PACIFICORP

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April 17, 2015

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. ER15-___-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, 2015, to coincide with the effective date of PacifiCorp's 2015 rate year and consistent with the Settlement Agreement governing PacifiCorp's transmission formula rate, as described further below.

I. Background and Reason for Filing

On May 26, 2011, as amended on a limited basis on June 9, 2011, PacifiCorp filed revised tariff sheets with the Commission to adopt and implement a cost-of-service formula rate for Network Integration Transmission Service ("NIT Service"), Point-to-Point Transmission Service, and Ancillary Service Schedule 1 (Scheduling, System Control and Dispatch Service) under its OATT. In an order issued August 8, 2011, the Commission accepted for filing and suspended the proposed tariff sheets for a five-month period to become effective December 25, 2011, subject to refund and the outcome of hearing and settlement judge procedures.[4]

On February 22, 2013, PacifiCorp, on behalf of itself and the other parties, filed a settlement agreement resolving all issues in the above-referenced proceeding (the

[1] 16 U.S.C. § 824(d) (2006).
[2] 18 C.F.R. Part 35 (2014).
[3] *Electronic Tariff Filings*, Order No. 714, 124 FERC ¶ 61,270 (2008).
[4] *PacifiCorp*, 136 FERC ¶ 61,092 (2011), *reh'g denied*, 137 FERC ¶ 61,147 (2011).

"Settlement Agreement"). PacifiCorp appended clean and redlined revised OATT tariff sheets to the Settlement Agreement, with the parties' understanding that the settlement rates would be made effective as of December 25, 2011.

PacifiCorp implemented settlement rates on a staggered schedule as approved by the Commission on February 28, 2013. The rates for OATT Schedules 3, 3A, 5, 6, and 10 were placed into effect on March 1, 2013. The rates for OATT Schedule 2 were placed into effect on May 1, 2013. The rates for OATT Schedules 1, 7, and 8 and for NIT Service were placed into effect June 1, 2013, consistent with the rate year commencing with PacifiCorp's 2013 annual update. On May 23, 2013, the Commission approved the Settlement Agreement, finding the settlement to be fair and reasonable and in the public interest.[5]

The Settlement Agreement reflected an amended OATT Schedule 10 that included an updated Transmission System loss factor of 4.26%.[6] Further, 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, once the segments have been in commercial operation for at least one full calendar year[7]. Such calculation must be consistent with the spreadsheet calculation identified in Appendix 16 to the Settlement Agreement (the "Loss Factor Calculation") and be based on PacifiCorp's most recent FERC Form No. 1 data for the prior calendar year. Further, PacifiCorp included a Loss Analysis Methodology as Appendix 17 of the Settlement Agreement to be employed prospectively in calculating adjustments to its Transmission System loss factor.

Section 3.6.9 of the Settlement Agreement further provided 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), 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.

PacifiCorp completed and placed in-service the Populus to Terminal segment of the Energy Gateway Project in November 2010. Subsequently, PacifiCorp placed in-service the Mona to Oquirrh segment of the Energy Gateway Project in May 2013. As such, PacifiCorp has prepared this filing to update its Transmission System loss factor

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[5] PacifiCorp, 143 FERC ¶ 61,162 at P 4 (2013).

[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%. PacifiCorp did not propose any change to its loss factor for use of its Distribution System of 3.56%, and is not proposing any such update with this filing.

[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.

following the full calendar year of commercial operation for the Mona to Oquirrh segment (*i.e.*, 2014).

PacifiCorp acknowledges that is it making this filing after April 1 of the calendar year. In preparing this filing, PacifiCorp recognized the critical link between its Loss Factor Calculation and the underlying data in its 2014 FERC Form No. 1, required to be filed before April 18, 2015. As a result, 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 no later than concurrent with the filing of its 2014 FERC Form No. 1. PacifiCorp received no opposition provided that PacifiCorp afforded a typical time frame for stakeholders to review the filing and an effective date of June 1, 2015.

II. Summary of Proposed Changes and Loss Factor Methodology

This filing contains a proposed amendment to Schedule 10 of PacifiCorp's OATT to reflect a Transmission System loss factor of 4.45%, an increase from the current Transmission System loss factor of 4.26%. In addition, Schedule 10 of PacifiCorp's OATT includes an amendment to reflect the resulting combination loss factor which is the result of adding the updated Transmission System loss factor of 4.45% and the existing distribution loss factor of 3.56% for uses of PacifiCorp's Transmission and Distribution Systems, of 8.01%. 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 increase in the Transmission System loss factor based on 2014 FERC Form No. 1 data over 2013 FERC Form No. 1 data used for the loss factor established under the Settlement Agreement include an increase in total energy losses from 4.3m megawatt hours in 2010 to 4.6m megawatt hours in 2014, an increase in the proportion of transmission sales to ultimate customers from 12.8m megawatt hours in 2010 to 14.1m megawatt hours in 2014 relative to an increase in distribution sales to ultimate customers, and an increase in off-system sales and purchases from 5.0m megawatt hours in 2010 to 5.6m megawatt hours in 2014. Each of these factors contributed to an increase in the Transmission System loss factor and, in particular, given a relatively small increase in total system resources of 69m megawatt hours in 2010 to approximately 70m megawatt hours in 2014.

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. While PacifiCorp made certain adjustments and assumptions to reflect its Transmission System uses since the execution of the Settlement Agreement, such adjustments and assumptions do not materially alter the methodology agreed upon by the settling parties. 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 2014 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 2014 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 2014 FERC Form No 1 data for modeling of the 2014 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 "2014 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 line 24, "Non-requirements Sales for Resale".

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 4.45% had been in effect in 2014 instead of the current Transmission System loss factor of 4.26%.

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 2014. The estimated impact on revenue for 2014 resulting from the update is an increase of approximately $202,334 or around 0.06% of total annual revenue for the 12-month period ending December 31, 2014.

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

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, 2015. FERC 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.[8]

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.[9] Good cause exists in this case because the Settlement Agreement required the updated loss factor to be based on PacifiCorp's 2014 FERC Form No. 1, which is being filed on the same date as this filing. Similarly, the Settlement Agreement required a June 1 effective date, 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, 2015.

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.[10] PacifiCorp respectfully requests waiver of any requirements of the Commission's rules and regulations, as well as any

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[8] 18 C.F.R. § 35.11.

[9] *See Central Hudson Gas & Elec. Corp.*, 60 FERC ¶ 61,106 at 61,338 (1992).

[10] *See, e.g., Westar Energy, Inc.*, 131 FERC ¶ 61,183 at P 21 (2010).

authorizations as may be necessary or required, to permit the revised rates 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:

Patrick Cannon	Rick Vail
Senior Counsel	Vice President, Transmission
PacifiCorp	PacifiCorp
825 NE Multnomah St., Suite 1800	825 NE Multnomah St., Suite 1600
Portland, OR 97232	Portland, OR 97232
Phone: (503) 813-5613	Phone: (503) 813-6938
patrick.cannon@pacificorp.com	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 Filing."[11] 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 filing, effective June 1, 2015 as requested. If you have any questions, or if I can be of further assistance, please do not hesitate to contact me.

