PACIFICORP
A MIDAMERICAN ENERGY HOLDINGS COMPANY

825 NE Multnomah Street
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April 1, 2013

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

RE: *PacifiCorp*, Revisions to Open Access Transmission Tariff
Docket No. ER13-___-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 proposed revisions to its Open Access Transmission Tariff ("OATT").[4] In this filing, PacifiCorp proposes to amend its OATT to update rates for PacifiCorp's Schedule 3, Regulation and Frequency Response Service, and Schedule 3A, Generator Regulation and Frequency Response Service.

PacifiCorp's currently-effective rates for Schedules 3 and 3A were established in PacifiCorp's last transmission rate case filing, in Docket No. ER11-3643-000. In that docket, PacifiCorp updated its Schedule 3 charges for Regulation and Frequency Response Service and added, for the first time, a new Schedule 3A for Generator Regulation and Frequency Response Service. FERC accepted the filing on August 8, 2011,[5] and the rates become effective December 25, 2011, subject to refund. On February 22, 2013, PacifiCorp filed a settlement agreement signed by the parties (the "Settlement Agreement") resolving all issues in the proceeding. In accordance with the Settlement Agreement, interim rates for both Schedule 3 and Schedule 3A went into effect on March 1, 2013.[6]

As a condition of the Settlement Agreement, PacifiCorp agreed to file new proposed rates for Schedules 3 and 3A on or before April 1, 2013, with a proposed effective date of June 1, 2013. In accordance with that agreement, PacifiCorp files the proposed tariff revisions.

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1 16 U.S.C. § 824d (2006).

2 18 C.F.R. Part 35 (2012).

3 *Electronic Tariff Filings*, Order No. 714, 124 FERC ¶ 61,270 (2008).

4 PacifiCorp's OATT is designated as PacifiCorp FERC Electric Tariff, Volume No. 11.

5 *See PacifiCorp*, 136 FERC ¶ 61,092 (2011) ("Hearing Order"), *reh'g denied*, 137 FERC ¶ 61,147 (2011).

6 *See PacifiCorp*, Docket Nos. ER11-3643-000, *et al.*, "Order of Chief Judge Granting Motion for Interim Rate Relief" (Feb. 28, 2013).

PacifiCorp respectfully requests that the Commission accept these proposed tariff revisions for filing to become effective, without any suspension or hearing, on June 1, 2013.

I. INTRODUCTION

PacifiCorp currently provides regulating margin reserve service[7] under Schedules 3 and 3A of its OATT. Schedule 3 applies to transmission customers delivering energy to load within one of PacifiCorp's Balancing Area Authorities ("BAA"). Schedule 3A applies to transmission customers delivering energy from generators (both thermal and renewable) in PacifiCorp's BAAs to other BAAs.[8] PacifiCorp does not charge transmission customers for service under both Schedule 3 and Schedule 3A for the same transaction.[9]

Under the interim rates currently in effect, the charge under Schedules 3 and 3A is $2.90/kW/year. These interim rates, as well as the rates proposed in Docket No. ER11-3643-000, use the same billing determinants for all transmission customers, and do not distinguish among variable energy resources ("VERs"), non-VERs, or load.[10]

In the instant filing, PacifiCorp proposes modifying Schedules 3 and 3A to update the per-unit capacity charge from $2.90/kW/year to: $4.16/kW/year for Schedule 3; $8.25/kW/year for Schedule 3A applied to VERs; and $0.001/kW/year for Schedule 3A applied to non-VERs, to better reflect PacifiCorp's current cost of providing such service. In addition, PacifiCorp proposes modifying Schedules 3 and 3A so that billing determinants for load, VER, and non-VER generation are differentiated based on the load or the generation resource's actual contribution to the regulation reserve demands placed on PacifiCorp's system. The billing determinant for Schedule 3 is the 2011 coincident peak ("CP") demand for transmission customers taking Schedule 3 service, and the billing determinant for Schedule 3A for VERs and non-VERs is the 2011 generator nameplate capacity.

In Order Nos. 890 and 890-A, the Commission concluded that it would consider, on a case-by-case basis, proposals by public utilities to assess regulation charges to generators selling within their own BAAs, as well as generators selling outside their BAAs.[11] In Order No. 764,

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[7] Order No. 764 refers to this service as "generator regulation service." ***See Integration of Variable Energy Resources,*** Order No. 764, 139 FERC ¶ 61,246, at P 4 (2012) ("Order No. 764"), ***order on reh'g***, 141 FERC ¶ 61,232 (2012) ("Order No. 764-A"). While PacifiCorp uses the term "regulating margin reserve service" to describe this service, the two are functionally identical.

[8] In addition, Schedule 3 and Schedule 3A charges are not assessed to a transmission customer that chooses to make alternative comparable arrangements for 100 percent of the applicable service. ***E.g.,*** Testimony of Sarah E. Edmonds at 7, 15.

[9] Edmonds Testimony at 15-16.

[10] "VER" is defined in PacifiCorp's revised Schedule 3A as a device for the production of electricity characterized by an energy source that: (1) is renewable; (2) cannot be stored; and (3) has variability beyond the control of the facility owner or operator. This definition is consistent with the definition in Order No. 764. ***See*** Order No. 764 at P 210.

[11] ***See, e.g., Preventing Undue Discrimination and Preference in Transmission Service***, Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 690 (2007), ***order on reh'g***, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007),

the Commission recognized that intermittent generation resources may impose a disproportionate impact on overall system variability, thereby requiring transmission providers to hold a greater per MW amount of regulation reserves for VERs than for load and/or other generation resources.[12] The Commission therefore concluded that it may be appropriate for a public utility to differentiate among customers (or customer classes) in determining their customers' relative regulating reserve responsibilities.[13]

Although Order No. 764 will not go into effect until November 12, 2013, the Commission's recognition that different types of customers may impose different impacts on overall system variability is not new. Even prior to Order No. 764, the Commission recognized the potential for VERs to impose disproportionate impacts on a transmission system and approved tariffs for two public utilities – Westar Energy, Inc. ("Westar") and Puget Sound Energy ("PSE") – that place proportionately higher regulation reserve obligations on VER generators compared to non-VER generators.[14]

In developing its proposed charges for Schedules 3 and 3A, PacifiCorp employed the methodology described by the Commission in Order No. 764, and used in both *Westar* and *Puget Sound Energy,* to ensure the charges are consistent with Commission policy.[15] In accordance with a commitment made in the Settlement Agreement, PacifiCorp's proposed rates are also based on a study containing at least one year's worth of data to determine both the amount of regulation reserves required by PacifiCorp's BAAs and the different amounts of reserves needed for loads and resources.

PacifiCorp's Schedules 3 and 3A should be accepted for filing by the Commission. The changes proposed to these rates are just and reasonable,[16] cost-justified, modeled after rates accepted by the Commission for other public utilities,[17] and consistent with recent Commission Order Nos. 764 and 764-A.

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order on reh'g, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[12] Order No. 764 at P 210.

[13] *See*, *e.g.*, *id.* at P 320.

[14] *See, e.g. Puget Sound Energy, Inc.*, 142 FERC ¶ 61,018 (2013) ("*Puget Sound Energy*") (approving settlement addressing PSE's ancillary service rates under Schedules 3 and 13, and providing for differentiated recovery of costs to serve non-dispatchable and dispatchable generators exporting from PSE's BAA); *Westar Energy, Inc.*, 130 FERC ¶ 61,215 (2010) ("*Westar*") (accepting Westar's proposed *pro forma* Schedule 3A, Generator Regulation and Frequency Response Service).

[15] PacifiCorp's methodology was modeled on Westar's. PacifiCorp's access to slightly different data and factual circumstances required some slight adjustments to the methodology, but the methodology is aimed at achieving the same principles articulated in *Westar* and in Order No. 764. PacifiCorp's methodology is described in detail in PAC-7, the testimony of Gregory N. Duvall.

[16] *See* FPA § 205(a), 16 U.S.C. § 824d(a).

[17] *See id.*

II. BACKGROUND

A. Description of PacifiCorp

PacifiCorp is an indirect, wholly-owned subsidiary of MidAmerican Energy Holdings Company. PacifiCorp provides delivery of electric power and energy to approximately 1.8 million retail electric customers in six western states. PacifiCorp consists of three core business units: (1) PacifiCorp Energy, which manages the electric generation, commercial and trading, and coal mining operations of the Company; (2) Pacific Power, which delivers electricity to retail customers in Oregon, Washington and California; and (3) Rocky Mountain Power, which delivers electricity to retail customers in Utah, Wyoming and Idaho. PacifiCorp's transmission operations and management personnel are headquartered in Portland, Oregon.[18]

PacifiCorp's bulk transmission network is highly integrated with other transmission providers in the western United States. PacifiCorp owns and operates approximately 16,763 miles of transmission lines in 10 states.[19]

As of December 31, 2011, PacifiCorp's current total transmission plant in service is approximately $4.5 billion. PacifiCorp is interconnected with more than 80 generation plants and 13 adjacent BAAs at approximately 152 points of interconnection. PacifiCorp owns, or has an interest in, generation resources directly interconnected to its transmission system with a system peak capacity of approximately 16,750 MW. This generation capacity includes a diverse mix of coal, hydroelectric, wind, natural gas-fired combined cycle and combustion turbines, and geothermal resources.[20]

Under its OATT, PacifiCorp provides Long-Term Firm Point-to-Point ("PTP") Transmission Service to nine transmission customers, Short-Term Firm and Non-Firm PTP Transmission Service to 69 transmission customers under umbrella service agreements, and Network Integration Transmission ("NIT") Service to eight transmission customers, including PacifiCorp Energy. PacifiCorp also provides transmission service to certain "legacy" transmission customers under transmission service agreements pre-dating the OATT.[21]

B. PacifiCorp's Currently Filed Schedules 3 and 3A

In Docket No. ER11-3643-000, PacifiCorp's last transmission rate case filing, PacifiCorp sought to adopt formula transmission rates. The Company also proposed changes to its then-existing Schedule 3 to reflect updated charges for providing Regulation and Frequency Response Service, and proposed the addition of new Schedule 3A, Generator Regulation and Frequency Response Service.

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[18] Edmonds Testimony at 3.

[19] *Id.* at 5.

[20] *Id.* at 4.

[21] *Id*.

As originally proposed in Docket No. ER11-3643, the rates for Schedule 3 and 3A were designed using the identical cost and billing determinants. PacifiCorp determined the rates for this service by dividing the total amount of regulation reserves needed to balance the system by a billing determinant equal to PacifiCorp's 2010 CP demand. The rates produced were included in both Schedule 3 applicable to a transmission customer serving load within PacifiCorp's BAAs and Schedule 3A applicable to a transmission customer exporting off-system from a generator physically located in one of PacifiCorp's BAAs. Generator Regulation and Frequency Response Service under Schedule 3A applies to the extent that a transmission customer is not already subject to Regulation and Frequency Response Service provided under Schedule 3. Transmission customers are required either to purchase Schedule 3 or 3A service, where applicable, or make alternative comparable arrangements (including self-supplying the service).[22]

C. The February 22, 2013 Settlement Agreement

On August 8, 2011, FERC issued an order in the docket accepting PacifiCorp's filing and allowing the proposed rates to become effective December 25, 2011, subject to refund.[23] On February 22, 2013, PacifiCorp filed the Settlement Agreement executed by the parties. In accordance with the Settlement Agreement, interim rates for both Schedule 3 and Schedule 3A went into effect on March 1, 2013.[24] PacifiCorp committed, as a condition of the February 22, 2013 Settlement Agreement, to file new proposed Schedule 3 and 3A rates by April 1, 2013, with a proposed effective date of June 1, 2013. PacifiCorp also agreed that the filing would be based on a study containing at least one year's worth of data to determine both the amount of regulation reserves required by PacifiCorp's BAAs and the different amounts of reserves needed for loads and resources.[25]

This filing satisfies all of the conditions in the February 22, 2013 Settlement Agreement. This filing requests a proposed effective date of June 1, 2013. Moreover, the Schedule 3 and 3A Study contains at least one year's worth of data to determine both the amount of regulation reserves required by PacifiCorp's BAAs and the different amounts of reserves needed for loads and resources.[26]

[22] *Id.* at 7, 15.

[23] *See PacifiCorp*, 136 FERC ¶ 61,092 (2011) ("Hearing Order"), *reh'g denied*, 137 FERC ¶ 61,147 (2011).

[24] *See PacifiCorp*, Docket Nos. ER11-3643-000, *et al.*, "Order of Chief Judge Granting Motion for Interim Rate Relief" (Feb. 28, 2013).

[25] On March 26, 2013, the Settlement Judge in the proceeding issued a Certification of Uncontested Settlement, certifying the offer of settlement filed by PacifiCorp. *PacifiCorp*, 142 FERC ¶ 63,023 (2013).

[26] *See, e.g.,* Duvall Testimony at 10 (describing use of data for calendar year 2011).

D. <u>Commission Standards for Generator Regulation Charges</u>

1. Order No. 890

In Order Nos. 890 and 890-A, the Commission held that public utility transmission providers may propose regulation charges to generators selling both within and outside the public utility's BAA.[27] The Commission determined it would consider such proposals on a case-by-case basis.[28] Since then, the Commission has accepted a number of proposals for such rates.[29]

2. *Westar* and *Puget Sound Energy*

In *Westar*, the transmission provider proposed a schedule for generator regulation service applicable to all generators exporting energy from its BAA.[30] Under the proposed schedule, VER generators would be responsible for a higher percentage of regulation reserves than would non-VER generators.[31]

In calculating the relative reserve burdens of each class, Westar employed the following methodology: it first measured the output of VER generators in its BAA in 10-minute intervals, and compared the output every 10 minutes to the output 10 minutes earlier. It then multiplied the standard deviation of these 10-minute deviations by two to determine the amount of regulation capacity it would need with a 95 percent confidence interval. Westar divided this amount of regulation capacity by the nameplate capacity of the VER generation on its system, yielding a regulation percentage attributable to VER generation.[32] Westar then applied data on offsetting system diversity to this VER regulation percentage to determine a proposed regulation percentage for VER generation.[33] The Commission conditionally accepted Westar's proposal subject to minor changes.[34]

After Westar's schedules were approved, PSE proposed its own schedules for generator regulation service, modeled after Westar's filing. Like Westar's proposal, PSE's schedules proposed charging VER generators a proportionately higher percentage of reserve regulation capacity than non-VERs, based on the VER generators' relative contribution to system demand.

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[27] *See, e.g.*, Order No. 890 at P 690.

[28] *Id.*

[29] *See, e.g.*, *Entergy Servs. Inc.*, 120 FERC ¶ 61,042 (2007); *Sierra Pac. Res. Operating Cos.*, 125 FERC ¶ 61,026 (2008).

[30] *Westar* at P 1.

[31] *Id.* at PP 35-36.

[32] *See Westar Energy, Inc.*, Form Balancing Area Services Agreement and Schedule 3A to OATT, Direct Testimony of Paul Dietz at 8, Docket No. ER09-1273-000 (filed Jun. 3, 2009)

[33] *Id.* at 8-16.

[34] *Westar* at PP 38-40.

PSE modeled its methodology for developing the differentiated generation regulation charges after Westar's methodology. The Commission approved PSE's proposed schedules as part of a settlement agreement.[35]

Thus, the Commission recognized in both *Westar* and *Puget Sound Energy* that VER generation may impose a higher burden on a transmission provider's system than non-VER generation, and that it may be appropriate for a transmission provider to apply differentiated charges to different types of generators reflecting these relative burdens.

3. Order No. 764

In 2010, the Commission issued a Notice of Proposed Rulemaking ("NOPR") on variable energy resource integration ("VER NOPR").[36] As part of that NOPR, FERC proposed adding a new service schedule for generator regulation service to the *pro forma* OATT. The proposed schedule would apply to all customers delivering energy from a resource located in the transmission customer's BAA and, like Schedule 3 of the OATT, would consist of both a per-unit rate for regulation service capacity and a volumetric component for regulation reserve capacity.[37]

Under the VER NOPR, the new proposed schedule (Schedule 10 - Generator Regulation and Frequency Response Service) would use the same per-unit rate for regulation as the existing Schedule 3 of the *pro forma* OATT, recognizing that the service provided under the two schedules would be functionally equivalent.[38] But with respect to the volumetric component of such rates, the Commission recognized, consistent with its approval of schedules in *Westar* and *Puget Sound Energy*, that VERs may impose a disproportionate impact on overall system variability, thereby justifying allocating to VERs a higher percentage of the system's required regulation reserves.[39]

In Order No. 764, issued on June 22, 2012, FERC ultimately declined to adopt the Schedule 10 proposed in its VER NOPR. Instead, the Commission stated that it would consider proposals for such schedules on a case-by-case basis.[40] The Commission did, however, provide guidelines for transmission providers seeking to adopt schedules allocating differentiated reserve requirements between VER and non-VER generators. The Commission stated, among other things, that the division of generators into various classes must be reasonably related to the

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[35] *Puget Sound Energy, Inc.*, 142 FERC ¶ 61,018 (2013) (approving settlement addressing rates under Schedules 3 and 13, and providing for differentiated recovery of costs to serve VER and non-VER generators exporting from PSE's BAA)

[36] *Integration of Variable Energy Resources*, Notice of Proposed Rulemaking, 75 Fed. Reg. 75,336 (Dec. 2, 2010), FERC Stats. & Regs. ¶ 32,664 (2010).

[37] *Id.* at PP 88, 92.

[38] *Id.* at P 93.

[39] *Id.* at P 94.

[40] Order No. 764 at P 4.

generator's operational characteristics, and noted that the transmission provider must explain in detail why the classifications are appropriate.[41] The transmission provider must also demonstrate that it has accounted for diversity benefits among all resources and loads within its system.[42] On December 20, 2012, the Commission issued its Order on Rehearing and Clarification and Granting Motion for Extension of Time ("Order No. 764-A"), which affirmed the Commission's determinations in Order No. 764 and modified the compliance date to November 12, 2013.[43]

In short, Order No. 764 affirmed the Commission's recognition in both *Westar* and *Puget Sound Energy* that it may be appropriate to allocate a higher percentage of regulation reserve responsibility to VER generators, reflecting the higher burden such generators impose on transmission provider's system. The Order also provided additional guidance for the development of such rates.

III. DESCRIPTION OF THE FILING

This filing proposes to update rates for PacifiCorp's Schedules 3 and 3A to allow PacifiCorp to recover the capacity cost of regulating margin reserves. PacifiCorp proposes implementing differentiated charges for load under Schedule 3, and for VER and non-VER generation under Schedule 3A, to better reflect the demands these customer classes place on the system. As a result, PacifiCorp proposes modifying Schedules 3 and 3A to update the per-unit capacity charge from $2.90/kW/year to: $4.16/kW/year for Schedule 3; $8.25/kW/year for Schedule 3A applied to VERs; and $0.001/kW/year for Schedule 3A applied to non-VERs.

A. Proposed Charges Under Schedule 3

The proposed charges under Schedule 3 are based on the weighted fixed cost of the units identified in Attachment B of Exhibit No. PAC-5. The weighting is calculated by applying the same method used by the Commission in recent years to determine the units most likely to provide off-system sales. Specifically, the approach weights the units based on their participation in providing the reserves. Then each plant's installed cost (gross plant) is multiplied by the fixed charge rate ("FCR") which includes the rate of return on common equity, income taxes, operations & maintenance, administration and general, and taxes other than income taxes. The cost study supports an annual cost of $96.726/kW. The resulting revenue requirement from multiplying the cost per kW by the amount of reserves necessary to cover the variability of the load, is then divided by the total load for which PacifiCorp provides Regulation Service. This produces a rate of $4.166/kW/year for Schedule 3.

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41 *Id.* at PP 319-320.

42 *Id.*

43 *Integration of Variable Energy Resources,* Order No. 764-A, 141 FERC ¶ 61,232 (2012).

B. Proposed Charges Under Schedule 3A

The cost support for the proposed Schedule 3A charge is the same as for Schedule 3 described above. As explained by Mr. Duvall in Exhibit No. PAC-7, the amount of capacity necessary for regulating VERs is greater per kW of generation than for non-VERs. In order to reflect the different cost causation between the VER and non-VER generators, separate charges were developed for each class of generator. As noted above, each plant's installed cost (see PAC-5, Attachment B) is multiplied by the FCR to determine an annual cost per kW of regulation capacity of $96.726/kW. The amount of capacity to regulate VER and non-VER generators is determined in Mr. Duvall's testimony. The revenue requirement for non-VERs is developed by multiplying the annual cost per kW by the amount of reserves necessary to regulate for the non-VERs, which is then divided by the total installed capacity of the non-VER generation located in a PacifiCorp BAA. This produces a rate for non-VERs of $0.001/kW/year for Schedule 3A. The revenue requirement for VERs is developed by multiplying the annual cost per kW by the amount of reserves necessary to regulate for the VERs, which is then divided by the total installed capacity of the VER generation located in a PacifiCorp BAA. This produces a rate for VER generators of $8.255/kW/year for Schedule 3A.

C. Impact on PacifiCorp's Customers

PacifiCorp's proposed changes to Schedules 3 and 3A are based on a year's worth of data and derived using a methodology consistent with the policies articulated in Order No. 764. Using this data and methodology, PacifiCorp's proposed Schedule 3 represents an approximately 43.7 percent rate increase for affected customers when compared to the currently effective black-box settlement rates.[44] The proposed changes result in a revenue increase for Schedule 3 of the OATT of approximately $10,570,094. For Schedule 3A, the proposed changes result in a revenue decrease of approximately $6,672,153. Under proposed Schedule 3A, the rate impacts vary considerably by customer. When the proposed 3A rates are compared to the currently effective black-box settlement rates, some customers will see a rate decrease of approximately 99.9 percent; others will see a rate increase of approximately 184.6 percent; and other customers will see no rate impact. The impact identified on Legacy Contract customers is an increase of approximately 43.7 percent. The revenue increase for Legacy Contracts is approximately $827,811.

PacifiCorp's Statements BH and BG include a detailed analysis of this filing's rate impact on PacifiCorp's transmission customers.

IV. CONTENTS OF THE FILING

This filing consists of the following documents:

- This transmittal letter;

[44] There is currently no rate impact under Schedule 3A for customers wheeling through PacifiCorp's BAAs.

- **<u>ATTACHMENT A:</u>** Attestation of PacifiCorp's Chief Financial Officer, Douglas K. Stuver, pursuant to 18 C.F.R. § 35.13(d)(6);
- **<u>ATTACHMENT B:</u>** Revised sheets to Schedules 3 and 3A of PacifiCorp's OATT (clean version);
- **<u>ATTACHMENT C:</u>** Revised sheets to Schedules 3 and 3A of PacifiCorp's OATT (black-lined version);[45]
- **<u>ATTACHMENT D:</u>** Testimony and Accompanying Exhibits of Sarah E. Edmonds, PacifiCorp's Director of Transmission Regulation, Strategy & Policy (Exhibit Nos. PAC-1 – PAC-2);
- **<u>ATTACHMENT E:</u>** Testimony and Accompanying Exhibits of Alan C. Heintz, Vice President of Brown, Williams, Moorhead and Quinn, Inc., including PacifiCorp's Statement BG and Statement BH pursuant to 18 C.F.R. § 35.13(c) (Exhibit Nos. PAC-3 – PAC-6); and
- **<u>ATTACHMENT F:</u>** Testimony and Accompanying Exhibits of Gregory H. Duvall, PacifiCorp's Director of Net Power Costs (Exhibit Nos. PAC-7 – PAC-10).

V. EFFECTIVE DATE AND APPROVAL

PacifiCorp respectfully requests that the Commission accept these proposed tariff revisions for filing to become effective, without any suspension or hearing, on June 1, 2013. PacifiCorp's proposed schedules for regulation service are substantially similar to those FERC has approved for use by other transmission providers and with the policies set forth in Order Nos. 764 and 764-A, and therefore are consistent with Commission precedent.

In the event the Commission determines that this filing requires further investigation and should be set for hearing, PacifiCorp respectfully requests that FERC direct any suspension of rates for only a nominal period. The Commission has required only a nominal suspension in similar rate filings.[46]

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 rates to be accepted by FERC and made effective in the manner proposed herein.

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[45] In addition to providing black-lined versions of the tariff sheets comparing them to the currently-effective versions, consistent with FERC filing requirements, PacifiCorp is also including, for informational purposes, black-lined versions of the tariff sheets comparing them to the tariff sheets appended to the Settlement Agreement. *See* Exhibit No. PAC-2. Such tariff sheets have not been submitted via eTariff to date, consistent with the Settlement Agreement commitment for PacifiCorp to do so upon Commission acceptance or approval of the agreement.

[46] *See, e.g., Westar*, 130 FERC ¶ 61,215 at P 130 (suspending filing for nominal period).

VI. COMMUNICATIONS

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

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VII. SERVICE

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

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

VIII. INFORMATION REQUIRED BY 18 C.F.R. § 35.13

The following information is required for filings of changes in rate schedules or tariffs, under Section 35.13(a)(1) of the Commission's regulations.[47]

[47] 18 C.F.R. § 35.13(a)(1).

a. Documents Submitted with the Rate Change - Section 35.13(b)(1)

See *supra* Section IV.

b. Date on Which the Utility Proposes to Make the Rate Change Effective - Section 35.13(b)(2)

June 1, 2013. See *supra* Section V.

c. The Names and Addresses of Persons to Whom a Copy of the Rate Change Has Been Posted - Section 35.13(b)(3)

See *supra* Section VII.

d. Brief Description of the Rate Change - Section 35.13(b)(4)

See supra Sections I and II. *See also* Testimony of Sarah E. Edmonds (Exhibit No. PAC-1).

e. Statement of the Reasons for the Rate Change - Section 35.13(b)(5)

See supra Sections I and II. *See also* Testimony of Sarah E. Edmonds (Exhibit No. PAC-1).

f. Showing re: Requisite Agreement to the Rate Change - Section 35.13(b)(6)

PacifiCorp is not required to obtain agreement to the rate changes proposed. PacifiCorp retains all rights under FPA Section 205 to file unilateral changes to the OATT. Customers holding service agreements under this OATT need not consent for this rate change to take effect.

g. Statement re: Expenses or Costs Included in the Cost-of-Service Statements - Section 35.13(b)(7)

No costs or expenses included herein have been alleged or judged in any administrative or judicial proceeding to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

h. Information Relating to the Effect of the Rate Change - Section 35.13(c)

Exhibit No. PAC-3, Testimony of Alan C. Heintz, includes PacifiCorp's Statement BG and Statement BH, which contain the requisite information relating to the effect of the rate change during Period I and Period II.

i. Cost-of-Service Information, Periods I and II Data - Sections 35.13(d)(1), (2) and Section 35.13(h)

As discussed above, PacifiCorp is proposing to revise the regulation capacity charge under Schedules 3 and 3A of its OATT, and revise the billing determinants for load, VER and non-VER generators. The cost-of-service and rate design information that support this filing are set forth in the Testimony and Exhibits of Alan C. Heintz and Gregory H. Duvall.

As this filing is limited to the rates for PacifiCorp's Schedule 3, Regulation and Frequency Response Service, and Schedule 3A, Generator Regulation and Frequency Response Service, the only statements provided are those relevant to these rates, which are Statements BG and BH. As stated above, Statements BG and BH are exhibits to the Testimony of Alan C. Heintz. *See also* request for waiver described below in Section IX.

j. Workpapers - Section 35.13(d)(5)

No workpapers are being submitted with the filing.

k. Attestation - Section 35.13(d)(6)

The attestation of PacifiCorp's Chief Financial Officer, Douglas K. Stuver, required by 18 C.F.R. § 35.13(d)(6), is included as Attachment A.

l. Testimony and Exhibits - Section 35.13(e)

In support of its request for changes to Schedules 3 and 3A, PacifiCorp presents the testimony of three witnesses, as described above in Section IV.

IX. REQUESTS FOR WAIVERS OF PART 35

PacifiCorp believes that the information contained in this filing provides a sufficient basis upon which to accept the proposed changes to its OATT Schedules 3 and 3A without condition, modification, or trial-type proceedings. To the extent necessary, however, PacifiCorp respectfully requests that the Commission waive any filing requirements contained in 18 C.F.R. Part 35 not met by this filing.[48]

[48] 18 C.F.R. Part 35 (2012).

X. CONCLUSION

PacifiCorp respectfully requests that the Commission: (1) accept these proposed tariff sheet revisions for filing; (2) allow such revisions to become effective June 1, 2013, without suspension, condition, or modification; and (3) grant any other waivers or authorizations necessary to make the revised tariff sheets effective upon the date requested.

Respectfully Submitted,

/s/ Mark M. Rabuano

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Enclosures

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 1st day of April, 2013.

<u>/s/ Mark M. Rabuano</u>
Mark M. Rabuano
PacifiCorp
825 N.E. Multnomah, Suite 1800
Portland, OR 97232
(503) 813-5744
Mark.Rabuano@PacifiCorp.com

ATTACHMENT A

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp	)	**Docket No. ER13-___-000**

ATTESTATION PURSUANT TO 18 C.F.R. § 35.13(d)(6)

Douglas K. Stuver attests that he is the Chief Financial Officer of PacifiCorp and that, to the best of his knowledge, information, and belief, the cost of service materials and supporting data submitted as part of this filing which purport to reflect the books of PacifiCorp are true, accurate, and current representations of the company's books, budgets, or other documents.

Doug K. S

Douglas K. Stuver

Subscribed and sworn before me at 825 NE Multnomah St, Portland, OR 97232

This 28 of March, 2013

Sheila R. Ho

Notary Public

My commission expires on August 30, 2015

OFFICIAL SEAL
SHEILA R HO
NOTARY PUBLIC-OREGON
COMMISSION NO. 460709
MY COMMISSION EXPIRES AUGUST 30, 2015

ATTACHMENT B

SCHEDULE 3

Regulation and Frequency Response Service

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

The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation, as further described in applicable PacifiCorp business practices. Alternative comparable arrangements may include a Transmission Customer self-supplying this service from generation or non-generation resources.

The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Charge for Regulation and Frequency Response Service: The charges below apply to all Network Integration Transmission Service. Firm imports do not reduce the load obligation. The Transmission Provider may not charge a Transmission Customer for service under both Schedule 3 and Schedule 3A for the same transaction.

The rates below are applied to the Transmission Customer’s Monthly Network Load for Network Integration Transmission Service.

1. Yearly Rate $4.166/kW/Year

2.	Monthly Rate	$0.347/kW/Month
3.	Weekly Rate	$0.080/kW/Week
4.	Daily Rate, On-Peak	$0.016/kW/Day
5.	Daily Rate, Off-Peak	$0.011/kW/Day
6.	Hourly Rate, On-Peak	$1.002/MWh
7.	Hourly Rate, Off-Peak	$0.477/MWh

The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 3 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 3 times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Alternative Comparable Arrangements: A Transmission Customer may choose to self-supply or purchase from a third-party its Regulation and Frequency Response Service obligation. Due to the nature of this service a Transmission Customer must either (1) purchase 100% of its requirements from the Transmission Provider, or (2) self-supply or arrange for the purchase from a third-party of 100% of its requirements. Failure of the Transmission Customer to account for 100% of its requirements through alternative comparable arrangements will result in the charges above being incurred for the amount the Transmission Customer failed to provide.

The total Regulation and Frequency Response Service obligation for a Transmission Customer who self-supplies or purchases this service from a third-party is determined by the currently-effective version of NERC Reliability Standard BAL-001. The requirement is such that the Transmission Customer that is providing Regulation and Frequency Response Service must show, on no less than an annual basis, that it is capable of meeting the requirements of the currently-effective version of BAL-001 consistent with applicable PacifiCorp business practices.

SCHEDULE 3A

Generator Regulation and Frequency Response Service

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

The Transmission Provider must offer this service when the transmission service is provided for a generator physically or electrically located in the Transmission Provider's Control Area and exported to another Control Area. Generator Regulation and Frequency Response Service applies to the extent that a Transmission Customer is not already subject to Regulation and Frequency Response Service provided under Schedule 3. When applicable, the Transmission Customer must either purchase Generator Regulation and Frequency Response Service from the Transmission Provider or make alternative comparable arrangements, as further described in applicable PacifiCorp business practices. Alternative comparable arrangements may include a Transmission Customer self-supplying this service from generation or non-generation resources or dynamically scheduling its generation to another Control Area.

The amount of and charges for Generator Regulation and Frequency Response Service are set forth below. To the extent a Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider may not charge a Transmission Customer for service under both Schedule 3 and Schedule 3A for the same transaction.

Charge for Regulation and Frequency Response Service: The charges below apply to service that originates in a PacifiCorp Control Area and terminates in another Control Area, including: 1) Long-Term Firm Point-to-Point Transmission Service and 2)

Short-Term Firm and Non-Firm Point-to-Point Transmission Service. The rates below are applied to the amount of the Transmission Customer's Reserved Capacity for Long-Term Firm Point-to-Point Transmission Service, or the Transmission Customer's hourly schedules for Short-Term Firm or Non-Firm Point-to-Point Transmission Service exported from the PacifiCorp Control Area. For purposes of charging the rates set forth in this Schedule 3A to Transmission Customers purchasing Point-to-Point Transmission Service, the billing determinants shall be the amount of system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff.

As used herein, "Variable Energy Resource" shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

For any Variable Energy Resource, the following charges will apply:

1.	Yearly Rate	$8.255/kW/Year
2.	Monthly Rate	$0.688/kW/Month
3.	Weekly Rate	$0.159/kW/Week
4.	Daily Rate, On-Peak	$0.032/kW/Day
5.	Daily Rate, Off-Peak	$0.023/kW/Day
6.	Hourly Rate, On-Peak	$1.984/MWh
7.	Hourly Rate, Off-Peak	$0.945/MWh

For any non-Variable Energy Resource, the following charges will apply:

1.	Yearly Rate	$0.001/kW/Year
2.	Monthly Rate	$0.000/kW/Month
3.	Weekly Rate	$0.000/kW/Week
4.	Daily Rate, On-Peak	$0.000/kW/Day
5.	Daily Rate, Off-Peak	$0.000/kW/Day
6.	Hourly Rate, On-Peak	$0.000/MWh
7.	Hourly Rate, Off-Peak	$0.000/MWh

The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 3A times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 3A times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Alternative Comparable Arrangements: A Transmission Customer may choose to self-supply or purchase from a third party its Generator Regulation and Frequency Response Service obligation. Due to the nature of this service a Transmission Customer must either (1) purchase 100% of its requirements from the Transmission Provider, or (2) self-supply or arrange for the purchase from a third party of 100% of its requirements. Failure of the Transmission Customer to account for 100% of its requirements through alternative comparable arrangements will result in the charges above being incurred for the amount the Transmission Customer failed to provide.

The total Generator Regulation and Frequency Response Service obligation for a Transmission Customer who self-supplies or purchases this service from a third party is determined by the currently-effective version of NERC Reliability Standard BAL-001. The requirement is such that the Transmission Customer that is providing Generator Regulation and Frequency Response Service must show, on no less than an annual basis, that it is capable of meeting the requirements of the currently–effective version of BAL-001 consistent with applicable PacifiCorp business practices.

ATTACHMENT C

SCHEDULE 3

Regulation and Frequency Response Service

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

The Transmission Provider must offer this service when the ~~Transmission Service~~transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation~~.~~, as further described in applicable PacifiCorp business practices. Alternative comparable arrangements may include a Transmission Customer self-supplying this service from generation or non-generation resources.

The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Charge for Regulation and Frequency Response Service: ~~A Transmission Customer purchasing Regulation and Frequency Response Service will be required to purchase an amount of reserved capacity equal to 4.24 percent of the Transmission Customer's Reserved Capacity for Point-to-Point Transmission Service or 4.24 percent of the Transmission Customer's Monthly Network Load for~~The charges below apply to all Network Integration Transmission Service. ~~The billing determinants for this service shall be reduced by any portion of the 4.24 percent purchase obligation that~~Firm imports do not reduce the load obligation. The Transmission Provider may not charge a

Transmission Customer ~~obtains from third-parties or supplies itself.~~for service under both Schedule 3 and Schedule 3A for the same transaction.

The~~ rates below reflect the percentage purchase obligation stated above multiplied by the cost of providing the ancillary services described in this Schedule 3. Accordingly, the~~ rates below are applied to the ~~amount of the Transmission Customer's Reserved Capacity for Point-to-Point Transmission Service or the~~ Transmission Customer's Monthly Network Load for Network Integration Transmission Service.

