-PT MW PHYSICAL SETTLEMENT AND BLACK HILLS

Page	Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Statistical Classification (d)	FERC Rate Schedule of Tariff Number (e)	MegaWatt Hours	Black Hills	Physical	Total
328	Line 23	Black Hills/Colorado Electric Utility Company	NF	SA 563	5.00	5		5
328	Line 25	Black Hills/Colorado Electric Utility Company	SFP	SA 562	260.00	260		260
328	Line 26	Black Hills Corporation	FNO	SA 347	268,629.00	268,629		268,629
328	Line 27	Black Hills Corporation	AD	SA 347	28,183.00	28,183		28,183
328	Line 28	Black Hills Corporation	LFP	SA 67	77,240.00	77,240		77,240
328	Line 29	Black Hills Corporation	AD	SA 67	5,623.00	5,623		5,623
328	Line 30	Black Hills Corporation	NF	SA 768	970.00	970		970
328	Line 31	Black Hills Corporation	AD	SA 768	36.00	36		36
328	Line 32	Black Hills Corporation	SFP	SA 767	265.00	265		265
328	Line 34	Black Hills Power Marketing	NF	SA 43	790.00	790		790
328.1	Line 2	Black Hills Power Marketing	SFP	SA 714	107.00	107		107
328.1	Line 7	Bonneville Power Administration	LFP	SA 656	211,091.00		211,091	211,091
328.1	Line 8	Bonneville Power Administration	AD	SA 656	14,920.00		14,920	14,920
328.1	Line 15	Bonneville Power Administration	LFP	SA 179	53,766.00		53,766	53,766
328.1	Line 16	Bonneville Power Administration	AD	SA 179	4,006.00		4,006	4,006
328.5	Line 25	State of South Dakota	LFP	SA 779	14,513.00		14,513	14,513
328.5	Line 26	State of South Dakota	AD	SA 779	1,658.00		1,658	1,658
				Total	682,062.00	382,108.00	299,954.00	682,062.00
				Accruals	(5,332)	(457)	(4,875)	(5,332)
				Total Black Hills & Physical Received	676,730	381,651	295,079	676,730
				REF		10	11	

2020 FERC FORM 1 PAGES 310 AND 311
SALES FOR RESALE (Account 447)
TRANSMISSION AGREEMENTS FINANCIALLY SETTLED

Page No.		Line No.	Name of Company or Public Authority [Footnote Affiliations] (a)	Statistical Classifi-cations (b)	Footnote for col (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand: Average Monthly NCP Demand (e)	Actual Demand: Average Monthly CP Demand (f)	Megawatthours Sold (g)	
			REF								
			Nonrequirement Sales								
		123	Transmission Loss Sales Revenue	AD	1	T-11	NA	NA	NA	14	
		124	Transmission Loss Sales Revenue	OS	4	T-11	NA	NA	NA	254,093	
			Total Pt-to-Pt, Network, and OS Financially Settled							254,107	35

2020 Off System Sales/Purchases Summary

Amounts in thousands of MWh	MWh	REF
PAC01 Off System Sales (MidC)-purchases	278	
PAC01 Off System Sales (Cholla, Col, Herm, Wyo, YTP etc) - sales	1,449	
Craig generation sales [1]	1,123	
Hayden generation sales [1]	393	
Total third-party off system sales/purchases	**3,243**	**16, 36**

MidC filter

LoadPoint Does Not=CHEHALIS
LCA Does Not=PACW
AssignmentRef=212;213;NOR
ContractMkt Does Not=ALCOA Exchange;No Spill Exch;RR CEA
Path=MIDC/MIDC;MIDC/MIDCRemote
TSSubClass Does Not=FCR_PHYSICAL;SECONDARY
ScheduleType=Energy
TagNotes Does Not=DOPD Settlement
FlowType=Export
LSE Does Not=PAC01

Cholla, Colstrip, Hermiston, Wyodak and YTP filter:

GPE=PAC01 [2]
Scheduletype = Energy
TagNotes does not = Coal Feed; Colstrip Startup
LSE does not = PAC01
LoadPoint does not = NWMTLosses
TSSubClass does not = FCR_PHYSICAL;SECONDARY
Assignment Ref = 201;204;205;207;215;216;217;218;NOR; 230SI;231SI; 235SI; 250SI [3]
FlowType=Export [4]
GeneratorPointDoes Not = PACENNH or PACWNNH [5]

Jim Bridger filter [6]

Path=JBSN/JBSN
ScheduleType=Energy
TagTransOwner=BHPM01
GCA=PACW
LSE Does Not=PAC01
TagNotes Does Not=54234800
AssignmentRef=206;NOR

Notes and adjustments to 2010 query :

[1] Off system sales at Craig and Hyden generation bus are not captured in the E-Tag query due to different tagging conventions. Data obtained from company records.
[2] Replaced "Path=....." with "GPE=PAC01" which has the same effect on the filter except there is no need to add a new path to this list whenever there is a new path to add.
[3] Added 230SI (Juniper Wind), 231SI (Goodnoe Hills), 235SI (Chehalis Gen) and 250SI (Hermiston Gen) to this list.
[4] Added "FlowType=Export" to limit the view to Export tags only as opposed to Export AND an Import which would cancel each other when tags are totaled.
[5] Added "GeneratorPointDoes Not = PACENNH or PACWNNH" to exclude non-generator bus transactions.
[6] No off system sales at Jim Bridger generation bus have been identified in 2014.

Enclosure 4

Loss Factor Methodology Matrix

MATRIX IDENTIFIYING INPUTS TO PACIFICORP'S TRANSMISSION SYSTEM LOSS FACTOR CALCULATION

Item Number[1]	Input	Value (all amounts in thousands of MWh)	Source Material, Calculations, and Assumptions Applied
	RECALCULATED AND ADJUSTED RECEIVED AND DELIVERED ENERGY: SOURCES		
1	**Generation**	61,588	PacifiCorp's 2020 FERC Form No. 1, page 401a, sum of lines 9 (Net Generation) and 10 (Purchases).
2	**Net exchange**	2,286	PacifiCorp's 2020 FERC Form No. 1, page 401a, line 14 (Net Exchanges).
3	**Transmission by Others Losses**	(249)	PacifiCorp's 2020 FERC Form No. 1, page 401a, line 19 (Transmission by Others Losses).
4	**Reconciliation of Transmission received (401a line 16)**	-	PacifiCorp's 2020 FERC Form No. 1, page 401a, line 16 (Energy Received): itemization of the total energy sources received.
5	**Pt-to-Pt transmission received - losses financially settled**	4,449	Attachment A of the Loss Factor Calculation identifies the total Point-to-Point Transmission contracts subject to losses financially, as enumerated on PacifiCorp's 2020 FERC Form No. 1, page 329, including an adjustment for accrual differences.
6	**Network transmission received - losses financially settled**	2,983	Attachment B of the Loss Factor Calculation identifies the total Network Transmission contracts subject to losses financially as enumerated on PacifiCorp's 2020 FERC Form No. 1, page 329, including an adjustment for accrual differences.
7	**WAPA RS 262 delivered**	1,628	Attachment C of the Loss Factor Calculation identifies the losses associated with the MWhs delivered pursuant to PacifiCorp's Rate Schedule 262 with Western Area Power Administration ("WAPA"), as included on PacifiCorp's 2020 FERC Form No. 1, pages 328-329, including accrual adjustments.
8	**WAPA RS 263 delivered**	43	Attachment C of the Loss Factor Calculation identifies the losses associated with the MWhs delivered pursuant to PacifiCorp's Rate Schedule 263 with WAPA, as included on PacifiCorp's 2020 FERC Form No. 1, page 328-329, including accrual adjustments.
9	**WAPA losses Received**	107	Attachment C of the Loss Factor Calculation identifies the difference between energy received and delivered pursuant to

[1] The Item Numbers used in this Appendix are intended to be illustrative only and do not change the Loss Factor Calculation methodology agreed to by the settling parties in Docket No. ER11-3643.