Respectfully Submitted,

/s/ Patrick Cannon
Patrick Cannon

Attorney for PacifiCorp

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

CERTIFICATE OF SERVICE

I hereby certify that I have on this day caused a copy of the foregoing document to be served via e-mail or first-class mail upon each of the parties listed in the service section of this transmittal letter.

Dated at Portland, Oregon, this 17th day of April, 2015.

/s/ Patrick Cannon

Patrick Cannon
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Enclosure 1

Statements BG and BH

PACIFICORP
ANNUAL COMPARISON
OATT PARTS II & III SERVICE AND LEGACY AGREEMENTS
2014

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	$ 74,872,592	$ 75,006,235	$ 133,643	0.18%
2	Black Hills: SA 67	1,398,956	1,401,453	2,497	0.18%
3	BPA GS: SA 179	503,624	504,523	899	0.18%
4	BPA - Lost Creek SA 656	1,566,830	1,569,627	2,797	0.18%
5	Idaho Power: SA 212	897,146	898,747	1,601	0.18%
6	Iberdrola: SA 279	839,373	840,872	1,498	0.18%
7	Thermo No. 1 (Cyrq Energy): SA 568	307,770	308,320	549	0.18%
8	Powerex: SA 169	2,238,329	2,242,325	3,995	0.18%
9	NextEra: SA 733	2,542,655	2,547,194	4,538	0.18%
10	State of South Dakota: SA 170	83,208	83,356	149	0.18%
11	Sacramento MUD: SA 751	839,373	840,872	1,498	0.18%
12	Enel Cove Fort LLC: SA 706	699,478	700,726	1,249	0.18%
13	Powerex: SA 700	1,798,006	1,798,006	-	0.00%
14	Powerex: SA 701	1,798,006	1,798,006	-	0.00%
15	Powerex: SA 702	1,771,170	1,771,170	-	0.00%
16	Powerex: SA 748	1,341,795	1,341,795	-	0.00%
17	Powerex: SA 749	4,025,386	4,025,386	-	0.00%
18	**Subtotal** (Part II Long-Term Firm Point-to-Point Transmission Service)	$ 97,523,698	$ 97,678,612	$ 154,914	0.16%
	OATT Part III - Network Service				
19	PacifiCorp: SA 66	$ 229,267,920	$ 229,267,920	$ -	0.00%
20	BPA Yakama: SA 328	162,126	162,415	289	0.18%
21	BPA Gazely: SA 229	84,343	84,493	151	0.18%
22	BPA Clark: SA 370	509,456	510,366	909	0.18%
23	BPA Benton/Rimrock: SA 539	21,594	21,633	39	0.18%
24	BPA Ore Wind/Echo: SA 538	4,533	4,541	8	0.18%
25	Tri State: SA 628	220,306	220,699	393	0.18%
26	Noble Americas: SA 299	548,013	548,992	978	0.18%
27	Basin: SA 505	10,307	10,325	18	0.18%
28	Black Hills: SA 347	1,238,336	1,238,336	-	0.00%
29	USBR (Burbank): SA 506	7,630	7,644	14	0.18%
30	WAPA: SA 175	33,680	33,740	60	0.18%
31	Iberdrola: SA 742	106,327	106,517	190	0.18%
32	**Subtotal** (Part III - Network Service)	$ 232,214,571	$ 232,217,620	$ 3,049	0.00%
	Legacy Agreements				
33	UAMPS: RS 297	$ 11,407,549	$ 11,427,911	$ 20,362	0.18%
34	UMPA: RS 637	3,027,736	3,033,140	5,404	0.18%
35	DGT: RS 280	2,242,580	2,246,583	4,003	0.18%
36	WAPA OIS: RS 262/RS263	8,180,557	8,195,159	14,602	0.18%
37	**Subtotal** (Legacy Agreements)	$ 24,858,422	$ 24,902,792	$ 44,371	0.18%
	Total	$ 354,596,691	$ 354,799,025	$ 202,334	0.06%