1.	Yearly Rate	$~~4.021~~4.166/kW/Year
2.	Monthly Rate	$~~0.335~~0.347/kW/Month
3.	Weekly Rate	$~~0.077~~0.080/kW/Week
4.	Daily Rate, On-Peak	$~~0.015~~0.016/kW/Day
5.	Daily Rate, Off-Peak	$0.011/kW/Day
6.	Hourly Rate, On-Peak	$~~0.967~~1.002/MWh
7.	Hourly Rate, Off-Peak	$~~0.460~~0.477/MWh

The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 3 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 3 times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Alternative Comparable Arrangements: A Transmission Customer may choose to self-supply or purchase from a third-party its Regulation and Frequency Response Service obligation. Due to the nature of this service a Transmission Customer must either (1) purchase 100% of its requirements from the Transmission Provider, or (2) self-supply or arrange for the purchase from a third-party of 100% of its requirements. Failure of the Transmission Customer to account for 100% of its requirements through alternative comparable arrangements will result in the charges above being incurred for the amount the Transmission Customer failed to provide.

The total Regulation and Frequency Response Service obligation for a Transmission Customer who self-supplies or purchases this service from a third-party is determined by the currently-effective version of NERC Reliability Standard BAL-001. The requirement is such that the Transmission Customer that is providing Regulation and Frequency Response Service must show, on no less than an annual basis, that it is capable of meeting the requirements of the currently-effective version of BAL-001 consistent with applicable PacifiCorp business practices.

SCHEDULE 3A

Generator Regulation and Frequency Response Service

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

The Transmission Provider must offer this service when the transmission service is provided for a generator physically or electrically located in the Transmission Provider's Control Area and exported to another Control Area. Generator Regulation and Frequency Response Service applies to the extent that a Transmission Customer is not already subject to Regulation and Frequency Response Service provided under Schedule 3. When applicable, the Transmission Customer must either purchase Generator Regulation and Frequency Response Service from the Transmission Provider or make alternative comparable arrangements, ~~which may include self-supplying regulation reserve capacity~~as further described in applicable PacifiCorp business practices. Alternative comparable arrangements may include a Transmission Customer self-supplying this service from generation or non-generation resources or ~~through~~ dynamically scheduling its generation to another Control Area.

The amount of and charges for Generator Regulation and Frequency Response Service are set forth below. To the extent a Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that ~~Balancing Authority~~Control Area operator. The Transmission Provider may not charge a Transmission Customer for ~~regulation reserves~~service under both Schedule 3 and Schedule 3A for the same transaction.

Charge for Regulation and Frequency Response Service:

~~A Transmission Customer purchasing Generator Regulation and Frequency Response Service will be required to purchase an amount of reserved capacity equal to 4.24 percent of the Transmission Customer's Reserved Capacity for Point-to-Point Transmission Service or 4.24 percent of the Transmission Customer's Monthly Network Load for Network Integration Transmission Service. The billing determinants for this service shall be reduced by any portion of the 4.24 percent purchase obligation that a Transmission Customer obtains from third parties or supplies itself. The rates below reflect the percentage purchase obligation stated above multiplied by the cost of providing the ancillary services described in this Schedule 3A. Accordingly, the~~The charges below apply to service that originates in a PacifiCorp Control Area and terminates in another Control Area, including: 1) Long-Term Firm Point-to-Point Transmission Service and 2) Short-Term Firm and Non-Firm Point-to-Point Transmission Service. The rates below are applied to the amount of the Transmission Customer's Reserved Capacity for Long-Term Firm Point-to-Point Transmission Service, or the Transmission Customer's ~~Monthly Network Load for Network Integration Transmission Service.~~ hourly schedules for Short-Term Firm or Non-Firm Point-to-Point Transmission Service exported from the PacifiCorp Control Area. For purposes of charging the rates set forth in this Schedule 3A to Transmission Customers purchasing Point-to-Point Transmission Service, the billing determinants shall be the amount of system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff.

As used herein, "Variable Energy Resource" shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

For any Variable Energy Resource, the following charges will apply:

1.	Yearly Rate	$~~4.021~~8.255/kW/Year
2.	Monthly Rate	$~~0.335~~0.688/kW/Month
3.	Weekly Rate	$~~0.077~~0.159/kW/Week
4.	Daily Rate, On-Peak	$~~0.015~~0.032/kW/Day
5.	Daily Rate, Off-Peak	$~~0.011~~0.023/kW/Day

6. Hourly Rate, On-Peak $~~0.967/kW/Day~~ 1.984/MWh
7. Hourly Rate, Off-Peak $~~0.460~~0.945/MWh

For any non-Variable Energy Resource, the following charges will apply:

1.	Yearly Rate	$0.001/kW/Year
2.	Monthly Rate	$0.000/kW/Month
3.	Weekly Rate	$0.000/kW/Week
4.	Daily Rate, On-Peak	$0.000/kW/Day
5.	Daily Rate, Off-Peak	$0.000/kW/Day
6.	Hourly Rate, On-Peak	$0.000/MWh
7.	Hourly Rate, Off-Peak	$0.000/MWh

The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 3A times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 3A times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Alternative Comparable Arrangements: A Transmission Customer may choose to self-supply or purchase from a third party its Generator Regulation and Frequency Response Service obligation. Due to the nature of this service a Transmission Customer must either (1) purchase 100% of its requirements from the Transmission Provider, or (2) self-supply or arrange for the purchase from a third party of 100% of its requirements. Failure of the Transmission Customer to account for 100% of its requirements through alternative comparable arrangements will result in the charges above being incurred for the amount the Transmission Customer failed to provide.

The total Generator Regulation and Frequency Response Service obligation for a Transmission Customer who self-supplies or purchases this service from a third party is determined by the currently-effective version of NERC Reliability Standard BAL-001. The requirement is such that the Transmission Customer that is providing Generator Regulation and Frequency Response Service must show, on no less than an annual basis, that it is capable of meeting the requirements of the currently-effective version of BAL-001 consistent with applicable PacifiCorp business practices.

ATTACHMENT D

Exhibit No. PAC-1

UNITED STATES OF AMERICA

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PacifiCorp	)	Docket No. ER13-___-000
	)	

TESTIMONY OF

SARAH E. EDMONDS
ON BEHALF OF PACIFICORP

April 1, 2013

TABLE OF CONTENTS

LIST OF EXHIBITS

I. <u>INTRODUCTION AND EXPERIENCE</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My Name is Sarah E. Edmonds. My business address is 825 NE Multnomah Street, Portland, Oregon 97232.

Q. IN WHAT POSITION ARE YOU CURRENTLY EMPLOYED?

A. I am the Director of Transmission Regulation, Strategy & Policy for PacifiCorp (also hereinafter called the "Company"). I have been employed at PacifiCorp since 2007.

Q. PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS EXPERIENCE.

A. I have a law degree from Georgetown University Law Center and a bachelor's degree from the University of Oregon. My experience spans over ten years in the energy industry, including representing energy clients as an attorney in matters before the Federal Energy Regulatory Commission ("FERC" or the "Commission") and in other administrative proceedings, advising energy clients related to energy regulatory, policy and business matters, and directing transmission customer service, regulatory, and policy activities for PacifiCorp's transmission services business unit. Since joining the Company in 2007, my responsibilities have included managing the following areas of PacifiCorp's transmission business: (i) Open Access Transmission Tariff ("OATT" or "Tariff") and Open Access Same-Time Information System ("OASIS") administration; (ii) transmission customer services; (iii) development of transmission policy and strategy; and (iv) development of transmission rates and recovery of transmission investments.

Q. PLEASE SUMMARIZE THE BASIS OF YOUR KNOWLEDGE AND CONCLUSIONS CONCERNING THE ISSUES TO WHICH YOU ARE TESTIFYING IN THIS CASE.

A. I was responsible for managing PacifiCorp's most recent transmission and ancillary services rate case, filed on May 26, 2011, in Docket No. ER11-3643-000. On February 22, 2013, PacifiCorp filed a settlement agreement resolving all issues in Docket No. ER11-3643-000, including proposals for amended charges for Schedules 3 and 3A, and a commitment for PacifiCorp to file revised Schedule 3 and 3A rates by April 1, 2013, with a proposed effective date of June 1, 2013 ("February 22, 2013 Settlement Agreement"). The Company needs to update Schedule 3 and 3A rates at this time in order to satisfy this settlement commitment and ensure that it is appropriately compensated for the costs it incurs in providing regulating margin reserve service[1] to its transmission customers serving load within the PacifiCorp Balancing Authority Areas ("BAAs") and those generators exporting from a PacifiCorp BAA.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide an overview of this filing, including the following: (1) the purpose of (and need for) the Company's proposed Schedule 3 and 3A rates; (2) PacifiCorp's proposed Schedule 3 and 3A tariff changes (*see* Exhibit No. PAC-2); and (3) the consistency of PacifiCorp's proposal with FERC policies for rates which recover the cost of regulating margin reserve service. My testimony also describes the other testimony supporting this filing.

II. <u>OTHER TESTIMONY SUPPORTING THIS FILING</u>

Q. ARE ANY OTHER INDIVIDUALS FILING TESTIMONY ON BEHALF OF PACIFICORP IN THIS PROCEEDING?

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[1] Order No. 764 refers to this service as "generator regulation service." *See Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246, at P 4 (2012) ("Order No. 764"), *order on reh'g*, 141 FERC ¶ 61,232 (2012) ("Order No. 764-A"). While PacifiCorp uses the term "regulating margin reserve service" to describe this service, the two are functionally identical.

A. Yes. The following individuals are providing testimony on behalf of PacifiCorp:

- Alan C. Heintz, Vice President of Brown, Williams, Morehead, and Quinn, Inc., has prepared testimony (*see* Exhibit No. PAC-3) supporting the rate methodologies employed for PacifiCorp's proposed charges for Schedules 3 and 3A of PacifiCorp's OATT.
- Gregory N. Duvall, Director of Net Power Costs for PacifiCorp, has prepared testimony (*see* Exhibit No. PAC-7) supporting (1) the total amount of regulating margin reserves that are needed by PacifiCorp to provide service under revised Schedules 3 and 3A of PacifiCorp's OATT; (2) the allocation of the total amount of regulating margin reserves among load, variable energy resources ("VERs") and non-VER generation; and (3) identification of the specific resources that supply the total amount of regulating margin reserves, including the proportional contributions of such resources (*see* Exhibit No. PAC-11). Mr. Duvall's testimony is supported in part by PacifiCorp's March 2013 study explaining these amounts (the "PacifiCorp Schedule 3 and 3A Study") (*see* Exhibit No. PAC-8).

III. <u>DESCRIPTION OF PACIFICORP</u>

Q. PLEASE PROVIDE A DESCRIPTION OF PACIFICORP.

A. PacifiCorp is an indirect, wholly-owned subsidiary of MidAmerican Energy Holdings Company. PacifiCorp provides delivery of electric power and energy to approximately 1.8 million retail electric customers in six western states. PacifiCorp consists of three core business units: (1) PacifiCorp Energy, which manages the electric generation, commercial and trading, and coal mining operations of the Company; (2) Pacific Power, which delivers electricity to retail customers in Oregon, Washington and California; and

(3) Rocky Mountain Power, which delivers electricity to retail customers in Utah, Wyoming and Idaho. PacifiCorp's transmission operations and management personnel are headquartered in Portland, Oregon.

Under its OATT, PacifiCorp provides Long-Term Firm Point-to-Point ("PTP") Transmission Service to 9 transmission customers, Short-Term Firm and Non-Firm PTP Transmission Service to 69 transmission customers under umbrella service agreements, and Network Integration Transmission ("NIT") Service to eight transmission customers, including PacifiCorp Energy. PacifiCorp also provides transmission service to certain "legacy" transmission customers under transmission service agreements pre-dating the OATT.

As of December 31, 2011, PacifiCorp's current total transmission plant in service is approximately $4.5 billion.[2] PacifiCorp is interconnected with more than 80 generation plants and 13 adjacent BAAs at approximately 152 points of interconnection. PacifiCorp owns, or has an interest in, generation resources directly interconnected to its transmission system with a system peak capacity of approximately 16,750 MW.[3] This generation capacity includes a diverse mix of coal, hydroelectric, wind, natural gas-fired combined cycle and combustion turbines, and geothermal resources.

Q. PLEASE DESCRIBE PACIFICORP'S TRANSMISSION SYSTEM.

A. PacifiCorp's bulk transmission network is designed to reliably transport electric energy from generation resources (owned generation or market purchases) to various load centers. The Company's transmission network is highly integrated with other

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[2] PacifiCorp 2011 FERC Form No. 1 at 206-207 (June 28, 2012).

[3] *Id*. at 400.

transmission providers in the western United States. PacifiCorp owns and operates approximately 16,763 miles of transmission lines in 10 states.[4] PacifiCorp operates two Balancing Authority Areas ("BAAs"), referred to as PACE for PacifiCorp's east BAA and PACW for PacifiCorp's west BAA.

Q. WHICH STATE PUBLIC UTILITY COMMISSIONS REGULATE PACIFICORP'S RETAIL SERVICE OPERATIONS?

A. PacifiCorp is subject to the jurisdiction of the following six state public utility commissions: (1) California Public Utilities Commission; (2) Idaho Public Utilities Commission; (3) Oregon Public Utility Commission; (4) Public Service Commission of Utah; (5) Washington Utilities and Transportation Commission; and (6) Wyoming Public Service Commission.

IV. <u>PURPOSE OF RATE FILING FOR SCHEDULES 3 AND 3A</u>

Q. WHY IS PACIFICORP FILING FOR NEW SCHEDULE 3 AND 3A RATES AT THIS TIME?

A. As discussed above, on February 22, 2013, PacifiCorp filed a settlement agreement resolving all issues in its transmission and ancillary services rate case, Docket No. ER11-3643-000. PacifiCorp committed, as a condition of the February 22, 2013 Settlement Agreement, to file new proposed Schedule 3 and 3A rates by April 1, 2013, with a proposed effective date of June 1, 2013. PacifiCorp also agreed that the filing would be based on a study containing at least one year's worth of data to determine both the amount of regulating margin reserves required by PacifiCorp's BAAs and the different amounts of reserves needed for loads and resources.

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[4] PacifiCorp 2011 FERC Form No. 1 at 422 (June 28, 2012).

Q. DOES THIS FILING SATISFY ALL OF THE CONDITIONS IN THE FEBRUARY 22, 2013 SETTLEMENT AGREEMENT?

A. Yes. PacifiCorp's filing, as described herein and in the other testimony, requests a proposed effective date of June 1, 2013. Further, the Schedule 3 and 3A Study contains at least one year's worth of data to determine both the amount of regulating margin reserves required by PacifiCorp's BAAs and the different amounts of reserves needed for loads and resources.

Q. PLEASE PROVIDE A DESCRIPTION OF PACIFICORP'S LAST FILING RESULTING IN RATES FOR SCHEDULES 3 AND 3A.

A. In PacifiCorp's last transmission rate case filing, submitted on May 26, 2011, in Docket No. ER11-3643-000, PacifiCorp sought to modify its transmission and ancillary services rates and adopt a formula transmission rate. PacifiCorp proposed employing a formula rate to calculate its rates for PTP Transmission Service and NIT Service, and such rates would be updated annually pursuant to the formula rate implementation protocols. In addition to seeking formula rates, the Company also modified its existing Schedule 3 to reflect updated charges for providing Regulation and Frequency Response Service, and proposed the addition of new Schedule 3A, Generator Regulation and Frequency Response Service. On August 8, 2011, FERC issued an order in the docket accepting PacifiCorp's filing and allowing the proposed rates to become effective December 25, 2011, subject to refund.[5] FERC established settlement proceedings to encourage the parties to reach agreement on a final set of rates. The parties executed the February 22,

[5] *See PacifiCorp*, 136 FERC ¶ 61,092 (2011) ("Hearing Order"), *reh'g denied*, 137 FERC ¶ 61,147 (2011).

2013 Settlement Agreement and, as noted above, PacifiCorp committed, as a condition of this agreement, to file new proposed Schedule 3 and 3A rates on or before April 1, 2013.

Q. PLEASE DESCRIBE PACIFICORP'S OATT SCHEDULES 3 AND 3A AS PROPOSED IN DOCKET NO. ER11-3643-000.

A. As originally proposed in PacifiCorp's transmission and ancillary service rate case in Docket No. ER11-3643, the rates for Schedule 3 and 3A were designed using the same costs and billing determinants. PacifiCorp determined the rates for this service by dividing the total amount of regulating margin reserves needed to balance the system by a billing determinant equal to PacifiCorp's 2010 coincident peak ("CP") demand. The rates produced were included in both Schedule 3 (Regulation and Frequency Response Service) applicable to a transmission customer serving load within PacifiCorp's BAAs and Schedule 3A (Generator Regulation and Frequency Response Service) applicable to a transmission customer exporting off-system from a generator physically located in one of PacifiCorp's BAAs. Generator Regulation and Frequency Response Service under Schedule 3A applies to the extent that a transmission customer is not already subject to Regulation and Frequency Response Service provided under Schedule 3. Transmission customers must either purchase Schedule 3 or 3A service, where applicable, or make alternative comparable arrangements (including self-supplying the service). Under the currently effective Schedules 3 and 3A, transmission customers are required to purchase an amount of reserved capacity equal to 4.24 percent of the customer's reserved capacity for PTP Transmission Service or 4.24 percent of the customer's Monthly Network Load for NIT Service. The tariff sheets for Schedules 3 and 3A were filed as part of PacifiCorp's May 26, 2011 transmission rate case filing, with a limited amendment to certain Ancillary Service schedules – including Schedules 3 and 3A – filed on June 9, 2011. In the Hearing Order, FERC accepted for filing and suspended the proposed tariff sheets to become effective December 25, 2011, subject to refund and the outcome of hearing and settlement judge procedures.

Q. DID PACIFICORP PROPOSE REVISIONS TO SCHEDULES 3 AND 3A AS PART OF THE FEBRUARY 22, 2013 SETTLEMENT AGREEMENT?

A. Yes. PacifiCorp included revised Schedules 3 and 3A tariff sheets as appendices to the February 22, 2013 Settlement Agreement, with a proposed tariff sheet effective date of December 25, 2011. Generally speaking, the revised Schedules 3 and 3A tariff sheets include decreased stated rates for Schedule 3 and 3A service compared to the rates filed as part of the May 26, 2011 transmission rate case. In addition, the February 22, 2013 Settlement Agreement includes a commitment for PacifiCorp to make a compliance filing via eTariff to incorporate the revisions to Schedules 3 and 3A of PacifiCorp's OATT, as reflected in the settlement agreement and appendices, within 30 calendar days of the Commission's acceptance or approval of the February 22, 2013 Settlement Agreement. However, PacifiCorp obtained authorization to institute the charges included in Schedules 3 and 3A on an interim basis, effective March 1, 2012, while the February 28, 2013 Settlement Agreement is pending before FERC.[6]

Q. WHAT ARE THE INTERIM RATES FOR SCHEDULES 3 AND 3A CURRENTLY APPLIED TO TRANSMISSION CUSTOMERS?

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[6] *See PacifiCorp*, Docket Nos. ER11-3643-000, *et al.*, "Order of Chief Judge Granting Motion for Interim Rate Relief" (Feb. 28, 2013). On March 26, 2013, the Settlement Judge in the proceeding issued a Certification of Uncontested Settlement, certifying the offer of settlement filed by PacifiCorp. *PacifiCorp*, 142 FERC ¶ 63,023 (2013).

A. Effective March 1, 2013, the following interim rates are applicable to both Schedules 3 and 3A:

1. Yearly Rate	$2.900/kW/Year
2. Monthly Rate	$0.242/kW/Month
3. Weekly Rate	$0.056/kW/Week
4. Daily Rate, On-Peak	$0.011/kW/Day
5. Daily Rate, Off-Peak	$0.008/kW/Day
6. Hourly Rate, On-Peak	$0.697/MWh
7. Hourly Rate, Off-Peak	$0.332/MWh

V. <u>DESCRIPTION OF FILING</u>

A. PacifiCorp's Proposed Schedule 3 and 3A Tariff Changes

Q. HAS PACIFICORP PREPARED REVISED TARIFF SHEETS REFLECTING THE PROPOSED CHANGES TO ITS SCHEDULE 3 AND SCHEDULE 3A TRANSMISSION RATES?

A. Yes. The Company has included as part of this filing both clean versions and black-lined versions of the revised OATT sheets (*see* Exhibit No. PAC-2). PacifiCorp includes with this filing two sets of black-lined Schedules 3 and 3A:

(1) the revised tariff sheets compared to the currently-effective versions of Schedules 3 and 3A (*i.e.*, those filed as part of the May 26, 2011 transmission rate case filing and effective December 25, 2011); and

(2) the revised tariff sheets compared to the versions appended to PacifiCorp's February 22, 2013 Settlement Agreement, for informational purposes. The February 22, 2013 Settlement Agreement requires PacifiCorp to make a

compliance filing via eTariff within 30 calendar days of FERC's approval or acceptance of the settlement agreement to incorporate these superseding revisions of the tariff sheets into PacifiCorp's OATT, with an effective date of December 25, 2011.

Q. PLEASE DESCRIBE THE CHANGES MADE IN THE REVISED TARIFF SHEETS.

A. PacifiCorp's tariff sheets for OATT Schedules 3 and 3A have been modified in this filing to reflect the revised charges for providing Regulation and Frequency Response Service and Generator Regulation and Frequency Response Service, respectively.

Q. PLEASE DESCRIBE THE PROPOSED REVISIONS TO SCHEDULE 3 OF THE TARIFF.

A. The revised Schedule 3 in this filing provides that the stated charges apply to all NIT Service (applied to the customer's Monthly Network Load). The revised Schedule 3 also clarifies that the failure of a transmission customer to account for 100 percent of its service requirements through alternative comparable arrangements will result in Schedule 3 charges being incurred for the amount the transmission customer failed to provide.

The revised Schedule 3 includes the following new charges for service:

1. Yearly Rate	\$4.166/kW/Year
2. Monthly Rate	\$0.347/kW/Month
3. Weekly Rate	\$0.080/kW/Week
4. Daily Rate, On-Peak	\$0.016/kW/Day
5. Daily Rate, Off-Peak	\$0.011/kW/Day
6. Hourly Rate, On-Peak	\$1.002/kW/Day

7. Hourly Rate, Off-Peak $0.477/MWh

Mr. Heintz's testimony further discusses the methodology by which the proposed rates for this Schedule 3 charge were derived. The testimony of Mr. Duvall provides additional detail on the Company's methodology for calculating the amount of regulating margin reserves required for Schedule 3 service.

Q. PLEASE DESCRIBE THE PROPOSED REVISIONS TO SCHEDULE 3A OF THE TARIFF.

A. The revised Schedule 3A in this filing maintains that the charges apply to service that originates in a PacifiCorp BAA and terminates in another utility's BAA, including Long-Term Firm PTP Transmission Service, Short-Term Firm PTP Transmission Service, and Non-Firm PTP Transmission Service. The revised Schedule 3A sets forth differentiated rates for service applied to VERs and non-VERs. Schedule 3A defines a "VER" as "a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator," consistent with the Commission's Integration of Variable Energy Resources Final Rule ("Order No. 764").[7] The revised Schedule 3A also clarifies that the failure of a transmission customer to account for 100 percent of its service requirements through alternative comparable arrangements will result in Schedule 3A charges being incurred for the amount the transmission customer failed to provide.

The revised Schedule 3A includes the following new charges for service:

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[7] Order No. 764 at P 210.

VER Generators:

1. Yearly Rate	\$8.255/kW/Year
2. Monthly Rate	\$0.688/kW/Month
3. Weekly Rate	\$0.159/kW/Week
4. Daily Rate, On-Peak	\$0.032/kW/Day
5. Daily Rate, Off-Peak	\$0.023/kW/Day
6. Hourly Rate, On-Peak	\$1.984/kW/MWh
7. Hourly Rate, Off-Peak	\$0.945/MWh

Non-VER Generators:

1. Yearly Rate	\$0.001/kW/Year
2. Monthly Rate	\$0.000/kW/Month
3. Weekly Rate	\$0.000/kW/Week
4. Daily Rate, On-Peak	\$0.000/kW/Day
5. Daily Rate, Off-Peak	\$0.000/kW/Day
6. Hourly Rate, On-Peak	\$0.000/kW/MWh
7. Hourly Rate, Off-Peak	\$0.000/MWh

Mr. Heintz's testimony further discusses the methodology by which the proposed rates for this Schedule 3A charge were derived. The testimony of Mr. Duvall provides additional detail on the Company's methodology for calculating the amount of regulating margin reserves required for Schedule 3A service, as applied to VERs and non-VERs for service originating in a PacifiCorp BAA and terminating in another BAA.

Q. PLEASE DESCRIBE THE IMPACT OF THIS FILING ON PACIFICORP'S SCHEDULE 3 AND 3A RATES.

A. Please see Exhibit No. PAC-6 included in the testimony of Mr. Heintz relating to impacts to transmission customers.

B. Consistency of PacifiCorp's Proposal with FERC Policies

Q. HAS FERC SET FORTH POLICIES RELATED TO GENERATOR REGULATING MARGIN RESERVE RATES?

A. Yes. Among other things, FERC discussed its policies for recovering generator regulation charges in Order No. 890-A[8], and has recently approved rates for utilities seeking to recover generator regulation reserve costs.[9] FERC also recently issued Order No. 764, effective November 12, 2013, removing barriers to the integration of VERs and providing additional guidance to public utility transmission providers proposing charges for generator regulation service.

Q. DID PACIFICORP CONSIDER THESE POLICIES IN ITS DEVELOPMENT OF THESE PROPOSED SCHEDULE 3 AND 3A RATES?

A. Yes. As discussed more fully below, these policies guided PacifiCorp's development of its proposed rates for Schedules 3 and 3A.

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[8] *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241 (2007) ("Order No. 890"), *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007) ("Order No. 890-A"), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[9] *See, e.g. Puget Sound Energy, Inc.,* 142 FERC ¶ 61,018 (2013) (approving settlement addressing Puget Sound Energy's ("PSE") ancillary service rates under Schedules 3 and 13, and providing for differentiated recovery of costs to serve non-dispatchable and dispatchable generators exporting from PSE's BAA); *Westar Energy, Inc.,* 130 FERC ¶ 61,215 (2010) (accepting Westar Energy, Inc.'s proposed *pro forma* Schedule 3A, Generator Regulation and Frequency Response Service).

Q. WHY DOES PACIFICORP NEED SCHEDULE 3A FOR GENERATOR REGULATING MARGIN RESERVES WHEN IT HAS SCHEDULE 3?

A. While OATT Schedule 3 allows transmission providers to recover the costs of regulating margin reserves associated with mitigating load variations within a BAA, it does not provide a mechanism for transmission providers to recover the costs of holding capacity in reserve for the provision of balancing the variations in generation whose output is delivered outside of the transmission provider's BAA. Accordingly, proposed Schedule 3A, which applies to VERs and non-VERs located in a PacifiCorp BAA that are exporting to serve load outside a PacifiCorp BAA, ensures that there is no cost recovery gap for PacifiCorp.

The Commission has recognized that such charges may be necessary to prevent under-recovery of costs. For instance, the Company's proposed Schedule 3A is within the scope of rates contemplated by Order No. 890-A, wherein the Commission allowed transmission providers to propose to assess regulation charges both to generators selling in the BAA and those selling outside their BAA. The Commission stated that it would consider such proposals on a case-by-case basis.[10] And, in fact, the Commission has approved proposals by various transmission providers to recover the costs of capacity associated with the provision of generator balancing service through rate schedules for generator regulation and frequency response service.[11]

Moreover, the Company's proposed Schedule 3A is also consistent with the Commission's Order No. 764, dated June 22, 2012, and its Order on Rehearing and

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[10] Order No. 890-A at P 313.

[11] *See supra* note 9.

Clarification and Granting Motion For Extension of Time ("Order No. 764-A"), dated December 20, 2012. In these rules, FERC again recognized the existence of a potential cost-recovery gap for such services, and set forth a series of principles it would consider when evaluating proposals for the rates, terms, and conditions that apply to Generator Regulation and Frequency Response Service.[12] As will be explained, PacifiCorp's Schedule 3A is consistent with the principles outlined in Order Nos. 764 and 764-A.

In short, PacifiCorp's Schedule 3A allows PacifiCorp to close the cost recovery gap that would otherwise exist with the type of ancillary service that FERC has contemplated and accepted in the past for other public utilities.[13] A transmission customer subject to PacifiCorp's proposed Schedule 3A must either (1) take Generator Regulation and Frequency Response Service from PacifiCorp, or (2) demonstrate that it has made alternative comparable arrangements to satisfy its regulating margin reserve service obligation, as described in the revised tariff sheets.

Q. WILL A CHARGE ASSESSED UNDER SCHEDULE 3A RESULT IN DOUBLE RECOVERY OF A CHARGE ASSESSED UNDER SCHEDULE 3?

A. No. Transmission customers subject to charges for regulating margin reserves may be assessed charges under either Schedule 3 or Schedule 3A for the same transaction, but not both. Transmission customers with schedules delivering to load *within* the PacifiCorp BAAs (in the absence of alternative comparable arrangements for 100 percent of the service) will pay Schedule 3 charges for Regulation and Frequency Response Service for such transactions, and will not pay any charges under Schedule 3A.

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12 Order No. 764-A.

13 *See supra* note 9.

Transmission customers with schedules serving load *outside* the PacifiCorp BAAs (to the extent such customers have not made alternative comparable arrangements for the service) will pay Schedule 3A charges for Generator Regulation and Frequency Response Service for such transactions, and will not pay any charges under Schedule 3. In other words, PacifiCorp will not charge transmission customers for service under both Schedules 3 and 3A for the same transaction.[14] In this manner, PacifiCorp can assure that it recovers its costs but does not double-charge any customer under Schedules 3 and 3A.

Q. WHAT IS THE DIFFERENCE BETWEEN CHARGES UNDER SCHEDULE 3A FOR GENERATOR REGULATION AND FREQUENCY RESPONSE SERVICE AND CHARGES UNDER SCHEDULE 9 FOR GENERATOR IMBALANCE SERVICE?

A. Schedule 3A recovers the Company's costs associated with holding generation capacity on-line and available to mitigate the moment-to-moment variations in generation output on an intra-hour basis. Schedule 9 recovers the costs of imbalance energy the Company must provide or accommodate when a difference occurs between the output of a generator located in a BAA and a delivery schedule from that generator based on output and schedule changes at the beginning of the scheduling hour and the end of the scheduling hour. In sum, Schedule 3A is a capacity-based charge and Schedule 9 is an energy-based charge that includes possible penalties to encourage accurate scheduling

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[14] *See, e.g.,* Order No. 764 at P 242 (citing Order No. 890 at P 690 (requiring transmission providers to demonstrate that any proposals to recover capacity costs associated with Generator Imbalance Service do not lead to double recovery)).

practices, consistent with Commission precedent acknowledging the difference between these charges.[15]

Q. ARE SCHEDULES 3 AND 3A CONSISTENT WITH THE PRINCIPLES SET FORTH IN FERC'S ORDER NOS. 764 AND 764-A?

A. Yes. While public utilities are not required to comply with FERC's Order Nos. 764 and 764-A until November 12, 2013, the orders nevertheless provide guidance on the principles the Commission will apply when considering proposed utility rate schedules for generator regulation service. PacifiCorp's revised Schedules 3 and 3A are consistent with the principles set forth in Order Nos. 764 and 764-A regarding recovery of capacity costs for generator regulation services. In particular, PacifiCorp's Schedules 3 and 3A require load, VERs, and non-VERs to purchase different quantities of regulation reserves. In support of these distinctions, Mr. Duvall's testimony discusses how these different quantities were derived and why the differences are reasonably related to the operational characteristics of load, VERs, and non-VERs in PacifiCorp's BAAs.[16] Mr. Duvall's testimony also discusses how PacifiCorp took into account the diversity between load, VERs, and non-VERs in determining the total regulation reserve requirement, in order to ensure that there is no over-recovery of these capacity costs.[17] Mr. Duvall further discusses how the total regulating margin reserve amount was allocated among load, VERs, and non-VERs based upon the operational characteristics of such customer classes.[18] Finally, the orders require transmission providers to take intra-hour scheduling

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[15] Order No. 890 at PP 663-667.

[16] Order No. 764 at P 322.

[17] *Id*. at P 319.

[18] *Id*. at P 320.

and power production forecasting into account when developing proposals for generator regulating margin reserve charges,[19] and, as discussed more fully below, PacifiCorp has accounted for these considerations in its revisions to Schedules 3 and 3A.

Q. PLEASE DESCRIBE PACIFICORP'S IMPLEMENTATION OF INTRA-HOUR SCHEDULING AND INVOLVEMENT WITH THE JOINT INITIATIVE.

A. Beginning in 2008, under a western regional joint initiative (the "Joint Initiative"), three western regional planning groups – ColumbiaGrid, Northern Tier Transmission Group, and WestConnect – pursued a successful voluntary effort resulting in several western utilities' implementation of business practices offering intra-hour scheduling on a 30-minute basis. The Joint Initiative effort identified 30-minute intra-hour scheduling as having the greatest potential to provide significant value for the region at the lowest implementation cost. PacifiCorp, as an active participant in the Joint Initiative, began accepting limited intra-hour schedules on the half-hour in December 2009. Prior to December 2009, PacifiCorp did not offer intra-hour scheduling. PacifiCorp Business Practice #48, "Intra-Hour Transmission Scheduling," was promulgated and posted to PacifiCorp's OASIS website January 2010 to clarify scheduling procedures for submitting new e-Tag schedules within the operating hour to allow for 30-minute schedules. The practice was limited to Non-Firm PTP Transmission Service and was further limited to one intra-hour non-firm schedule per purchase-selling entity per hour.

Beginning August 1, 2011, intra-hour scheduling was expanded more broadly throughout the Pacific Northwest region, including for PacifiCorp's transmission customers. As a result, and in order to better accommodate changes in loads and resources that occur after

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[19] *Id*. at PP 322-323.

the start of the operating hour, PacifiCorp revised Business Practice #48 to establish procedures by which a transmission customer may submit either a new e-Tag or an adjustment to an existing e-Tag for transmission service to PacifiCorp within the current operating hour for a period that begins within that hour. New transmission service requests necessary to facilitate intra-hour schedules will be granted if there is Available Transmission Capability, while requests that will create a reliability issue will be denied. In addition, the previous restriction limiting the practice to one intra-hour non-firm schedule per purchase-selling entity per hour was lifted. PacifiCorp's Business Practice #48 can be found at the following link:

http://www.oasis.oati.com/PPW/PPWdocs/BP48.pdf.

The Commission's Order Nos. 764 and 764-A require PacifiCorp to offer 15-minute scheduling by November 12, 2013. PacifiCorp has developed a compliance plan related to the orders and will meet the compliance deadline.

Q. PLEASE DESCRIBE HOW INTRA-HOUR SCHEDULING HAS BEEN ACCOUNTED FOR IN DETERMINING THE QUANTITY OF REGULATING MARGIN RESERVES REQUIRED FOR SCHEDULES 3 AND 3A.

A. While current operational practices in the Pacific Northwest are based on a 60-minute market, PacifiCorp's Schedule 3 and 3A Study assessed the benefits of a 30-minute intra-hour clearing market for PacifiCorp's customers in determining the total regulating margin reserve amount for Schedules 3 and 3A. PacifiCorp has not experienced a material amount of intra-hour scheduling since it began offering the service as described above. For example, in 2011, PacifiCorp only received 114 total intra-hour schedules, 89 of which were approved pursuant to its business practice. In 2012, PacifiCorp received only slightly more intra-hour schedules – 156 – 127 of which were approved pursuant to its business practice. In 2011, PacifiCorp processed 306,665 transmission schedules, and in 2012 PacifiCorp processed 301,311 transmission schedules. Intra-hour schedules, therefore, represent less than 0.05% of total transmission schedules. For these reasons, while PacifiCorp analyzed utilization of intra-hour schedules for purposes of this filing, the amount of intra-hour schedules was so small that it was deemed to have no measurable impact on the regulating margin reserves level. It is possible that PacifiCorp will see greater levels of utilization following the November 12, 2013, compliance date for implementing 15-minute scheduling, in which case PacifiCorp would consider undertaking an additional analysis to determine whether any measurable impacts to the regulating margin reserves level are occurring.

Q. HOW HAS PACIFICORP CONSIDERED POWER PRODUCTION FORECASTING IN DETERMINING THE QUANTITY OF REGULATING MARGIN RESERVES REQUIRED FOR SCHEDULES 3 AND 3A?

A. Please refer to the testimony of Mr. Duvall for discussion of PacifiCorp's wind forecasting practices and procedures.

Q. WILL PACIFICORP CONSIDER ALTERNATIVE COMPARABLE ARRANGEMENTS TO SATISFY A CUSTOMER'S REGULATION AND FREQUENCY RESPONSE SERVICE OBLIGATION?