MATRIX IDENTIFIYING INPUTS TO PACIFICORP'S TRANSMISSION SYSTEM LOSS FACTOR CALCULATION

Item Number[1]	Input	Value (all amounts in thousands of MWh)	Source Material, Calculations, and Assumptions Applied
			PacifiCorp's Rate Schedules 262 and 263 with WAPA, as included on PacifiCorp's 2020 FERC Form No. 1, page 328.5 and FERC Form No.1, line 17 (Energy delivered).
10	**Black Hills transmission received - losses financially settled**	382	Attachment D of the Loss Factor Calculation identifies the losses in MWhs sold to Black Hills Power ("Black Hills") under power purchase agreements with PacifiCorp Energy, as included in PacifiCorp's 2020 FERC Form No. 1, page 329, including an adjustment for accrual differences.
11	**Transmission received - losses physically settled, other**	295	Attachment D of the Loss Factor Calculation identifies the losses derived from Point-to-Point Transmission contracts which settle losses physically (i.e. State of South Dakota), as included in PacifiCorp's 2020 FERC Form No. 1, page 329, including accrual adjustments.
12	**Transmission received – supplied losses – network customers**	7,037	Attachment C of the Loss Factor Calculation identifies the adjusted total energy delivered for network and "other service" ("OS") contracts, which are reported in PacifiCorp's 2020 FERC Form No. 1, page 328 , primarily through imbalance (FERC Account 555), including an adjustment for accrual differences.
13	**Total Transmission received**	16,923	Sum of Items 5 through 12.
14	**Gross Received**	80,549	Sum of Items 1-3 and 13.
15	**Less third-party sales on-system (reported in Energy Received (duplicate transactions))**	(130)	This adjustment removes duplicate transactions reflected in both net generation and received/delivered energy (sales for resale by PacifiCorp Energy), which are also accounted for as part of wheeling received and delivered. This amount represents specific transactions between third parties and PacifiCorp Energy. Same value as item 37.
16	**Less off-system sales/purchases without losses**	(3,243)	Attachment F of the Loss Factor Calculation identifies the sales and purchase transactions at generator buses which do not utilize PacifiCorp's transmission system. The data is sourced from PacifiCorp's e-Tag and company records (using the e-Tag query

MATRIX IDENTIFIYING INPUTS TO PACIFICORP'S TRANSMISSION SYSTEM LOSS FACTOR CALCULATION

Item Number[1]	Input	Value (all amounts in thousands of MWh)	Source Material, Calculations, and Assumptions Applied
			and descriptions set forth in PacifiCorp's Loss Analysis Methodology). Same value as item 36.
17	**Net on-system received**	77,174	Item 14 less Items 15-16. This value must be compared to net delivered energy to determine total system losses before losses are allocated between transmission and distribution.
	RECALCULATED AND ADJUSTED RECEIVED AND DELIVERED ENERGY: USES		
18	**Sales to ultimate customers**	54,560	PacifiCorp's 2020 FERC Form No. 1, page 401a, line 22 (Sales to Ultimate Consumers).
19	**Requirement sales for Resale**	267	PacifiCorp's 2020 FERC Form No. 1, page 401a, line 23 (Requirements Sales for Resale).
20	**On system non-requirements sales subject to losses**	1,343	PacifiCorp's 2020 FERC Form No. 1, page 401a, line 24 (Non-Requirements Sales for Resale), adjusted to remove financial transactions, duplicate transactions and off-system activity detailed in items 33-37.
21	**Company sales**		PacifiCorp's 2020 FERC Form No. 1, page 401a, line 26 (Energy Used by the Company).
22	**Transmission delivered without losses**	16,172	This amount is the total contractual amounts of energy received by PacifiCorp (item 13) adjusted to remove the volumes subject to losses by multiplying the total energy received by current transmission loss factor (4.45%). See also the description and value from item 45 column titled "Adjusted to remove current Loss Factor".
23	**Total delivered with on-system losses**	72,342	Sum of Items 18 through 22. Total sales to customers adjusted for sales subject to losses.
24	**Total system delivered loss rate including off-system**	6.7%	Item 25 / Item 23 (illustrative only). Loss rate includes both transmission and distribution losses.
25	**Total Losses**	4,834	Item 17 less item 23.
26	**Distribution losses**	2,042	Applies 4.64% distribution loss factor (from PacifiCorp's 2007 Distribution Loss Study) to total distribution losses (see item 46 column titled "Dist. Loss".