PACIFICORP
STATEMENT BG — REVENUE DATA TO REFLECT CHANGED RATES
OATT PARTS II & III SERVICE AND LEGACY AGREEMENTS
2014

Proposed 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													
1	PacifiCorp: multiple SAs	$ 6,249,604	$ 6,249,604	$ 6,249,604	$ 6,249,604	$ 6,249,604	$ 6,883,207	$ 6,820,894	$ 6,101,896	$ 6,101,896	$ 6,101,896	$ 5,874,213	$ 5,874,213	$ 75,006,235
2	Black Hills: SA 67	112,524	112,524	112,524	112,524	112,524	119,833	119,833	119,833	119,833	119,833	119,833	119,833	1,401,453
3	BPA GS: SA 179	40,509	40,509	40,509	40,509	40,509	43,140	43,140	43,140	43,140	43,140	43,140	43,140	504,523
4	BPA - Lost Creek SA 656	126,027	126,027	126,027	126,027	126,027	134,213	134,213	134,213	134,213	134,213	134,213	134,213	1,569,627
5	Idaho Power: SA 212	-	-	-	-	-	179,749	179,749	179,749	179,749	179,749	-	-	898,747
6	Iberdrola: SA 279	67,515	67,515	67,515	67,515	67,515	71,900	71,900	71,900	71,900	71,900	71,900	71,900	840,872
7	Thermo No. 1 (Cyrq Energy): SA 568	24,755	24,755	24,755	24,755	24,755	26,363	26,363	26,363	26,363	26,363	26,363	26,363	308,320
8	Powerex: SA 169	180,039	180,039	180,039	180,039	180,039	191,733	191,733	191,733	191,733	191,733	191,733	191,733	2,242,325
9	NextEra: SA 733	222,798	222,798	222,798	222,798	222,798	191,733	191,733	191,733	191,733	191,733	237,269	237,269	2,547,194
10	State of South Dakota: SA 170	9,002	9,002	9,002	9,002	9,002	-	-	-	9,587	9,587	9,587	9,587	83,356
11	Sacramento MUD: SA 751	67,515	67,515	67,515	67,515	67,515	71,900	71,900	71,900	71,900	71,900	71,900	71,900	840,872
12	Enel Cove Fort LLC: SA 706	56,262	56,262	56,262	56,262	56,262	59,916	59,916	59,916	59,916	59,916	59,916	59,916	700,726
13	Powerex: SA 700 [1]	144,364	144,364	144,364	144,364	144,364	153,741	153,741	153,741	153,741	153,741	153,741	153,741	1,798,006
14	Powerex: SA 701 [1]	144,364	144,364	144,364	144,364	144,364	153,741	153,741	153,741	153,741	153,741	153,741	153,741	1,798,006
15	Powerex: SA 702 [1]	142,209	142,209	142,209	142,209	142,209	151,446	151,446	151,446	151,446	151,446	151,446	151,446	1,771,170
16	Powerex: SA 748 [1]	107,734	107,734	107,734	107,734	107,734	114,732	114,732	114,732	114,732	114,732	114,732	114,732	1,341,795
17	Powerex: SA 749 [1]	323,203	323,203	323,203	323,203	323,203	344,196	344,196	344,196	344,196	344,196	344,196	344,196	4,025,386
18	**Subtotal** (Part II Long-Term Firm Point-to-Point Transmission Service)	$ 8,018,426	$ 8,018,426	$ 8,018,426	$ 8,018,426	$ 8,018,426	$ 8,891,543	$ 8,829,229	$ 8,110,231	$ 8,119,818	$ 8,119,818	$ 7,757,922	$ 7,757,922	$ 97,678,612
	OATT Part III - Network Service													
19	PacifiCorp: SA 66 [1]	$ 18,216,930	$ 18,771,909	$ 16,462,409	$ 15,903,345	$ 17,663,484	$ 20,443,784	$ 23,665,788	$ 22,109,165	$ 20,004,275	$ 16,625,632	$ 19,047,730	$ 20,353,469	$ 229,267,920
20	BPA Yakama: SA 328	13,717	15,906	14,741	13,123	12,171	12,065	14,696	13,369	13,203	12,623	15,233	11,569	162,415
21	BPA Gazely: SA 229	7,194	7,035	6,754	6,845	5,634	7,108	7,266	8,508	6,616	7,000	6,756	7,779	84,493
22	BPA Clark: SA 370	53,819	81,463	47,395	40,747	22,641	24,215	28,212	35,734	22,822	24,881	60,208	68,229	510,366
23	BPA Benton/Rimrock: SA 539	2,672	3,687	2,387	2,187	863	740	931	777	354	662	2,807	3,565	21,633
24	BPA Ore Wind/Echo: SA 538	619	900	-	56	-	60	60	200	676	876	1,094	-	4,541
25	Tri State: SA 628	158	35,745	30,157	1,237	164	1,929	1,287	120	414	27,173	48,480	73,835	220,699
26	Noble Americas: SA 299	38,877	41,968	41,778	40,665	42,249	50,161	53,979	55,209	48,377	49,804	41,589	44,336	548,992
27	Basin: SA 505	488	522	1,746	1,686	451	336	699	531	1,841	653	648	724	10,325
28	Black Hills: SA 347 [1]	111,828	102,068	90,044	82,632	80,650	115,742	118,656	122,557	106,632	82,630	106,838	118,059	1,238,336
29	USBR (Burbank): SA 506	9	11	11	619	1,185	1,421	1,428	1,437	828	676	9	11	7,644
30	WAPA: SA 175	5	-	-	9	6,435	6,551	7,673	6,687	3,797	2,570	7	5	33,740
31	Iberdrola: SA 742	6,851	7,969	6,106	5,884	7,374	8,170	9,121	9,834	10,390	10,708	11,737	12,372	106,517
32	**Subtotal** (Part III - Network Service)	$ 18,453,168	$ 19,069,184	$ 16,703,529	$ 16,099,034	$ 17,843,300	$ 20,672,278	$ 23,909,797	$ 22,364,126	$ 20,220,225	$ 16,845,888	$ 19,343,138	$ 20,693,953	$ 232,217,620
	Legacy Agreements													
33	UAMPS: RS 297	$ 764,466	$ 759,651	$ 629,577	$ 543,454	$ 954,888	$ 1,212,444	$ 1,447,770	$ 1,348,681	$ 1,210,695	$ 881,470	$ 755,226	$ 919,588	$ 11,427,911
34	UMPA: RS 637	198,969	181,515	159,686	112,896	255,193	329,921	442,490	376,698	332,829	224,936	220,678	197,328	$ 3,033,140
35	DGT: RS 280	152,965	169,946	196,204	153,217	156,358	254,474	212,067	205,222	220,775	181,310	164,371	179,674	$ 2,246,583
36	WAPA OIS: RS 262/RS263	707,999	712,316	615,182	645,402	643,243	632,152	708,010	691,919	772,375	558,592	721,802	786,167	$ 8,195,159
37	**Subtotal** (Legacy Agreements)	$ 1,824,399	$ 1,823,428	$ 1,600,650	$ 1,454,968	$ 2,009,681	$ 2,428,992	$ 2,810,338	$ 2,622,520	$ 2,536,673	$ 1,846,309	$ 1,862,078	$ 2,082,756	$ 24,902,792
	Change													
38	Updated revenues with proposed loss factor	$ 28,295,993	$ 28,911,038	$ 26,322,605	$ 25,572,428	$ 27,871,407	$ 31,992,812	$ 35,549,364	$ 33,096,877	$ 30,876,716	$ 26,812,015	$ 28,963,139	$ 30,534,632	$ 354,799,025
39	Revenues with current loss factor (From Statement BH)	28,279,769	28,894,689	26,306,732	25,556,883	27,854,898	31,974,076	35,530,037	33,079,153	30,859,169	26,795,648	28,947,298	30,518,337	354,596,691
40	Absolute Difference (*proposed* minus *current*)	$ 16,224	$ 16,348	$ 15,872	$ 15,545	$ 16,509	$ 18,736	$ 19,327	$ 17,724	$ 17,547	$ 16,367	$ 15,841	$ 16,295	$ 202,334
41	Percent Difference	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.05%	0.05%	0.06%	0.06%	0.05%	0.05%	0.06%

Note [1] Per customers' contract agreements, no losses 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 BH — REVENUE DATA TO REFLECT PRESENT RATES
OATT PARTS II & III SERVICE AND LEGACY AGREEMENTS
2014