A. Yes. PacifiCorp's Schedules 3 and 3A currently state that customers can satisfy their obligation to purchase regulating margin reserve services under Schedules 3 or 3A by making alternative comparable arrangements.

Q. WHAT TYPES OF ARRANGEMENTS WILL PACIFICORP CONSIDER AS ALTERNATIVE COMPARABLE ARRANGEMENTS TO SATISFY A CUSTOMER'S SERVICE OBLIGATION FOR SCHEDULES 3 AND 3A?

A. PacifiCorp would consider acceptable any alternative comparable arrangement that effectively removes PacifiCorp's obligation to provide regulation and frequency response service or generator regulation and frequency response service to the transmission customer. Such arrangements could include, without limitation, a pseudo-tie of the generation output to a receiving BAA, or a dynamic schedule of self-supplied regulation capacity into a PacifiCorp BAA capable of adjusting to the variable output of the third-party resource in a PacifiCorp BAA. PacifiCorp's posted Business Practice #34, "Self-supply or Third-party Supply of Ancillary Services-Certification Process and Requirements," describes in detail PacifiCorp's certification process and requirements for customers electing to self-supply or to arrange for third-party supply of specific ancillary services, including services under Schedules 3 and 3A, within a PacifiCorp BAA. PacifiCorp's Business Practice #34 can be found at the following link: http://www.oasis.oati.com/PPW/PPWdocs/BP34.pdf.

C. Method Used to Determine Cost for Resources that Contribute to the Regulation Reserve Requirement

Q. IS PACIFICORP PROPOSING CHANGES TO THE BILLING DETERMINANTS FOR SCHEDULES 3 AND 3A?

A. Yes. Under currently effective Schedules 3 and 3A, transmission customers are required to purchase an amount equal to 4.24 percent of the customer's reserved capacity for PTP Transmission Service or 4.24 percent of the customer's Monthly Network Load for NIT

Service. Under the revised Schedules 3 and 3A, PacifiCorp is proposing to use different billing determinants for load, VERs and non-VERs. Under Schedule 3, PacifiCorp proposes to charge load based upon the monthly transmission demand determined on a 12 CP basis according to a stated rate. Under Schedule 3A, PacifiCorp proposes to charge VERs and non-VERs based upon generation nameplate according to a stated rate.

Q. PLEASE DESCRIBE WHY PACIFICORP IS USING DIFFERENT BILLING DETERMINANTS FOR LOAD, VERS AND NON-VERS.

A. PacifiCorp believes its proposed billing determinants more accurately reflect the regulating margin reserves demands placed on PacifiCorp's transmission system by load and resources. Using the monthly transmission demand determined on a 12 CP basis for the load charge set forth in Schedule 3 provides an accurate representation of the regulating margin reserves demand that load places on PacifiCorp's system. It would not necessarily be accurate to use transmission demand as the billing determinant for VERs and non-VERs, however, because generators may be exporting from PacifiCorp's BAAs and may not have purchased firm transmission in amounts that represent the full regulating margin reserves burden such generators place on PacifiCorp. Use of generation nameplate ensures that VERs and non-VERs are fully compensating PacifiCorp for their use of Schedule 3A services. The use of different billing determinants does not impact in any way the calculation of the total regulating margin reserves amount, or the allocation of these reserves among load, VERs, and non-VERs. It simply ensures full and appropriate cost recovery from each customer class.

Q. WHY IS IT IMPORTANT FOR PACIFICORP TO RECOVER THESE COSTS?

A. As a public utility, PacifiCorp should be given the reasonable opportunity to recover the costs it prudently incurs in providing service.[20] The Commission, in Order No. 764, stated that it "believes that public utility transmission providers need an effective opportunity to file for cost recovery, while VERs need assurance that they are not unduly assigned costs."[21] As noted above, Schedule 3 allows PacifiCorp to recover the costs of regulating margin reserves associated with mitigating load variations within its BAAs, but the *pro forma* OATT does not provide a mechanism for transmission providers to recover the costs of holding capacity in reserve for the provision of balancing the variations in generation whose output is delivered outside of the BAA. As such, Schedule 3A is needed to ensure there is no cost recovery gap for PacifiCorp that would otherwise exist under the *pro forma* OATT.

Q. PLEASE DESCRIBE PACIFICORP'S EFFORTS TO INFORM ITS CUSTOMERS OF THE PROPOSED RATE INCREASE IN ANTICIPATION OF THIS FILING.

A. PacifiCorp has discussed its need and justification for the proposed rate increase with its affected transmission customers prior to making this rate filing. Specifically, in addition to the six-state integrated resource planning review processes that applied to the study efforts described in Mr. Duvall's testimony, PacifiCorp has consulted with transmission customers specifically on the proposed Schedule 3 and 3A changes. PacifiCorp has offered to meet with customers interested in more detail regarding the Schedule 3 and 3A

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[20] *See, e.g., Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944); *Bluefield Waterworks & Improvement Co. v. Pub. Serv. Comm'n,* 262 U.S. 679, 690 (1923).

[21] Order No. 764 at P 324.

proposals. Only one customer requested such a meeting – Bonneville Power Administration ("BPA") – and PacifiCorp met with BPA on January 8, 2013.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS CASE?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp) **Docket No. ER13-___-000**

VERIFICATION

I, Sarah E. Edmonds, being first duly sworn, depose and state that I am the witness identified in the foregoing prepared testimony, and that the statements of fact in the testimony and supporting exhibits are true and correct to the best of my knowledge, information and belief.

Sarah E. Edmonds

Subscribed and sworn before me at 825 NE Multnomah St Portland OR 97232

This 26th of March, 2013

Patricia Ann Deas
Notary Public

My commission expires on: 4-18-15

OFFICIAL SEAL
PATRICIA ANN DEAS
NOTARY PUBLIC-OREGON
COMMISSION NO. 457250
MY COMMISSION EXPIRES APRIL 18, 2015

EXHIBIT NO. PAC-2

Schedule 3

Clean and Black-Line

SCHEDULE 3

Regulation and Frequency Response Service

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

The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation, as further described in applicable PacifiCorp business practices. Alternative comparable arrangements may include a Transmission Customer self-supplying this service from generation or non-generation resources.

The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Charge for Regulation and Frequency Response Service: The charges below apply to all Network Integration Transmission Service. Firm imports do not reduce the load obligation. The Transmission Provider may not charge a Transmission Customer for service under both Schedule 3 and Schedule 3A for the same transaction.

The rates below are applied to the Transmission Customer's Monthly Network Load for Network Integration Transmission Service.

1.	Yearly Rate	$4.166/kW/Year
2.	Monthly Rate	$0.347/kW/Month
3.	Weekly Rate	$0.080/kW/Week
4.	Daily Rate, On-Peak	$0.016/kW/Day
5.	Daily Rate, Off-Peak	$0.011/kW/Day
6.	Hourly Rate, On-Peak	$1.002/MWh
7.	Hourly Rate, Off-Peak	$0.477/MWh

The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 3 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 3 times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Alternative Comparable Arrangements: A Transmission Customer may choose to self-supply or purchase from a third-party its Regulation and Frequency Response Service obligation. Due to the nature of this service a Transmission Customer must either (1) purchase 100% of its requirements from the Transmission Provider, or (2) self-supply or arrange for the purchase from a third-party of 100% of its requirements. Failure of the Transmission Customer to account for 100% of its requirements through alternative comparable arrangements will result in the charges above being incurred for the amount the Transmission Customer failed to provide.

The total Regulation and Frequency Response Service obligation for a Transmission Customer who self-supplies or purchases this service from a third-party is determined by the currently-effective version of NERC Reliability Standard BAL-001. The requirement is such that the Transmission Customer that is providing Regulation and Frequency Response Service must show, on no less than an annual basis, that it is capable of meeting the requirements of the currently-effective version of BAL-001 consistent with applicable PacifiCorp business practices.

SCHEDULE 3

Regulation and Frequency Response Service

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

The Transmission Provider must offer this service when the ~~Transmission Service~~transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation~~.~~, as further described in applicable PacifiCorp business practices. Alternative comparable arrangements may include a Transmission Customer self-supplying this service from generation or non-generation resources.

The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Charge for Regulation and Frequency Response Service: ~~A Transmission Customer purchasing Regulation and Frequency Response Service will be required to purchase an amount of reserved capacity equal to 4.24 percent of the Transmission Customer's Reserved Capacity for Point-to-Point Transmission Service or 4.24 percent of the Transmission Customer's Monthly Network Load for~~The charges below apply to all Network Integration Transmission Service. ~~The billing determinants for this service shall be reduced by any portion of the 4.24 percent purchase obligation that~~Firm imports do not reduce the load obligation. The Transmission Provider may not charge a Transmission Customer ~~obtains from third-parties or supplies itself.~~for service under both Schedule 3 and Schedule 3A for the same transaction.

The~~ rates below reflect the percentage purchase obligation stated above multiplied by the cost of providing the ancillary services described in this Schedule 3. Accordingly, the~~ rates below are applied to the ~~amount of the Transmission Customer's Reserved Capacity for Point-to-Point Transmission Service or the~~ Transmission Customer's Monthly Network Load for Network Integration Transmission Service.

1.	Yearly Rate	$~~4.021~~4.166/kW/Year
2.	Monthly Rate	$~~0.335~~0.347/kW/Month
3.	Weekly Rate	$~~0.077~~0.080/kW/Week
4.	Daily Rate, On-Peak	$~~0.015~~0.016/kW/Day
5.	Daily Rate, Off-Peak	$0.011/kW/Day
6.	Hourly Rate, On-Peak	$~~0.967~~1.002/MWh
7.	Hourly Rate, Off-Peak	$~~0.460~~0.477/MWh

The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 3 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 3 times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Alternative Comparable Arrangements: A Transmission Customer may choose to self-supply or purchase from a third-party its Regulation and Frequency Response Service obligation. Due to the nature of this service a Transmission Customer must either (1) purchase 100% of its requirements from the Transmission Provider, or (2) self-supply or arrange for the purchase from a third-party of 100% of its requirements. Failure of the Transmission Customer to account for 100% of its requirements through alternative comparable arrangements will result in the charges above being incurred for the amount the Transmission Customer failed to provide.

The total Regulation and Frequency Response Service obligation for a Transmission Customer who self-supplies or purchases this service from a third-party is determined by the currently-effective version of NERC Reliability Standard BAL-001. The requirement is such that the Transmission Customer that is providing Regulation and Frequency Response Service must show, on no less than an annual basis, that it is capable of meeting the requirements of the currently-effective version of BAL-001 consistent with applicable PacifiCorp business practices.

Schedule 3A

Clean and Black-Line

SCHEDULE 3A

Generator Regulation and Frequency Response Service

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

The Transmission Provider must offer this service when the transmission service is provided for a generator physically or electrically located in the Transmission Provider's Control Area and exported to another Control Area. Generator Regulation and Frequency Response Service applies to the extent that a Transmission Customer is not already subject to Regulation and Frequency Response Service provided under Schedule 3. When applicable, the Transmission Customer must either purchase Generator Regulation and Frequency Response Service from the Transmission Provider or make alternative comparable arrangements, as further described in applicable PacifiCorp business practices. Alternative comparable arrangements may include a Transmission Customer self-supplying this service from generation or non-generation resources or dynamically scheduling its generation to another Control Area.

The amount of and charges for Generator Regulation and Frequency Response Service are set forth below. To the extent a Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider may not charge a Transmission Customer for service under both Schedule 3 and Schedule 3A for the same transaction.

Charge for Regulation and Frequency Response Service: The charges below apply to service that originates in a PacifiCorp Control Area and terminates in another Control Area, including:

1) Long-Term Firm Point-to-Point Transmission Service and 2) Short-Term Firm and Non-Firm Point-to-Point Transmission Service. The rates below are applied to the amount of the Transmission Customer's Reserved Capacity for Long-Term Firm Point-to-Point Transmission Service, or the Transmission Customer's hourly schedules for Short-Term Firm or Non-Firm Point-to-Point Transmission Service exported from the PacifiCorp Control Area. For purposes of charging the rates set forth in this Schedule 3A to Transmission Customers purchasing Point-to-Point Transmission Service, the billing determinants shall be the amount of system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff.

As used herein, "Variable Energy Resource" shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

For any Variable Energy Resource, the following charges will apply:

1.	Yearly Rate	$8.255/kW/Year
2.	Monthly Rate	$0.688/kW/Month
3.	Weekly Rate	$0.159/kW/Week
4.	Daily Rate, On-Peak	$0.032/kW/Day
5.	Daily Rate, Off-Peak	$0.023/kW/Day
6.	Hourly Rate, On-Peak	$1.984/MWh
7.	Hourly Rate, Off-Peak	$0.945/MWh

For any non-Variable Energy Resource, the following charges will apply:

1.	Yearly Rate	$0.001/kW/Year
2.	Monthly Rate	$0.000/kW/Month
3.	Weekly Rate	$0.000/kW/Week
4.	Daily Rate, On-Peak	$0.000/kW/Day
5.	Daily Rate, Off-Peak	$0.000/kW/Day
6.	Hourly Rate, On-Peak	$0.000/MWh
7.	Hourly Rate, Off-Peak	$0.000/MWh

The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 3A times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 3A times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Alternative Comparable Arrangements: A Transmission Customer may choose to self-supply or purchase from a third party its Generator Regulation and Frequency Response Service obligation. Due to the nature of this service a Transmission Customer must either (1) purchase 100% of its requirements from the Transmission Provider, or (2) self-supply or arrange for the purchase from a third party of 100% of its requirements. Failure of the Transmission Customer to account for 100% of its requirements through alternative comparable arrangements will result in the charges above being incurred for the amount the Transmission Customer failed to provide.

The total Generator Regulation and Frequency Response Service obligation for a Transmission Customer who self-supplies or purchases this service from a third party is determined by the currently-effective version of NERC Reliability Standard BAL-001. The requirement is such that the Transmission Customer that is providing Generator Regulation and Frequency Response Service must show, on no less than an annual basis, that it is capable of meeting the requirements of the currently–effective version of BAL-001 consistent with applicable PacifiCorp business practices.

SCHEDULE 3A

Generator Regulation and Frequency Response Service

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

The Transmission Provider must offer this service when the transmission service is provided for a generator physically or electrically located in the Transmission Provider's Control Area and exported to another Control Area. Generator Regulation and Frequency Response Service applies to the extent that a Transmission Customer is not already subject to Regulation and Frequency Response Service provided under Schedule 3. When applicable, the Transmission Customer must either purchase Generator Regulation and Frequency Response Service from the Transmission Provider or make alternative comparable arrangements, ~~which may include self-supplying regulation reserve capacity~~as further described in applicable PacifiCorp business practices. Alternative comparable arrangements may include a Transmission Customer self-supplying this service from generation or non-generation resources or ~~through~~ dynamically scheduling its generation to another Control Area.

The amount of and charges for Generator Regulation and Frequency Response Service are set forth below. To the extent a Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that ~~Balancing Authority~~Control Area operator. The Transmission Provider may not charge a Transmission Customer for ~~regulation reserves~~service under both Schedule 3 and Schedule 3A for the same transaction.

Charge for Regulation and Frequency Response Service:

~~A Transmission Customer purchasing Generator Regulation and Frequency Response Service will be required to purchase an amount of reserved capacity equal to 4.24 percent of the Transmission Customer's Reserved Capacity for Point-to-Point Transmission Service or 4.24 percent of the Transmission Customer's Monthly Network Load for Network Integration Transmission Service. The billing determinants for this service shall be reduced by any portion of the 4.24 percent purchase obligation that a Transmission Customer obtains from third parties or supplies itself. The rates below reflect the percentage purchase obligation stated above multiplied by the cost of providing the ancillary services described in this Schedule 3A. Accordingly, the~~The charges below apply to service that originates in a PacifiCorp Control Area and terminates in another Control Area, including: 1) Long-Term Firm Point-to-Point Transmission Service and 2) Short-Term Firm and Non-Firm Point-to-Point Transmission Service. The rates below are applied to the amount of the Transmission Customer's Reserved Capacity for Long-Term Firm Point-to-Point Transmission Service, or the Transmission Customer's ~~Monthly Network Load for Network Integration Transmission Service.~~ hourly schedules for Short-Term Firm or Non-Firm Point-to-Point Transmission Service exported from the PacifiCorp Control Area. For purposes of charging the rates set forth in this Schedule 3A to Transmission Customers purchasing Point-to-Point Transmission Service, the billing determinants shall be the amount of system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff.

As used herein, "Variable Energy Resource" shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

For any Variable Energy Resource, the following charges will apply:

1. Yearly Rate $~~4.021~~8.255/kW/Year

2. Monthly Rate $~~0.335~~0.688/kW/Month

3. Weekly Rate $~~0.077~~0.159/kW/Week

4. Daily Rate, On-Peak $~~0.015~~0.032/kW/Day

5. Daily Rate, Off-Peak $~~0.011~~0.023/kW/Day

6. Hourly Rate, On-Peak $~~0.967/kW/Day~~ 1.984/MWh

7. Hourly Rate, Off-Peak $~~0.460~~0.945/MWh

For any non-Variable Energy Resource, the following charges will apply:

1.	Yearly Rate	$0.001/kW/Year
2.	Monthly Rate	$0.000/kW/Month
3.	Weekly Rate	$0.000/kW/Week
4.	Daily Rate, On-Peak	$0.000/kW/Day
5.	Daily Rate, Off-Peak	$0.000/kW/Day
6.	Hourly Rate, On-Peak	$0.000/MWh
7.	Hourly Rate, Off-Peak	$0.000/MWh

The total charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 3A times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 3A times the highest amount in megawatts of Reserved Capacity in any hour during such week.

Alternative Comparable Arrangements: A Transmission Customer may choose to self-supply or purchase from a third party its Generator Regulation and Frequency Response Service obligation. Due to the nature of this service a Transmission Customer must either (1) purchase 100% of its requirements from the Transmission Provider, or (2) self-supply or arrange for the purchase from a third party of 100% of its requirements. Failure of the Transmission Customer to account for 100% of its requirements through alternative comparable arrangements will result in the charges above being incurred for the amount the Transmission Customer failed to provide.

The total Generator Regulation and Frequency Response Service obligation for a Transmission Customer who self-supplies or purchases this service from a third party is determined by the currently-effective version of NERC Reliability Standard BAL-001. The requirement is such that the Transmission Customer that is providing Generator Regulation and Frequency Response Service must show, on no less than an annual basis, that it is capable of meeting the requirements of the currently-effective version of BAL-001 consistent with applicable PacifiCorp business practices.

Schedules 3 and 3A

Black-Line Against the

February 22, 2013 Settlement Agreement

SCHEDULE 3

Regulation and Frequency Response Service

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

The Transmission Provider must offer this service when the ~~Transmission Service~~transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider~~, self-supply the service,~~ or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation, as further described in applicable PacifiCorp business practices. Alternative comparable arrangements may include a Transmission Customer self-supplying this service from generation or non-generation resources.

The amount of and charges for Regulation and Frequency Response Service are set forth below. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

Charge for Regulation and Frequency Response Service: The charges below apply to all Network Integration Transmission Service. Firm imports do not reduce the load obligation. The Transmission Provider may not charge a Transmission Customer for service under both Schedule 3 and Schedule 3A for the same transaction.

The rates below are applied to the Transmission Customer's Monthly Network Load for Network Integration Transmission Service.

1. Yearly Rate $~~2.900~~4.166/kW/Year
2. Monthly Rate $~~0.242~~0.347/kW/Month
3. Weekly Rate $~~0.056~~0.080/kW/Week
4. Daily Rate, On-Peak $~~0.011~~0.016/kW/Day
5. Daily Rate, Off-Peak $~~0.008~~0.011/kW/Day
6. Hourly Rate, On-Peak $~~0.697~~1.002/MWh
7. Hourly Rate, Off-Peak $~~0.332~~0.477/MWh

The total charge in any day, ~~including any charges for failure to self-supply as described in the following section,~~ pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 3 times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 3 times the highest amount in megawatts of Reserved Capacity in any hour during such week.

~~Self-Supply~~: ~~A Network~~**Alternative Comparable Arrangements:** A Transmission Customer may choose to self-supply or purchase from a third-party its Regulation and Frequency Response Service obligation. Due to the nature of this service a ~~Network~~Transmission Customer must either (1) purchase 100% of its requirements ~~or self-supply~~from the Transmission Provider, or (2) self-supply or arrange for the purchase from a third-party of 100% of its requirements. Failure of the Transmission Customer to account for 100% of its requirements through alternative comparable arrangements will result in the charges above being incurred for the amount the Transmission Customer failed to provide.

The total Regulation and Frequency Response Service obligation for a Transmission Customer who self-supplies or purchases this service from a third-party is determined by the currently-effective version of NERC Reliability Standard BAL-001. The requirement is such that the Transmission Customer that is ~~self-supplying~~providing Regulation and Frequency Response Service must show, on no less than an annual basis, that it is capable of meeting the requirements of the currently-effective version of BAL-001 consistent with applicable PacifiCorp business practices.

SCHEDULE 3A

Generator Regulation and Frequency Response Service

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

The Transmission Provider must offer this service when the transmission service is provided for a generator physically or electrically located in the Transmission Provider's Control Area and exported to another Control Area. Generator Regulation and Frequency Response Service applies to the extent that a Transmission Customer is not already subject to Regulation and Frequency Response Service provided under Schedule 3. When applicable, the Transmission Customer must either purchase Generator Regulation and Frequency Response Service from the Transmission Provider~~, self supply the service,~~ or make alternative comparable arrangements, as further described in applicable PacifiCorp business practices~~ which~~. Alternative comparable arrangements may include a Transmission Customer self-supplying ~~regulation reserve capacity~~this service from generation or non-generation resources or~~ through~~ dynamically scheduling its generation to another Control Area.

The amount of and charges for Generator Regulation and Frequency Response Service are set forth below. To the extent a Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that ~~Balancing Authority~~Control Area operator. The Transmission Provider may not charge a Transmission Customer for ~~regulation reserves~~service under both Schedule 3 and Schedule 3A for the same transaction.

Charge for Regulation and Frequency Response Service: The charges below apply to service that originates in ~~the~~a PacifiCorp Control Area and terminates in another Control Area, including: 1) Long-Term Firm Point-to-Point Transmission Service and 2) Short-Term Firm and Non-Firm Point-to-Point Transmission Service~~, assessed based upon the Transmission Customer's hourly usage~~. The rates below are applied to the amount of the Transmission Customer's Reserved Capacity for Long-Term Firm Point-to-Point Transmission Service, or the Transmission Customer's hourly schedules for Short-Term Firm or Non-Firm Point-to-Point Transmission Service exported from the PacifiCorp Control Area. For purposes of charging the rates set forth in this Schedule 3A to Transmission Customers purchasing Point-to-Point Transmission Service, the billing determinants shall be the amount ~~at~~of system output multiplied by the Transmission System loss factor in Schedule 10 of the Tariff.

As used herein, "Variable Energy Resource" shall mean a device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

For any Variable Energy Resource, the following charges will apply:

1.	Yearly Rate	$~~2.900~~8.255/kW/Year
2.	Monthly Rate	$~~0.242~~0.688/kW/Month
3.	Weekly Rate	$~~0.056~~0.159/kW/Week
4.	Daily Rate, On-Peak	$~~0.011~~0.032/kW/Day
5.	Daily Rate, Off-Peak	$~~0.008~~0.023/kW/Day
6.	Hourly Rate, On-Peak	$~~0.697~~1.984/MWh
7.	Hourly Rate, Off-Peak	$~~0.332~~0.945/MWh

For any non-Variable Energy Resource, the following charges will apply:

1.	Yearly Rate	$0.001/kW/Year
2.	Monthly Rate	$0.000/kW/Month
3.	Weekly Rate	$0.000/kW/Week
4.	Daily Rate, On-Peak	$0.000/kW/Day
5.	Daily Rate, Off-Peak	$0.000/kW/Day
6.	Hourly Rate, On-Peak	$0.000/MWh
7.	Hourly Rate, Off-Peak	$0.000/MWh

The total charge in any day~~, including any charges for failure to self-supply as described in the following section~~, pursuant to a reservation for Hourly delivery, shall not exceed the Daily Rate pursuant to this Schedule 3A times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the Weekly Rate pursuant to this Schedule 3A times the highest amount in megawatts of Reserved Capacity in any hour during such week.

~~**Self-Supply:**~~

Alternative Comparable Arrangements: A Transmission Customer may choose to self-supply or purchase from a third party its Generator Regulation and Frequency Response Service obligation. Due to the nature of this service a Transmission Customer must either (1) purchase 100% of its requirements ~~or self-supply~~from the Transmission Provider, or (2) self-supply or arrange for the purchase from a third party of 100% of its requirements. Failure of the Transmission Customer to account for 100% of its requirements through alternative comparable arrangements will result in the charges above being incurred for the amount the Transmission Customer failed to provide.

The total Generator Regulation and Frequency Response Service obligation for a Transmission Customer who self-supplies or purchases this service from a third party is determined by the currently-effective version of NERC Reliability Standard BAL-001. The requirement is such that the Transmission Customer that is ~~self-supplying~~providing Generator Regulation and Frequency Response Service must show, on no less than an annual basis, that it is capable of meeting the requirements of the currently-effective version of BAL-001 consistent with applicable PacifiCorp business practices.

ATTACHMENT E

Exhibit No. PAC-3

UNITED STATES OF AMERICA

BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PacifiCorp	)	**Docket No. ER13-___-000**
	)	

TESTIMONY OF

ALAN C. HEINTZ

ON BEHALF OF PACIFICORP

April 1, 2013

TABLE OF CONTENTS

LIST OF EXHIBITS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND POSITION.

A. My name is Alan C. Heintz. My business address is Brown, Williams, Moorhead & Quinn, Inc. ("BWMQ"), 1155 Fifteenth Street, NW, Suite 400, Washington, DC 20005. I am a Vice President of BWMQ.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of PacifiCorp ("PacifiCorp" or "Company").

Q. WHAT ARE YOUR DUTIES IN YOUR CURRENT POSITION?

A. I provide consulting services on matters relating to power sales, transmission, and ancillary service issues associated with the Federal Energy Regulatory Commission's ("FERC" or "Commission") open access transmission service and FERC's Order Nos. 888, 889, 2000, 679, and 890. I have provided consulting services to numerous Independent System Operators ("ISO") and Regional Transmission Organizations ("RTO"), including the transmission owners of the Midwest Independent Transmission System Operator, Inc. ("MISO"), DesertSTAR, such entities as American Transmission Company, LLC and Trans-Elect, Inc., and participants in other ISOs and RTOs, including Alliance, GridFlorida, New York ISO, SeTrans Independent System Administrator, ISO New England Inc., and California ISO.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL EXPERIENCE.

A. I was employed by the FERC from November 1985 to February 1995. I served as a Public Utilities Specialist in the [Electric] Rate Filings Branch from November 1985 to October 1989. In November 1989, I was promoted to Section Chief in the Division of [Electric] Applications, and was responsible for supervising the review of the terms, conditions, and rates of electric rate applications for such services as interchange power, requirements power, and transmission. During my tenure with the FERC, I prepared or supervised the preparation of memoranda recommending acceptance, rejection, deficiency, or investigation in hundreds of cases. These included cases that set important precedents on electric transmission pricing, such as the merger compliance transmission tariffs for Northeast Utilities, the first generation of Open Access Transmission Tariffs ("OATT") filed by utilities such as Entergy Services, Louisville Gas & Electric Co., PacifiCorp, Kansas City Power & Light Co., and American Electric Power Co., and the Pennsylvania Electric Company case involving Penntech Papers, Inc. I also taught a one-year course to FERC Staff and gave several presentations to the Edison Electric Institute Interconnection and Interchange Arrangements Committee on the pricing of power and transmission services.

From February 1995 through October 2000, I was a Vice President of Stone & Webster Management Consultants, Inc. In this position, I provided consulting services to numerous electric utilities on matters involving requirements and off-system power rates, and rate and implementation strategies for developing OATT filings, and organizing ISOs and RTOs. I also assisted several utilities in preparing their retail delivery services filings. I joined R.J. Rudden Associates, Inc. in November 2000 as a Vice President, where I continued providing consulting services to the electric industry. I joined BWMQ in February 2004.

Q. PLEASE SUMMARIZE YOUR OTHER EXPERIENCE TESTIFYING BEFORE REGULATORY BODIES AND COURTS ON UTILITY-RELATED MATTERS.

A. During my tenure at the FERC, I was assigned to the Commission's advisory staff and, therefore, was precluded from testifying before the FERC. However, while at the FERC, I presented cases publicly to the FERC Commissioners at their bi-weekly public meetings and was the technical contact to the Commissioners in numerous cases. Since leaving the employ of FERC, I have filed testimony before the FERC in numerous proceedings. I have also testified before the British Columbia Utilities Commission in Canada, the Illinois Commerce Commission, the Maine Public Utilities Commission, the United States Court of Federal Claims, and the United States District Court for the District of Florida. Exhibit No. PAC-4 contains a summary of my previous testimony experience.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I received the degree of Bachelor of Science in Business and the degree of Bachelor of Arts in Economics from the University of Colorado, in Boulder, Colorado, in May 1982. I also received the degree of Master of Business Administration in Finance from George Washington University in Washington, DC, in December 1988.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to explain and support PacifiCorp's revised rates for Regulation and Frequency Response Service ("Regulation Service") (Schedule 3) and for Generator Regulation and Frequency Response Service ("Generator Regulation Service") (Schedule 3A).

Q. ARE YOU SPONSORING ANY EXHIBITS TO YOUR TESTIMONY?

A. Yes, I am sponsoring three exhibits. Exhibit No. PAC-4 contains a summary of my testimony experience. Exhibit No. PAC-5 provides cost support for the ancillary services addressed in the subject filing. Exhibit No. PAC-6 contains PacifiCorp's Statements BG and BH calculated for this filing. All are discussed in this testimony.

II. OTHER TESTIMONY SUPPORTING THIS FILING

Q. ARE ANY OTHER INDIVIDUALS FILING TESTIMONY ON BEHALF OF PACIFICORP IN THIS PROCEEDING?

A. Yes. The following individuals are providing testimony on behalf of PacifiCorp:

- Sarah E. Edmonds, Director of Transmission Regulation, Strategy & Policy for PacifiCorp has prepared testimony (*see* Exhibit No. PAC-1) supporting (1) the purpose of (and need for) the Company's proposed Schedule 3 and 3A rates; (2) PacifiCorp's proposed Schedule 3 and 3A tariff changes (*see* Exhibit No. PAC-2); and (3) the consistency of PacifiCorp's proposal with FERC policies for generator regulating margin reserve service rates.[1]
- Gregory N. Duvall, Director of Net Power Costs for PacifiCorp, has prepared testimony (s*ee* Exhibit No. PAC-7) supporting (1) the total amount of regulating margin reserves that are needed by PacifiCorp to provide service under revised Schedules 3 and 3A of PacifiCorp's OATT; (2) the allocation of the total amount of regulating margin reserves among load, variable energy resources ("VERs") and non-VER generation; and (3) identification of the specific resources that supply the total amount of regulating margin reserves, including the proportional contributions of such resources (*see* Exhibit No. PAC-11). Mr. Duvall's testimony is supported in part by PacifiCorp's March 2013 study explaining these amounts (the "PacifiCorp Schedule 3 and 3A Study") (*see* Exhibit No. PAC-8).

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[1] Order No. 764 refers to this service as "generator regulation service." See *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246, at P 4 (2012) ("Order No. 764"), *order on reh'g*, 141 FERC ¶ 61,232 (2012) ("Order No. 764-A"). While PacifiCorp uses the term "regulating margin reserve service" to describe this service, the two are functionally identical.

III. EXPLANATION OF REVISED RATES

Q. PLEASE EXPLAIN HOW THE REVISED SCHEDULE 3 AND 3A RATES WERE DEVELOPED.

A. Exhibit No. PAC-5 shows the development of the Schedule 3 and 3A rates and is comprised of Attachment A and Attachment B. Attachment B (pages 5-6) shows the derivation of the proposed revenue requirement associated with the revised Schedule 3 and 3A rates at issue. These rates have been developed based on Commission-accepted mechanisms for developing ancillary service rates. The method that has been employed by PacifiCorp is a levelized gross plant method. Attachment A develops the fixed charge rate ("FCR") which includes the rate of return on common equity, income taxes, operations & maintenance (or "O&M"), administration and general (or "A&G"), and taxes other than income taxes. The FCR is then multiplied by the gross plant balance (installed cost) of each generating plant providing the respective service to calculate annual carrying costs of the units (Attachment B, pages 5-6). The Commission approved this approach in *American Electric Power Service Corporation*, 88 FERC ¶ 61,141 (1999).

Q. HOW ARE RETURN AND INCOME TAXES CALCULATED?

A. PacifiCorp's balances of the outstanding long-term debt, preferred stock, and common stock are used to determine the capitalization ratios, to which the cost rates for the capital cost components are weighted. (Attachment A, page 4). The debt cost rate is the ratio of long-term interest to long-term debt and the preferred dividend cost rate is the ratio of preferred dividends to preferred stock outstanding. The return on equity ("ROE") is 9.8%.

The following two income tax components are included in the fixed charge calculations: (1) the federal and state marginal tax rates (Attachment A, page 3) and (2) the Accumulated Deferred Income Taxes ("ADIT") (Attachment A, page 5).

Q. WHAT IS THE SUPPORT FOR 9.8% ROE?

A. PacifiCorp filed a settlement agreement on February 22, 2013 in Docket No. ER11-3643-000, to resolve all issues among the parties in the transmission rate case and ancillary services proceeding, and such settlement agreement is currently pending before the Commission. In calculating the settlement rates, PacifiCorp used a stated base ROE of 9.8%. Because the settlement agreement among the parties was executed very close in time to this filing, it is reasonable to apply the same 9.8% ROE to the calculation of these Schedule 3 and 3A rates. Further, in the settlement agreement, the parties specified in Section 3.6.4 that the ROE to be used in this filing would be 9.8% and that "[n]o party shall submit comments or protests challenging use of a 9.8% ROE in this Schedule 3 and 3A filing." In its March 14, 2013 Initial Comments in Support of Settlement Agreement in Docket No. ER11-3643, Commission Trial Staff acknowledged the stated base ROE of 9.8% and expressed its belief that the settlement provides a fair and reasonable resolution of the issues in the proceeding.[2]

Q. PLEASE DESCRIBE THE OTHER COMPONENTS OF THE FIXED CHARGE RATES.

A. Please refer to Attachment A, pages 1 through 5, for the fixed charge worksheet that calculates the levelized FCR applicable to the generating plants that comprise the calculated rates. The methodology of the spreadsheet "template" underlying the

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[2] On March 26, 2013, the Settlement Judge in the proceeding issued a Certification of Uncontested Settlement, certifying the offer of settlement filed by PacifiCorp. *PacifiCorp*, 142 FERC ¶ 63,023 (2013).

calculation is recognized as the industry standard and is the approach that FERC posted on its website for many years and directed industry participants to use in order to facilitate approval of their filings. It was also referenced by the Commission in Order No. 888 and has been accepted by the Commission in numerous cases.[3]

The FCR computed in Attachment A is a product of several rate base related and non-O&M expense components (summarized on page 5), but the calculated rate is essentially a company total revenue requirement for production (excluding O&M), divided by total production plant investment at original cost (Attachment A, page 5). This rate is then multiplied by the original cost investments of the units most likely to be selected to supply the various services (regulation and generator regulation), to which is added the production unit-specific, demand-related operation and maintenance expenses.

Q. WHAT TEST PERIOD DID PACIFICORP USE FOR THIS RATE FILING?

A. PacifiCorp used calendar year 2011 as the test period for this filing. This is also the year applied in the PacifiCorp Schedule 3 and 3A Study.

Q. PLEASE DESCRIBE THE PROPOSED SCHEDULE 3 RATE FOR REGULATION SERVICE.

A. As described in more detail above, the proposed rates are based on the weighted fixed cost of the units identified in Attachment B. The weighting is calculated by applying the same method used by the Commission in recent years to determine the units most likely to provide off-system sales. Specifically, the approach weights the units based on their participation in providing the reserves. See Attachment B, pages 5-6. Then each plant's installed cost (gross plant) (also found on pages 5-6) is multiplied by the FCR. The cost

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3 *See, e.g., Detroit Edison Co.*, 78 FERC ¶ 61,149 at 61,629 (1997) ("The Commission has found that the levelized fixed charge method to be an acceptable basis for setting rates."); *Toledo Edison Co.*, 78 FERC ¶ 61,088 at 61,418 (1997) ("A levelized method accurately accounts for the utility's capital costs.").

study supports an annual cost of \$96.726/kW. Please see the testimony of Mr. Duvall describing how the Company quantified the amount of regulating margin reserves that are needed by PacifiCorp to provide service under revised Schedule 3 of PacifiCorp's OATT. The resulting revenue requirement from multiplying the cost per kW by the amount of reserves necessary to cover the variability of the load, is then divided by the total load for which PacifiCorp provides Regulation Service. This produces a rate of \$4.166/kW/year for Schedule 3.