MATRIX IDENTIFIYING INPUTS TO PACIFICORP'S TRANSMISSION SYSTEM LOSS FACTOR CALCULATION

Item Number[1]	Input	Value (all amounts in thousands of MWh)	Source Material, Calculations, and Assumptions Applied
27	**Remaining losses = transmission losses**	2,792	Item 25 less Item 26.
28	**Transmission deliveries = total deliveries + distribution loss**	74,384	Sum of Items 23 and 26.
29	**Transmission loss rate @ delivery**	**3.75%**	Resulting transmission loss factor is derived from dividing Item 27 by Item 28.
	TRANSMISSION AND DISTRIBUTION LOSSES ADJUSTMENTS AND ALLOCATION		
30	**Transmission: Sales to ultimate consumers – transmission (including interdepartmental sales)**	12,592	Items 30 & 31 represent a split of total retail sales as stated on PacifiCorp's 2020 FERC Form No. 1, page 401a, line 22 (Sales to Ultimate Consumers) into the volumes delivered to the customers through transmission and distribution lines. The transmission/distribution split is determined based on 1) rate schedules with specific voltage types, such as residential and transmission service rate schedules, and 2) delivery voltage codes by customer in the company's billing system for rate schedules for which multiple voltage levels are applicable. The distribution volumes are then adjusted for losses which are determined by multiplying the retail distribution by the distribution loss factor (4.64%).
31	**Distribution: Sales to ultimate consumers – distribution (including interdepartmental sales)**	41,968	
32	**Requirements sales for resale**	267	PacifiCorp's 2020 FERC Form No. 1, page 401a, line 23 (Requirements Sales for Resale).
33	**Non-requirements sales for resale**	4,982	PacifiCorp's 2020 FERC Form No. 1, page 401a, line 24 (Non-Requirements Sales for Resale).
Adjustments to remove financial transactions, duplicate transactions, and off-system activity (items 34-37)			
34	**Less losses included paid by Black Hills**	(11)	Attachment E of Loss Calculation identifies energy, including losses, sold to Black Hills under a long-term firm contract and included in PacifiCorp's 2020 FERC Form No. 1, page 401a, line 24 (Non-Requirements Sales for Resale), as stated in Account 447 details (FERC Form No. 1, page 311.1). This adjustment is derived from the FERC Form No. 1 data by applying the current transmission loss factor (4.45%).