Current Transmission Loss System Factor **4.26%**

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													
1	PacifiCorp: multiple SAs	$ 6,238,469	$ 6,238,469	$ 6,238,469	$ 6,238,469	$ 6,238,469	$ 6,870,943	$ 6,808,741	$ 6,091,024	$ 6,091,024	$ 6,091,024	$ 5,863,747	$ 5,863,747	$ 74,872,592
2	Black Hills: SA 67	112,324	112,324	112,324	112,324	112,324	119,619	119,619	119,619	119,619	119,619	119,619	119,619	1,398,956
3	BPA GS: SA 179	40,437	40,437	40,437	40,437	40,437	43,063	43,063	43,063	43,063	43,063	43,063	43,063	503,624
4	BPA - Lost Creek SA 656	125,803	125,803	125,803	125,803	125,803	133,974	133,974	133,974	133,974	133,974	133,974	133,974	1,566,830
5	Idaho Power: SA 212	-	-	-	-	-	179,429	179,429	179,429	179,429	179,429	-	-	897,146
6	Iberdrola: SA 279	67,394	67,394	67,394	67,394	67,394	71,772	71,772	71,772	71,772	71,772	71,772	71,772	839,373
7	Thermo No. 1 (Cyrq Energy): SA 568	24,711	24,711	24,711	24,711	24,711	26,316	26,316	26,316	26,316	26,316	26,316	26,316	307,770
8	Powerex: SA 169	179,718	179,718	179,718	179,718	179,718	191,391	191,391	191,391	191,391	191,391	191,391	191,391	2,238,329
9	NextEra: SA 733	222,401	222,401	222,401	222,401	222,401	191,391	191,391	191,391	191,391	191,391	236,847	236,847	2,542,655
10	State of South Dakota: SA 170	8,986	8,986	8,986	8,986	8,986	-	-	-	9,570	9,570	9,570	9,570	83,208
11	Sacramento MUD: SA 751	67,394	67,394	67,394	67,394	67,394	71,772	71,772	71,772	71,772	71,772	71,772	71,772	839,373
12	Enel Cove Fort LLC: SA 706	56,162	56,162	56,162	56,162	56,162	59,810	59,810	59,810	59,810	59,810	59,810	59,810	699,478
13	Powerex: SA 700 [1]	144,364	144,364	144,364	144,364	144,364	153,741	153,741	153,741	153,741	153,741	153,741	153,741	1,798,006
14	Powerex: SA 701 [1]	144,364	144,364	144,364	144,364	144,364	153,741	153,741	153,741	153,741	153,741	153,741	153,741	1,798,006
15	Powerex: SA 702 [1]	142,209	142,209	142,209	142,209	142,209	151,446	151,446	151,446	151,446	151,446	151,446	151,446	1,771,170
16	Powerex: SA 748 [1]	107,734	107,734	107,734	107,734	107,734	114,732	114,732	114,732	114,732	114,732	114,732	114,732	1,341,795
17	Powerex: SA 749 [1]	323,203	323,203	323,203	323,203	323,203	344,196	344,196	344,196	344,196	344,196	344,196	344,196	4,025,386
18	**Subtotal** (Part II Long-Term Firm Point-to-Point Transmission Service)	$ 8,005,674	$ 8,005,674	$ 8,005,674	$ 8,005,674	$ 8,005,674	$ 8,877,335	$ 8,815,133	$ 8,097,416	$ 8,106,986	$ 8,106,986	$ 7,745,735	$ 7,745,735	$ 97,523,698
	OATT Part III - Network Service													
19	PacifiCorp: SA 66 [1]	$ 18,216,930	$ 18,771,909	$ 16,462,409	$ 15,903,345	$ 17,663,484	$ 20,443,784	$ 23,665,788	$ 22,109,165	$ 20,004,275	$ 16,625,632	$ 19,047,730	$ 20,353,469	$ 229,267,920
20	BPA Yakama: SA 328	13,692	15,878	14,714	13,099	12,149	12,043	14,670	13,345	13,180	12,601	15,206	11,548	162,126
21	BPA Gazely: SA 229	7,182	7,022	6,742	6,833	5,624	7,095	7,253	8,492	6,604	6,987	6,744	7,765	84,343
22	BPA Clark: SA 370	53,723	81,318	47,310	40,674	22,601	24,172	28,162	35,670	22,781	24,837	60,101	68,107	509,456
23	BPA Benton/Rimrock: SA 539	2,668	3,680	2,383	2,183	862	739	929	776	353	661	2,802	3,559	21,594
24	BPA Ore Wind/Echo: SA 538	618	899	-	56	-	60	60	200	675	874	1,092	-	4,533
25	Tri State: SA 628	157	35,682	30,103	1,235	164	1,925	1,285	119	413	27,125	48,394	73,704	220,306
26	Noble Americas: SA 299	38,808	41,894	41,704	40,592	42,174	50,071	53,883	55,110	48,291	49,716	41,515	44,257	548,013
27	Basin: SA 505	487	521	1,743	1,683	450	335	698	530	1,838	652	647	723	10,307
28	Black Hills: SA 347 [1]	111,828	102,068	90,044	82,632	80,650	115,742	118,656	122,557	106,632	82,630	106,838	118,059	1,238,336
29	USBR (Burbank): SA 506	9	11	11	618	1,183	1,418	1,425	1,434	826	675	9	11	7,630
30	WAPA: SA 175	5	-	-	9	6,424	6,539	7,660	6,675	3,790	2,566	7	5	33,680
31	Iberdrola: SA 742	6,839	7,955	6,096	5,874	7,360	8,155	9,105	9,816	10,372	10,688	11,716	12,350	106,327
32	**Subtotal** (Part III - Network Service)	$ 18,452,946	$ 19,068,836	$ 16,703,260	$ 16,098,833	$ 17,843,123	$ 20,672,077	$ 23,909,573	$ 22,363,890	$ 20,220,030	$ 16,845,643	$ 19,342,802	$ 20,693,557	$ 232,214,571
	Legacy Agreements													
33	UAMPS: RS 297	$ 763,104	$ 758,297	$ 628,456	$ 542,486	$ 953,187	$ 1,210,284	$ 1,445,191	$ 1,346,278	$ 1,208,538	$ 879,900	$ 753,880	$ 917,949	$ 11,407,549
34	UMPA: RS 637	198,615	181,192	159,402	112,694	254,738	329,333	441,702	376,027	332,236	224,535	220,285	196,976	$ 3,027,736
35	DGT: RS 280	152,692	169,643	195,855	152,944	156,079	254,021	211,690	204,856	220,382	180,987	164,078	179,353	$ 2,242,580
36	WAPA OIS: RS 262/RS263	706,738	711,047	614,086	644,252	642,097	631,025	706,749	690,686	770,998	557,597	720,516	784,766	$ 8,180,557
37	**Subtotal** (Legacy Agreements)	$ 1,821,149	$ 1,820,179	$ 1,597,798	$ 1,452,376	$ 2,006,101	$ 2,424,664	$ 2,805,330	$ 2,617,847	$ 2,532,154	$ 1,843,019	$ 1,858,760	$ 2,079,045	$ 24,858,422
	Change													
38	Updated revenues with proposed loss factor (From Statement BG)	$ 28,295,993	$ 28,911,038	$ 26,322,605	$ 25,572,428	$ 27,871,407	$ 31,992,812	$ 35,549,364	$ 33,096,877	$ 30,876,716	$ 26,812,015	$ 28,963,139	$ 30,534,632	$ 354,799,025
39	Revenues with current loss factor	28,279,769	28,894,689	26,306,732	25,556,883	27,854,898	31,974,076	35,530,037	33,079,153	30,859,169	26,795,648	28,947,298	30,518,337	354,596,691
40	Absolute Difference (*proposed* minus *current*)	$ 16,224	$ 16,348	$ 15,872	$ 15,545	$ 16,509	$ 18,736	$ 19,327	$ 17,724	$ 17,547	$ 16,367	$ 15,841	$ 16,295	$ 202,334
41	Percent Difference	0.06%	0.06%	0.06%	0.06%	0.06%	0.06%	0.05%	0.05%	0.06%	0.06%	0.05%	0.05%	0.06%

Note [1] Per customers' contract agreements, no losses 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	4.45%
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%

<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	~~4.26~~4.45%
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	~~7.82~~8.01%

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 2014 FERC Form No.1, Page 401a

SOURCES		USES	
Net Generation, Ln 9	60,205	Sales to Ultimate Consumers, Ln 22	54,999
Purchases, Ln 10	9,846	Requirements Sales for Resale, Ln 23	225
	70,052		
Net Exchanges, Ln 14	363	Non-requirements Sales for Resale, Ln 24	10,045
		Energy Used by the Company, Ln 26	134
Received, Ln 16	13,675	Total Energy Losses, Ln 27	4,638
Delivered, Ln 17	(13,564)		
Transmission By Others Losses, Ln 19	(483)		
Total	**70,042**	Total	**70,042**