Q. PLEASE DESCRIBE THE PROPOSED SCHEDULE 3A RATE FOR GENERATOR REGULATION SERVICE.

A. The cost support for Generator Regulation Service is the same as for Regulation Service described above. Please see the testimony of Mr. Duvall describing how the Company quantified the amount of regulating margin reserves that are needed by PacifiCorp to provide service under Schedule 3A of PacifiCorp's OATT. As explained by Mr. Duvall in Exhibit No. PAC-7, the amount of capacity necessary for regulating VERs[4] is greater per kW of generation than for non-VERs. In order to reflect the different cost causation between the VER and non-VER generators, separate charges were developed for each class of generator. As noted above, each plant's installed cost (found on pages 5-6 of Attachment B) is multiplied by the FCR to determine an annual cost per kW of regulation capacity of \$96.726/kW. The amount of capacity to regulate VER and non-VER generators is determined in Mr. Duvall's testimony. The revenue requirement for non-VERs is developed by multiplying the annual cost per kW by the amount of reserves necessary to regulate for the non-VERs, which is then divided by the total installed

[4] "VER" is defined in PacifiCorp's revised Schedule 3A as a device for the production of electricity characterized by an energy source that: (1) is renewable; (2) cannot be stored; and (3) has variability beyond the control of the facility owner or operator.

capacity of the non-VER generation located in a PacifiCorp Balancing Authority Area ("BAA"). This produces a rate for non-VERs of $0.001/kW/year for Schedule 3A. The revenue requirement for VERs is developed by multiplying the annual cost per kW by the amount of reserves necessary to regulate for the VERs, which is then divided by the total installed capacity of the VER generation located in a PacifiCorp BAA. This produces a rate for VER generators of $8.255/kW/year for Schedule 3A.

Q. WHAT IS THE CHANGE IN REVENUE TO CUSTOMERS FROM THE PROPOSED CHANGE IN SCHEDULE 3 AND 3A RATES?

A. Exhibit No. PAC-6, Statements BG/BH, demonstrates the impact of the change in rates on PacifiCorp's individual OATT transmission customers. The proposed changes result in a revenue decrease for Schedule 3A of the OATT of approximately $6,672,153. The impact on Schedule 3A customers varies from zero impact for some customers, an increase of approximately 184.6 percent for others, and a 99.9 percent decrease for the remainder. The proposed changes result in a revenue increase for Schedule 3 of the OATT of approximately $10,570,094. The impact on Schedule 3 customers affected by the change is approximately 43.7 percent. The revenue increase for Legacy Contracts is $827,811. The impact on Legacy Contract customers is an increase of approximately 43.7 percent.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp) **Docket No. ER13-___-000**

VERIFICATION

I, Alan C. Heintz, being first duly sworn, depose and state that I am the witness identified in the foregoing prepared testimony, and that the statements of fact in the testimony and supporting exhibits are true and correct to the best of my knowledge, information and belief.

Alan C. Heintz

Subscribed and sworn before me at District of Columbia

This 27th of March, 2013

Notary Public

My commission expires on: Stephanie J. Wilkerson Notary Public, District of Columbia My Commission Expires 6/30/2014

STEPHANIE J. WILKERSON NOTARY PUBLIC DISTRICT OF COLUMBIA

EXHIBIT NO. PAC-4

SUMMARY OF TESTIMONY EXPERIENCE
ALAN C. HEINTZ

#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
1	FERC	ER95-836-000	Maine Public Service Company	Maine Public Service Company	1995	Rates, Terms and Conditions for Open Access Transmission Services
2	FERC	ER95-854-000	Kentucky Utilities Company	Kentucky Utilities Company	1995	Rates, Terms and Conditions for Open Access Transmission Services
3	FERC	ER95-1686-000 ER96-496-000	Northeast Utilities Service Company	Northeast Utilities Service Company	1996	Rates, Terms and Conditions for Open Access Transmission Services
4	FERC	ER96--58-000	Allegheny Power Services Corporation	Allegheny Power Services Corporation	1995 & 1996	Rates, Terms and Conditions for Open Access Transmission Services
5	FERC	OA96-138-000	Consolidated Edison Company of New York, Inc.	Consolidated Edison Company of New York, Inc.	1997	Rates, Terms and Conditions for Open Access Transmission Services
6	FERC	ER96-1208-000	Interstate Power Company	Interstate Power Company	1996	Rates, Terms and Conditions for Open Access Transmission Services
7	British Columbia Utilities Commission		British Columbia Hydro and Power Authority	Bonneville Power Administration	1997	Rates, Terms and Conditions for Open Access Transmission Services

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
8	FERC	ER98-1438-000 EC98-24-000	Cincinnati Gas & Electric Company, et al. (Midwest Independent System Operator)	Midwest ISO Transmission Owners	1998 & 1999	Rates, Terms and Conditions for Midwest ISO Tariff
9	FERC	EC98-2770-000 ER98-2770-000 ER98-2786-000	American Electric Power Company, Inc. and Central & Southwest Corporation	Midwest Independent System Operator Transmission Owners	1999	Reasonableness of the conditions to be placed on the merging parties
10	Illinois Commerce Commission	99-0117	Commonwealth Edison Company	Commonwealth Edison Company	1998	Cost of service for Retail Distribution Services Tariff
11	FERC	ER99-3110-000	Nevada Power Company	Nevada Power Company	1998	Rates, Terms and Conditions for Open Access Transmission Services
12	FERC	ER99-4415-000	Illinois Power Company	Illinois Power Company	1999	Rates, Terms and Conditions for Open Access Transmission Services
13	FERC	ER99-4470-000	Commonwealth Edison Company	Commonwealth Edison Company	1999	Rates, Terms and Conditions for Open Access Transmission Services
14	U.S. District Court, FL	92-35-CIV-ORL-3A22	Florida Municipal Power Agency vs. Florida Power and Light Company	Florida Power and Light Company	1999	Rates, Terms and Conditions for Network Service in an anti-trust case
15	U.S. Court of Federal Claims, DC	97-268C	Carolina Power & Light Company vs. U.S. Department of Energy	Carolina Power & Light Company	1999	Cost recovery of Decontamination & Decommissioning Fund Assessments

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
16	FERC	ER98-496-006 ER98-2160-004	San Diego Gas & Electric	Dynegy	1999	Rates for Must Run units
17	FERC	ER00-980-000	Bangor Hydro Electric Company	Bangor Hydro Electric Company	1999	Rates, Terms and Conditions for Open Access Transmission Services
18	Maine Public Utilities Commission	99-185	Bangor Hydro Electric Company	Bangor Hydro Electric Company	2000	Rates, Terms and Conditions for Open Access Transmission Services
19	FERC	EL00-98-000, et al.	Dynegy Power Marketing, Inc, et al.	Dynegy Power Marketing, Inc.	2000	Nexus between fuel and emissions costs and the market prices in California
20	Illinois Commerce Commission	No. 01-0423	Commonwealth Edison Company	Commonwealth Edison Company	2001	Direct, Rebuttal and Surrebuttal: Cost of service for Retail Distribution Services Tariff
21	FERC	ER01-2992	Commonwealth Edison Company	Commonwealth Edison Company	2001	Rates, Terms and Conditions for Open Access Transmission Services
22	FERC	ER01-123.004	Midwest ISO Transmission Owners	Midwest ISO Transmission Owners	2001	Super Region Adjustment for the MISO/ARTO Super Region
23	FERC	ER01-2999	Illinois Power Company	Illinois Power Company	2001	Rates, Terms and Conditions for Open Access Transmission Services
24	FERC	ER01-3142, et. al	Midwest ISO	Midwest ISO Transmission Owners	2001	Revised treatment of Network Upgrades

#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
25	FERC	ER01-3142, et. al	Midwest ISO	Midwest ISO Transmission Owners	2001	Uncertainties that support a higher ROE
26	FERC	EL000-95-045, et.al	San Diego Gas & Electric Company v. Sellers of Energy and Ancillary Service Into Markets Operated by the CALISO…	Dynegy, Mirant, Reliant and Williams	2001 & 2002	Costing of emissions and start-up costs
27	FERC	EC02-23 & ER02-320	Trans-Elect, Inc., et. al	Trans-Elect, Inc.	2001 & 2002	Support of rates and ratemaking methodology for new transmission company
28	FERC		Sithe New Boston, LLC	Sithe New Boston, LLC	2001 & 2002	Cost of Service for Must Run Unit
29	FERC	RM01-12	FERC Technical Conference	SeTrans	2002	Allocation of FTRs/CRRs
30	FERC	EL02-111	Midwest ISO & PJM	Midwest ISO Transmission Owners	2002	Through and Out Rates
31	FERC	ER02-2595	Midwest ISO	Midwest ISO Transmission Owners	2002	Cost Allocation for FTR and Market Administration
32	FERC	ER03-37	Sierra Pacific Resources	Sierra Pacific and Nevada Power	2003	Ancillary Service Rates
33	FERC	ER03-626	Empire District Electric Co.	Empire District Electric Co.	2003	Cost of Service; Wholesale Requirements Customers
34	FERC	EL-02-25-001, et. al	Intermountain, Holy Cross, Yampa and Aquila	Public Service Co. of Colorado	2003	Fuel Adjustment Clause

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
35	FERC	ER03-959	Exelon Framingham LLC, et al.	Exelon Framingham LLC, et al.	2003	Production Cost of Service
36	FERC	ER03-1187	MidWest Generation, LLC	Commonwealth Edison	2003	Black Start Rates
37	FERC	ER03-1223	Montana Megawatts I, LLC, et al.	Montana Megawatt	2003	Production Formula Rates
38	FERC	ER03-1335	Commonwealth Edison	Commonwealth Edison	2003	Transmission Tariff Rates
39	FERC	ER03-1354	Black Hills Power Company, et al.	Black Hills Power Company, et al.	2003	Joint transmission Tariff Rates
40	FERC	ER03-1328	Sierra Pacific Resources	Nevada Power	2003	Transmission Tariff Rates
41	FERC	EL02-111, et. Al	Midwest ISO and PJM Transmission Owners	Midwest ISO Transmission Owners	2004	Long-term Transmission Pricing Plan
42	FERC	ER05-14	Sierra Pacific Resources	Sierra Pacific	2004	Transmission Tariff Rates
43	FERC	ER05-26	Mirant Kendall, LLC	Mirant Kendall, LLC	2004	Reliability Must Run Agreement and Rates
44	Illinois Commerce Commission	No.04-0779	NICOR Gas Company	NICOR Gas Company	2004	Distribution Service Embedded Cost of Service Study
45	FERC	ER05-163	Milford Power Company LLC	Milford Power Company LLC	2004	Reliability Must Run Agreement and Rates

#	JURISDICTION	CASE OR DOCKET NO.	UTILITY/ORGANIZATION INITIATING PROCEEDING	CLIENT	APPROXIMATE DATE	SUBJECT MATTER
46	FERC	EL02-111, et. al	Midwest ISO and PJM Transmission Owners	Midwest ISO Transmission Owners	2004	Seams Elimination
47	FERC	EL00-95, et. al	SDG&E V. Sellers, et al.	Portland General Electric Company	2005	California Refund Proceeding
48	FERC	ER05-447	Midwest ISO	Midwest ISO Transmission Owners	2005	Schedule 10 & 17 Recovery for Grandfathered Agreements
49	FERC	EL02-111, et. al	Midwest ISO and PJM Transmission Owners	Midwest ISO Transmission Owners	2005	Seams Elimination
50	FERC	ER05-860	Whiting Clean Energy	Whiting Clean Energy	2005	Cost Based Power Rates
51	FERC	ER05-903	Con. Ed. Energy Mass., Inc.	Con. Ed. Energy Mass., Inc.	2005	Reliability Must Run Agreement and Rates
52	FERC	EL02-111, et. al	Midwest ISO and PJM Transmission Owners	Midwest ISO Transmission Owners	2005	Seams Elimination
53	FERC	ER05-1050	AmerGen Energy Company, L.L.C.	AmerGen Energy Company, L.L.C.	2005	Reactive power charges
54	Illinois Commerce Commission	No.05-0597	Commonwealth Edison Co.	Commonwealth Edison Co.	2005	Distribution Service Embedded Cost of Service Study
55	FERC	ER05-1179	Berkshire Power Company, LLC	Berkshire Power Company, LLC	2005	Reliability Must Run Agreement and Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
56	FERC	ER05-1243	Basin Electric Power Cooperative	Basin Electric Power Cooperative	2005	Revised Transmission Cost of Service
57	FERC	ER05-1304 & ER05-1305	Mystic I, LLC and Mystic Development, LLC	Mystic I, LLC and Mystic Development, LLC	2005	Reliability Must Run Agreement and Rates
58	FERC	ER05-273	Midwest ISO	Midwest ISO Transmission Owners	2005	Proper Pricing for Regional Non-firm Redirects
59	FERC	ER05-515	PHI and BGE	PHI and BGE	2005	Transmission Formula Rates
60	FERC	EL05-19	Southwestern Public Service Company	Southwestern Public Service Company	2005	Production rates and Fuel Adjustment Clause,
61	FERC	ER06-427	Mystic Development, LLC	Mystic Development, LLC	2006	Reliability Must Run Agreement and Rates
62	FERC	ER06-822	Fore River Development, LLC	Fore River Development, LLC	2006	Reliability Must Run Agreement and Rates
63	FERC	ER06-819	Consolidated Edison Energy Massachusetts, Inc	Consolidated Edison Energy Massachusetts, Inc	2006	Reliability Must Run Agreement and Rates
64	FERC	ER07-169	Ameren Energy Marketing Company	Ameren Energy Marketing Company	2006	Ancillary service rates
65	FERC	ER06-1549	Duquesne Light Company	Duquesne Light Company	2006	Transmission Formula Rates
66	FERC	ER07-170	Ameren Energy, Inc.	Ameren Energy, Inc.	2006	Ancillary service rates
67	FERC	ER06-787	Idaho Power	Idaho Power	2006 & 2007	Transmission Formula Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
68	FERC	ER07-562	Trans-Allegheny Interstate Line Company	Trans-Allegheny Interstate Line Company	2007	Transmission Formula Rates
69	FERC	ER07-583	Commonwealth Edison	Commonwealth Edison	2007	Transmission Formula Rates
70	FERC	ER07-1171	Arizona Public Service Co.	Arizona Public Service Co.	2007	Transmission Formula Rates
71	Illinois Commerce Commission	No. 07-0566	Commonwealth Edison Co.	Commonwealth Edison Co.	2007	Distribution Service Embedded Cost of Service Study
72	FERC	ER07-1371	Sierra Pacific Resources	Sierra Pacific Resources	2007	Transmission Rates
73	FERC	ER08-281	Oklahoma Gas & Electric	Oklahoma Gas & Electric	2007	Transmission Formula Rates
74	FERC	ER08-313	Southwestern Public Service	Southwestern Public Service	2007	Transmission Formula Rates
75	FERC	ER08-386	Potomac-Appalachian Transmission Highline, LLC	Potomac-Appalachian Transmission Highline, LLC	2007	Transmission Formula Rates
76	FERC	ER08-374	Atlantic Path 15, LLC	Atlantic Path 15, LLC	2007	Transmission Rates
77	Illinois Commerce Commission	No. 08-0363	NICOR Gas Company	NICOR Gas Company	2008	Distribution Service Embedded Cost of Service Study
78	FERC	ER08-951	PSEG Energy Resources & Trade, LLC	PSEG Energy Resources & Trade, LLC	2008	Reactive Power Charges
79	FERC	ER08-1233	Public Service Gas & Electric Company	Public Service Gas & Electric Company	2008	Transmission Formula Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
80	FERC	ER08-1457	PPL Electric Utilities Corp.	PPL Electric Utilities Corp.	2008	Transmission Formula Rates
81	FERC	ER08-1584	Black Hills Power	Black Hills Power	2008	Transmission Formula Rates
82	FERC	ER08-1600	Basin Electric Power Coop	Basin Electric Power Coop	2008	Transmission Rates
83	FERC	ER09-36	Prairie Wind Transmission, LLC	Prairie Wind Transmission, LLC	2008	Transmission Formula Rates
84	FERC	ER09-35	Tallgrass Transmission, LLC	Tallgrass Transmission, LLC	2008	Transmission Formula Rates
85	FERC	ER09-75	Pioneer Transmission, LLC	Pioneers Transmission, LLC	2008	Transmission Formula Rates
86	FERC	ER09-255	Nebraska Public Power District	Nebraska Public Power District	2008	Transmission Formula Rates
87	FERC	ER09-528	ITC Great Plains, LLC	ITC Great Plains, LLC	2009	Transmission Formula Rates
88	Illinois Commerce Commission	ER08-0532	Commonwealth Edison Co.	Commonwealth Edison Co.	2009	Distribution Service Embedded Cost of Service Study
89	FERC	ER08-370 & EL09-22	Missouri River Energy Services & MISO	Otter Tail Power Co.	2009	Formula Transmission Rate
90	FERC	ER10-152	PPL Electric Utilities Corp.	PPL Electric Utilities Corp.	2009	Revised Depreciation Method
91	FERC	ER09-1727	ALLETE, INC	ALLETE. INC	2009	Formula Transmission Rate
92	FERC	ER10-230	KCP&L	KCP&L	2009	Formula Transmission Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
93	FERC	ER10-455	Ameren Energy Marketing Company	Ameren Energy Marketing Company	2009	Reactive Power Rates
94	FERC	ER10-516	SCE&G	SCE&G	2010	Formula Transmission Rates
95	FERC	ER10-962	Union Electric Company	Union Electric Company	2010	Reactive Power Rates
96	FERC	ER10-1149	FP&L	FP&L	2010	Formula Transmission Rates
97	FERC	ER10-1418	Exelon Generation	Exelon Generation	2010	Reliability Must Run
98	FERC	ER10-1782	Tampa Electric Company	Tampa Electric Company	2010	Formula Transmission Rates
99	FERC	ER10-2061	Tampa Electric Company	Tampa Electric Company	2010	Formula Production Rates
100	FERC	ER05-6	Midwest ISO	MISO Transmission Owners	2010	Seams Elimination
101	FERC	ER11-2127	Terra Gen Dixie Valley	Terra Gen Dixie Valley	2010	Transmission Rates
102	FERC	ER09-1148	PPL Electric Utilities	PPL Electric Utilities	2011	Formula Transmission Rates
103	FERC	ER11-3643	PacifiCorp	PacifiCorp	2011	Formula Transmission Rates
104	FERC	ER11-3826	Black Hills	Black Hills	2011	Transmission Rates
105	FERC	ER11-3643	Puget Sound Energy	Puget Sound Energy	2012	Formula Transmission Rates
106	FERC	ER12-1378	CLECO	CLECO	2012	Formula Transmission Rates
107	FERC	ER12-1593	DATC	DATC	2012	Formula Transmission Rates

#	Jurisdiction	Case or Docket No.	Utility/Organization Initiating Proceeding	Client	Approximate Date	Subject Matter
108	FERC	ER12-2274	PSE&G	PSE&G	2012	Abandonment Costs
109	FERC	ER12-2554	Transource Missouri, LLC	Transource Missouri, LLC	2012	Formula Transmission Rate

EXHIBIT NO. PAC-5

Attachment A

All items are found by page number, line number, and column letter.

PacifiCorp

FIXED CHARGE WORKSHEET

Company:	PacifiCorp
Form 1	2011

O&M EXPENSE: [Note: This section should only be completed if sales are based on system average energy cost]

Production *

A. Total Power Production Expenses (p.321.80b)				>	1,959,425,284
B. Purchased Power Expenses (p.321.76b)				>	398,261,268
C. Energy Related O&M					
(p.320.5b)	(fuel)	>	722,758,588		
(p.320.7b)	(steam other)	>	3,583,830		
(p.320.8b) Cre.	(steam trans.)	>	-		
(p.320.15b)	(maint. S&E)	>	6,365,300		
(p.320.17b)	(maint. boiler plt)	>	109,128,194		
(p.320.18b)	(maint. elect. plt)	>	39,898,808		
(p.320.25b)	(fuel)	>	-		
(p.320.35b)	(maint. S&E)	>	-		
(p.320.37b)	(maint. react. plt)	>	-		
(p.320.38b)	(maint. elect. plt)	>	-		
(p.320.56b)	(maint. elect. plt)	>	2,553,749		
(p.321.63b)	(fuel)	>	367,320,902		
		total >		=	1,251,609,371
D. Total Production Plant Investment (p.204.46g)				>	10,420,953,789
$\frac{A-B-C}{D}$ =			0.0297		Not Used

Transmission:

A. Total Transmission Expenses (p.321.112b)	204,716,008	>	Not Used
B. Transmission by Others and Load Dispatching (p.321.96b & p.321.86b)	146,028,889	>	Not Used
C. Total Transmission Plant Investment ** (p.206.58g)	4,500,418,059	>	Not Used
$\frac{A-B}{C}$ =	0.0130	>	Not Used

*This method should be used to compute the O&M component of the fixed charge rate only for sales of system power where energy is priced on an average system basis. In all other circumstances, O&M is computed on a unit-specific basis using the unit participation work sheets.

PacifiCorp

OTHER TAXES EXPENSE

X. Other Taxes (Electric Only) (p.115.14g)	Excluding Prior Year Adjustments	>	151,699,035
Y. Electric Plant in Service (p.207.104g)		>	22,769,523,982

X / Y = 0.0067

A&G EXPENSE

A. Production Wages Expense (p.354.20b)	>	137,383,311
B. Transmission Wages Expense (p.354.21b)	>	22,707,903
C. A&G Wages Expense (p.354.27b)	>	41,949,915
D. Total Wages Expense (p.354.28b)	>	357,213,635
E. Total A&G related O&M (p.323.197b)	>	152,657,357
P. Total Production Plant Investment (p.205.46g)	>	10,420,953,789
T. Total Transmission Plant Investment (p.207.58g)	>	4,500,418,059

Production A&G Expense:

$$\frac{A}{(D-C)} \times \frac{E}{P} = 0.0064$$

Transmission A&G Expense:

$$\frac{B}{(D-C)} \times \frac{E}{T} = 0.0024$$

Not Used

PacifiCorp

DEPRECIATION EXPENSE

DEp =	Production Depreciation Expense (Sum of p. 336.2b through p. 336.6b)				>	274,139,628
DEt =	Transmission Depreciation Expense (p. 336.7b)				>	84,271,946
P =	Total Production Plant Investment (p. 204.46g)					10,420,953,789
T =	Total Transmission Plant Investment (p. 207.58g)					4,500,418,059
	Production Depreciation					
	SLDp =	DEp / P	=	0.0263		
	n =	38				
	SFDp =	R / ((1+R)^n)-1	=	0.0045		
	Transmission Depreciation					
	SLDt =	DEt / T	=	0.0187		Not Used
	n =	53				
	SFDt =	R / ((1+R)^n)-1	=	-0.9987		Not Used

COMPOSITE INCOME TAX EXPENSE

Composite Tax Rate (T):	37.95%		
Production CIT=	0.0233	= (T/(1-T))*(ROR+SFD-SLD)*(1-(WDTLTD/ROR))	
Transmission CIT=	-0.3745	= (T/(1-T))*(ROR+SFD-SLD)*(1-(WDTLTD/ROR))	Not Used
General and Intangible Plant >	2,170,031,310		
PRODUCTION G.P. =	0.0907	= [A&G EXPENSE: A / (D - C)] * Plant / Prod Plant Investment	
TRANS. G.P. =	0.0347	= [A&G EXPENSE: B / (D - C)] * Plant / Trans Plant Investment	Not Used

PacifiCorp

RATE OF RETURN WORKSHEET
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1. Common Stock Calculation

	Proprietary Capital (p.112.16c)	7,311,715,892	>	
Less:	Preferred Stock (p.112.3c)	40,733,100	>	
Less:	Account No. 216.1 (p.112.12c)	151,915,641	>	
	Common Stock = Proprietary Capital minus Preferred Stock minus Acct. 216.1			7,119,067,151

2. Rate of Return Calculation

LTD = Long Term Debt (Total) (p.112, sum of 18c through 22c) (details on pp. 256 & 257)	>	6,171,085,127
PF = Preferred Stock (Total) (p.112.3c)		40,733,100
Common Stock (See Above)		$7,119,067,151
Total Capital =		13,330,885,378
i = LTD interest (p.117, sum of 62c through 66c)	>	$370,236,355
d(pf) = Preferred Dividends (p.118.29c)	>	-

	CAPITAL	%	COST		WEIGHTED COST	
LONG-TERM DEBT / CAPITAL	$6,171,085,127	46.29%	6.00%		2.78%	
PREFERRED STOCK	$40,733,100	0.31%	0.00%		0.00%	
COMMON STOCK	$7,119,067,151	53.40%	9.80%		5.23%	
	$13,330,885,378	100.00%	R	=	8.01%	OVERALL ROR

PacifiCorp

SUMMARY

	Production	
(1) O&M	0.0000	Not Used
(2) Other Taxes	0.0067	
(3) A&G	0.0064	
(4) Return	0.0801	
(5) Depreciation	0.0045	
(6) Composite Income Tax	0.0233	
(7) General Plant	0.0095	
(8) Cash Working Capital	0.0006	
(9) Less: ADIT Adjustment*	-0.0103	
(10) Materials & Supplies ****	0.0030	
FIXED CHARGE RATE (Use for system avg. fuel sales)	0.1237	
FIXED CHARGE RATE (Less O&M)** (Use for all other sales)	0.1237	

NOTE: 1 MW = 1000 kW

* Item 9 is an adjustment to the fixed charge rate to reflect the utility's Accumulated Provision for Deferred Income Taxes.

** Use the FCR without O & M in the stacking sheet.

*** Annual cost includes General and Intangible Plant.

		Production
**** Materials & Supplies EOY	(p.227, 1 & 7)	302,233,250
	x Return & Taxes	0.1034
	subtotal	$31,254,650
	/ plant	10,420,953,789
		0.0030

Attachment B

PacifiCorp

Stacking of Generating Units to Determine the Units Likely to Participate in Providing Ancillary Services — Attachment B

PACW

Line No	Plant	Fuel Expense ($) (p402, p406, p410)	Generation (kwh) (pp. 326, 402, 406, 410)	Fuel Expense ($/kwh) (b) / (c)	Nameplate (MW) (pp 326, 402, 406, 410)	PACW Cumulative NP capacity (MW)	Production Investment ($/KW) (p402, p406, p410)	Plant factor (c)/(e)/8760/1000	Provides Regulating? (1 = yes)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(k)
1	Prospect 1	0	24,770,000	0.0000	4	4	477.56	0.7520	
2	MidColumbia	0	1,128,681,000	0.0000	135	139	119.94	0.9516	1
3	Prospect 4	0	4,925,000	0.0000	1	140	1,735.57	0.5622	
4	Condit	0	88,226,000	0.0000	14	154	110.61	0.7351	
5	Camas Co-Gen	0	89,501,000	0.0000	62	215	560.17	0.1661	
6	Fall Creek	0	11,651,000	0.0000	2	218	622.17	0.6046	
7	Eastside	0	0	0.0000	3	221	622.41	0.0000	
8	Eagle Point	0	18,508,000	0.0000	3	224	646.96	0.7519	
9	West Side	0	2,040,000	0.0000	1	224	780.96	0.3881	
10	Prospect 3	0	46,679,000	0.0000	7	231	973.91	0.7401	
11	Bend	0	2,115,000	0.0000	1	232	1,202.79	0.2175	
12	Marengo	0	403,408,000	0.0000	140	373	1,693.94	0.3280	
13	Marengo II Wind	0	194,378,000	0.0000	70	443	1,827.24	0.3161	
14	Wallowa Falls	0	7,892,000	0.0000	1	444	2,575.95	0.8190	
15	Iron Gate	0	119,843,000	0.0000	18	462	1,318.83	0.7600	
16	Copco 1	0	113,105,000	0.0000	20	482	492.74	0.6456	1
17	Copco 2	0	142,876,000	0.0000	27	509	593.77	0.6041	1
18	Prospect 2	36,925	251,221,000	0.0001	32	541	1,005.51	0.8962	
19	JC Boyle	0	335,014,000	0.0000	98	639	341.98	0.3903	
20	Fish Creek	7,102	46,160,000	0.0002	11	650	1,401.24	0.4790	
21	Soda Springs	7,102	70,977,000	0.0001	11	661	1,546.28	0.7366	
22	Clearwater 1	9,684	43,500,000	0.0002	15	676	465.88	0.3311	
23	Slide Creek	14,121	37,135,000	0.0004	18	694	1,415.28	0.2355	
24	Clearwater 2	16,786	56,329,000	0.0003	26	720	703.15	0.2473	
25	Lemolo 1	20,653	168,158,000	0.0001	32	752	745.12	0.6001	
26	Yale	19,309	661,211,000	0.0000	134	886	447.43	0.5633	1
27	Merwin	19,597	576,030,000	0.0000	136	1,022	573.11	0.4835	
28	Lemolo 2	24,856	182,966,000	0.0001	39	1,061	1,274.59	0.5425	
29	Toketee	27,438	263,816,000	0.0001	43	1,103	388.44	0.7086	
30	Swift 1	34,584	791,748,000	0.0000	240	1,343	417.60	0.3766	1
31	Colstrip	14,374,159	1,024,321,000	0.0140	156	1,499	1,416.89	0.7515	
32	Hermiston	59,623,564	1,161,094,000	0.0514	280	1,778	611.12	0.4741	1
33	Chehalis	45,556,011	664,323,000	0.0686	593	2,372	580.34	0.1278	
34	Jim Bridger	205,181,742	8,905,672,000	0.0230	1,545	3,917	685.39	0.6580	

Stacking of Generating Units to Determine the Units Likely to Participate in Providing Ancillary Services

PACE

Line No	Plant	Fuel Expense ($) (p402, p406, p410)	Generation (kwh) (pp. 326, 402, 406, 410)	Fuel Expense ($/kwh) (b) / (c)	Nameplate (MW) (pp 326, 402, 406, 410)	PACE Cumulative NP capacity (MW)	Production Investment ($/KW) (p402, p406, p410)	Plant factor (c)/(e)/8760/1000	Provides Regulating? (1 = yes)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(k)
1	US MagCorp PP	0	0	0.0000	-	-	-	-	
2	Nucor PP	0	0	0.0000	-	-	-	-	
3	Monsanto PP	0	0	0.0000	-	-	-	-	
4	Paris	0	3,126,000	0.0000	1	1	609.54	0.4956	
5	Weber	0	23,866,000	0.0000	4	5	768.20	0.7076	
6	Snake Creek	0	3,539,000	0.0000	1	6	0.00	0.3424	
7	Gunlock	0	2,198,000	0.0000	1	7	910.88	0.3346	
8	Sand Cove	0	2,304,000	0.0000	1	7	1,167.15	0.3288	
9	Dunlap	0	421,086,000	0.0000	111	118	2,158.65	0.4331	
10	Foote Creek	0	105,082,000	0.0000	33	151	1,119.36	0.3677	
11	Ashton	0	18,071,000	0.0000	7	158	2,796.81	0.3079	
12	Stairs	0	7,356,000	0.0000	1	159	1,621.16	0.8397	
13	Viva Naughton	0	773,000	0.0000	1	159	1,614.17	0.1192	
14	Last Chance	0	6,943,000	0.0000	2	161	1,620.01	0.4581	
15	Veyo	0	1,359,000	0.0000	1	162	1,750.24	0.3103	
16	McFadden Ridge	0	102,595,000	0.0000	29	190	1,993.08	0.4109	
17	Seven Mile Hill	0	381,679,000	0.0000	99	289	2,014.67	0.4401	
18	Glenrock	0	340,863,000	0.0000	99	388	2,029.93	0.3930	
19	Rolling Hills	0	309,180,000	0.0000	99	487	2,033.56	0.3565	
20	Seven Mile Hill II	0	83,613,000	0.0000	20	507	2,146.38	0.4895	
21	Pioneer	0	28,634,000	0.0000	5	512	2,184.72	0.6537	
22	High Plains	0	335,463,000	0.0000	99	611	2,213.39	0.3868	
23	Glenrock III	0	130,197,000	0.0000	39	650	2,236.11	0.3811	
24	Granite	0	8,377,000	0.0000	2	652	2,617.08	0.4781	
25	St. Anthony	0	0	0.0000	1	652	2,674.56	0.0000	
26	Blundell	0	278,079,000	0.0000	38	690	3,135.61	0.8332	
27	Fountain Green	0	69,000	0.0000	0	690	3,735.19	0.0492	
28	Olmsted	0	45,255,000	0.0000	10	701	91.50	0.5016	
29	Soda	0	35,155,000	0.0000	14	715	1,054.14	0.2867	
30	Oneida	0	77,321,000	0.0000	30	745	457.52	0.2942	1
31	Cutler	0	158,075,000	0.0000	30	775	1,004.36	0.6015	
32	Grace	0	163,373,000	0.0000	33	808	517.69	0.5651	
33	Gadsby Steam	9,413,917	69,094,000	0.1362	252	1,059	323.79	0.0313	1
34	Little Mountain	12,500,058	58,348,000	0.2142	16	1,075	108.27	0.4163	
35	Wyodak	15,125,638	1,457,709,000	0.0104	290	1,365	1,528.60	0.5744	
36	Carbon	20,346,469	1,332,218,000	0.0153	189	1,554	672.96	0.8064	1
37	Gadsby Peakers	11,760,826	125,295,000	0.0939	181	1,735	437.07	0.0790	1
38	Hunter 2	25,913,796	1,613,030,000	0.0161	295	2,029	1,024.71	0.6252	1
39	Hunter 1	45,927,126	2,845,170,000	0.0161	458	2,487	752.14	0.7096	1
40	Hunter 3	49,631,646	2,986,883,000	0.0166	496	2,982	1,034.35	0.6880	1
41	Dave Johnston	55,295,019	5,059,927,000	0.0109	817	3,799	1,086.22	0.7072	1
42	Cholla	54,754,988	2,688,370,000	0.0204	414	4,213	1,268.44	0.7413	1
43	Huntington	94,465,053	5,961,371,000	0.0158	996	5,209	820.46	0.6833	1
44	Naughton	101,169,233	5,102,251,000	0.0198	707	5,916	892.42	0.8236	1
45	Lake Side	104,792,180	1,845,528,000	0.0568	591	6,508	603.28	0.3563	1
46	Currant Creek	133,088,264	2,397,142,000	0.0555	567	7,075	626.41	0.4827	1