MATRIX IDENTIFIYING INPUTS TO PACIFICORP'S TRANSMISSION SYSTEM LOSS FACTOR CALCULATION

Item Number[1]	Input	Value (all amounts in thousands of MWh)	Source Material, Calculations, and Assumptions Applied
35	**Less Pt-to-Pt and network losses - financially settled**	(254)	Adjustment for Point-to-Point Transmission, Network, and other services for which the losses are settled financially in order to remove double counting of losses from the generation activity. Attachment E of Loss Calculation identifies these contracts as stated in FERC Form No.1, details for Account 447 (pages 311.1-311.11).
36	**Off-system sales/purchases without losses**	(3,243)	Same value and description as item 16.
37	**Third party sales on-system (reported in energy received (duplicated transactions)**	(130)	Same value and description as item 15.
38	**Total on-system non-requirements sales for resale subject to losses**	1,343	Same value and description as item 20.
39	**Energy used by the company (electric department only, excluding station use)**		PacifiCorp's 2020 FERC Form No. 1, page 401a, line 26 (Energy Used by the Company).
Transmission received/delivered (adjusted 401a, lines 16&17 (items 40-45)			
40	**Transmission received - losses financially settled**	7,432	Attachments A and B of the Loss Factor Calculation identify total Point-to-Point Transmission, Network, and Other services subject to losses settled financially, as enumerated on PacifiCorp's 2020 FERC Form No. 1, page 329 and adjusted for current transmission loss factor.
41	**WAPA RS 262 & 263**	1,777	Sum of items 7-9 and adjusted value for current transmission loss factor.
42	**Point-to-Point Transmission to Black Hills**	382	Same value and description as item 10 and adjusted value for current transmission loss factor.
43	**Transmission other – losses physically settled**	295	Same value and description as item 11 and adjusted value for current transmission loss factor.
44	**Transmission recieved - supplied losses**	7,037	Same value and description as item 12 and adjusted value for current transmission loss factor.
45	**Total Transmission**	16,923	Sum of Items 40 through 44 and adjusted value for current transmission loss factor.

MATRIX IDENTIFIYING INPUTS TO PACIFICORP'S TRANSMISSION SYSTEM LOSS FACTOR CALCULATION

Item Number[1]	Input	Value (all amounts in thousands of MWh)	Source Material, Calculations, and Assumptions Applied
46	**Total**	73,094	Sum of items 30-32 plus sum of items 38-39 plus item 45 and adjusted for current transmission and distribution loss factor.

Enclosure 5

E-Tag Adjustments

E-Tag Filter Adjustments:

PacifiCorp performed a similar E-Tag query rule to the one that was established in the Docket No. ER11-3643 Settlement Agreement. The Docket No. ER11-3643 “2010 E-Tag query” consisted of the following parameters:

- Path=CHOLLA500/CHOLLA500;Colstrip/Colstrip;HERMISTONGEN/HERMIS
- TONGEN;JEFF/JEFF;UINTA/UINTA;WYODAK/WYODAK;YTP
- Scheduletype = Energy
- TagTransOwner = PAC01
- TagNotes does not = Coal Feed; Colstrip Startup
- LSE does not = PAC01
- LoadPoint does not = NWMTLosses
- TSSubClass does not = FCR_PHYSICAL;SECONDARY
- Assignment Ref = 201;204;205;207;215;216;217;218;NOR

PacifiCorp made minor adjustments to the 2010 E-Tag query to remove transactions which occurred at a generator bus that did not utilize PacifiCorp’s transmission. The E-Tag adjustments are listed in Appendix F and are explained in more detail below.

1. Off system sales at Craig and Hyden generation bus are not captured in the E-Tag query because these resources are not located in our control area. Thus, any generator bus sale for these resources will not use any PacifiCorp transmission and we will not have these transactions in our E-Tagging system.
2. Replaced the path name with “GPE=PAC01”. This parameter identifies all PacifiCorp managed generation that was used for off system sales. PacifiCorp uses this parameter to tag resources when they are used for off system sales.
3. Added Juniper Hills, Goodnoe Hills, Chehalis, and Hermiston to the assignment ref parameter. The addition of the generator reservation is necessary when using GPE=PAC01 instead of the specific path parameter. Juniper Hills, Goodnoe Hills, Chehalis, and Hermiston resources could be used for off system sales. When a resource is used for off system sales the resource will be undesignated and will not use PacifiCorp transmission.
4. Added a flow type parameter of export because the PacifiCorp E-Tagging system would cancel tags out if an export and import parameter were used. This allows PacifiCorp to include exports only when determining transactions that occurred to support off system sales.
5. Added “GeneratorPointDoes Not = PACENNH or PACWNNH” to exclude any transactions at a non-generator bus. This parameter is necessary when using a non-path specific parameter.
6. A path specific filter was used for Jim Bridger.