Recalculated and Adjusted Received and Delivered Energy

REF	Sources				Uses		REF
1	Generation, 401a lines 9,10			70,052	Sales to Ultimate Consumers, 401a line 22	54,999	18
2	Net exchange, 401a line 14			363	Requirements Sales for Resale, 401a line 23	225	19
3	Transmission by Others Losses, 401a line 19			(483)			
				69,931			
4	Reconciliation of Transmission Received (401a line 16):				On-system non-requirements sales for resale subject to losses	3,788	20
5	Pt-to-Pt transmission received - losses ***financially*** settled	Att. A	3,609				
6	Network transmission received - losses ***financially*** settled	Att. B	89				
7	WAPA RS 262 delivered	Att. C	1,649		Company sales, 401a line 26	134	21
8	WAPA RS 263 delivered	Att. C	87				
9	WAPA losses received	Att. C	111				
10	Black Hills transmission received - losses ***financially*** settled	Att. D	222				
11	Transmission received - losses p***hysically*** settled	Att. D	17				
12	Transmission received -- supplied losses - network customers	Att. C	7,890				
13	Total Transmission Received:			13,675	Transmission delivered without losses	13,081	22
14	**Gross Received**			**83,606**			
15	Less third-party sales on-system (reported in Energy Received (duplicate transactions))			(391)			
16	Less off-system sales/purchases w/o losses	Att. F		(5,692)			
17	**Net on-system received**			77,523	**Total delivered with on-system losses**	72,227	23
					Total system delivered loss rate including off-system	7.3%	24

		REF
Total losses (Sources-Uses)	**5,295**	25
Distribution losses / Fixed 4.64% Loss Rate (see page 2)	1,995	26
Transmission losses (total losses - distribution losses)	3,300	27
Transmission deliveries = Total delivered (Uses) + Distribution losses =	74,223	28
Transmission loss rate @ delivery =	**4.45%**	29

Amounts in thousands of MWh

Transmission and Distribution Losses Adjustments and Allocation

REF					Current Tran Loss Factor 4.26%		Distribution Loss Factor 4.64%	
REF	**Schedule 10 loss factor (prior to update)**			**FERC # w/ Current Loss Factor** A	**Trans Loss embedded in current #s** C =A-B	**Adjusted to remove current Loss Factor (total delivered)** B	**Retail Load w/ Dist. Loss**	**Dist. Loss**
30	TRANSMISSION: Sales to ultimate consumers transmission (including interdepartmental sales)			14,166		14,166	14,166	
31	DISTRIBUTION: Sales to ultimate consumers distribution (including interdepartmental sales)			40,833		40,833	42,822	1,989
32	Requirements sales for resale			225		225		
	Adjustments:							
33	Non-requirements sales for resale, 401a line 24		10,045					
	Adjustments to remove financial transactions, duplicate transactions and off-system activity:							
34	Less losses included paid by Black Hills	Att. E	(14)					
35	Less Pt-to-Pt, network, and OS losses - financially settled	Att. E	(160)					
36	Off system sales/purchases w/o losses	Att. F	(5,692)					
37	Third party sales on-system (reported in Energy Received (duplicate transactions))		(391)					
38	Total on-system non-requirements sales for resale subject to losses			3,788		3,788		
39	Energy used by the company (electric dept only, excluding station use, 401a line 26)			134		134	141	7
	Transmission received/delivered (adjusted 401a lines 16 & 17):							
40	Transmission received - losses ***financially*** settled	Att. A, B		*3,698*	*151*	*3,547*		
41	WAPA adjustments (losses and RS 262 & 263 adj.)	Att. C		*1,847*	*111*	*1,736*		
42	Transmission pt-to-pt Black Hills - losses ***financially*** settled	Att. D		*222*	*9*	*213*		
43	Transmission other - losses ***physically*** settled	Att. D		*17*	*0*	*17*		
44	Transmission received - supplied losses	Att. C		*7,890*	*322*	*7,568*		
45	Total Transmission:			13,675	594	13,081		
46	**Total**			**72,821**	**594**	**72,227**	**42,963**	**1,995**