PacifiCorp

Demand Related Expenses for Participating Units

Attachment B

PACW

Line No	Plant	Nameplate capacity (MW)	Production Expenses: Oper, Supv, & Engr ($) (p402, p406, p410)	Coolants & Water (Nuclear Only) ($) (p402, p406, p410)	Steam Expenses ($) (p402, p406, p410)	Electric Expenses ($) (p402, p406, p410)	Misc Steam (or Nuclear) Power Expenses ($) (p402, p406, p410)	Rents ($) (p402, p406, p410)	Maintenance of Structures ($) (p402, p406, p410)	Maintenance of Misc Steam (or Nuclear) Plant ($) (p402, p406, p410)	Total Expenses ($) sum((c):(j))	Total ($/kW) (k)/(b)/1000
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	Prospect 1	4	205,274	0	0	0	0	0	36,778	0	242,052	64.38
2	MidColumbia	135	0	0	0	0	0	0	0	0	0	0.00
3	Prospect 4	1	121,086	0	0	0	0	0	31,308	0	152,394	152.39
4	Condit	14	209,397	0	0	0	0	0	40,064	0	249,461	18.21
5	Camas Co-Gen	62	0	0	0	87,940	0	0	0	0	87,940	1.43
6	Fall Creek	2	175,143	0	0	0	0	0	104,368	0	279,511	127.05
7	Eastside	3	(28,259)	0	0	0	0	0	9,989	0	(18,270)	(5.71)
8	Eagle Point	3	233,734	0	0	0	0	0	97,402	0	331,136	117.84
9	West Side	1	46,788	0	0	0	0	0	13,871	0	60,659	101.10
10	Prospect 3	7	309,200	0	0	0	0	0	339,943	0	649,143	90.16
11	Bend	1	65,032	0	0	0	0	0	92,127	0	157,159	141.58
12	Marengo	140	5,574,816	0	0	0	0	0	172,606	0	5,747,422	40.94
13	Marengo II Wind	70	2,741,761	0	0	0	0	0	19,894	0	2,761,655	39.34
14	Wallowa Falls	1	54,602	0	0	0	0	0	32,888	0	87,490	79.54
15	Iron Gate	18	1,091,878	0	33,634	0	1,209,642	1,226	4,224	15,058	2,355,662	130.87
16	Copco 1	20	(39,865)	0	2,945	0	1,345,967	3,153	12,826	20,931	1,345,957	67.30
17	Copco 2	27	(36,851)	0	3,976	0	1,772,458	1,623	22,382	38,543	1,802,131	66.75
18	Prospect 2	32	270,681	0	11,433	0	550,234	3,507	53,010	86,578	975,443	30.48
19	JC Boyle	98	293,295	0	14,430	0	713,604	(901)	13,244	65,017	1,098,689	11.21
20	Fish Creek	11	(18,149)	0	41,563	0	351,274	(8,620)	17,360	43,558	426,986	38.82
21	Soda Springs	11	(7,982)	0	41,563	0	289,766	(8,620)	16,149	31,387	362,263	32.93
22	Clearwater 1	15	(25,475)	0	56,677	0	392,897	(11,754)	57,831	45,038	515,214	34.35
23	Slide Creek	18	(31,242)	0	68,012	0	364,257	(14,105)	26,116	160,135	573,173	31.84
24	Clearwater 2	26	(45,372)	0	98,240	0	523,610	(20,374)	36,724	74,187	667,015	25.65
25	Lemolo 1	32	(48,405)	0	120,873	0	659,403	(25,068)	48,126	91,279	846,208	26.45
26	Yale	134	763,873	0	639,110	0	991,015	(75,955)	40,796	348,809	2,707,648	20.21
27	Merwin	136	778,698	0	648,649	0	1,131,169	(77,088)	149,101	312,967	2,943,496	21.64
28	Lemolo 2	39	(55,033)	0	145,471	0	751,145	(30,169)	69,888	117,042	998,344	25.93
29	Toketee	43	(73,100)	0	160,585	0	726,392	(33,304)	61,154	121,268	962,995	22.66
30	Swift 1	240	1,346,620	0	1,278,034	0	1,602,699	(136,038)	35,542	490,818	4,617,675	19.24
31	Colstrip	156	32,071	0	1,011,088	61,416	1,290,085	19,524	441,300	427,374	3,282,858	21.10
32	Hermiston	280	0	0	0	6,950,632	0	0	0	0	6,950,632	24.86
33	Chehalis	593	129,916	0	0	2,781,650	0	36,263	2,721	0	2,950,550	4.97
34	Jim Bridger	1,545	15,431,407	0	3,732,333	15,495	(12,200,227)	227,829	8,264,038	3,573,047	19,043,922	12.33

Demand Related Expenses for Participating Units
PACE

Line No	Plant	Nameplate capacity (MW)	Production Expenses: Oper, Supv, & Engr ($) (p402, p406, p410)	Coolants & Water (Nuclear Only) ($) (p402, p406, p410)	Steam Expenses ($) (p402, p406, p410)	Electric Expenses ($) (p402, p406, p410)	Misc Steam (or Nuclear) Power Expenses ($) (p402, p406, p410)	Rents ($) (p402, p406, p410)	Maintenance of Structures ($) (p402, p406, p410)	Maintenance of Misc Steam (or Nuclear) Plant ($) (p402, p406, p410)	Total Expenses ($) sum((c):(j))	Total ($/kW) (k)/(b)/1000
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
1	US MagCorp PP	-	0	0	0	0	0	0	0	0	0	#DIV/0!
2	Nucor PP	-	0	0	0	0	0	0	0	0	0	#DIV/0!
3	Monsanto PP	-	0	0	0	0	0	0	0	0	0	#DIV/0!
4	Paris	1	62,906	0	0	0	0	0	33,944	0	96,850	134.51
5	Weber	4	275,584	0	0	0	0	0	60,819	0	336,403	87.38
6	Snake Creek	1	81,443	0	0	0	0	0	17,063	0	98,506	83.48
7	Gunlock	1	63,876	0	0	0	0	0	41,721	0	105,597	140.80
8	Sand Cove	1	64,358	0	0	0	0	0	53,637	0	117,995	147.49
9	Dunlap	111	2,206,801	0	0	0	0	0	108,206	0	2,315,007	20.86
10	Foote Creek	33	1,916,623	0	0	0	0	0	106,885	0	2,023,508	62.03
11	Ashton	7	430,337	0	0	0	0	0	88,851	0	519,188	77.49
12	Stairs	1	175,080	0	0	0	0	0	80,317	0	255,397	255.40
13	Viva Naughton	1	120,554	0	0	0	0	0	27,458	0	148,012	200.02
14	Last Chance	2	105,552	0	0	0	0	0	29,285	0	134,837	77.94
15	Veyo	1	72,728	0	0	0	0	0	136,045	0	208,773	417.55
16	McFadden Ridge	29	276,012	0	0	0	0	0	631,060	0	907,072	31.83
17	Seven Mile Hill	99	1,622,325	0	0	0	0	0	512,371	0	2,134,696	21.56
18	Glenrock	99	1,009,112	0	0	0	0	0	458,098	0	1,467,210	14.82
19	Rolling Hills	99	1,084,314	0	0	0	0	0	427,203	0	1,511,517	15.27
20	Seven Mile Hill II	20	304,785	0	0	0	0	0	103,509	0	408,294	20.94
21	Pioneer	5	297,559	0	0	0	0	0	125,685	0	423,244	84.65
22	High Plains	99	995,588	0	0	0	0	0	2,138,787	0	3,134,375	31.66
23	Glenrock III	39	358,639	0	0	0	0	0	168,292	0	526,931	13.51
24	Granite	2	143,210	0	0	0	0	0	25,155	0	168,365	84.18
25	St. Anthony	1	58,950	0	0	0	0	0	2,578	0	61,528	123.06
26	Blundell	38	41,563	0	49,466	0	2,207,430	6,247	520,949	34,658	2,860,313	75.07
27	Fountain Green	0	21,797	0	0	0	0	0	5,808	0	27,605	172.53
28	Olmsted	10	(23,072)	0	18,775	0	327,521	(54)	2,065	145,068	470,303	45.66
29	Soda	14	(157,778)	0	25,758	0	601,475	1,184	462	42,990	514,091	36.72
30	Oneida	30	(378,124)	0	55,196	0	1,006,504	2,537	9,030	115,315	810,458	27.02
31	Cutler	30	(65,863)	0	54,686	0	837,252	(159)	15,336	233,527	1,074,779	35.83
32	Grace	33	(409,794)	0	60,715	0	1,896,430	3,991	39,377	101,709	1,692,428	51.29
33	Gadsby Steam	252	45,847	0	0	0	3,660,485	0	257,733	305,328	4,269,393	16.97
34	Little Mountain	16	0	0	0	933,523	0	228,838	0	0	1,162,361	72.65
35	Wyodak	290	302,145	0	13,169	0	4,158,309	5,701	412,626	238,999	5,130,949	17.71
36	Carbon	189	44,274	0	1,629,639	2,111,880	4,213,408	0	325,434	274,457	8,599,092	45.59
37	Gadsby Peakers	181	0	0	0	948,474	0	0	148,930	0	1,097,404	6.06
38	Hunter 2	295	59	0	2,014,131	0	(1,773,864)	2,341	2,232,392	164,934	2,639,993	8.96
39	Hunter 1	458	92	0	3,066,089	0	2,416,651	3,338	2,179,362	205,484	7,871,016	17.20
40	Hunter 3	496	101	0	3,311,933	0	2,579,207	3,673	2,136,616	412,053	8,443,583	17.04
41	Dave Johnston	817	527,243	0	157,589	0	17,485,536	6,135	1,824,395	1,650,053	21,650,951	26.51
42	Cholla	414	2,321,461	0	8,463,931	1,143,719	1,678,311	623	645,306	2,069,412	16,322,763	39.43
43	Huntington	996	13,687	0	7,704,010	0	12,330,552	1,000	2,441,557	1,146,487	23,637,293	23.73
44	Naughton	707	89,488	0	4,470,634	11,279	13,043,071	1,243	1,286,755	1,616,276	20,518,746	29.01
45	Lake Side	591	203,394	0	0	4,323,244	0	8,047	2,538,016	0	7,072,701	11.96
46	Currant Creek	567	96,501	0	0	3,039,306	0	1,363	249,281	0	3,386,451	5.97

PacifiCorp

Schedule 3 - Regulation and Frequency Response Service

PACW

12.368%

Line No	Plant	Nameplate (MW)	Available Capacity (MW)	Cumulative Available Capacity (MW)	Contribution Ratio	Installed Cost ($/kW)	Operation and Maintenance ($/kW)	Fixed charge ($/kW) (f) x Att A FCR	Cost of providing reactive supply services ($/kW)	Weighted Annual Cost ($/kW) ((h)+(g)-(i)) x (e)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Prospect 1	4	-	-	0.0%				0.00	0.00
2	MidColumbia	135	36.32	36	6.3%	119.94	0.00	119.94	0.00	7.59
3	Prospect 4	1	-	36	0.0%				0.00	0.00
4	Condit	14	-	36	0.0%				0.00	0.00
5	Camas Co-Gen	62	-	36	0.0%				6.58	0.00
6	Fall Creek	2	-	36	0.0%				0.00	0.00
7	Eastside	3	-	36	0.0%				0.00	0.00
8	Eagle Point	3	-	36	0.0%				0.00	0.00
9	West Side	1	-	36	0.0%				0.00	0.00
10	Prospect 3	7	-	36	0.0%				4.56	0.00
11	Bend	1	-	36	0.0%				0.00	0.00
12	Marengo	140	-	36	0.0%				0.00	0.00
13	Marengo II Wind	70	-	36	0.0%				0.00	0.00
14	Wallowa Falls	1	-	36	0.0%				0.00	0.00
15	Iron Gate	18	-	36	0.0%				0.84	0.00
16	Copco 1	20	0.16	36	0.0%	492.74	67.30	60.94	3.31	0.03
17	Copco 2	27	0.12	37	0.0%	593.77	66.75	73.44	3.94	0.03
18	Prospect 2	32	-	37	0.0%				1.80	0.00
19	JC Boyle	98	-	37	0.0%				0.78	0.00
20	Fish Creek	11	-	37	0.0%				1.41	0.00
21	Soda Springs	11	-	37	0.0%				2.19	0.00
22	Clearwater 1	15	-	37	0.0%				1.69	0.00
23	Slide Creek	18	-	37	0.0%				1.51	0.00
24	Clearwater 2	26	-	37	0.0%				2.05	0.00
25	Lemolo 1	32	-	37	0.0%				1.71	0.00
26	Yale	134	28.76	65	5.0%	447.43	20.21	55.34	1.51	3.71
27	Merwin	136	-	65	0.0%				2.61	0.00
28	Lemolo 2	39	-	65	0.0%				1.92	0.00
29	Toketee	43	-	65	0.0%				2.27	0.00
30	Swift 1	240	46.90	112	8.2%	417.60	19.24	51.65	1.41	5.68
31	Colstrip	156	-	112	0.0%				0.54	0.00
32	Hermiston	280	66.35	179	11.6%	611.12	24.86	75.58	2.96	11.27
33	Chehalis	593	-	179	0.0%				3.84	0.00
34	Jim Bridger	1,545	-	179	0.0%				0.69	0.00

12.368%

Line No	Plant (a)	Nameplate (MW) (b)	Available Capacity (MW) (c)	Cumulative Available Capacity (MW) (d)	Contribution Ratio (e)	Installed Cost ($/kW) (f)	Operation and Maintenance ($/kW) (g)	Fixed charge ($/kW) (f) x Attach A FCR (h)	Cost of providing reactive supply services ($/kW) (i)	Weighted Annual Cost ($/kW) ((h)+(g)-(i)) x € (j)
1	US MagCorp PP	-	-	179	0.0%				0.00	0.00
2	Nucor PP	-	-	179	0.0%				0.00	0.00
3	Monsanto PP	-	-	179	0.0%				0.00	0.00
4	Paris	1	-	179	0.0%				0.00	0.00
5	Weber	4	-	179	0.0%				0.00	0.00
6	Snake Creek	1	-	179	0.0%				0.00	0.00
7	Gunlock	1	-	179	0.0%				0.00	0.00
8	Sand Cove	1	-	179	0.0%				0.00	0.00
9	Dunlap	111	-	179	0.0%				0.00	0.00
10	Foote Creek	33	-	179	0.0%				0.00	0.00
11	Ashton	7	-	179	0.0%				9.63	0.00
12	Stairs	1	-	179	0.0%				0.00	0.00
13	Viva Naughton	1	-	179	0.0%				0.00	0.00
14	Last Chance	2	-	179	0.0%				0.00	0.00
15	Veyo	1	-	179	0.0%				0.00	0.00
16	McFadden Ridge	29	-	179	0.0%				0.00	0.00
17	Seven Mile Hill	99	-	179	0.0%				0.00	0.00
18	Glenrock	99	-	179	0.0%				0.00	0.00
19	Rolling Hills	99	-	179	0.0%				0.00	0.00
20	Seven Mile Hill II	20	-	179	0.0%				0.00	0.00
21	Pioneer	5	-	179	0.0%				0.00	0.00
22	High Plains	99	-	179	0.0%				0.00	0.00
23	Glenrock III	39	-	179	0.0%				0.00	0.00
24	Granite	2	-	179	0.0%				0.00	0.00
25	St. Anthony	1	-	179	0.0%				0.00	0.00
26	Blundell	38	-	179	0.0%				10.26	0.00
27	Fountain Green	0	-	179	0.0%				0.00	0.00
28	Olmsted	10	-	179	0.0%				0.00	0.00
29	Soda	14	-	179	0.0%				2.41	0.00
30	Oneida	30	0.00	179	0.0%	457.52	27.02	56.59	1.82	0.00
31	Cutler	30	-	179	0.0%				13.74	0.00
32	Grace	33	-	179	0.0%				2.28	0.00
33	Gadsby Steam	252	8.05	187	1.4%	323.79	16.97	40.05	1.07	0.78
34	Little Mountain	16	-	187	0.0%				0.00	0.00
35	Wyodak	290	-	187	0.0%				1.21	0.00
36	Carbon	189	0.71	187	0.1%	672.96	45.59	83.23	2.03	0.16
37	Gadsby Peakers	181	8.57	196	1.5%	437.07	6.06	54.06	4.88	0.82
38	Hunter 2	295	8.04	204	1.4%	1,024.71	8.96	126.74	0.00	1.90
39	Hunter 1	458	18.92	223	3.3%	752.14	17.20	93.03	0.00	3.63
40	Hunter 3	496	21.68	245	3.8%	1,034.35	17.04	127.93	0.00	5.48
41	Dave Johnston	817	0.34	245	0.1%	1,086.22	26.51	134.35	1.22	0.09
42	Cholla	414	32.51	277	5.7%	1,268.44	39.43	156.88	1.88	11.01
43	Huntington	996	24.44	302	4.3%	820.46	23.73	101.48	0.59	5.31
44	Naughton	707	5.21	307	0.9%	892.42	29.01	110.38	1.07	1.26
45	Lake Side	591	90.84	398	15.8%	603.28	11.96	74.62	2.47	13.31
46	Currant Creek	567	176.00	574	30.7%	626.41	5.97	77.48	3.06	24.65
					100.0%				Total Reg/LF cost ($/kW)	96.73
									losses	0.00%
									Annual Cost ($/MW)	96,726

Rate Design

Rate Design

Regulating Margin Requirements (MW)

	Regulation Reserves	Ramp Reserves	**Total Reserves**
Load	275.34	118.79	**394.12**
Non-VERs	0.19	0.00	**0.19**
VERs	175.81	9.46	**185.28**
Total	451.34	128.25	579.59

Cost of Service Method

Cost of Service Method	a	b	c	d	e	f	g
			a * b			c / d	d * f
	Regulating Margin (MW)	Cost of Regulating Margin ($/MW)	Revenue Requirement	Billing Determinants (MW)	Description of Billing Determinants	**Rate** ($/MW-year)	Revenue
Load	394.12	96,726	38,122,254	9,150	12CP	**4,166.404**	38,122,254
Export - Non-VERs	0.19	96,726	18,360	13,103	Installed Cap	**1.401**	18,360
Export - VERs	185.28	96,726	17,921,088	2,171	Installed Cap	**8,254.952**	17,921,088
Total	579.59		56,061,702				56,061,702

Rate Summary

Rate Summary	t	u	v	w	x	y	z
	f / 1000	t / 12	t / 52	v / 5	v / 7	w / 16 * 1000	x / 24 * 1000
	Yearly Rate ($/kW-Yr)	Monthly Rate ($/kW-month)	Weekly Rate ($/kW-week)	Daily Rate, On-Peak ($/kW-day)	Daily Rate, Off-Peak ($/kW-day)	Hourly Rate, On-Peak ($/MWh)	Hourly Rate, Off-Peak ($/MWh)
Schedule 3: Load	4.166404	0.347200	0.080123	0.016025	0.011446	1.002	0.477
Schedule 3A: Export - Non-VERs	0.001401	0.000117	0.000027	0.000005	0.000004	0.000	0.000
Schedule 3A: Export - VERs	8.254952	0.687913	0.158749	0.031750	0.022678	1.984	0.945

EXHIBIT NO. PAC-6

PACIFICORP
ANNUAL COMPARISON
OATT PART II AND III SERVICE (includes Ancillary Services)
CHANGED RATES VERSUS PRESENT RATES

Line No.	Service/Customer/Service Agreement ("SA") No.	Proposed	Current	Difference	Percent Increase/Decrease
	Schedule 3A				
	OATT (Part II Long-Term Firm Point-to-Point Transmission Service)				
1	Black Hills: SA 67	-	-	-	0.00%
2	Bonneville Power Administration SA 656	-	-	-	0.00%
3	Bonneville Power Administration SA 179	-	-	-	0.00%
4	Columbia Energy Partners SA 662	358,610	125,980	232,630	184.66%
5	Idaho Power SA 212	-	-	-	0.00%
6	Iberdrola SA 279	-	-	-	0.00%
7	Raser-Intermountain SA 509	12	33,264	(33,252)	-99.96%
8	PacifiCorp (various)	3,529	7,403,117	(7,399,588)	-99.95%
9	Powerex SA 169	-	-	-	0.00%
10	Seattle City Light SA 289	215,160	75,588	139,572	184.65%
11	NextEra Capacity assignment SA 426	598,874	210,389	388,485	184.65%
12	State of SD SA 170	-	-	-	0.00%
13	Total OATT Part II Long-Term Firm Point-to-Point Transmission Service	1,176,185	7,848,338	(6,672,153)	-85.01%
	Schedule 3				
	OATT (Part III - Network Service)				
14	Basin SA 505	1,388	968	420	43.4%
15	Black Hills SA 347	-	-	-	0.00%
16	BPA Gazely SA 229	12,504	8,700	3,804	43.7%
17	BPA Yakima SA 328	21,179	14,739	6,440	43.7%
18	BPA Clark SA 370	85,064	59,210	25,854	43.7%
19	BPA Benton/Rimrock SA 539	2,776	1,936	840	43.4%
20	BPA OR Wind SA 538	-	-	-	0.00%
21	PacifiCorp	34,578,032	24,067,825	10,510,207	43.7%
22	Tri State SA 628	47,915	33,351	14,564	43.7%
23	USBR SA 506	1,388	968	420	43.4%
24	WAPA SA 175	-	-	-	0.00%
25	Noble Americas SA 299	24,825	17,280	7,545	43.7%
26	Total OATT Part III Network Service	34,775,071	24,204,977	10,570,094	43.7%
	Legacy Contracts				
27	Deseret Generation & Transmission RS 280	924,258	643,324	280,934	43.7%
28	Utah Associated Municipal Power Systems RS 297	1,413,453	983,825	429,628	43.7%
29	Utah Municipal Power Agency RS 637	385,740	268,491	117,249	43.7%
30	Total Purchased Reserves and Other	2,723,451	1,895,640	827,811	43.7%
	Total	38,674,707	33,948,955	4,725,752	

PACIFICORP
STATEMENT BG
OATT PART II AND III SERVICE
REVENUE DATA TO REFLECT CHANGED RATES

Line No.	Service/Customer/Service Agreement ("SA") No.	Jan	Feb	March	April	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
	OATT (Part II Long-Term Firm Point-to-Point Transmission Service)													
1	Black Hills SA 67	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Bonneville Power Administration SA 656	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Bonneville Power Administration SA 179	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Columbia Energy Partners SA 662	-	-	-	-	-	71,722	71,722	71,722	71,722	71,722	-	-	358,610
5	Idaho Power SA 212	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Iberdrola SA 279	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Raser-Intermountain SA 509	1	1	1	1	1	1	1	1	1	1	1	1	12
8	PacifiCorp SA (various)	282	282	282	282	282	311	311	311	311	311	282	282	3,529
9	Powerex SA 169	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Seattle City Light SA 289	17,930	17,930	17,930	17,930	17,930	17,930	17,930	17,930	17,930	17,930	17,930	17,930	215,160
11	NextEra Capacity Assignment SA 426	57,377	57,377	57,377	57,377	57,377	39,447	39,447	39,447	39,447	39,447	57,377	57,377	598,874
12	State of SD SA 170	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Total OATT Part II Long-Term Firm Point-to-Point Transmission Service	75,590	75,590	75,590	75,590	75,590	129,411	129,411	129,411	129,411	129,411	75,590	75,590	1,176,185
	OATT (Part III - Network Service)													
14	Basin SA 505	-	347	347	347	-	-	-	-	-	-	-	347	1,388
15	Black Hills SA 347	-	-	-	-	-	-	-	-	-	-	-	-	-
16	BPA Gazely SA 229	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042	1,042	12,504
17	BPA Yakima SA 328	1,736	2,083	1,736	1,736	1,389	1,736	1,736	2,083	1,736	1,736	1,736	1,736	21,179
18	BPA Clark SA 370	10,069	9,722	8,680	8,333	5,208	3,472	4,166	4,861	5,555	8,680	7,638	8,680	85,064
19	BPA Benton/Rimrock SA 539	347	347	347	347	347	-	-	-	-	347	347	347	2,776
20	BPA OR Wind SA 538	-	-	-	-	-	-	-	-	-	-	-	-	-
21	PacifiCorp SA 66	3,014,394	2,986,618	2,684,206	2,610,252	2,460,609	2,990,437	3,215,423	3,274,447	2,954,675	2,618,932	2,717,537	3,050,502	34,578,032
22	Tri State SA 628	4,861	5,208	4,861	4,514	4,514	4,861	5,555	4,514	4,166	4,514	347	-	47,915
23	USBR SA 506	-	-	-	-	-	347	347	347	347	-	-	-	1,388
24	WAPA SA 175	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Noble Americas SA 299	2,083	1,736	1,736	1,736	1,910	2,257	2,604	2,604	2,604	1,736	1,910	1,910	24,825
26	Total OATT Part III Network Service	3,034,532	3,007,103	2,702,955	2,628,307	2,475,019	3,004,152	3,230,873	3,289,898	2,970,125	2,636,987	2,730,557	3,064,564	34,775,071
	Legacy Contracts													
27	Deseret Generation & Transmission RS 280	79,309	82,702	66,060	67,789	67,109	88,295	85,291	92,857	86,588	69,973	62,507	75,778	924,258
	Utah Associated Municipal Power Systems RS 297	122,562	104,855	104,507	103,466	82,286	147,907	131,589	167,351	162,143	80,550	90,272	115,965	1,413,453
28	Utah Municipal Power Agency RS 637	33,678	28,818	20,832	15,624	19,096	44,442	46,525	53,816	38,192	23,610	28,470	32,637	385,740
29	Total Legacy Contracts	112,987	111,520	86,892	83,413	86,205	132,737	131,816	146,673	124,780	93,583	90,977	108,415	1,309,998
30	**Percent Change**													
31	Changed Rates	3,223,109	3,194,213	2,865,437	2,787,310	2,636,814	3,266,300	3,492,100	3,565,982	3,224,316	2,859,981	2,897,124	3,248,569	35,951,256
32	Present Rates	2,812,398	2,792,289	2,563,445	2,509,065	2,404,313	2,882,856	3,040,023	3,091,448	2,853,634	2,600,041	2,585,500	2,830,121	32,965,130
33	Percent Difference	14.60%	14.39%	11.78%	11.09%	9.67%	13.30%	14.87%	15.35%	12.99%	10.00%	12.05%	14.79%	9.1%

PACIFICORP
STATEMENT BH
OATT PART II AND III SERVICE
REVENUE DATA TO REFLECT CURRENT RATES

Line No.	Service/Customer/Service Agreement ("SA") No.	Jan	Feb	March	April	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec	Total
	OATT (Part II Long-Term Firm Point-to-Point Transmission Service)													
1	Black Hills SA 67	-	-	-	-	-	-	-	-	-	-	-	-	-
2	Bonneville Power Administration SA 656	-	-	-	-	-	-	-	-	-	-	-	-	-
3	Bonneville Power Administration SA 179	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Columbia Energy Partners SA 662	-	-	-	-	-	25,196	25,196	25,196	25,196	25,196	-	-	125,980
5	Idaho Power SA 212	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Iberdrola SA 279	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Raser-Intermountain SA 509	2,772	2,772	2,772	2,772	2,772	2,772	2,772	2,772	2,772	2,772	2,772	2,772	33,264
8	PacifiCorp (various)	592,360	592,362	592,360	592,360	592,360	651,319	651,319	651,319	651,319	651,319	592,360	592,360	7,403,117
9	Powerex SA 169	-	-	-	-	-	-	-	-	-	-	-	-	-
10	Seattle City Light SA 289	6,299	6,299	6,299	6,299	6,299	6,299	6,299	6,299	6,299	6,299	6,299	6,299	75,588
11	NextEra Capacity Assignment SA 426	20,157	20,157	20,157	20,157	20,157	13,858	13,858	13,858	13,858	13,858	20,157	20,157	210,389
12	State of SD SA 170	-	-	-	-	-	-	-	-	-	-	-	-	-
13	Total OATT Part II Long-Term Firm Point-to-Point Transmission Service	621,588	621,590	621,588	621,588	621,588	699,444	699,444	699,444	699,444	699,444	621,588	621,588	7,848,338
14	**OATT (Part III - Network Service)**													
14	Basin SA 505	-	242	242	242	-	-	-	-	-	-	-	242	968
15	Black Hills SA 347	-	-	-	-	-	-	-	-	-	-	-	-	-
16	BPA Gazely SA 229	725	725	725	725	725	725	725	725	725	725	725	725	8,700
17	BPA Yakima SA 328	1,208	1,450	1,208	1,208	967	1,208	1,208	1,450	1,208	1,208	1,208	1,208	14,739
18	BPA Clark SA 370	7,008	6,767	6,042	5,800	3,625	2,417	2,900	3,383	3,867	6,042	5,317	6,042	59,210
19	BPA Benton/Rimrock SA 539	242	242	242	242	242	-	-	-	-	242	242	242	1,936
20	BPA OR Wind SA 538	-	-	-	-	-	-	-	-	-	-	-	-	-
21	PacifiCorp SA 66	2,098,150	2,078,817	1,868,325	1,816,850	1,712,692	2,081,475	2,238,075	2,279,158	2,056,583	1,822,892	1,891,525	2,123,283	24,067,825
22	Tri State SA 628	3,383	3,625	3,383	3,142	3,142	3,383	3,867	3,142	2,900	3,142	242	-	33,351
23	USBR SA 506	-	-	-	-	-	242	242	242	242	-	-	-	968
24	WAPA SA 175	-	-	-	-	-	-	-	-	-	-	-	-	-
25	Noble Americas SA 299	1,450	1,209	1,209	1,209	1,329	1,571	1,813	1,813	1,813	1,209	1,329	1,329	17,280
26	Total OATT Part III Network Service	2,112,166	2,093,077	1,881,376	1,829,418	1,722,722	2,091,021	2,248,830	2,289,913	2,067,338	1,835,460	1,900,588	2,133,071	24,204,977
27	**Legacy Contracts**													
27	Deseret Generation & Transmission RS 280	55,202	57,564	45,981	47,184	46,711	61,458	59,366	64,633	60,269	48,704	43,507	52,745	643,324
28	Utah Associated Municipal Power Systems RS 297	85,308	72,983	72,742	72,017	57,275	102,950	91,592	116,483	112,858	56,067	62,833	80,717	983,825
29	Utah Municipal Power Agency RS 637	23,442	20,058	14,500	10,875	13,292	30,933	32,383	37,458	26,583	16,433	19,817	22,717	268,491
30	Total Legacy Contracts	78,644	77,622	60,481	58,059	60,003	92,391	91,749	102,091	86,852	65,137	63,324	75,462	911,815
31	**Percent Change**													
32	Changed Rates	3,223,109	3,194,213	2,865,437	2,787,310	2,636,814	3,266,300	3,492,100	3,565,982	3,224,316	2,859,981	2,897,124	3,248,569	35,951,256
33	Present Rates	2,812,398	2,792,289	2,563,445	2,509,065	2,404,313	2,882,856	3,040,023	3,091,448	2,853,634	2,600,041	2,585,500	2,830,121	32,965,130
34	Percent Difference	14.60%	14.39%	11.78%	11.09%	9.67%	13.30%	14.87%	15.35%	12.99%	10.00%	12.05%	14.79%	9.1%

ATTACHMENT F

Exhibit No. PAC- 7

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
PacifiCorp	)	**Docket No. ER13-___-000**
	)	

TESTIMONY OF

GREGORY N. DUVALL
ON BEHALF OF PACIFICORP

April 1, 2013

TABLE OF CONTENTS

LIST OF EXHIBITS

I. <u>INTRODUCTION AND EXPERIENCE</u>

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Gregory N. Duvall and my business address is 825 NE Multnomah St., Suite 600, Portland, Oregon 97232.

Q. IN WHAT POSITION ARE YOU CURRENTLY EMPLOYED?

A. I am the Director, Net Power Costs, at PacifiCorp (also hereinafter called the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS EXPERIENCE.

A. I received a degree in Mathematics from University of Washington in 1976 and a Masters of Business Administration from University of Portland in 1979. I was first employed by PacifiCorp in 1976 and have held various positions in resource and transmission planning, regulation, resource acquisitions and trading. From 1997 through 2000 I lived in Australia where I managed the Energy Trading Department for Powercor, a PacifiCorp subsidiary at that time. Currently, I direct the work of the load forecasting group, the net power cost group, and the renewable compliance area.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony explains how the Company quantified the total amount of regulating margin reserves[1] that are needed by PacifiCorp to provide service under PacifiCorp's revised Schedules 3 and 3A of PacifiCorp's Open Access Transmission Tariff ("OATT"). Schedule 3 applies to transmission customers serving load in the PacifiCorp Balancing Authority Areas ("BAAs"), while Schedule 3A applies to transmission customers

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[1] Order No. 764 refers to this service as "generator regulation service." *See Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246, at P 4 (2012) ("Order No. 764"), *order on reh'g*, 141 FERC ¶ 61,232 (2012) ("Order No. 764-A"). While PacifiCorp uses the term "regulating margin reserve service" to describe this service, the two are functionally identical.

exporting out of PacifiCorp's BAAs to deliver variable energy resource ("VER") and non-VER generation to serve load outside the PacifiCorp BAAs. Both Schedules 3 and 3A provide for regulating margin reserve service under the OATT. My testimony explains the method used to allocate the total amount of regulating margin reserves among load allocated for Schedule 3 service and VER and non-VER generation allocated for Schedule 3A service. Finally, I describe the analysis and methodology used to identify the generating units that provide regulating margin reserve service, which form the basis of the costs allocated under Schedules 3 and 3A. I refer to the total amount of capacity required to provide Schedule 3 and 3A services as "regulating margin reserves."

II. <u>OTHER TESTIMONY</u>

Q. ARE ANY OTHER INDIVIDUALS FILING TESTIMONY ON BEHALF OF PACIFICORP IN THIS PROCEEDING?

A. Yes. The following individuals are providing testimony on behalf of PacifiCorp:

- Alan C. Heintz, Vice President of Brown, Williams, Morehead, and Quinn, Inc., has prepared testimony (*See* Exhibit No. PAC-3) supporting the rate methodologies employed for PacifiCorp's proposed Ancillary Services charges for Schedules 3 and 3A of PacifiCorp's OATT.
- Sarah E. Edmonds, Director of Transmission Regulation, Strategy & Policy for PacifiCorp has prepared testimony (*See* Exhibit No. PAC-1) supporting (1) the purpose of (and need for) the Company's proposed Schedule 3 and 3A rates; (2) PacifiCorp's proposed Schedule 3 and 3A tariff changes (*See* Exhibit No. PAC-2); and (3) the consistency of PacifiCorp's proposal with FERC policies for generator regulating margin reserve service rates.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony describes the study PacifiCorp performed to establish the total amount of regulating margin reserves ("PacifiCorp Schedule 3 and 3A Study", Exhibit No. PAC-8), and the method used to allocate the total amount of regulating margin reserves among load, VERs and non-VERs. My testimony also describes the analysis and methodology PacifiCorp used to determine the contribution ratio of generating units providing regulating margin reserve service for use in the development of a cost-based rate.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I provide the following in my testimony:

- A description of the study which produces the total amount of regulating margin reserves needed for load, VERs and non-VERs;
- A description of the methodology used to allocate the total amount of regulating margin reserves among load, VERs and non-VERs; and
- A description of the analysis used to identify the generating units that provided regulating margin reserves service; such analysis forms the basis of the costs allocated under Schedules 3 and 3A.

Q. PLEASE DESCRIBE THE REGULATING MARGIN RESERVES THAT WILL BE DISCUSSED IN YOUR TESTIMONY.

A. Regulating margin reserves are required and needed to support PacifiCorp's OATT Schedules 3 and 3A. Regulating margin reserves consist of ramp reserves and regulation reserves. Ramp reserve represents the minimum amount of flexibility required to follow hourly actual net load (which is equal to load minus VERs output) with dispatchable generation. Regulation reserve represents the required flexibility maintained to manage forecast errors relating to uncertainty or variability associated with load, VERs and non-VERs. Regulation reserve required to respond to generation and load variability over ten-minute time intervals is referred to as *regulating* reserves, while regulation reserve required to respond to VERs and load variability over intra-hourly time intervals is referred to as *following* reserves. There are five components of regulation reserve service: load regulating, load following, VERs regulating, VERs following, and non-VERs regulating. The following outlines the structural makeup of regulating margin reserves:

Regulating Margin Reserves

A. Ramp Reserves

B. Regulation Reserves

1. Load Regulating
2. Load Following
3. VERs Regulating
4. VERs Following
5. Non-VERs Regulating

Regulating margin reserves are required and needed to support the variability of generators located within the Company's BAAs, including VER and non-VER generators that do not serve load within the BAAs and instead export generation off-system, and as such, are not subject to Schedule 3 charges. For customers within the PacifiCorp BAAs not subject to Schedule 3 charges, PacifiCorp proposes to apply a charge for regulating margin reserves under Schedule 3A to provide a mechanism to recover the costs of holding reserve capacity associated with balancing variations in generation. As more fully explained in Ms. Edmonds' testimony, Schedules 3 and 3A contain tariff charges developed based on the revenue requirement for regulating margin reserve service provided by the Company in a manner consistent with Federal Energy Regulatory Commission ("FERC" or "Commission") precedent.

III. <u>DETERMINATION OF TOTAL REGULATING MARGIN RESERVES FOR SCHEDULES 3 AND 3A</u>

Q. IS THERE A PRE-DEFINED AMOUNT OF REGULATING MARGIN RESERVES THE COMPANY IS REQUIRED TO MAINTAIN IN ORDER TO MEET ITS OBLIGATIONS?

A. No. The volumetric requirement of regulating margin reserves required and needed to manage load and generation variation is not pre-defined by any standard. Rather, the Company is required to ensure that sufficient regulating margin reserves are held to meet the Company's reliability compliance requirements under North American Electric Reliability Corporation ("NERC") control performance standards on real power balancing control performance,[2] contributing to the system frequency regulation.[3] Therefore, the Company must always have sufficient regulating margin reserves that can respond to uncertain and variable changes in load and generation in order to maintain compliance. Maintaining sufficient regulating margin reserves thus necessitates the need

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[2] Requirement R2 of NERC Reliability Standard BAL-001-0.1a Real Power Balancing Control Performance Standard 2 ("CPS2") requires that "each Balancing Authority shall operate such that its average ACE [Area Control Error] for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit," effectively dictating that the Company keep its loads and resources in real-time balance.