FF1 2014 328 MWH RECEIVED/DELIVERED
TRANSMISSION MWH FINANCIAL SETTLEMENT of LOSSES

Page #	Line #	Customer	Statistical Classification	Rate Schedule Tariff Number	MWH
329	4	Basin Electric Power Cooperative	NF	V11-1,2,8	2,688
329	14	Black Hills Wyoming	SFP	V11-1,2,7	215
329	15	Black Hills Wyoming	NF	V11-1,2,8	427
329	19	Bonneville Power Administration	LFP	V11-2,7	241,995
329	20	Bonneville Power Administration	AD	V11-2,7	13,872
329	27	Bonneville Power Administration	LFP	V11-2,7	68,312
329.1	1	Bonneville Power Administration	NF	V11-1,2,8	298
329.1	4	Cargill Power Markets, LLC	NF	V11-1,2,8	39,210
329.1	5	Cargill Power Markets, LLC	AD	V11-1,2,8	13,699
329.1	7	Cargill Power Markets, LLC	AD	V11-1,2,7	1,263
329.1	8	Constellation Energy Commodities Group	NF	V11-5,6,11	1,789
329.1	9	Constellation Energy Commodities Group	SFP	V11-1-3,7	1,650
329.1	10	Coral Power, LLC	NF	V11-1,2,8	50,003
329.1	11	Coral Power, LLC	AD	V11-1,2,8	1,208
329.1	12	Coral Power, LLC	SFP	V11-1,2,7	115,557
329.1	13	Coral Power, LLC	AD	V11-1,2,7	10,375
329.1	18	Deseret Generation & Trans.	NF	V11-1,2	6,386
329.1	21	Enel Cove Fort, LLC	AD	V11	13,969
329.1	26	Iberdrola Renewables, LLC	NF	V11-1-3,8,9,11	248,249
329.1	27	Iberdrola Renewables, LLC	AD	V11-1-3,8,9	30,155
329.1	28	Iberdrola Renewables, LLC	SFP	V11-1,2,3,7	67,933
329.1	29	Iberdrola Renewables, LLC	AD	V11-1,2,3,7	13,621
329.1	32	Iberdrola Renewables, LLC	LFP	V11-1,2,7	81,958
329.1	33	Iberdrola Renewables, LLC	AD	V11-1,2,7	11,604
329.2	3	Idaho Power Company	LFP	V11-1,2,7	59,643
329.2	9	Idaho Power Company	NF	V11-1,2,8	54,046
329.2	10	Idaho Power Company	AD	V11-1,2,8	81
329.2	11	Idaho Power Company	SFP	V11-1,2,7	3,080
329.2	13	Idaho Power Marketing Operations	NF	V11-1,2,8	811
329.2	14	JP Morgan Ventures Energy Corp.	NF	V11-1-3,8,9,11	28,479
329.2	15	JP Morgan Ventures Energy Corp.	AD	V11-1,2,3	6,172
329.2	16	Los Angeles Department of Water & Power	NF	V11-1,2,8	4,356
329.2	17	Macquarie Energy, LLC	NF	V11-1,2,8	5,642
329.2	18	Macquarie Energy, LLC	AD	V11-1,2,8	9,248
329.2	19	Macquarie Energy, LLC	SFP	V11-1,2,7	6,687
329.2	20	Macquarie Energy, LLC	AD	V11-1,2,7	8,050
329.2	23	Morgan Stanley Capital Group, Inc.	NF	V11-1-3,8	149,158
329.2	24	Morgan Stanley Capital Group, Inc.	AD	V11-1-3,8	10,975
329.2	25	Morgan Stanley Capital Group, Inc.	SFP	V11-1,2,7	10,892
329.2	26	Morgan Stanley Capital Group, Inc.	AD	V11-1,2,7	1,582
329.2	27	Nevada Power Company	NF	V11-1,2,8	4,001
329.2	28	Nevada Power Company	AD	V11-1,2,8	466
329.2	29	Nevada Power Company	SFP	V11-1,2,7	1,500
329.2	30	NextEra Energy Resources, LLC	LFP	V11-1-3,5-6,7,9	211,794
329.2	31	NextEra Energy Resources, LLC	AD	V11-5,6,7,9	25,327
329.2	32	NextEra Energy Resources, LLC	NF	V11-1,2,3,8,11	1,048
329.2	33	NextEra Energy Resources, LLC	AD	V11-1,2,8	42
329.3	5	Pacific Gas & Electric Company	NF	V11-1,2,8	260
329.3	6	Portland General Electric Company	NF	V11-1,2,8	9,388
329.3	7	Portland General Electric Company	AD	V11-1,2,8	1,149
329.3	8	Portland General Electric Company	SFP	V11-1,2,7	1,768
329.3	9	Portland General Electric Company	AD	V11-1,2,7	1,210
329.3	13	Powerex Corporation	LFP	V11-1,2,7	620,286
329.3	14	Powerex Corporation	AD	V11-1,2,7	13,947
329.3	23	Powerex Corporation	NF	V11-1,2,3,8	488,152
329.3	24	Powerex Corporation	AD	V11-1,2,8	4,162
329.3	25	Powerex Corporation	SFP	V11-1,2,3,7	33,375
329.3	26	Powerex Corporation	AD	V11-1,2,7	611
329.3	27	PPL Energy Plus, LLC	NF	V11-1,2,8	4,136
329.3	28	PPL Energy Plus, LLC	AD	V11-1,2,8	641
329.3	29	PPL Energy Plus, LLC	SFP	V11-1,2,7	4,626
329.3	32	Puget Sound Power & Light Company	NF	V11-1,2,8	1,976
329.3	33	Rainbow Energy Marketing Corporation	NF	V11-1,2,8	492
329.3	34	Rainbow Energy Marketing Corporation	AD	V11-1,2	1,200
329.4	1	Rainbow Energy Marketing Corporation	SFP	V11-1,2,7	17,328
329.4	2	Sacramento Municipal Utility District	LFP	V11-1,2,7	105,118
329.4	3	Sacramento Municipal Utility District	AD	V11-1,2,7	1,632
329.4	5	Salt River Project	LFP	V11-1,2,7	121,700
329.4	6	Salt River Project	NF	V11-1,2,3,8	3,577
329.4	7	Salt River Project	AD	V11-1,2,3,7	1,586
329.4	11	Sierra Pacific Power Company	NF	V11-1,2,8	280
329.4	12	Southern California Edison Company	NF	V11-1-3,8,9,11	315,360
329.4	13	Southern California Edison Company	AD	V11-1-3,8,9,11	17,895
329.4	14	Southern California Edison Company	SFP	V11-1-3,7	1,000
329.4	15	Southern California Edison Company	AD	V11-1-3,7	270
329.4	17	Southern California Public Power Authority	OS	V11-9,11	1,144
329.4	21	Tenaska Power Services Co	NF	V11-1,2,8	43,092
329.4	22	Tenaska Power Services Co	AD	V11-1,2,8	8,321
329.4	23	Tenaska Power Services Co	SFP	V11-1,2,7	40,590
329.4	24	Tenaska Power Services Co	AD	V11-1,2,7	11,080
329.4	25	The Energy Authority, Inc.	NF	V11-1,2,8	2,661
329.4	26	Thermo No. 1 BE -01	LFP	V11-1-3,5-6,7,9	53,417
329.4	27	Thermo No. 1 BE -01	AD	V11-1-3,5-6,7,9	5,984
329.4	28	TransAlta Energy Marketing	NF	V11-1,2,8	54,023
329.4	29	TransAlta Energy Marketing	AD	V11-1,2,8	1,813
329.4	34	Tri-State Generation & Trans.	NF	V11-1,2,8	14,522
329.5	1	Tri-State Generation & Trans.	AD	V11-1,2,8	246
329.5	2	Tri-State Generation & Trans.	SFP	V11-1,2,7	244
329.5	3	Tri-State Generation & Trans.	AD	V11-1,2,7	9
329.5	11	Utah Associated Municipal Power Systems	NF	V11-1,2,3,8	4,241
329.5	12	Utah Associated Municipal Power Systems	AD	V11-1,2,8	105
329.5	15	Utah Municipal Power Agency	NF	V11-1,2,8	40
329.5	26	Western Area Power Administration Colorado	SFP	V11-1,2,7	63
329.5	27	Western Area Power Administration Colorado	NF	V11-1,2,8	636
		Total MWH			3,654,872
		Accrual Adjustment			(46,003)
		Total point-to-point schedules subject to losses (as reported on FERC Form No. 1, page 329)			3,608,869
				REF	5

FF1 2014 328 MWH RECEIVED/DELIVERED
TRANSMISSION MWH FINANCIAL SETTLEMENT of LOSSES - Network customers

Page #	Line #	Customer	Statistical Classification	Rate Schedule Tariff Number	MWH
329	2	Basin Electric Power Cooperative	FNO	V11-1,2,3	335
329	21	Bonneville Power Administration	FNO	V11-1,2,3	2,047
329	23	Bonneville Power Administration	FNO	V11-1,2,3	617
329	25	Bonneville Power Administration	FNO	V11-1,2,3	126
329	31	Bonneville Power Administration	FNO	V11-1,2,3,4	3,230
329.1	2	Bonneville Power Administration	FNO	V11-1,2,3,4	11,986
329.1	34	Iberdrola Renewables, LLC	FNO	V11-1,2,3	3,540
329.2	34	Noble Americas Energy Solutions LLC	FNO	V11-1,2,3,4	-
329.4	32	Tri-State Generation & Transmission	FNO	V11-1,2,3,4	12,796
329.5	4	U.S. Department of the Interior, Bureau of Reclamation	FNO	V11-1,2,3	3
329.5	23	Western Area Power Administration	FNO	V11-1,2	2
			Total MWH		34,682
			Accrual		54,693
			Total		89,375
				REF	6

Western Area Power Administration Total Received/Delivered & Total Received Per FF1 2014 328 and 401a Summary
2014

Amounts in MWh		Western Rec./Del. Reconciliation						
			RS 262	RS 263	Subtotal	Energy Return (Variation)	Net	REF Loss Factor Clauclation Worksheet
		Energy Received	1,753,557	93,353	1,846,910	-	***1,846,910***	
		Losses	(104,834)	(5,998)	(110,832)		(110,832)	9
		Energy Delivered	1,648,723	87,355	1,736,078	-	***1,736,078***	
		Details:						
Page #	Line #	Total Received: Reported						
FF1 Pg 328.5	18,20(i)	OS Reported	1,583,864	84,635	1,668,499	-	1,668,499	
FF1 Pg 328.5	19,21(i)	AD Reported	187,719	8,557	196,276	-	196,276	
FF1 Pg 328.5		Accrual Adjustment (included in total Accrual)	(18,026)	161	(17,865)	-	(17,865)	
		Total Received	1,753,557	93,353	1,846,910	-	1,846,910	
		Total Delivered: Reported						
FF1 Pg 328.5	18,20(j)	OS Reported	1,489,212	79,280	1,568,492		1,568,492	
FF1 Pg 328.5	19,21(j)	AD Reported	176,455	8,075	184,530		184,530	
FF1 Pg 328.5		Accrual Adjustment (included in total Accrual)	(16,944)	-	(16,944)		(16,944)	
		Total Delivered	1,648,723	87,355	1,736,078		1,736,078	7, 8

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

	Received per 328	Accrual Received FF1 Pg 328.5	Total Received Per 401a	
Total point-to-point schedules subject to losses - as reported on 328 (financial settlement)	3,654,872	(46,003)	3,608,869	5
Total network schedules ***financially*** settled - subst of total report on 328	34,682	54,693	89,375	6
Western RS 262 Received reported on page 328	1,771,583	(18,026)	1,753,557	see above
Western RS 263 Received reported on page 328	93,192	161	93,353	see above
Black Hills (losses paid financially to PacifiCorp Energy)	210,175	12,160	222,335	10
State of South Dakota - losses ***physically*** settled	17,212	22	17,234	11
Network/OS/and other rate schedules [1]	8,021,359	(131,483)	7,889,876	12
Total Received per 401a Line 16	13,803,075	(128,476)	13,674,599	

2014 328 MWH RECEIVED/DELIVERED
PT-TO-PT MW PHYSICAL SETTLEMENT AND BLACK HILLS

Page #	Line #	Customer	Statistical Classification	Rate Schedule Tariff Number	MWH	Black Hills	Physical	Total
329	5	Black Hills/Colorado Electric Utility Company, L.P.	NF	V11-1,2,8	1,398	1,398		1,398
329	6	Black Hills/Colorado Electric Utility Company, L.P.	SFP	V11-1,2,7	1,829	1,829		1,829
329	9	Black Hills Corporation	NF	V11-1,2,8	13,155	13,155		13,155
329	10	Black Hills Corporation	AD	V11-1,2,8	397	397		397
329	11	Black Hills Corporation	SFP	V11-1,2,7	4,035	4,035		4,035
329	14	Black Hills Corporation	LFP	V11-1,2,7	182,880	182,880		182,880
329	15	Black Hills Corporation	AD	V11-1,2,7	6,481	6,481		6,481
329.4	18	State of South Dakota	LFP	7V11-7	12,235		12,235	12,235
329.4	19	State of South Dakota	AD	7V11-7	1,496		1,496	1,496
329.4	20	State of South Dakota	SFP	7V11-7	3,481		3,481	3,481
		Total			227,387	210,175	17,212	227,387
		Accruals			12,182	12,160	22.00	12,182
		Total Black Hills and Physical received/delivered			239,569	222,335	17,234	239,569
					REF	10	11	

2014 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								
311.1	5	Basin Electric Power Cooperative	SF		T-11	NA	NA	NA	173	
311.1	9	Black Hills Wyoming, Inc.	SF		T-11	NA	NA	NA	39	
311.1	11	Bonneville Power Administration	LF	3	368	NA	NA	NA	2,748	
311.1	12	Bonneville Power Administration	LF	4	T-11	NA	NA	NA	16,022	
311.1	14	Bonneville Power Administration	SF		T-11	NA	NA	NA	13	
311.2	8	Cargill Power Markets, LLC	SF		T-11	NA	NA	NA	1,706	
311.3	3	Constellation Energy Commodities Group, Inc.	SF		T-11	NA	NA	NA	122	
311.3	4	Constellation Energy Commodities Group, Inc.	SF		T-11	NA	NA	NA	26	
311.3	5	Coral Power, LLC	SF		T-11	NA	NA	NA	7,367	
311.3	6	Deseret Generation & Transmission Cooperative	SF		T-11	NA	NA	NA	273	
311.4	2	Iberdrola Renewables, LLC	LF	5	T-11	NA	NA	NA	3,787	
311.4	3	Iberdrola Renewables, LLC	SF		T-11	NA	NA	NA	14,435	
311.4	4	Iberdrola Renewables, LLC	SF		T-11	NA	NA	NA	34	
311.4	7	Idaho Power Company	LF	6	T-11	NA	NA	NA	2,737	
311.4	8	Idaho Power Company	SF		T-11	NA	NA	NA	2,468	
311.4	12	J.P. Morgan Ventures Energy Corporation	SF		T-11	NA	NA	NA	997	
311.4	13	J.P. Morgan Ventures Energy Corporation	SF		T-11	NA	NA	NA	224	
311.5	1	Los Angeles Department of Water and Power	SF		T-11	NA	NA	NA	186	
311.5	3	Macquarie Energy LLC	SF		T-11	NA	NA	NA	525	
311.5	7	Morgan Stanley Capital Group Inc.	SF		T-11	NA	NA	NA	6,959	
311.5	11	Nevada Power Company	SF	7	T-11	NA	NA	NA	234	
311.5	13	NextEra Energy Power Marketing, LLC	LF	8	T-11	NA	NA	NA	9,697	
311.5	14	NextEra Energy Power Marketing, LLC	SF		T-11	NA	NA	NA	47	
311.6	1	NextEra Energy Power Marketing, LLC	SF		T-11	NA	NA	NA	7	
311.6	3	Noble Americas Energy Solutions LLC	LF	9	T-11	NA	NA	NA	923	
311.6	8	PPL EnergyPlus, LLC	SF		T-11	NA	NA	NA	427	
311.6	10	Pacific Gas & Electric Company	SF		T-11	NA	NA	NA	22	
311.6	11	Portland General Electric Company	SF		T-11	NA	NA	NA	475	
311.6	14	Powerex Corporation	LF	10	T-11	NA	NA	NA	28,390	
311.7	1	Powerex Corporation	SF		T-11	NA	NA	NA	22,426	
311.7	4	Public Service Company of Colorado	SF		T-11	NA	NA	NA	27	
311.8	1	Puget Sound Energy, Inc.	SF		T-11	NA	NA	NA	84	
311.8	4	Rainbow Energy Marketing Corporation	SF		T-11	NA	NA	NA	759	
311.8	8	Sacramento Municipal Utility District	LF	12	T-11	NA	NA	NA	5,027	
311.8	10	Salt River Project	LF	13	T-11	NA	NA	NA	5,655	
311.8	11	Salt River Project	SF		T-11	NA	NA	NA	188	
311.9	5	Sierra Pacific Power Company	SF	14	T-11	NA	NA	NA	12	
311.9	8	Southern California Edison Company	SF		T-11	NA	NA	NA	13,694	
311.9	9	Southern California Edison Company	SF		T-11	NA	NA	NA	9	
311.9	11	Southern California Public Power Authority	SF		T-11	NA	NA	NA	49	
311.10	1	Tenaska Power Services Co.	SF		T-11	NA	NA	NA	3,857	
311.10	5	The Energy Authority, Inc.	SF		T-11	NA	NA	NA	146	
311.10	7	Thermo No. 1 BE-01, LLC	LF	15	T-11	NA	NA	NA	2,510	
311.10	8	TransAlta Energy Marketing (U.S.) Inc.	SF		T-11	NA	NA	NA	2,624	
311.10	11	Tri-State Generation and Transmission Association, Inc.	LF	16	T-11	NA	NA	NA	1,257	
311.10	12	Tri-State Generation and Transmission Association, Inc.	SF		T-11	NA	NA	NA	631	
311.11	4	Utah Associated Municipal Power Systems	SF		T-11	NA	NA	NA	288	
311.11	8	Utah Municipal Power Agency	SF		T-11	NA	NA	NA	2	
311.11	11	Western Area Power Administration	SF		T-11	NA	NA	NA	40	
					Total Pt-to-Pt, Network, and OS Financially Settled				160,348	35
311.1	7	Black Hills Power, Inc (sales plus losses)	LF		441	NA	NA	NA	343,081	