[3] PacifiCorp is currently participating in the reliability-based control ("RBC") field trial which began on March 1, 2010 in the Western Electricity Coordinating Council ("WECC"). During the field trial, participating BAAs have received waivers from compliance with CPS2. RBC is intended to reduce cycling of thermal generating units, but does not reduce the overall amount of resource capacity required to provide regulating margin reserves.

for sufficient capacity from generators that can respond to sudden changes in loads or resources.

Q. DESCRIBE ANY UNIQUE LOADS ON PACIFICORP'S SYSTEM THAT IMPACT THE VOLUME OF REGULATING MARGIN RESERVES THE COMPANY REQUIRES.

A. The Company has several large industrial customers that operate arc furnaces, which can result in near-instantaneous load fluctuations of up to 100 MW. These changes occur throughout every hour on PacifiCorp's system. Regulating margin reserves are necessary to maintain reliability during routine load changes by large (and varied) industrial customers. Regulating margin reserves are also required to mitigate unexpected load changes, either up or down, due to rapidly developing load events (such as unexpected weather changes and/or deviations in expected load due to forecast errors).

Q. HAS PACIFICORP EXPERIENCED A GREATER NEED FOR REGULATING MARGIN RESERVE CAPABILITIES WITH INCREASING AMOUNTS OF VER GENERATION ON ITS SYSTEM?

A. Yes. In order to maintain compliance with the mandatory reliability standards, PacifiCorp must operate an ongoing balance of supply and demand in accordance with the prevailing operating criteria and standards, such as those established by NERC as discussed earlier in my testimony. Fluctuations in generation from VERs introduce incremental variability and uncertainty, thereby increasing the amount of regulating margin reserves that the Company sets aside. VER generation interconnected into PacifiCorp's BAAs has grown more than three-fold over the past six years, from 800 MW at the end of 2007 to 2,553 MW at the end of 2012.

Q. PLEASE ELABORATE ON THE IMPACTS TO PACIFICORP'S SYSTEM FROM INCREMENTAL VARIABILITY AND UNCERTAINTY.

A. As has been discussed above, the Company has experienced a greater need for regulating margin reserves due to the increased levels of VER generation on its system. As the magnitude of the installed VER generation has increased, the need for dispatchable generation capacity required to respond to intra-hour volatility has increased as well. In addition, it is difficult to forecast generation levels from VER generation sources, and with the increased VER generation in the Company's BAAs, incremental dispatchable generation capacity is required to manage increased VERs generation forecast errors. This increased forecast error results in an increased regulation reserve requirement. Although the Company strives to have accurate VER generation forecasts and subscribes to third-party expert forecast services, the inherent inaccuracy of VER forecasts dictates that a significant amount of reserves must be held on the system.

Q. PLEASE DESCRIBE HOW THE COMPANY USES VER FORECASTS AND FORECAST SERVICES TO DEVELOP ACCURATE FORECASTS.

A. The Company subscribes to a VERs forecasting service that is used day-ahead of delivery for both forecasting the amount of energy from VERs and the amount of regulating margin reserves due to anticipated variation in VERs. For the hour ahead of delivery, the Company uses persistence forecasts for VERs and holds regulating margin reserve due to anticipated variation in VERs output based on dispatcher experience.

Q. DOES THE COMPANY PERFORM ANALYSIS ON VERS WITHIN ITS BAAS?

A. Yes. PacifiCorp has undertaken studies to analyze the level and impact of VERs on its system in its Integrated Resource Plan ("IRP") processes.

Q. HAS THE COMPANY UNDERTAKEN RECENT ANALYSIS OF VERS WITHIN ITS BAAS?

A. Yes. As part of its IRP processes, the Company has recently performed its 2012 Wind Integration Resource Study, which estimates the regulating margin reserve requirement from historical load and wind generation production data. Regulating margin reserves are required to manage area control error ("ACE") variations due to load and VERs within PacifiCorp's BAAs. The 2012 Wind Integration Resource Study estimates regulating margin reserve requirement based on load combined with VERs variation and separately estimates the regulating margin reserve requirement based solely on load variation. The difference between these two calculations, with and without the estimated regulating margin reserve required to manage VER variability and uncertainty, provides the amount of incremental regulating margin reserves required to maintain system reliability due to the presence of VERs in PacifiCorp's BAAs.

Q. DID THE 2012 WIND INTEGRATION RESOURCE STUDY ADDRESS NON-VERS?

A. No. When PacifiCorp undertook the 2012 Wind Integration Resource Study in January 2012, the Company did not examine the variability of non-VERs because this differentiation is not required by PacifiCorp's state regulators.[4] The study was well underway by June 2012 when the Commission issued Order No. 764[5], which required transmission providers seeking to differentiate among resource types in balancing reserve capacity rates to consider variability of load, VERs and non-VERs.

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4 The 2012 Wind Integration Resource Study is the latest in a series of wind integration studies conducted by PacifiCorp in its IRP public process.

5 *Integration of Variable Energy Resources*, Order No. 764, 139 FERC ¶ 61,246 (2012) ("Order No. 764"), *order on reh'g*, 141 FERC ¶ 61,232 (2012) ("Order No. 764-A").

In anticipation of the requirements in Order No. 764, which will become effective November 12, 2013, PacifiCorp performed a subsequent analysis to quantify regulation reserve requirements for non-VERs using the same methodology as used in the 2012 Wind Integration Resource Study. This analysis is included in the PacifiCorp Schedule 3 and 3A Study.

Q. DESCRIBE THE METHODOLOGY USED IN THE PACIFICORP SCHEDULE 3 AND 3A STUDY TO DETERMINE REGULATING MARGIN REQUIREMENT FOR LOAD, VERS AND NON-VERS.

A. The first step in the study was to gather and analyze actual data for purposes of calculating regulating margin reserves. Actual data was used to identify ramp reserves and regulation reserves, the two components of regulating margin reserves. Ramp reserves for load and VERs were calculated as half the absolute value of the difference between the net load, which is equal to load minus VERs output at the top of one hour, minus the net load at the top of the prior hour. Ramp reserves were not identified for non-VERs due to the operational characteristics of these resources which are typically providing reserves through ramping. This calculation was performed for each ten-minute time interval in 2011, which was used to calculate 60-minute ramp periods.[6] These results were then added and averaged into monthly values for ramp reserves for 2011.

Regulation reserves were calculated by identifying forecast errors for five components of regulation reserves: 1) load regulating, 2) load following, 3) VERs regulating, 4) VERs following, and 5) non-VERs regulating. Regulating reserve for load, VERs and non-

[6] There are six non-overlapping ten-minute intervals in any 60-minute or hourly period. For purposes of the PacifiCorp Schedule 3 and 3A Study, hourly values for ramp or following reserves are constant across the six non-overlapping ten-minute intervals.

VERs was developed using 2011 ten-minute interval data collected from the Company's Energy Management System ("EMS"). Following reserve for load and VERs was developed using the same 2011 ten-minute interval data, which was used to calculate 60-minute hourly following periods. For non-VERs, only 2011 ten-minute interval data for regulating reserve was used due to the operational nature of non-VERS, which are actively controlled by operators from hour-to-hour and do not tend to deviate from controls on an hour-to-hour basis.

The next step to determine regulation reserves was to compare ten-minute data to operational forecasts in order to identify deviations. Deviations are the difference between what operations would have expected to happen and what actually occurred as expressed by actual data recorded by the Company's systems. The result of this step was identification of deviations for every ten-minute interval in 2011 for each of the five components of regulation reserves.

The next step for determining regulation reserves was to analyze the deviations by separating them into "bins" based on their characteristic forecasts for each ten-minute time interval in 2011, as discussed in more detail later in my testimony. The component forecasts and regulation reserves requirements are then applied to the operational data and combined in a backcasting procedure, which is described further in the PacifiCorp Schedule 3 and 3A Study (*See* Exhibit No. PAC-8 at 22). The result of the bin analysis is five component forecast values for load following, VERs following, load regulating, VERs regulating, and non-VERs regulating for each ten-minute interval of 2011.

The next step in the analysis was to take the five components and apply a root-sum-square calculation to each ten-minute interval for 2011. For each time interval where a root-sum-square calculation was applied, the Company subtracted regulation reserves in an amount equal to the allowable deviations in interchange values between BAA systems, as explained further in my testimony (sometimes referred to in my testimony as "L_{10}") This calculation produced a total amount of regulation reserve need for each ten-minute interval in 2011. These results were then added and averaged to produce monthly totals to establish the regulation reserve requirement.

Q. HOW DID THE COMPANY CALCULATE A COMBINED VALUE FOR REGULATING MARGIN RESERVE INCLUDING RAMP RESERVE AND REGULATION RESERVE?

A. Using the calculated totals described above for monthly ramp and regulation reserve requirements, the Company combined the monthly results using the following equation: monthly ramp requirements were calculated for load ("Y") and load plus VERs ("X") behavior. The monthly ramp requirements for VERs are the difference between "X" and "Y". The Company calculated monthly regulating margin reserve requirements for load ("A", load regulation plus load ramp, "Y," and subtracting the respective system L_{10}), then for load and non-VERs ("B", load and non-VER regulation plus load ramp, "Y," and subtracting the respective system L_{10}), then for load, non-VERs and VERs together ("C", load, non-VER and VER regulation plus ramp for load and VER, "X," and subtracting the respective system L_{10}). The monthly regulating margin requirement for non-VERs is the difference between "B" and "A"; the requirement for VERs is the difference between "C" and "B." These monthly results were then added and averaged to produce one annual value for regulating margin reserve requirements for load, VERs and non-VERs. I describe each of these steps below.

Q. WHAT IS THE TOTAL REQUIRED AMOUNT OF REGULATING MARGIN RESERVES HELD ATTRIBUTED TO SCHEDULE 3 AND 3A REQUIREMENTS USING THE CALCULATIONS ABOVE?

A. The total required amount of regulating margin reserves determined by the study are shown in the following table:

	Total MW
Load	394.12
non-VERs	0.19
VERs	185.28
Total	579.59

Q. IN WHAT ORDER DID THE COMPANY CALCULATE REGULATING MARGIN REQUIREMENTS IN THE EQUATION?

A. Traditionally, regulating margin reserve was held for load. Regulating margin reserve needed for resources was calculated incremental to the regulating margin required for load. The Company chose to determine the regulating margin for non-VERs second and VERs last.

Q. DESCRIBE THE METHOD USED IN THE PACIFICORP SCHEDULE 3 AND 3A STUDY TO DETERMINE THE REGULATING MARGIN RESERVE NEED FOR NON-VER GENERATION.

A. As explained above, because the 2012 Wind Integration Resource Study did not analyze deviations for non-VERs, a subsequent calculation was performed and the result was then combined with the results for load and VERs described above using a similar methodology. In addition, a different approach was used to determine an operational forecast for non-VERs than was used for load and VERs. PacifiCorp does not create and maintain a complete set of revised, hour-ahead schedules in real time for its non-VERs. It was therefore necessary to review the actual output data from PacifiCorp's non-VERs in order to estimate an operational level to measure against the units' actual output. This was accomplished by identifying eight representative non-VER units from the PacifiCorp fleet by type of resource: one coal unit, three gas units, two hydro units, a waste heat unit and one geothermal unit. The three representative gas units were comprised of two combined cycle units and one single cycle combustion turbine unit. One of the two combined cycle units is consistently operated using Automatic Generation Control ("AGC"). The two hydro units were composed of one unit with a large reservoir and one operated in run-of-river mode based on available inflow.

The analysis for non-VERs used 10-minute average actual generation data from 2011 to calculate regulation reserve requirement. To measure deviations for non-VERs, PacifiCorp separated the periods of time that the non-VER units were providing reserves from the times they were potentially using regulation reserves, the latter being the focus of the deviation analysis. Deviation periods were identified for each representative non-VER unit and excluded contingency events, ramping periods, manual control adjustments and AGC operations. These types of events or periods were excluded because the units were either providing regulation reserves or contingency reserves (i.e., not contributing to the need for regulation reserves) in most of these circumstances.[7]

Of these exclusions, ramping events and manual control adjustments proved difficult to identify algorithmically, so the selection of the deviation periods was done by sequentially plotting the non-VER generation data week-by-week and by recording the

[7] Contingency reserve is capacity the Company holds in reserve that can be used to respond to contingency events on the bulk power system (e.g., an instantaneous trip of a large generator).

beginning and ending of the periods where deviations requiring regulation reserves were evident. The process used to address regulation needs for non-VERs is similar to the process described in a recent study conducted by Puget Sound Energy in Docket No. ER11-3735.[8]

The intermediate result of the representative non-VER analysis was a percentage of regulation reserve based on the capacity of the representative generating units. The results were scaled up to the fleet based on the hourly generation in 2011. In other words, if a unit was generating at any level in a given hour during 2011, the capacity of that unit was multiplied by the percentage produced by the representative non-VERs analysis.

Q. HOW WERE THE DEVIATION RESULTS FOR LOAD, VERS AND NON-VERS COMBINED TO PRODUCE REGULATION REQUIREMENTS?

A. Once deviation results for load, VERs and non-VERs were identified, they were sorted using a "binning" analysis. A binned approach is a method whereby forecasts associated with deviations are grouped by hour and by system state before the overall results are averaged together to produce a regulation reserve need for any ten-minute interval in 2011. The bins are defined by every 5th percentile of the identified forecasts, creating 20 bins for each month's forecasts and their associated deviations. In other words, each month of the study will exhibit 20 bins of load following deviations, 20 bins of load regulating deviations, and the same for VER regulating and following. For non-VERs, 20 bins of regulating deviations were identified for calendar year 2011. Monthly binning was not feasible for non-VERs since the annual variability of non-VER generation

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[8] *Puget Sound Energy, Inc.*, FERC Docket No. ER11-3735, Exh. PSE-100, Testimony of Lloyd C. Reed, at 24-25 (Jun. 6, 2011).

resulted in non-overlapping bins at the highest and lowest generation bins, as well as a dearth of available data.

The resulting bins are used to identify an amount of load regulating, load following, VER regulating, VER following, and non-VER regulating for each ten-minute interval in 2011. This analysis is further described in the PacifiCorp Schedule 3 and 3A Study (*See* Exhibit No. PAC-8).

Q. WHY DID PACIFICORP USE A BINNED APPROACH IN THE PACIFICORP SCHEDULE 3 AND 3A STUDY?

A. The binned approach is necessary to prevent over-assignment of reserves in different system states, owing to certain characteristics of load, VERs and non-VERs. For example, when the balancing area load is near the lowest values for any particular day, it is highly unlikely the load deviation will require substantial down reserves to maintain balance because load will typically drop only so far. Similarly, when the load is near the peak of the month's load values, it is likely perhaps to go only a little higher, but could drop substantially at any time. Similarly for VERs or non-VERs, when output is at the maximum value for a system, there will not be a deviation taking the value above that maximum value. In other words, the directional nature of the reserves requirements can change greatly by the state of the load or generation output. At high load or VER generation states, there is not likely to be a significant need for reserves covering a surprise increase in those values. Similarly, at the lowest states, there is not likely to be a need for the direction of reserves covering a significant shortfall in load or generation. The use of bins prevents averaging particular system extremes in load or generation state over an entire month, limiting the influence of a given data point to only one of 20 bins per month.

Q. AFTER THE DATA WAS SORTED USING THE BINNED APPROACH, PLEASE DESCRIBE THE NEXT STEPS IN THE ANALYSIS.

A. It is important to stress that each of the five components which result from the binning analysis are critical to maintain system integrity, but the components are not additive. In order to properly account for the diversity among these components, the load, VER and non-VER reserve requirements are combined using a root-sum-square calculation assuming their variability is independent or uncorrelated for each time interval in the study. (*See* Exhibit No. PAC-8, Equation 2, at p. 29).

Q. PLEASE EXPLAIN DIVERSITY BENEFITS.

A. In Order No. 764, the Commission required that overall generator regulation requirements be established by taking "diversity benefits" into account. The concept of diversity benefits was first established in the *Westar* case.[9] The Commission defined diversity benefits as the result of aggregating the variations of all resources so that one resource's negative deviation can offset some or all of another resource's positive deviation.[10] The Commission noted, however, that "this concept will need to be reconciled with any customer classifications proposed by the public utility transmission *provider in a way that prevents any over-recovery of these capacity costs*."[11]

Q. WHAT IS THE CONCEPT OF CAUSAL CORRELATION BETWEEN DEVIATIONS AND HOW DOES IT RELATE TO PACIFICORP'S ANALYSIS?

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[9] *See Westar Energy, Inc.*, 130 FERC ¶ 61,215 at PP 37-38 (2010) ("Westar").

[10] Order No. 764 at P 319.

[11] *Id.* (emphasis added)

A. While there is little Commission precedent on this topic, it may be inferred from the descriptions of diversity benefits that one approach to achieving such benefits is to assume that any and all negative deviations will offset any and all positive deviations. In other words, deviations using this approach are assumed to be perfectly correlated (*i.e.*, +/- 100%). As part of its analysis in the 2012 Wind Integration Resource Study, PacifiCorp analyzed load and VER data, but determined that the data did not show with any reasonable certainty that negative deviations offsetting positive deviations, or vice versa, are causally related in a manner which would justify correlating the results to reflect perfect correlation (*i.e.*, a correlation of +/- 100%).

The PacifiCorp Schedule 3 and 3A Study explains how a regression plot analysis was used to examine the potential for causal correlation and how the results indicate that such an assumption would not be reasonable. Because reserves are intended to manage the deviations from expected load and generation, the question becomes not whether the raw generation output and balancing area load are correlated, but rather whether the respective forecast errors between the Company's expected generation output and load are correlated. The forecast deviations for VERs and load in the Company's BAAs were analyzed for correlation by performing a linear regression using the load deviation as an independent variable and the concurrent VER deviation as the dependent variable. The results indicate that while there is a calculable correlation between VER and load deviations in the data, the relationships are so weak from a causal perspective such that neither explains the other, and so this relationship is not useful in an operational context. The value of the load deviation offers no ability to explain the VER deviation, and so the two are unrelated.

In summary, the study provides an analysis which disproves a causal connection between offsetting deviations for load, VERs and non-VERs. To put it into a simple illustration, an occurrence of the actual wind deviating significantly from forecast in Wyoming has no causal relationship to how customers in the Company's six states will differ their decisions from projected behavior in manufacturing their products, opening their commercial establishments, irrigating their crops or operating their space heating or air conditioning units. In addition, the rejection of the assumption that deviations are causally correlated is supported by reputable wind integration studies which reach similar conclusions.[12]

Q. ALTHOUGH PACIFICORP'S SCHEDULE 3 AND 3A STUDY REJECTS THE CONCEPT OF CAUSAL CORRELATION BETWEEN DEVIATIONS, DID PACIFICORP ENSURE THAT THE SCHEDULES INCLUDE DIVERSITY BENEFITS?

A. Yes. The results of the PacifiCorp Schedule 3 and 3A Study include diversity benefits by using the root-sum-square calculation approach. The root-sum-square method performs two important functions to ensure that the ultimate result is reasonable: 1) by taking the root of the sum of the squares of the five components (for non-VER regulating, load following, load regulating, VER regulating, and VER following), the calculation produces a result for total regulation reserve need that is much lower than what would be

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[12] *See, e.g.*, GE Energy, *Western Wind and Solar Integration Study* (prepared for the National Renewable Energy Laboratory), http://www.nrel.gov/docs/fy10osti/47434.pdf (May 2010), 70-71, 92:

> Considering the wind and load deltas over several years of data, the study concluded that load and wind deltas are not highly correlated at the footprint level, and large load deltas are not usually accompanied by similarly large wind deltas, *i.e.*, the risk of simultaneous delta reinforcement is relatively small. Nevertheless, there are a few hours during the year when load and wind deltas combine to increase net load down-ramps, and many more hours where net load up-ramps are greater than the largest load-alone up-ramp. The latter events are driven by large wind drops and are more of an operational concern than the former.

if these components were simply added together to produce total regulation need; and 2) while the method does not assume causal correlation between the components, the method captures a reasonable amount of diversity benefits because it includes the interaction of load, VERs and non-VERs within the boundaries of the calculation. In other words, the root-sum-square calculation achieves a result which is between a purely additive approach which includes no diversity benefits and an approach which assumes the components are causally correlated. Given that PacifiCorp's analysis demonstrated no causal correlation, it would not be accurate to include additional diversity benefits that cannot be supported by the study.

Q. DID PACIFICORP MAKE ANY OTHER ADJUSTMENTS WHEN DETERMINING THE TOTAL REGULATION RESERVE AMOUNT?

A. Yes. As explained earlier in my testimony, PacifiCorp subtracted an amount of reserve which represents a bandwidth of acceptable deviation prescribed by WECC between net scheduled interchange and net actual interchange on the Company's BAAs. Subtracting this amount lowers the regulating margin reserves required to serve customers by 81.29 MW. PacifiCorp subtracted these values for PacifiCorp's East and West BAAs from the total regulation reserve amount determined by the PacifiCorp Schedule 3 and 3A Study. Since PacifiCorp must hold these amounts for interchange balancing notwithstanding Schedule 3 and 3A regulating margin reserve needs, PacifiCorp determined that the amounts should be subtracted from the total regulating margin reserve amount. For PacifiCorp's East BAA, the current L_{10} value is 47.88 MW, and for PacifiCorp's West BAA, the current L_{10} value is 33.41 MW.[13]

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[13] For more information, please refer to: http://www.wecc.biz/committees/StandingCommittees/OC/OPS/PWG/Shared%20Documents/Annual%20Frequenc

Q. WHAT OTHER MEASURES HAS PACIFICORP TAKEN TO ENSURE THAT ITS RESULTS DO NOT RESULT IN OVER-RECOVERY OF CAPACITY COSTS?

A. PacifiCorp used three methods to ensure that it does not over-recover capacity costs and that the amount of regulating margin reserves is just and reasonable. These methods include:

1) Application of the binned approach explained earlier in my testimony, which ensures that averaging hourly results over an entire month does not overstate or represent particular system extremes in load or generation state which may have occurred during that month, thereby limiting the influence of a given data point to only one of 20 bins per month for load and VERs and the 20 bins in 2011 for non-VERs;

2) Subtraction of the L_{10} values of PacifiCorp's BAAs. Crediting customers with reserves equal to the East BAA and West BAA L_{10} values saves 81.29 average MW of reserves annually; and

3) Application of the root-sum-square equation to combine component reserve requirements rather than adding them accounts for the diversity of the component requirements in an unbiased manner with an appropriate zero correlation value.

Q. DOES PACIFICORP BELIEVE THAT THESE METHODS ACHIEVE A RESULT THAT SATISFIES THE COMMISSION'S DIRECTIVE TO ENSURE THAT TRANSMISSION PROVIDERS DO NOT OVER-RECOVER GENERATOR REGULATION CAPACITY COSTS?

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A. Yes. The methods I have described meaningfully reduce the overall amount of regulation reserves identified in the study. PacifiCorp understands the Commission's concern that some methodological approaches may have the potential to overstate regulating margin reserve need. PacifiCorp focused its study efforts on approaches which arrive at just and reasonable results and which capture a reasonable and accurate level of diversity benefits.

Q. HAS PACIFICORP INCLUDED STAKEHOLDERS IN THE DEVELOPMENT OF ITS METHODS TO IDENTIFY TOTAL REGULATING MARGIN RESERVE NEED?

A. Yes. PacifiCorp conducted an extensive public process for the 2012 Wind Integration Resource Study as part of the IRP process, which included stakeholders from PacifiCorp's six retail states. In addition to providing numerous opportunities for stakeholder review and input, the Company used a technical review committee to develop the study approach. After working with the technical review committee for several months, PacifiCorp held its first meeting with stakeholders in the IRP process to discuss the 2012 Wind Integration Resource Study in May 2012. The technical review committee members were present at that meeting. Stakeholders had an opportunity to provide feedback to PacifiCorp on the methodology and the results. A timeline of significant milestones during this process is provided in Exhibit No. PAC-9.

Q. PLEASE DESCRIBE THE TECHNICAL REVIEW COMMITTEE AND ITS INVOLVEMENT IN THE 2012 WIND INTEGRATION RESOURCE STUDY.

A. The technical review committee consisted of the following six people:

- Andrea Coon, Director, Western Renewable Energy Generation Information System (WREGIS) for the WECC;

- Randall Falkenberg – President, RFI Consulting, Inc.;
- Matt Hunsaker, Manager, Renewable Integration Manager for the WECC;
- Michael Milligan, Lead research for the Transmission and Grid Integration Team at the National Renewable Energy Laboratory; and
- J. Charles Smith, Executive Director, Utility Variable-Generation Integration Group.

The technical review committee began work on PacifiCorp's 2012 Wind Integration Resource Study in January 2012. They reviewed and critiqued the methodology, identified sensitivities to conduct, and reviewed the results of the study. Additional information on the members' background is provided in Exhibit No. PAC-10.

Q. DID PACIFICORP UNDERTAKE ANY OTHER STAKEHOLDER INVOLVEMENT IN THE DEVELOPMENT OF THE PACIFICORP SCHEDULE 3 AND 3A STUDY?

A. Yes. In addition to the six-state IRP review process described above, PacifiCorp consulted with customers specifically on the proposed Schedule 3 and 3A changes. PacifiCorp has offered to meet with customers interested in more detail regarding the Schedule 3 and 3A proposals. Only one customer requested such a meeting – the Bonneville Power Administration ("BPA") – and PacifiCorp met with BPA on January 8, 2013.

IV. <u>ALLOCATION OF TOTAL REGULATING MARGIN RESERVES FOR SCHEDULES 3 AND 3A</u>

Q. DOES PACIFICORP INTEND TO APPLY DIFFERENT CHARGES FOR DIFFERENT CUSTOMER CLASSES UNDER SCHEDULES 3 AND 3A?

A. Yes. Schedule 3 service applies to load in the PacifiCorp BAAs, and Schedule 3A is for VERs and non-VERs exporting from the PacifiCorp BAAs. These customer classes have different operational characteristics, so it is appropriate to apply different regulation reserve charges to them.

Q. WHAT IS PACIFICORP'S BASIS FOR DISTINGUISHING BETWEEN LOAD, VER AND NON-VER GENERATION UNDER SCHEDULES 3 AND 3A?

A. The PacifiCorp Schedule 3 and 3A Study analyzes deviations for load, VERs and non-VERs based upon a comparison of actual ten-minute and hourly data to operational forecasts. Because the comparison utilizes deviations which are the result of the actual operations of load and generation on PacifiCorp's system, the operational characteristics justifying differential treatment in capacity cost allocation are expressed in the results. Accordingly, the proposed rates, which reflect different quantities of regulation reserves, do so only to the extent such differentiation among load, VERs and non-VERs are reasonably related to operational differences among those resources.

V. <u>IDENTIFICATION OF RESOURCES SUPPLYING TOTAL REGULATING MARGIN RESERVES FOR SCHEDULES 3 AND 3A</u>

Q DO ALL OF PACIFICORP'S RESOURCES CONTRIBUTE TO THE SUPPLY FOR THE TOTAL REGULATING MARGIN RESERVES FOR SCHEDULES 3 AND 3A?

A. No. Many of PacifiCorp's resources contribute to the supply for the total regulating margin reserves for Schedules 3 and 3A. As discussed below, PacifiCorp has undertaken an analysis to determine the contribution of each of PacifiCorp's resources to the supply for the total regulating margin reserves for Schedules 3 and 3A. PacifiCorp has also determined the proportionate amount of such contribution to the total amount for each resource ("contribution ratio").

Q. HOW DOES THE CONTRIBUTION RATIO RELATE TO THE TOTAL REGULATING MARGIN RESERVE AMOUNT IDENTIFIED IN THE PACIFICORP SCHEDULE 3 AND 3A STUDY?

A. The contribution ratio represents the proportionate contribution of PacifiCorp's resources that are deployed to meet the total regulating margin reserve requirement on PacifiCorp's system, but it does not have anything to do with the megawatt amount of the total regulating margin reserve requirement identified in the study.

Q. HOW DID PACIFICORP IDENTIFY THE GENERATING UNITS THAT PROVIDE THE SERVICE WHICH FORMS THE BASIS FOR THE COSTS ALLOCATED PURSUANT TO SCHEDULES 3 AND 3A?

A. As I noted earlier in my testimony, the Company records data in its EMS showing the amount of total ten-minute reserves credited to individual generation resources and contracts by hour. PacifiCorp used this data to identify the generation resources that provided reserves in 2011; however, the data recorded for individual units was <u>not</u> used to determine the amount of regulating margin reserve need. As explained earlier in my testimony, regulating margin reserve need for the Schedule 3 and 3A rates was determined in the PacifiCorp Schedule 3 and 3A Study by comparing actual data to operational forecasts to determine and then analyze deviations for regulation reserves and to add an additional amount for ramp reserves. The analysis of EMS data recorded for individual units was to identify the units providing service in 2011 for which it would be reasonable to include the capital costs of in the rates. This is more fully explained in the testimony of Mr. Heintz.

In order to identify units providing regulating margin reserve service, it was first necessary to identify units providing spinning and supplemental reserves necessary to comply with mandatory NERC or WECC reliability standards. Once these units were identified, the remaining units holding reserves were identified as the units available for regulating margin reserves.

Q. HOW DOES IDENTIFICATION OF UNITS PROVIDING SPINNING AND SUPPLEMENTAL RESERVES, WHICH ARE NOT PART OF SCHEDULES 3 AND 3A, RELATE TO IDENTIFYING UNITS PROVIDING REGULATING MARGIN RESERVE SERVICE FOR SCHEDULES 3 AND 3A?

A. The identification of units providing regulating margin reserves is dependent on the removal of 10-minute reserves allocated to spinning and supplemental reserves because the 10-minute reserves recorded in the Company's records are total 10-minute reserves and are not broken-down into spinning, supplemental and regulation reserves. The following details the identification of units providing regulating reserves and following reserves, which comprise total units providing regulation reserve service. Ramp reserves can be supplied by units providing either regulating or following reserves. While the following descriptions relate to calculating amounts of reserves, the calculations are only for the purposes of determining which units were providing regulating margin reserve service and in what ratio, not for establishing the amount of regulating margin reserve need which has already been established in the PacifiCorp Schedule 3 and 3A Study.

Q. DOES THE RESERVE DATA IN THE COMPANY'S EMS INCLUDE THE AMOUNT OF REGULATING MARGIN RESERVES IN INDIVIDUAL UNITS USED TO MEET NERC'S CONTROL PERFORMANCE STANDARD CRITERIA?

A. No. The Company's EMS only records the amount of 10-minute reserves credited to individual generation resources and contracts by hour. Instead, identification of units providing regulation reserve service in 2011 must be performed through a calculation.

Q. PLEASE DESCRIBE HOW THE COMPANY IDENTIFIED UNITS PROVIDING SPINNING AND SUPPLEMENTAL RESERVE SERVICE.

A. The Company analyzed 10-minute reserve data for 2011 and identified an amount of reserve to satisfy the WECC requirement for spinning and supplemental reserves which is five percent of hydroelectric and wind generation and seven percent of thermal generation in each hour during the year. Fifty percent of the total requirement must be spinning reserves with the remainder supplemental. Tables A and B below show these amounts and the identification of the units that were used to provide this service.

Q. PLEASE DESCRIBE HOW THE COMPANY IDENTIFIED UNITS PROVIDING REGULATING MARGIN RESERVES.

A. To identify units providing regulating margin reserves, the Company next analyzed the remaining 10-minute reserves above what was allocated to meet spinning and supplemental reserve requirements. Regulating reserves are the final slice of the total 10-minute reserve resource pool. The three slices of the 10-minute reserves – one to meet the supplemental reserve requirement, one to meet spinning reserves, and one to provide regulating reserves – account for 100 percent of the 10-minute reserves recorded in the

Company's historic records. Exhibit No. PAC-11, Table C shows the amount for regulating reserves and the identification of the units that were assumed to provide this service. To identify units providing following reserves, the Company used real-time values stored in the Company's archived records. Hydro and thermal generation data was sourced from the data maintained for the NERC Generating Availability Data System ("GADS") reporting. The generation and maximum dependable capability ("MDC") data for the shared-ownership Craig and Hayden plants were sourced from the Company's archived data. Thermal MDC data was also sourced from the data maintained for NERC GADS reporting. Hydro unit MDC data was sourced from the Ranger PI system. Ranger is the EMS used by PacifiCorp to manage its BAAs.

Q. PLEASE FURTHER DESCRIBE HOW YOU DEFINE AND IDENTIFY THE UNITS PROVIDING REGULATING RESERVE SERVICE IN CALENDAR YEAR 2011.

A. The ability to provide regulating reserves on a resource is based on how fast and how much the unit can ramp during a 10-minute period. Similarly, the ability to provide following reserves on a resource is based on how fast and how much the unit can ramp during a 60-minute period. In either instance, the regulating reserve and following reserve capability of any given resource can never exceed the operating range of the resource. The operating range of the resource is defined as the difference between that resource's minimum operating capability and the MDC.

Q. PLEASE FURTHER DESCRIBE HOW YOU DEFINE AND IDENTIFY THE UNITS PROVIDING FOLLOWING RESERVE SERVICE IN CALENDAR YEAR 2011.

A. Unlike regulating reserves, which are used to manage the net moment-to-moment load and generation variation, following reserves are used to manage changes and uncertainty in load and generation over a 60-minute period. An additional calculation was done to determine the amount of following reserves held on each unit in each balancing hour of calendar year 2011.

Q. PLEASE EXPLAIN HOW AVAILABLE FOLLOWING RESERVES WERE CALCULATED FOR PURPOSES OF IDENTIFYING THE UNITS PROVIDING THE SERVICE IN CALENDAR YEAR 2011.

A. Given the time period defining following reserves is six times the time period used to define regulating reserves, the amount of following reserves is six times the regulating reserves being held or the difference between actual generation and the MDC, whichever is less. For example, a 500 MW resource with a 5 MW/minute ramp rate could provide 50 MW of regulating reserves in response to variations in system load and generation over a 10-minute period (5 MW/minute x 10 minutes = 50 MW). If this unit had a minimum operating capability of 200 MW, it is capable of providing up to 250 MW of following reserves in response to unexpected changes in system load and generation over a 60-minute period (5 MW/minute x 60 minutes less 50 MW of regulating reserves being used to manage variability over 10-minute periods).[14] However, if this resource were being used to generate 400 MW, the following reserve capability would be reduced to 50 MW owing to the fact that it could not exceed its 500 MW rating (minimum of 250 MW

[14] The full 300 MW of load following reserve capability could not be used to manage 60-minute uncertainty without compromising the amount of regulating reserves being held. As such, the 50 MW of regulating reserves is netted against the load following reserve capability to arrive at the amount of load following reserves that can be used.

of following capability or the difference between the 400 MW actual generation level and 500 MW rating less 50 MW of regulating reserves = 50 MW).

Q. PLEASE DESCRIBE THE RESULTS OF THE ANALYSIS TO IDENTIFY UNITS PROVIDING REGULATING MARGIN RESERVE SERVICE FOR SCHEDULE 3 AND 3A SERVICES.

A. Once the calculations described earlier in my testimony have been performed, the results represent how much regulating margin reserves were held on specific units in 2011. As I have explained earlier in my testimony, the Company did not use these amounts to determine total regulating margin reserve need. Instead, the results are used to determine a relative contribution ratio among the units that provided the service. The contribution ratio for each individual unit can then be used to allocate an appropriate amount of embedded capital costs of that unit for purposes of developing Schedule 3 and 3A rates.

The results are shown in Exhibit No. PAC-11 to my testimony and illustrate the calculation results that are used to ultimately derive the regulation reserve contribution ratio shown in Table E.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PacifiCorp	)	**Docket No. ER13-___-000**

VERIFICATION

I, Gregory N. Duvall, being first duly sworn, depose and state that I am the witness identified in the foregoing prepared testimony, and that the statements of fact in the testimony and supporting exhibits are true and correct to the best of my knowledge, information and belief.

Gregory N. Duvall
Gregory N. Duvall

Subscribed and sworn before me at 825 NE MULTNOMAH ST Portland OR 97232
This 26th of March, 2013

Patricia Ann Deas
Notary Public

My commission expires on: 4-18-15

OFFICIAL SEAL
PATRICIA ANN DEAS
NOTARY PUBLIC-OREGON
COMMISSION NO. 457250
MY COMMISSION EXPIRES APRIL 18, 2015

EXHIBIT NO. PAC-8

PacifiCorp Schedule 3 and 3A Study

Executive Summary

This document ("PacifiCorp Schedule 3 and 3A Study" or the "Study") presents the methodology and results of the regulating margin requirements for variable energy resources ("VERs"), load and non-VERs components, as well as the total requirements. The period for analysis for the Study was calendar year 2011 ("Study Period"). The total requirement for PacifiCorp's East and West balancing authority areas ("BAAs") is as follows:

Table 1. Regulating Margin Requirements Calculated for Hourly Balancing Intervals on PacifiCorp's BAAs.

	Total
Load	394.12
non-VERs	0.19
VERs	185.28
Total	579.59

The methods used to calculate the load, VERs, and non-VERs components are addressed in their respective sections in this Study, as well as the calculation methods for the comprehensive reserves requirement.

Method

Overview

This section presents the approach used to establish regulating margin reserve requirements. Ten-minute interval load and generation data was used to estimate the amount of regulating margin reserves, both up and down, needed to manage variation in load, VERs and non-VERs within PacifiCorp's BAAs.

In order to clarify this requirement, this section discusses the North American Electric Reliability Corporation ("NERC") regional reliability standard operating reserve requirement and how it fits into this study. Western Electricity Coordinating Council ("WECC") regional reliability standard BAL-STD-002-0[15] requires each Balancing Authority, such as PacifiCorp, to carry sufficient operating reserve at all times. Operating reserve consists of contingency reserve and regulating margin. These reserve requirements necessitate available generation surplus to that required to meet load obligations. Each of these types of operating reserve is further defined below.

Contingency reserve is capacity the Company holds in reserve that can be used to respond to contingency events on the bulk power system (e.g., an instantaneous trip of a large generator). The amount of required contingency reserve is defined in WECC BAL-STD-002-0. Contingency reserve may not be applied to manage other system fluctuations such as changes in load or VER output. Therefore, this study focuses on the operating reserve component needed to manage load and generation variations, which is incremental to contingency reserve, and also referred to in WECC BAL-STD-002-0 as regulating margin.

Regulating margin is the additional capacity the Company holds in reserve to ensure it has adequate reserve at all times to meet the NERC Control Performance Criteria in BAL-007-1[16]. NERC Control Performance Criteria require the Company to carry regulating margin incremental to contingency reserves to maintain reliability. However, these additional regulating reserves are not defined by a simple formula, but rather are the amount of reserves required by each BAA to meet control performance standards. Since the Company's 2010 Wind Integration Study[17], the performance standards have evolved from a calculated Control Performance

[15] http://www.nerc.com/files/BAL-STD-002-0.pdf.

[16] NERC Standard BAL-007-1:http://www.nerc.com/docs/standards/sar/BAL-007-011_clean_last_posting_30-day_Pre-ballot_06Feb07.pdf. According to Western Electricity Coordinating Council ("WECC") Operating Committee meeting highlights (page 4, item 5), the field trial of this standard has been extended an additional year. The highlights are published here: http://www.wecc.biz/committees/StandingCommittees/OC/20130108/Lists/Agendas/1/OC%20Voting%20Record%20January%202013_Final_Revised.pdf.

[17] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/PacifiCorp_2010WindIntegrationStudy_090110.pdf, page 11.

Standard 2 ("CPS2")[18] mandated by NERC BAL-001-0[19] to a more dynamic regime mandated by NERC BAL-007-1, called Balances of Resources and Demands, in which the Company's performance standard can be affected by the frequency of the interconnection. This new standard allows a greater level of Area Control Error ("ACE") during periods when the ACE is helping frequency. However, the Company cannot plan on knowing when ACE will help or exacerbate frequency so an additional amount of reserves (referred to as "L_{10}") is used for bandwidth in both directions of ACE. Thus, the Company determines, based on the unique level of load and resource variation in its system and by prevailing operating conditions, the unique level of incremental operating reserve it must carry. This reserve, or regulating margin, must respond to follow load and resource changes throughout the delivery hour. PacifiCorp further segregates regulating margin into two components to assist in the analysis: ramp reserve and regulation reserve, as explained below:

Ramp Reserve. Due to a number of factors (fluctuations in customer demand, spot transactions, varying amounts of generation produced by VERs) the net balancing area load changes from minute-to-minute and hour-to-hour continuously at all times. This variability (increasing and decreasing net load) requires ready capacity to follow continuously, through short deviations, at all times. Treating this variability as though it is perfectly known for future time intervals (as though the operator would know exactly what the net balancing area load would be a minute from now, ten minutes from now, and an hour from now) defines the ramp of the system.

Regulation Reserve. Changes in load or resources are not considered contingency events, yet these events still require that capacity be set aside. The Company has defined two types of regulation reserve – regulating and following reserves. Regulating reserve covers short-term variations (seconds to minutes, normally using automatic generation control "AGC") in system load and generation output, whereas following reserve covers uncertainty across an hour, normally using manual generation control.

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18 PacifiCorp has not controlled to CPS2 since March 1, 2010.

19 http://www.nerc.com/files/BAL-001-0_1a.pdf.

To summarize, regulating margin consists of operating reserves the Company holds over and above the mandated contingency reserve requirement in order to maintain moment-to-moment system balance between load and generation. The regulating margin is the sum of two parts; ramp reserve and regulation reserve. The ramp reserve represents a minimum amount of flexibility required to follow actual net load (load minus generation output) with dispatchable generation. Regulation reserve represents flexibility maintained to manage intra-hour and hourly forecast errors relating to net system load, and consists of five components: load following, load regulating, VERs following, VERs regulating, and non-VERs regulating.

Regulating Margin Requirements

As noted above, ten-minute interval generation and load data drives the calculation of the regulating margin requirement for ramp reserve and regulation reserve. The approach for calculating regulating margin requirements necessary to supply adequate operational capacity is based on merging current operational practice with a survey of papers on wind integration.[20]

Ramp Reserve

Ramp reserve represents the minimal amount of flexible system capacity required to follow net load requirements without any error or deviation; in other words, if a system operator had the gift of perfect foresight for following changes in load and VER generation from minute-to-minute, and hour-to-hour, the amount of reserve it would hold would be equal to ramp reserve. These amounts are calculated as follows:

- If system is ramping down: [(Net Load Hour H – Net Load Hour (H+1))/2]
- If system is ramping up: [(Net Load Hour (H+1)– Net Load Hour H)/2]

[20] Many of the external studies PacifiCorp has relied on can be found on the Utility Variable Integration Group ("UVIG") website at the following link: http://www.uwig.org/opimpactsdocs.html.

Essentially, the ramp reserve calculation is equal to half the absolute value of the difference between the net balancing load at the top of one hour minus the net balancing load at the top of the prior hour.

Ramp reserve is calculated for load using only the load values for the BAA at the top of each hour. The ramp reserve for load and VERs is calculated using net load at the top of each hour. The ramp reserve required for VERs is the difference between that for load and that for load and VERs combined. There is no ramp reserve requirement attributed to non-VERs due to there being no hourly reserve (following) requirement for these resources (see discussion infra).

Regulation Reserve

As ramp reserves represent the system flexibility required to follow the system's requirements without any uncertainty or error, regulation reserve is necessary to cover uncertainty which is ever-present in power system operations. Very short-term fluctuations in weather, load, generation output and other system conditions cause short-term forecasts to change at all times. Therefore, system operators rely on regulation reserve to allow for the unpredictable changes bound to occur between the time the next hour's schedule is made and the arrival of the next hour, or the ability to follow net load. Also, these very same sources of instability are active throughout each hour, requiring flexibility to regulate generation output to the myriad ups and downs of customer demand, fluctuations of other generation, and other system disturbances. To assess regulation reserve requirements for PacifiCorp's BAAs, the Company compared the operational data to hypothetical forecasts as described fully in its Wind Integration Study[21] for the load and VERs components' deviations, and analyzed historical generation data from the same time period for the non-VERs regulation deviations.

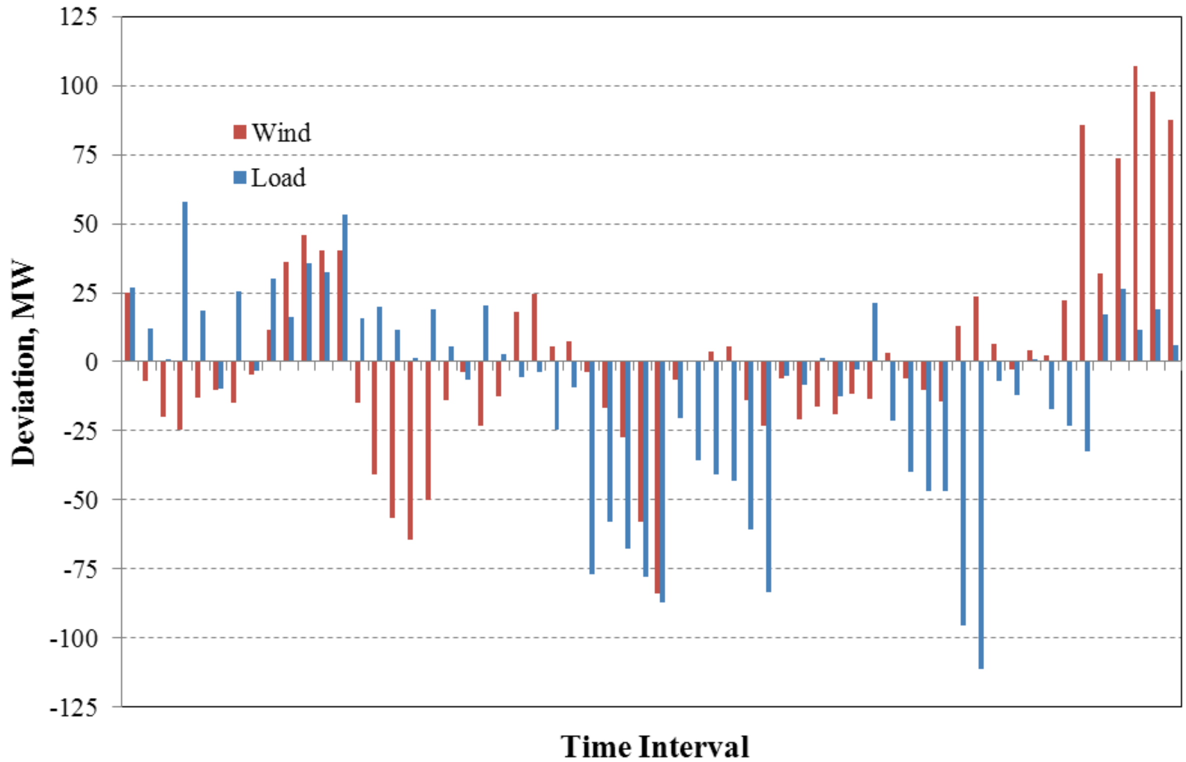
Recording of Deviations

Load and VERs Deviations for Regulation Reserve

[21] The latest PacifiCorp Wind Integration Study is available at the Company's Wind Integration site: http://www.pacificorp.com/es/irp/wind_integration/2012WICS.html.

The hypothetical operational forecasts are netted against historical load and VERs production data to derive four component forecast deviations: 1) load following; 2) VER following; 3) load regulating; and 4) VER regulating. The deviations each represent different components (or vectors) of forecast error which have to be covered by operating reserves. For example, if the VER following forecast for a given hour is 550 MW, and the average VER generation on the system only produces 400 MW for that hour, then 150 average MW will have to be produced by other generation on the system to remedy the shortfall and maintain system balance. This is an example of reserves being deployed upward (additional generation dispatched) in real time. A similar effect happens when load exceeds the load forecast – additional generation is dispatched to cover the shortfall due to changing forecasts or unpredictable conditions. Figure 1 shows an illustrative example of independent load and VER regulating deviations from the PacifiCorp East ("PACE") BAA on June 1, 2011. Each time interval on the horizontal axis represents ten minutes. Note how the deviations are randomly constructive (both positive or both negative) or destructive (opposing, one positive and one negative).

Figure 1. **Illustrative Example of Independent Load and VERs Regulating Deviations.**



Non-VERs Deviations for Regulation Reserve

Non-VERs also contribute to the need for regulation reserves due to deviations from set point or expected generation. Similar to the analysis for load and VERs, hypothetical operational forecasts are netted against historical non-VERs production data to derive a fifth component of regulation reserve: non-VER regulating. Unanticipated outages and the associated need for reserves are covered by contingency reserves and are not considered deviations. Periods when generators were actively operating in AGC mode are omitted since AGC operations dictate that the generators were actively responding to correct system deviations.

The procedures used to quantify the deviations of conventional generation resources (non-VERs) was guided by the analysis of variable energy resources as well as the approaches used by other utility companies.[22]

[22] *Puget Sound Energy*, Docket No. ER11-3735-000.

Due to the intensive data analysis required to identify non-VERs deviations and because PacifiCorp does not create and maintain a complete set of revised, hour-ahead schedules or set point data in real time for its non-VERs, the analysis focused on eight sample or representative non-VERs units, as shown below, selected from each resource type, and applied to all conventional generators based on the maximum dependable capacity ("MDC") of each unit in the fleet by BAA.

1. Coal – Hunter 3 (set point data available)
2. Natural Gas – Combined cycle – Lake Side (non-AGC periods only)
3. Natural Gas – Combined cycle - Hermiston
4. Natural Gas – Simple cycle - Gadsby 4
5. Hydro – Storage - Yale 2
6. Hydro – Run-of-river - Soda Springs
7. Waste Heat – Camas Mill
8. Geothermal – Blundell 1

Ten-minute average generation data for calendar year 2011 was downloaded from the Company's PI database.

Generation control set point data was sought for all samples as a basis for identifying potential deviations, and was a factor in selecting the samples, but was not available for some resource types. For example, simple cycle natural gas generation control set points are established based on their unique "heat curve" to maximize efficiency, run-of-river hydro set points are dependent on available water, waste heat generation is a secondary consideration in operation of that type of unit, and geothermal generation is flat and not operated to a specific set point. Set point data was available for the Lake Side resource, but the data was incomplete. Set point data was not available for the Hermiston resource. Reliable ten-minute generation control set point data was available only for Hunter 3 resource.

Lake Side was operated on AGC 22.3% of the time in 2011, hence additional natural gas generation resource sample types were sought to make sure that an appropriate, representative period of record was available. The Hermiston and Gadsby 4 natural gas-fired units were selected. Lake Side was still useful as a sample, with AGC periods omitted, and the addition of Hermiston confirmed the magnitude of gas unintended deviations at a similar scaled combined cycle gas plant. Gadsby 4 proved to be a good sample for the seven other 40 MW simple cycle turbines (the other two Gadsby peaker units as well as the five similar units at the West Valley Plant).

The basis for the unintended deviation calculations for Hunter 3 was the difference between ten-minute average actual generation and set point data. For the other representative non-VERs units, the basis for the unintended deviation calculations was the difference between ten-minute average actual generation and the average of the four nearest ten-minute intervals (two leading and two trailing).

Initial processing of the data revealed that a labor-intensive process would be required to identify periods that excluded manual control changes, ramping, and contingency events. AGC periods for the applicable units were well documented and easily excluded. Formulaic identification of periods suitable for unintended deviation analysis proved untenable. After several failed attempts at refinements to a formulaic approach, an alternative approach requiring analysis of plotted generation data was used to identify the periods of unintended deviations. The process used the interactive plotting functions of the statistical software package R (http://cran.r-project.org/) as follows:

For each representative non-VERs:

1. Plot one week of 10-minute generation, reference generation (set-point for Hunter 3) and AGC mode information (only applicable for Hunter 3 and Lake Side).
2. The time index (ten-minute intervals since the beginning of 2011) of the beginning and ending of periods of unintended deviations in generation, excluding ramping, outages and contingency events, were manually recorded. (Note: For resources that are not adjusted to meet changing loads such as geothermal and run-of-river hydro, only variations that were obviously contingency events (e.g., generation fell to zero) were excluded. Deviations, even extreme ones, where generation did not fall to zero were not excluded.)

3. Repeat until all of the weeks in 2011 have been evaluated.
4. Re-plot all of the weeks with the selected periods highlighted to assure that the periods selected were accurate and validated.
5. Re-verify the periods selected.

Gadsby 4 was used so intermittently that even weekly plotting lacked sufficient resolution to capture periods of unintended deviations, so two-day periods were used for plotting that representative non-VERs unit.

In summary, deviations are calculated for each ten-minute interval, for each of the five components of regulation reserves (load following, VER following, load regulating, VER regulating, non-VERs regulating). Across any given hourly time interval, the six ten-minute intervals within each hour would have a common following deviation (for load and VERs), but different regulation deviations (for load, VERs, and non-VERs). For example, considering load deviations only, if the load forecast for a given hour was 300 MW below the actual load realized in that hour, then a load following deviation of -300 MW would be recorded for all six of the ten-minute periods within that hour. However, as the load regulating forecast and the actual load recorded in each ten-minute interval vary, so will the deviations for load regulating. The same trend holds for VERs following and VERs regulating deviations. The following deviation is recorded as equal for the hour, and the regulating deviation varies each ten-minute interval.

Analysis of Deviations

Since the recorded deviations represent the amount of unpredictable variation on the electrical system, the key question becomes how much regulation reserve to hold in order to cover the deviations, thereby maintaining system reliability. The deviations are analyzed by separating the deviations into bins by their characteristic forecasts for each month in the Study Period. The bins are defined by every 5^{th} percentile of recorded forecasts or generation values, creating 20 bins for each month's deviations for each component of regulation reserve. In other words, each month of the Study Period exhibits 20 bins of load following deviations, 20 of load regulating deviations, and the same for VERs following and VERs regulating. Non-VERs was sorted into 20 bins for calendar year 2011. Tables 1 and 2 depict this process in action for June 2011.

Table 3 depicts the calculation of percentiles (every 5%) among the load regulating forecasts for June 2011 using PACE operational data. For example, a load regulating forecast of 4,359.9 MW represents the fifth percentile of such forecasts for that month. Any forecast values below that value will be in Bin 20, along with the respective deviations recorded for those time intervals. Any forecast values between 4,359.9 MW and 4,447.5 MW will land the deviation for that particular interval in Bin 19.

Table 3. **Percentiles Dividing the June 2011 Load Regulating Forecasts into 20 Bins.**

East		
Bin Number	Percentile	Load Forecast
	MAX	7,615.4
1	0.95	6,916.8
2	0.90	6,549.0
3	0.85	6,210.6
4	0.80	5,984.1
5	0.75	5,803.9
6	0.70	5,685.5
7	0.65	5,599.5
8	0.60	5,523.1
9	0.55	5,445.0
10	0.50	5,356.4
11	0.45	5,267.4
12	0.40	5,160.0
13	0.35	5,037.1
14	0.30	4,924.5
15	0.25	4,812.5
16	0.20	4,683.5
17	0.15	4,570.0
18	0.10	4,447.5
19	0.05	4,359.9
20	MIN	4,107.2

Table 4 depicts a sample of the assignment of several intervals' data into bins following the definition of bins in Table 3.

Table 4. Recorded Interval Load Regulating Forecasts And Their Respective Errors, Or Deviations, For June 2011 Operational Data From PACE.

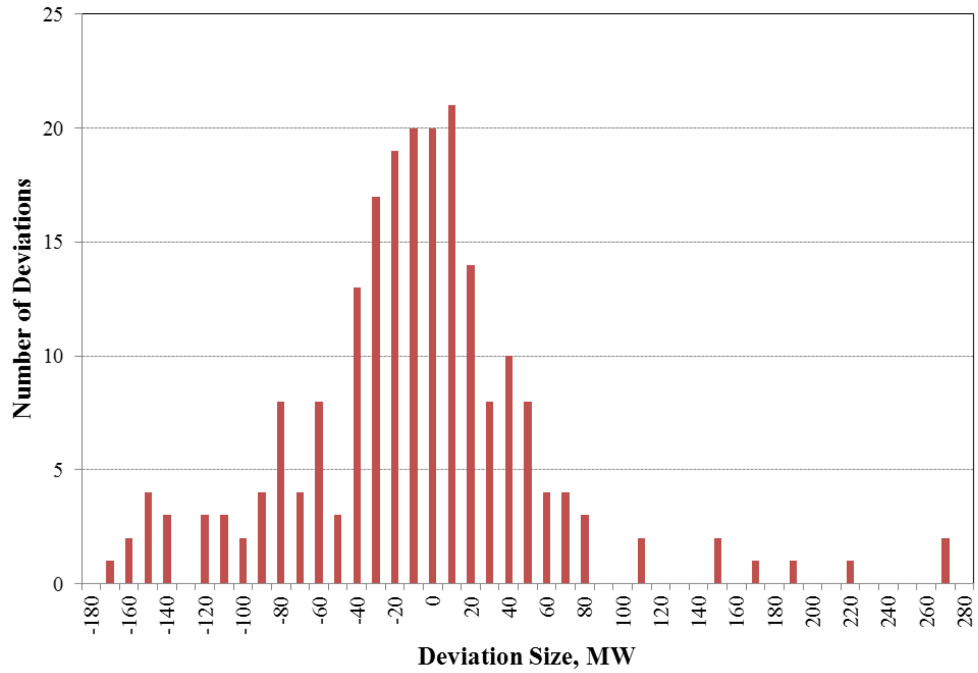
EAST

DATE / TIME	LOAD REGULATION FORECAST	LOAD REGULATION ERROR	BIN ASSIGNMENT
06/01/2011 01:00	4,297.0	26.89	20
06/01/2011 01:10	4,277.7	12.17	20
06/01/2011 01:20	4,285.3	0.76	20
06/01/2011 01:30	4,292.9	57.93	20
06/01/2011 01:40	4,300.4	18.72	20
06/01/2011 01:50	4,308.0	-9.78	20
06/01/2011 02:00	4,315.6	25.25	20
06/01/2011 02:10	4,315.9	-3.19	20
06/01/2011 02:20	4,341.4	29.87	20
06/01/2011 02:30	4,366.9	16.33	19
06/01/2011 02:40	4,392.4	35.67	19
06/01/2011 02:50	4,417.9	32.28	19
06/01/2011 03:00	4,443.5	53.28	19
06/01/2011 03:10	4,429.4	15.66	19
06/01/2011 03:20	4,468.6	20.02	18
06/01/2011 03:30	4,507.8	11.52	18
06/01/2011 03:40	4,547.0	1.15	18
06/01/2011 03:50	4,586.2	18.98	17
06/01/2011 04:00	4,625.4	5.76	17
06/01/2011 04:10	4,658.2	-6.29	17
06/01/2011 04:20	4,696.8	20.29	16
06/01/2011 04:30	4,735.3	2.56	16
06/01/2011 04:40	4,773.9	-5.57	16
06/01/2011 04:50	4,812.5	-3.52	16
06/01/2011 05:00	4,851.0	-24.55	15
06/01/2011 05:10	4,905.0	-9.43	15

The binned approach is necessary to prevent over-assignment of reserves in different system states, owing to certain characteristics of load, VERs and non-VERs. For example, when the balancing area load is near the lowest values for any particular day, it is highly unlikely the load deviation will require substantial down reserves to maintain balance because load will typically drop only so far. Similarly, when the load is near the peak of the month's load values, it is likely perhaps to go only a little higher, but could drop substantially at any time. Similarly for VERs and non-VERs, when generation output is at the peak value for a system, there will not be a deviation taking the resource value above that peak. In other words, the directional nature of the reserves requirements can change greatly by the state of the load or resource output. At high load, or at high VERs or non-VERs generation states, there is not likely to be a significant need for reserves covering a surprise increase in those values. Similarly, at the lowest states, there is not likely to be a need for the direction of reserves covering a significant shortfall in load or resource generation.

For example, consider the deviations grouped into one of the load regulating bins for June 2011 data in Figure 2. The deviations in this bin all occurred in time intervals with a load regulating forecast near 6,898 MW, from the PACE BAA using June, 2011 operational data. Most of the deviations are within 80 MW of the actual load value (a little over one percent, plus or minus). However, for load regulating deviations in this range, there is apparently a greater tendency where actual load was lower (more negative deviations than positive in Figure 2 below, and of greater magnitude), which requires the system's installed generation to have to increase its output in a very short timeframe to balance, thus requiring what are called "up reserves". It also bears noting that the deviations form a statistical distribution which is not normally shaped; and as more bins are examined, they also are not normally distributed and the longer tail can appear on either side.

Figure 2. **Histogram of Deviations Occurring About a June 2011 PACE Load Regulating Forecast of 6,898 MW.**



Bin Analysis

Up and down deviations must be served by operating reserves, so the percentile equivalent to a deviation tolerance was sampled above and below the median of each of the bins. The difference between the target reliability percentiles and the median of the bins represents the implied incremental load following service for regulation reserve demand within that bin for a given tolerance level. The component reserve value for each bin, as a function of the tolerance target is represented in Equation 1:

Equation 1. Derivation of the Component Reserves Requirement as a Function of Deviations Recorded in Each Bin.

$$\textbf{Component Reserve}_j = \mathbf{f}(\mathbf{P}_{\text{tolerance}}(\textbf{Forecast Bin}_i))$$

Where:

$\mathbf{P}_{\textbf{tolerance}}$ = The percentile of a two-tailed distribution representing an operational tolerance target

$\textbf{Forecast Bin}_i$ = the component forecast errors in each bin

The tolerance level, per Equation 1, represents a percentage of component deviations intended to be covered by the associated component reserve. The Company cannot apply contingency reserves to manage load VERs and non-VERs fluctuations, and therefore must carry sufficient regulating margin to avoid dipping into contingency reserve for this purpose. Any failure to manage these fluctuations can lead to disruption of services to customers. Surveying other recent wind integration studies[23], the Company focused on two other large regional entities grappling with the same concerns; BC Hydro and Bonneville Power Administration ("BPA"). BC Hydro applies a 99.7% tolerance to respective load and VERs reserve requirements[24], while the BPA customarily applies a 99.5% tolerance to its balancing requirements[25]. Considering the actions of other major market participants, and the requirement to maintain contingency reserves at all times, the Company decided to apply a 99.7% tolerance in the calculation of component reserves. In doing so, the Company has sought to plan for as many deviations as possible, while excluding the very largest data points to allow for the potential existence of outlier values. However, in a departure from BC Hydro's and BPA's approaches, the Company will also net the appropriate system L_{10} from the resulting total reserves requirement[26], effectively reducing the

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[23] PacifiCorp reviewed wind integration studies sponsored by other regional utilities (Portland General Electric, Avista, Idaho Power, BC Hydro, BPA) and the National Renewable Electrical Laboratory. The more recent BC Hydro and BPA approaches are consistent with the Company's requirement to maintain contingency reserve requirements at all times.

[24] BC Hydro's Wind Integration Study is part of its Integrated Resource Plan, Appendix 6E, page 6E-9: http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/iep_ltap/2012q2/draft_2012_irp_appendix23.Par.0001.File.DRAFT_2012_IRP_APPX_6E.pdf.

[25] Pacific Northwest National Laboratory, page 5: http://energyenvironment.pnnl.gov/ei/pdf/NWPP%20report.pdf.

[26] The L_{10} of PacifiCorp's balancing authority areas are 33.41MW for the West and 47.88 MW for the East. For more information, please refer to:

target reserve requirement to a more aggressive level than those other market participants. The L_{10} represents a bandwidth of acceptable deviation prescribed by WECC between the net scheduled interchange and the net actual electrical interchange on the Company's BAAs. Subtracting the L_{10} credits customers with the natural buffering effect it entails. Despite exclusion of extreme deviations with the use of the 99.7% tolerance, the Company's system operators will still be expected to meet reserve requirements without exceptions. The Company may also change the tolerance based on operational and customer feedback in the future.

Taking the binned data illustrated in Figure 2 as an example, approximately all of the deviations fall between -180 MW of deviation and +270 MW of deviation. Therefore, at a 99.7% tolerance level, the load regulating up reserves recommended for time intervals reflecting a load regulating forecast near 6,097 MW in the PACE in June 2011 is 173 MW. As each respective bin also has an implied probability by the number of data points falling within it (five percent), five percent of the ten-minute intervals in June 2011 will be assigned a load regulating component reserves value of 210 MW up reserves and 130 MW down reserves. The very same analysis is performed for each bin (20 in total) for VERs regulating, non-VERs regulating, load following, and VERs following component reserves.

The binned results can be reviewed for a month at a time, and patterns in the up- and down-reserves requirements by forecast level become more apparent for load and for VERs as shown in Figures 3 and 4. For example, Figure 4 can be used to further explain the calculation method for the resulting component reserve demand. Bin 4 describes 36 hours (five percent of June's 720 hours) of VERs generation forecast outcomes in the operational data from June, 2011. The average hypothetical operational VERs forecast modeled for these hours was 710 MW of production, and 99.7% of the actual hourly production values would be between 305 MW (the bottom of the green shaded area) and 955 MW (the top of the red shaded area). Therefore, for these 36 hours, and other periods in the future where the PACE VERs production forecast is near

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http://www.wecc.biz/committees/StandingCommittees/OC/OPS/PWG/Shared%20Documents/Annual%20Frequency%20Bias%20Settings/2012%20CPS2%20Bounds%20Report%20Final.pdf.

710 MW, this method recommends 405 MW of up reserves (710 – 305 = 405) in order to be prepared for a shortfall in VERs production compared to the hourly forecast.

Figure 3. **Load Following Component Reserve Profile; Operational Data from June, 2011.**

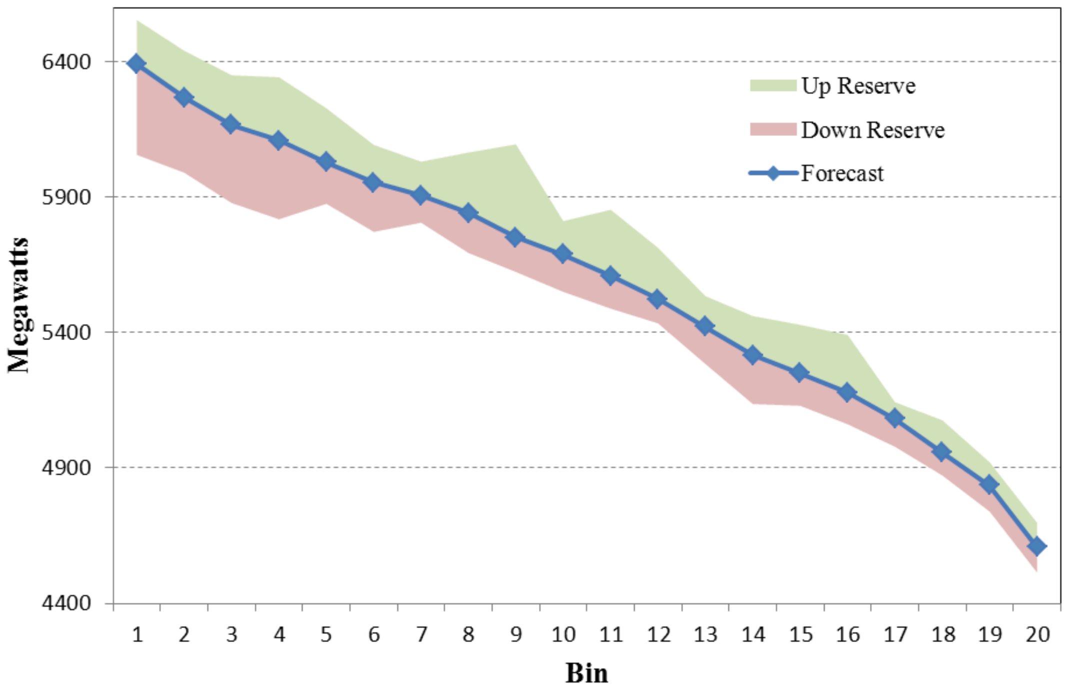
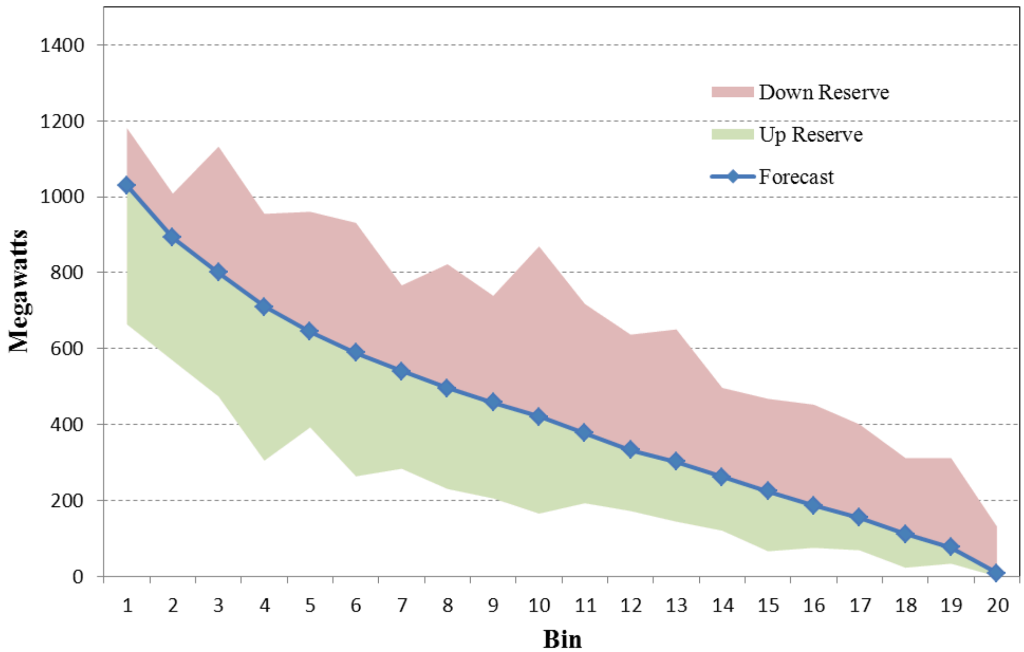


Figure 4. **VERs Following Component Reserve Profile; Operational Data from June, 2011.**



It is also useful to note the relatively small amount of up reserve required when the VERs generation is forecast to be low (Bins 19 and 20), and vice-versa when little VERs generation is forecast (Bins 1 and 2 in Figure 4). This is how the bin analysis helps prevent over-assigning reserves—by adjusting the reserves requirements per VERs generation state. For instance, the output of VERs generators is less stable when the VERs is picking up or slowing down, and the VERs generators are speeding up or slowing down accordingly. This behavior is represented in Bins 3 through 15 in Figure 4 above; the amount of VERs following component reserve recommended in those bins (represented by the distance between the blue forecast line and the red and green lines) is greater than that needed at the higher and lower rates of production, which represent either sustained VERs or sustained calmer conditions.

The deviations were summarized in 20 bins defined by the generation level. The bins were based on the quantiles of generation, similar to what was done with the VERs deviations. The deviations that would require up-ramp regulating reserves were then calculated for each bin (the

99.85^{th} percentile[27]). The up-ramp regulating reserve determined for all of the bins was averaged to produce the final proxy up-ramp regulating reserve value. Table 6 shows an example for Hunter 3. The average 1.48 MW of up-regulating reserve is used to scale up the other coal units by the capacity of Hunter 3, 460 MW as a percentage, as shown in Table 7.

The percentages shown in Table 6 were applied to the maximum dependable capacity of all units hour-by-hour when online and generating, omitting periods when the unit was actively used for AGC. These up-regulating reserves were combined using the square root of the sum of squares.

[27] The 99.7^{th} percentile used for load and VERs is a *two-sided* application, but when applied to just the up-regulating reserve, it's the 99.85^{th} percentile that is calculated (100-99.7=0.3; 0.3/2 = 0.15 on each end). The non-VERs only uses the up-regulating reserve.

Figure 5. **Hunter 3 Deviations Period Selection Final Verification Plot.**

The analyzed periods are delineated by dotted vertical lines with bars along the x-axis showing the included periods. The yellow bars highlight equipment outages which were considered, but did not necessarily exclude a period from selection. Note the AGC-induced fluctuations between time index 3200 and 3400.