2014 Off System Sales/Purchases Summary

Amounts in thousands of MWh	MWh	REF
PAC01 Off System Sales (MidC)-purchases	1,823	
PAC01 Off System Sales (Cholla, Col, Herm, Wyo, YTP etc) - sales	2,500	
Craig generation sales [1]	788	
Hayden generation sales [1]	580	
Total third-party off system sales/purchases	**5,692**	**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 and 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
LoadPoint Does Not=IPCO_LOSS

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 and 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**	70,052	PacifiCorp's 2014 FERC Form No. 1, page 401a, sum of lines 9 (Net Generation) and 10 (Purchases).
2	**Net exchange**	363	PacifiCorp's 2014 FERC Form No. 1, page 401a, line 14 (Net Exchanges).
3	**Transmission by Others Losses**	(483)	PacifiCorp's 2014 FERC Form No. 1, page 401a, line 19 (Transmission by Others Losses).
4	**Reconciliation of Transmission received (401a line 16)**	-	PacifiCorp's 2014 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**	3,609	Attachment A of the Loss Factor Calculation identifies the total Point-to-Point Transmission contracts subject to losses financially, as enumerated on PacifiCorp's 2014 FERC Form No. 1, page 329, including an adjustment for accrual differences.
6	**Network transmission received - losses financially settled**	89	Attachment B of the Loss Factor Calculation identifies the losses settled financially by network customers after the launch of the multi-state real-time energy imbalance market (EIM) on November 1, 2014.
7	**WAPA RS 262 delivered**	1,649	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 2014 FERC Form No. 1, pages 328-329, including accrual adjustments.
8	**WAPA RS 263 delivered**	87	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 2014 FERC Form No. 1, page 328-329, including accrual adjustments.
9	**WAPA losses Received**	111	Attachment C of the Loss Factor Calculation identifies the difference between energy received and delivered pursuant to PacifiCorp's Rate Schedules 262 and 263 with WAPA, as

[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
			included on PacifiCorp's 2014 FERC Form No. 1, page 328.5 and FERC Form No.1, line 17 (Energy delivered).
10	**Black Hills transmission received - losses financially settled**	222	Attachment D of the Loss Factor Calculation identifies the losses in MWhs sold to Black Hills Power ("Black Hills") under current Point-to-Point power purchase agreements with PacifiCorp Energy, as included in PacifiCorp's 2014 FERC Form No. 1, page 329, including an adjustment for accrual differences.
11	**Transmission received - losses physically settled, other**	17	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 2014 FERC Form No. 1, page 329, including accrual adjustments.
12	**Transmission received – supplied losses – network customers**	7,890	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 2014 FERC Form No. 1, page 328 , primarily through imbalance (FERC Account 555), including an adjustment for accrual differences.
13	**Total Transmission received**	13,675	Sum of Items 5 through 12.
14	**Gross Received**	83,606	Sum of Items 1-3 and 13.
15	**Less third-party sales on-system (reported in Energy Received (duplicate transactions))**	(391)	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**	(5,692)	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 and descriptions set forth in PacifiCorp's Loss Analysis Methodology). Same value as item 36.

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
17	**Net on-system received**	77,523	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**	54,999	PacifiCorp's 2014 FERC Form No. 1, page 401a, line 22 (Sales to Ultimate Consumers).
19	**Requirement sales**	225	PacifiCorp's 2014 FERC Form No. 1, page 401a, line 23 (Requirements Sales for Resale).
20	**On system non-requirements sales subject to losses**	3,788	PacifiCorp's 2014 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**	134	PacifiCorp's 2014 FERC Form No. 1, page 401a, line 26 (Energy Used by the Company).
22	**Transmission delivered without losses**	13,081	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 (4.26%). See also the description and value from item 45 column titled "Adjusted to remove current Loss Factor".
23	**Total delivered with on-system losses**	72,227	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**	7.3%	Item 25 / Item 23 (illustrative only). Loss rate includes both transmission and distribution losses.
25	**Total Losses**	5,295	Item 17 less item 23.
26	**Distribution losses**	1,995	Applies 4.64% distribution loss factor (from PacifiCorp's 2007 Distribution Loss Study) to total distribution losses (see item 46 column titled "Dist. Loss".
27	**Remaining losses = transmission losses**	3,300	Item 25 less Item 26.
28	**Transmission deliveries = total deliveries + distribution loss**	74,223	Sum of Items 23 and 26.

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
29	**Transmission loss rate @ delivery**	**4.45%**	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)**	14,166	Items 30 & 31 represent a split of total retail sales as stated on PacifiCorp's 2014 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)**	40,833	
32	**Requirements sales for resale**	225	PacifiCorp's 2014 FERC Form No. 1, page 401a, line 23 (Requirements Sales for Resale).
33	**Non-requirements sales for resale**	10,045	PacifiCorp's 2014 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**	(14)	Attachment E of Loss Calculation identifies energy, including losses, sold to Black Hills under a long-term firm contract and included in PacifiCorp's 2014 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 (4.26%).
35	**Less Pt-to-Pt and network losses - financially settled**	(160)	Adjustment for Point-to-Point Transmission contracts 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).

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
36	**Off-system sales/purchases without losses**	(5,692)	Same value and description as item 16.
37	**Third party sales on-system (reported in energy received (duplicated transactions)**	(391)	Same value and description as item 15.
38	**Total on-system non-requirements sales for resale subject to losses**	3,788	Same value and description as item 20.
39	**Energy used by the company (electric department only, excluding station use)**	134	PacifiCorp's 2014 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**	3,698	Attachments A and B of the Loss Factor Calculation identify total Point-to-Point Transmission contracts subject to losses settled financially, as enumerated on PacifiCorp's 2014 FERC Form No. 1, page 329 and adjusted for current transmission loss factor.
41	**WAPA RS 262 & 263**	1,847	Sum of items 7-9 and adjusted value for current transmission loss factor.
42	**Point-to-Point Transmission to Black Hills**	222	Same value and description as item 10 and adjusted value for current transmission loss factor.
43	**Transmission other – losses physically settled**	17	Same value and description as item 11 and adjusted value for current transmission loss factor.
44	**Transmission network: supplied losses**	7,890	Same value and description as item 12 and adjusted value for current transmission loss factor.
45	**Total Transmission**	13,675	Sum of Items 40 through 44 and adjusted value for current transmission loss factor.
46	**Total**	72,821	Sum of items 30-32 plus sum of items 38-39 plus item 45 and adjusted for current transmission and distribution loss factor.