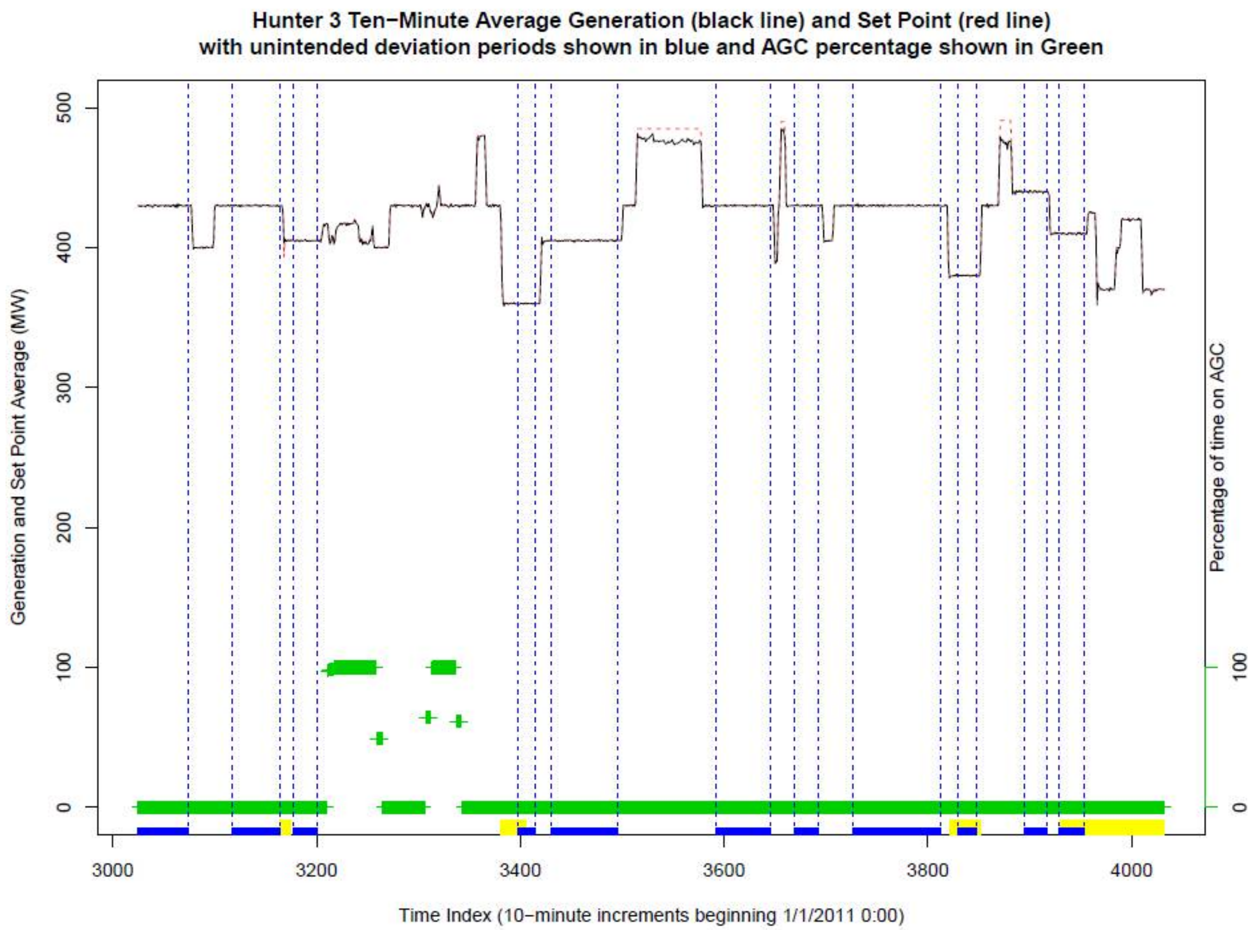


Table 6. Characteristic Regulating Reserve Values for Hunter 3, Typical Format Used for All Samples.

Bin Number	Lower Threshold of Generation for Bin	99.85th percentile by bin (up-regulating reserve required)
20	179.6	3.75
19	359.6	0.86
18	364.7	2.40
17	371.7	1.27
16	375.5	3.97
15	379.8	0.27
14	380.0	0.00
13	380.4	1.37
12	395.0	1.47
11	405.2	1.63
10	409.9	0.38
9	410.8	1.50
8	420.7	2.14
7	429.5	0.51
6	429.8	0.24
5	430.0	0.04
4	430.2	0.00
3	430.4	1.30
2	434.5	1.31
1	450.2	5.25
Average of all 99.85th percentile values by bin		**1.48**

The result of the bin analysis is five component forecast values (load following, VERs following, load regulating, VERs regulating, non-VERs regulating) for each ten-minute interval of the

Study Period. The component forecasts and reserves requirements are then applied to the operational data and combined in the backcasting procedure described below.

Backcasting

Given the development of component reserves demands for regulating and following timeframes shaped to system state, reserve requirements were then assigned to each ten-minute interval in 2011 according to their respective operational states (operational load and VERs forecasts, or non-VERs output levels) to simulate the combination of the component reserves values as they would have happened in real-time operations. Doing so results in a total reserves requirement for each interval informed by the data.

Operational Load and VERs Backcasts

The component reserves requirements calculated from the bin analysis described above are first turned into reference tables. Table 8 shows a sample (June 2011, PACE BAA) reference tables for load and VERs following reserves at varying levels of forecasted load and VERs generation. Table 9 shows a sample (June 2011, PACE BAA) reference table for load and VERs regulating reserves at varying forecast levels.

Table 8. Sample Reference Table for Load and VERS Following Component Reserves.

	East			East		
Bin	Up	Load Forecast	Down	Up	VERs Forecast	Down
	163	10000	335	365	5000	151
1	163	6953	335	365	1029	151
2	172	6544	278	324	893	115
3	182	6240	289	327	801	331
4	233	5954	291	405	710	245
5	199	5802	153	252	645	316
6	138	5699	182	325	589	342
7	126	5601	99	256	540	227
8	223	5526	147	265	495	327
9	**345**	**5432**	**126**	**253**	**459**	**281**
10	123	5362	138	255	420	449
11	245	5260	120	184	377	340
12	189	5151	89	161	333	304
13	113	5033	137	158	302	348
14	145	4931	180	141	262	235
15	179	4809	120	158	224	243
16	213	4694	117	111	187	266
17	62	4551	102	86	155	246
18	119	4437	85	89	112	200
19	85	4338	97	44	77	234
20	90	4098	94	44	9	122
	90	0	94	44	0	122

Table 9. Sample Reference Table for Load and VERS Regulating Component Reserves.

	East			East		
Bin	Up	Load Forecast	Down	Up	VERs Forecast	Down
	171	10000	263	244	10000	152
1	171	6917	263	244	1025	152
2	183	6549	251	302	902	224
3	177	6211	163	353	794	237
4	173	5984	272	224	713	180
5	204	5804	130	317	649	270
6	155	5686	156	263	585	450
7	219	5600	114	202	539	352
8	239	5523	146	260	501	394
9	**159**	**5445**	**134**	270	461	244
10	235	5356	124	**190**	**425**	**299**
11	170	5267	115	182	378	251
12	170	5160	112	149	334	265
13	239	5037	151	153	299	260
14	116	4925	138	148	261	172
15	126	4812	162	86	224	288
16	161	4683	103	122	188	287
17	98	4570	113	105	149	174
18	97	4448	95	60	112	144
19	82	4360	101	38	76	150
20	72	4107	92	39	10	82
	72	0	92	39	0	82

Each of the relationships recorded in the tables is then applied to component forecasts. This is clarified in the example below.

Application to Load and VERs Component Forecasts

Each interval's component forecasts are used, in conjunction with Tables 8 and 9, to derive a recommended reserve requirement informed by the load and VERs generation conditions for the time interval. This process is most easily explained with an example using the tables shown above, and hypothetical operational forecasts from June, 2011 operational data for PACE. Table 10 illustrates the outcome of the process for the load following and regulating components:

Table 10. Interval Load Forecasts and Component Reserves Requirement Data for Hour-Ending 11 AM, June 1, 2011 in PACE.

East	East	East	East	East	East	East	East	East
Time	Actual Load (10-min Avg)	Actual Load (Hourly Avg)	Following Forecast Load:	Load Following Up Reserves Specified by Tolerance Level	Load Following Down Reserves Specified by Tolerance Level	Regulating Load Forecast:	Load Regulating Up Reserves Specified by Tolerance Level:	Load Regulating Down Reserves Specified by Tolerance Level:
06/01/2011 10:00	5,533.04	5,543.46	5,509.68	344.8	126.2	5500.6	159.4	134.4
06/01/2011 10:10	5,525.38	5,543.46	5,509.68	344.8	126.2	5542.6	239.4	145.5
06/01/2011 10:20	5,525.54	5,543.46	5,509.68	344.8	126.2	5552.1	239.4	145.5
06/01/2011 10:30	5,550.23	5,543.46	5,509.68	344.8	126.2	5561.6	239.4	145.5
06/01/2011 10:40	5,551.93	5,543.46	5,509.68	344.8	126.2	5571.1	239.4	145.5
06/01/2011 10:50	5,574.64	5,543.46	5,509.68	344.8	126.2	5580.7	239.4	145.5

The load following forecast for this particular hour is 5,509.68 MW, which designates reserves requirements from Bin 9 as depicted (with shading for emphasis) in Table 8. Note the same following forecast is applied to each interval in the hour for the purpose of developing reserves requirements. The first ten minutes of the hour exhibits a load regulating forecast of 5,500.6 MW, which designates reserves requirements from Bin 9 as depicted in Table 9. Note that the regulating forecast changes every ten minutes, and as a result, the regulating component reserve requirement may do so as well. In this particular case, the second interval's forecast shifts the component reserves requirement from Bin 9 to Bin 8 (per Table 8), and so the component reserves requirement changes accordingly. A similar process is followed for VERs reserves, illustrated in Table 11:

Table 11. Interval VERs Forecasts and Component Reserves Requirement Data for Hour-Ending 11 AM June 1, 2011 in PACE.

East	East	East	East	East	East	East	East	East
Time	Actual VERs (10-min Avg)	Actual VERs (Hourly Avg)	Following Forecast VERs:	VERs Follow Up Reserves Specified by Tolerance Level	VERs Follow Down Reserves Specified by Tolerance Level	East VERs Regulating Forecast:	VERs Regulating Up Reserves Specified by Tolerance Level:	VERs Regulating Down Reserves Specified by Tolerance Level:
06/01/2011 10:00	550.82	555.26	485.02	252.87	280.56	453.5	190.0	298.9
06/01/2011 10:10	557.30	555.26	485.02	252.87	280.56	548.5	201.5	352.2
06/01/2011 10:20	529.71	555.26	485.02	252.87	280.56	546.1	201.5	352.2
06/01/2011 10:30	550.40	555.26	485.02	252.87	280.56	543.8	201.5	352.2
06/01/2011 10:40	560.53	555.26	485.02	252.87	280.56	541.4	201.5	352.2
06/01/2011 10:50	582.79	555.26	485.02	252.87	280.56	539.1	259.7	394.0

The VERs following forecast for this particular hour is 485.0 MW, which designates reserves requirements from Bin 9 under VERs forecasts as depicted in Table 8. Note the following forecast is applied to each interval in the hour for the same of developing reserves requirements. Meanwhile, the regulating forecast changes every ten minutes. The first ten minutes of the hour exhibits a VERs regulating forecast of 453.5 MW, which designates reserves requirements from Bin 10 as depicted in Table 9. As for load, the VERs regulating forecast changes every ten minutes, and as a result, the regulating component reserve requirement may do so as well. In this particular case, the second interval's forecast shifts the VERs regulating component reserves requirement from Bin 10 into Bin 7 (per Table 9), and so the component reserves requirement changes accordingly.

The selection of component reserves using component hypothetical operational forecasts as depicted above is replicated for each ten-minute interval, assigning component reserves requirements in each interval throughout 2011.

Application to Non-VERs Component Forecast

For non-VERs, the regulating reserve percentages shown in Table 13 are applied using the associated resource type as shown in Table 12. For each hour in 2011, each non-zero generation hour when the unit is not operating in AGC mode, the regulating reserve percentage is multiplied by the corresponding hourly capacity for that unit. The total regulating reserve amount required each hour is combined using the root-sum-square ("RSS") calculation by BAA. The results are shown in Table 13.

Table 12. **Non-VERs Resource Type Classifications Used to Apply the Sample Up-Regulating Reserve Percentages.**

Resource Type	**Applicable Units**
Coal	Carbon 1 & 2; Cholla 4; DJ 1 through 4; Huntington 1 & 2; Hunter 1 through 3; Naughton 1 through 3; Bridger; Colstrip 3 & 4; Craig 1 & 2; Hayden 1 & 2
Combined Cycle Gas	Gadsby 1 through 3; Currant Creek; Lake Side; Hermiston
Combustion Turbine Gas	Gadsby 4 through 6; West Valley 1 through 5
Hydro Storage	Oneida 1 through 3; Cutler 1 & 2; Mid-Columbia (all AGC operation, no contribution); Swift 1; Swift 2; Yale; Clearwater 1; Clearwater 2
Hydro Run-of-river	Merwin; Copco1 1 & 2; Copco2 1 & 2; Ashton; Bigfork; Fountain Green; Grace; Granite; Gunlock; Last Chance; Olmsted; Paris; Pioneer; Sand Cove; Snake Creek; Soda; Stairs; Veyo; Viva Naughton; Weber; Bend; Condit; Eagle Point; Fall Creek; Fish Creek; Iron Gate; JC Boyle; Lemolo 1; Lemolo 2; Prospect 1; Prospect 2; Prospect 3; Prospect 4; Slide Creek; Soda Springs; Toketee; Wallowa Falls; Westside
Waste Heat	Camas Mill
Geothermal	Blundell 1 & 2

In the example in Table 13, the generation for Gadsby 1 and Lake Side was 0, so the regulating reserve is zero. For Hunter 2, it was generating, not on AGC and had a capacity of 319 MW that hour, so the regulating reserve was 319 * 0.323% or 1.03 MW. The total non-VERS reserves for the hour ending at 11:00 am June 1 was 3.54 MW.

Table 13. Non-VERS Component Reserves Requirement Data for Hour-Ending 11 AM June 1, 2011 in PACE (Selected Units).

TYPE	CT Gas	Coal	CC Gas	Hydro - Storage	
Regulating Reserve %	0.365%	0.323%	0.365%	0.976%	
Date/Time (hour ending)	**Gadsby 1**	**Hunter 2**	**Lake Side**	**Cutler 1**	**PACE Regulation reserve required**
01-Jun-11 11:00:00	0.00	1.03	0.00	0.15	3.54

The five components are combined into a single regulating reserves requirement as described below.

Total Regulating Reserves Requirement

After the assignment of the component reserves requirements, each ten-minute interval of the Study Period exhibits values for load following reserves, VERs following reserves, load regulating reserves, VERs regulating reserves and non-VERs regulating reserves. Each of these values is derived by comparing a unique component forecast to a unique actual value; in the case of load following, the load following forecast is compared to the average load for a given hour. For load regulating reserves requirements, the load regulating forecast is compared to the actual load observed at the same time. However, while adjusting operations for each of the five component factors is critical to maintaining system integrity, the components are not additive. Therefore, the VERs and load reserve requirements are combined using the RSS calculation in each direction (up and down), assuming their variability in the short-term is independent or uncorrelated. Then, the appropriate system L_{10} is subtracted from the result. The complete calculation is shown in Equation 2.

Equation 2. Total Regulation Reserves Calculated from Five Component Reserves Using the Root-Sum-Square Formulation at Time Interval *i*:

$$\boldsymbol{Regulation\ Reserves_i} = \sqrt{LoadFollowing_i{}^2 + LoadRegulating_i{}^2 + VERsFollowing_i{}^2 + VERsRegulating_i{}^2 + nonVERsRegulating_i{}^2} - L_{10}$$

Drawing from the first ten-minute interval in the example above as depicted in Tables 10, 11 and 13, the component up reserves requirements were as follows:

Load Following = 344.8 MW

Load Regulating = 159.4 MW

VERs Following = 252.9 MW

VERs Regulating = 190.0 MW

Non-VERs Regulating = 3.54 MW

East System L_{10} = 47.9 MW

Applying Equation 2:

$$\boldsymbol{Regulation\ Reserves} = \sqrt{344.8^2 + 159.4^2 + 252.9^2 + 190.0^2 + 3.54^2} - 47.9$$

Applying Equation 2 to these values yields a result of 446.4 MW of up reserves recommended for regulation reserve for the time interval between 10:00am and 10:10am, June 1, 2011 in PACE BAA. In this manner, the component reserves requirements are used to calculate an overall reserves requirement for each ten-minute interval of the Study Period. A similar calculation is also made for the regulation reserve requirements pertaining only to the variability and uncertainty of load, which employs Equation 2 but applies zero reserves for the VERs and non-VERs components. The incremental reserves assigned to VERs demand are calculated as the difference between the total requirement for load and VERs minus the load requirement. The results of these calculations can be quoted in hourly or monthly requirements by averaging the reserves requirements of all the ten-minute intervals within the specified hour or month.

A ramp component reserve is also calculated for each hourly interval for load and VERs components. The ramp requirements are then also, like regulation, able to be quoted in hourly or monthly quantities. The regulating margin requirements are the sum of the ramp and regulation requirements in any given interval. Annual regulating margin requirements are quoted as the average of the twelve monthly requirements.

Correlation Analysis

In cases of zero correlation, the Parallelogram Law reduces to the RSS formulation (and **α** is a right angle, and the parallelogram is a square). For this Study, rather than using two sides of a parallelogram to form a resultant (**R** in the illustration), five uncorrelated vectors corresponding to the component reserves for load following, load regulating, VERs following, VERs regulating, and non-VERs regulating deviations are combined into a reserves requirement.

The Company applied the RSS formulation in its 2010 Wind Integration Study[28] after reviewing samples of the load and VERs data used to perform the study[29], and reviewing studies by Idaho Power[30] and the Eastern Wind Integration and Transmission Study[31]. Since that time, additional

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[28] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/PacifiCorp_2010WindIntegrationStudy_090110.pdf, p. 19.

[29] http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/Wind_Integration/PacifiCorp_2010WindIntegrationStudy_090110.pdf, Table 5, p. 6.

[30] http://www.idahopower.com/pdfs/AboutUs/PlanningForFuture/wind/Addendum.pdf, pages 12, 20.

[31] http://www.nrel.gov/C821B4E9-F70E-4245-9C6D-D5CB68B670DC/FinalDownload/DownloadId-286D6B0AF14A941F45E5F431BACF4DCF/C821B4E9-F70E-4245-9C6D-D5CB68B670DC/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf, page 145.

studies have suggested use of this formulation directly[32] or noted that short-term deviations from schedule in VERs generation output and load are not correlated[33].

The forecast deviations for VERs generation and load in the Company's BAAs were analyzed for correlation by performing a linear regression using the load deviation as an independent variable and the concurrent VERs deviation as the dependent variable. Therefore, to estimate the East VERs following deviation for a given time period, the East load following deviation was used as a predictive variable. The correlation between the two variables (load errors and VERs errors) would be represented by the slope of the regression, and the predictive capability by the $\mathbf{r}^2$ (or goodness-of-fit). The procedure was followed for 2011 operational data applying the four component forecasts detailed previously for PACE and PACW. The results appear in Table 12.

Table 14. Results of Regression Analyses Between VERs and Load Deviations.

	Slope	r-Square
East Following	-0.097	0.45%
East Regulating	-0.087	0.63%
West Following	0.026	0.05%
West Regulating	-0.007	0.00%

The results indicate that while there is a calculable correlation between VERs and load deviations in the data, the relationships are so weak such that neither explains the other, and so this relationship is not useful in an operational context. The value of the load deviation offers no ability to explain the VERs deviation, and so the two are unrelated. This is consistent with the findings of wind studies noted above.

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32 http://www.bchydro.com/etc/medialib/internet/documents/planning_regulatory/iep_ltap/2012q2/draft_2012_irp_appendix23.Par.0001.File.DRAFT_2012_IRP_APPX_6E.pdf, page 6E-9.

33 http://www.nrel.gov/wind/systemsintegration/pdfs/2010/wwsis_final_report.pdf, page 92.

EXHIBIT NO. PAC-9

2013 Integrated Resource Plan
2012 Wind Integration Study
Major Milestones
Update - March 27, 2013

- **January 24, 2012** – Kickoff meeting and introductions with TRC members, where the Company discussed integration study methods.

- **January 25, 2012 to February 22, 2012** – The Company initiated its development of a draft methodology and scope that incorporated comments and suggestions made by the TRC in the kickoff meeting.

- **February 23, 2012** – Progress review meeting with TRC members with a focus on study methods.

- **April 2012** – The Company continued on-going correspondence with TRC members to communicate progress in sample operating reserve calculations and initial implementation of general methods.

- **May 7, 2012** – IRP stakeholder public kickoff meeting, with TRC members present. Discussion of 2012 WIS methodology and results from preliminary operating reserve calculations.

- **May 2012 to June 2012** – IRP stakeholders provided comments on the methods and preliminary operating reserve calculations presented at the IRP stakeholder kickoff meeting held May 7, 2012. The Company evaluated comments and addressed IRP stakeholder feedback in coordination with the TRC.

- **June 11, 2012** – Progress review meeting with TRC members with a focus on regulation reserve calculations.

  June 20, 2012 – IRP stakeholder public meeting, which was a technical workshop, with detailed discussion on how the reserves were calculated for the preliminary results presented at the IRP stakeholder kickoff meeting held on May 7, 2012.

- **June 22, 2012** – FERC issues Order No. 764 (Docket No. RM10-11-000) which required transmission providers seeking to differentiate among resource types in balancing reserve capacity rates to consider variability of load, variable energy resources ("VERs") and non-VERs.

- **July to August 2012** – IRP stakeholders provided comments on draft 2012 WIS methodology and preliminary results.

- **August 7, 2012** – Progress review meeting with TRC members with a focus on correlation analysis, tolerance level for errors and additional analysis requested by TRC members.

- **August 13, 2012** – IRP stakeholder public meeting with discussion on correlation analysis, tolerance level for errors and additional analysis requested by TRC members.

- **September 2012 to October 2012** – IRP stakeholders provided comments on draft 2012 WIS methodology and preliminary results, the TRC made additional comments, and the Company drafted the 2012 WIS report.

- **October 24, 2012** – IRP stakeholder public meeting with discussion on errors discovered in the input data and the impact on the 2012 WIS methodology and preliminary results, and results of the production cost modeling.

- **November 2012 to January 2013** - Reviewed draft 2012 WIS report, including incorporation of TRC comments, preparation and review of work papers and final results for presentation to the TRC and IRP stakeholders.

- **January 29, 2013** - Progress review meeting with TRC members to discuss latest results, material to be presented in final 2012 WIS report, and anticipated delivery of final work papers.

- **January 31, 2013** – IRP stakeholder public meeting with discussion on correction made to the application of the designed method and the revised results.

- **February 2013** – Completed variability study for VERs and non-VERs.

- **March 1, 2013** – Final 2012 WIS report distributed to TRC. Comments from TRC on final report anticipated by end of March 2013.

- **March 2013** - PacifiCorp Schedule 3 and 3A Report prepared.

- **April 30, 2013** – Final 2012 WIS report will be released to IRP stakeholders as part of the publication of PacifiCorp's 2013 IRP.

EXHIBIT NO. PAC-10

2013 Integrated Resource Plan
2012 Wind Integration Study
Technical Review Committee
Update - March 27, 2013

PacifiCorp initiated its 2012 Wind Integration Study ("2012 WIS") in January 2012 in support of the 2013 Integrated Resource Plan ("2013 IRP"). The 2012 WIS is being performed in coordination with a technical review committee ("TRC") to ensure that the study is performed according to current best practice. The TRC's recommendations are reflected in the study method and scenarios addressed. The TRC consists of six qualified individuals having a broad background in the electric utility industry and with expertise in the field of wind integration studies and variable resource generation. The Company appreciates each of the six TRC members that have graciously volunteered their time in support of the Company's 2012 WIS. The six members of the TRC are:

Andrea Coon, Director, Western Renewable Energy Generation Information System ("WREGIS") for the Western Electricity Coordinating Council ("WECC")

Dr. Coon is the Director of WREGIS for the WECC. She has been involved in the utility industry for over a decade. Dr. Coon started in the utility industry by working in regulation in Utah, first for the former Committee of Consumer Services and then for the Division of Public Utilities, where she testified before the Utah Public Service Commission on a variety of issues including system power costs and special contract pricing. Dr. Coon then moved on to working for WECC where she has worked on all aspects of the WREGIS program, including policy as well as technical aspects such as user testing. Dr. Coon earned a PhD in Economics from the University of Utah as well as a Master of Professional Communication from Westminster College and a B.S. in Economics from Brigham Young University.

Mr. Randall Falkenberg – President RFI Consulting, Inc.

Mr. Falkenberg has 35 years of experience in the electric utility industry and is an expert in production cost models, and utility generation planning. Mr. Falkenberg has been a witness in numerous cases concerning plant expansion planning, power costs and energy cost recovery. In addition, Mr. Falkenberg has appeared as an expert witness on production cost models, reliability analysis, market price forecasts, energy cost recovery, and wind integration costs. He has testified before numerous state regulatory commissions, in court, and the Federal Energy Regulatory Commission, in more than 200 cases. Since 1998, Mr. Falkenberg has been a witness in more than 40 PacifiCorp proceedings and has testified in each of PacifiCorp's six state jurisdictions regarding the Company's production cost modeling, and planning matters. Mr. Falkenberg has a M.S. in Physics from the University of Minnesota, and a B.S. in Physics from Indiana University.

Matt Hunsaker, Manager, Renewable Integration Manager for the WECC

Mr. Hunsaker is the Renewable Integration Manager for the WECC. In this position, he works with the WECC Variable Generation Subcommittee to identify issues and opportunities related to variable generation in the Western Interconnection. He has been involved with many studies related to variable generation integration, generation portfolio planning, transmission planning, resource selection, and economic modeling. Mr. Hunsaker has over ten years of experience working in the energy and consulting sectors. He has a BS in Chemical Engineering (emphasis in combustion) from Brigham Young University and a MA in Economics (emphasis in energy economics) from the University of Kansas. He is also a licensed professional engineer.

Michael Milligan, Lead research for the Transmission and Grid Integration Team at the National Renewable Energy Laboratory ("NREL")

Mr. Milligan leads power system operations research for the Transmission and Grid Integration Team at the NREL. He has authored more than 140 papers and book chapters and has served on numerous technical review committees for integration studies, including the recently-released New England Wind Integration Study and the U.S. Department of Energy ("DOE")/NREL Western Wind and Solar Integration Study and Eastern Wind Integration and Transmission Study. Mr. Milligan is co-lead for the probabilistic methods team of the North American Electric Reliability Corporation ("NERC") Variable Generation Task Force, member of the WECC Variable Generation Subcommittee, the International Energy Agency Task 25 on large-scale wind integration, and has served on the Western Governors' Association Clean and Diverse Energy Wind Task Force. Mr. Milligan has M.A. and Ph.D. degrees from the University of Colorado, and a B.A. from Albion College.

J. Charles Smith, Executive Director, Utility Variable-Generation Integration Group ("UVIG")

Mr. Smith is a Senior Member of the Institute of Electrical and Electronics Engineers ("IEEE") Power Engineering Society, and a member of CIGRE (the International Council on Large Electric Systems). He is a guest editor for the IEEE Power and Energy magazine, and an associate editor for the IEEE Transactions on Sustainable Energy. He received his BSME and MS degrees from MIT in 1970. He currently serves as the Executive Director of the UVIG. Previously, he served as President of Electrotek Concepts, a power engineering consulting firm. He has over 40 years of experience in the electric power industry.

Robert Zavadil, Executive Vice President of Power Systems Consulting, EnerNex

As a co-founder of EnerNex, Mr. Zavadil is responsible for developing and overseeing the company's power system engineering consulting business. He has worked on electric power system issues for wind generation for over 20 years. Clients include wind turbine designers and manufacturers, project developers and operators, transmission service providers and Independent System Operators ("ISOs"), and research and development organizations including NREL and Electric Power Research Institute ("EPRI"). From 1989 to the summer of 2003, Mr. Zavadil served in various consulting and product development capacities for Electrotek Concepts and its parent company, WPT. Mr. Zavadil began his career in the electric power industry in 1982 as a special studies engineer in the Transmission and Distribution Engineering Division of the Nebraska Public Power District. He is a member of the IEEE Power Engineering, Power Electronics, and Industrial Applications Societies, and serves as Secretary of the IEEE Power Engineering Society Wind Power Coordinating Committee.

EXHIBIT NO. PAC-11

Table A
2011 Study Results
Schedule 5, Spinning Reserves

		Total 10-Minute Reserves		10-Minute Reserves Held for Spinning Reserve Requirements	
Plant	**Type**	(aMW)	% of Total	(aMW)	% of Total
MidColumbia	Hydro	68.5	11.8%	17.8	6.9%
Swift 1	Hydro	84.8	14.6%	20.1	7.8%
Yale	Hydro	34.5	5.9%	8.2	3.2%
Cutler 2	Hydro	6.7	1.1%	6.5	2.5%
Cutler 1	Hydro	5.1	0.9%	5.0	1.9%
Oneida 1	Hydro	4.2	0.7%	4.1	1.6%
Merwin	Hydro	0.0	0.0%	0.0	0.0%
Oneida 2	Hydro	3.9	0.7%	3.8	1.5%
Oneida 3	Hydro	3.9	0.7%	3.8	1.5%
Copco 2 - 2	Hydro	2.3	0.4%	1.8	0.7%
Copco 2 - 1	Hydro	0.5	0.1%	0.4	0.1%
Copco 1 - 1	Hydro	0.4	0.1%	0.3	0.1%
Copco 1 - 2	Hydro	2.0	0.3%	1.6	0.6%
Swift 2	Hydro	0.0	0.0%	0.0	0.0%
Currant Creek	Gas	109.7	18.8%	61.4	23.8%
Lake Side	Gas	49.4	8.5%	27.7	10.7%
Hermiston	Gas	65.9	11.3%	17.1	6.6%
Gadsby 4 CT	Gas	5.0	0.9%	2.8	1.1%
Gadsby 6 CT	Gas	4.9	0.8%	2.7	1.1%
Gadsby 5 CT	Gas	4.1	0.7%	2.3	0.9%
Gadsby 3	Gas	3.1	0.5%	1.7	0.7%
Gadsby 2	Gas	1.8	0.3%	1.0	0.4%
Gadsby 1	Gas	1.2	0.2%	0.7	0.3%
Cholla 4	Coal	26.3	4.5%	14.7	5.7%
Hunter 3	Coal	23.2	4.0%	13.0	5.0%
Hunter 1	Coal	19.0	3.3%	10.6	4.1%
Huntington 2	Coal	11.6	2.0%	6.5	2.5%
Naughton 3	Coal	6.2	1.1%	3.5	1.3%
Huntington 1	Coal	16.4	2.8%	9.2	3.6%
Hunter 2	Coal	14.4	2.5%	8.1	3.1%
Naughton 2	Coal	1.9	0.3%	1.0	0.4%
DJ 4	Coal	0.2	0.0%	0.2	0.1%
Naughton 1	Coal	0.6	0.1%	0.3	0.1%
Carbon 2	Coal	0.2	0.0%	0.1	0.0%
Carbon 1	Coal	0.2	0.0%	0.1	0.0%
DJ 3	Coal	0.1	0.0%	0.1	0.0%
Bridger	Coal	0.0	0.0%	0.0	0.0%
DJ 1	Coal	0.0	0.0%	0.0	0.0%
DJ 2	Coal	0.0	0.0%	0.0	0.0%
Monsanto	Contract	0.0	0.0%	0.0	0.0%
Nucor	Contract	0.0	0.0%	0.0	0.0%
MagCorp	Contract	0.0	0.0%	0.0	0.0%
Cool Keeper	Contract	0.0	0.0%	0.0	0.0%
SCL	Contract	0.0	0.0%	0.0	0.0%
Totals		**582.2**	**100%**	**258.2**	**100%**

Table B
2011 Study Results
Schedule 6, Supplemental Reserves

		10-Minute Reserves Held for Supplemental Reserve Requirement		Supplemental Reserves Held for Supplemental Reserve Requirement		Total 10-Minute & Supplemental Reserves Held for Supplemental Reserve Requirement	
Plant	**Type**	(aMW)	% of Total	(aMW)	% of Total	(aMW)	% of Total
MidColumbia	Hydro	14.3	22.6%	0.0	0.0%	14.3	5.7%
Swift 1	Hydro	17.8	27.9%	0.0	0.0%	17.8	7.0%
Yale	Hydro	7.2	11.4%	0.0	0.0%	7.2	2.9%
Cutler 2	Hydro	0.2	0.3%	0.0	0.0%	0.2	0.1%
Cutler 1	Hydro	0.1	0.2%	0.0	0.0%	0.1	0.1%
Oneida 1	Hydro	0.1	0.2%	0.0	0.0%	0.1	0.0%
Merwin	Hydro	0.0	0.0%	0.0	0.0%	0.0	0.0%
Oneida 2	Hydro	0.1	0.2%	0.0	0.0%	0.1	0.0%
Oneida 3	Hydro	0.1	0.2%	0.0	0.0%	0.1	0.0%
Copco 2 - 2	Hydro	0.5	0.8%	0.0	0.0%	0.5	0.2%
Copco 2 - 1	Hydro	0.1	0.2%	0.0	0.0%	0.1	0.0%
Copco 1 - 1	Hydro	0.1	0.1%	0.0	0.0%	0.1	0.0%
Copco 1 - 2	Hydro	0.4	0.6%	0.0	0.0%	0.4	0.2%
Swift 2	Hydro	0.0	0.0%	0.0	0.0%	0.0	0.0%
Currant Creek	Gas	3.2	5.0%	0.0	0.0%	3.2	1.3%
Lake Side	Gas	1.4	2.3%	0.0	0.0%	1.4	0.6%
Hermiston	Gas	13.8	21.7%	0.0	0.0%	13.8	5.5%
Gadsby 4 CT	Gas	0.1	0.2%	0.0	0.0%	0.1	0.1%
Gadsby 6 CT	Gas	0.1	0.2%	0.0	0.0%	0.1	0.1%
Gadsby 5 CT	Gas	0.1	0.2%	0.0	0.0%	0.1	0.0%
Gadsby 3	Gas	0.1	0.1%	0.0	0.0%	0.1	0.0%
Gadsby 2	Gas	0.1	0.1%	0.0	0.0%	0.1	0.0%
Gadsby 1	Gas	0.0	0.1%	0.0	0.0%	0.0	0.0%
Cholla 4	Coal	0.8	1.2%	0.0	0.0%	0.8	0.3%
Hunter 3	Coal	0.7	1.1%	0.0	0.0%	0.7	0.3%
Hunter 1	Coal	0.6	0.9%	0.0	0.0%	0.6	0.2%
Huntington 2	Coal	0.3	0.5%	0.0	0.0%	0.3	0.1%
Naughton 3	Coal	0.2	0.3%	0.0	0.0%	0.2	0.1%
Huntington 1	Coal	0.5	0.7%	0.0	0.0%	0.5	0.2%
Hunter 2	Coal	0.4	0.7%	0.0	0.0%	0.4	0.2%
Naughton 2	Coal	0.1	0.1%	0.0	0.0%	0.1	0.0%
DJ 4	Coal	0.0	0.0%	0.0	0.0%	0.0	0.0%
Naughton 1	Coal	0.0	0.0%	0.0	0.0%	0.0	0.0%
Carbon 2	Coal	0.0	0.0%	0.0	0.0%	0.0	0.0%
Carbon 1	Coal	0.0	0.0%	0.0	0.0%	0.0	0.0%
DJ 3	Coal	0.0	0.0%	0.0	0.0%	0.0	0.0%
Bridger	Coal	0.0	0.0%	0.0	0.0%	0.0	0.0%
DJ 1	Coal	0.0	0.0%	0.0	0.0%	0.0	0.0%
DJ 2	Coal	0.0	0.0%	0.0	0.0%	0.0	0.0%
Monsanto	Contract	0.0	0.0%	68.4	36.3%	68.4	27.2%
Nucor	Contract	0.0	0.0%	32.5	17.3%	32.5	12.9%
MagCorp	Contract	0.0	0.0%	72.0	38.2%	72.0	28.6%
Cool Keeper	Contract	0.0	0.0%	0.4	0.2%	0.4	0.1%
SCL	Contract	0.0	0.0%	15.0	8.0%	15.0	6.0%
Totals		**63.6**	**100%**	**188.3**	**100%**	**251.9**	**100%**

Table C
2011 Study Results
Schedule 3 and 3A, Regulating Reserves

		Total 10-Minute Reserves		10-Minute Reserves Held for Spinning and Supplemental Reserves		10-Minute Reserves Held for Regulating Reserves	
Plant	Type	(aMW)	% of Total	(aMW)	% of Total	(aMW)	% of Total
MidColumbia	Hydro	68.5	11.8%	32.2	10.3%	36.3	13.9%
Swift 1	Hydro	84.8	14.6%	39.8	12.8%	46.9	18.0%
Yale	Hydro	34.5	5.9%	16.2	5.2%	19.1	7.3%
Cutler 2	Hydro	6.7	1.1%	3.9	1.3%	0.0	0.0%
Cutler 1	Hydro	5.1	0.9%	3.0	1.0%	0.0	0.0%
Oneida 1	Hydro	4.2	0.7%	2.5	0.8%	0.0	0.0%
Merwin	Hydro	0.0	0.0%	0.0	0.0%	0.0	0.0%
Oneida 2	Hydro	3.9	0.7%	2.3	0.7%	0.0	0.0%
Oneida 3	Hydro	3.9	0.7%	2.3	0.7%	0.0	0.0%
Copco 2 - 2	Hydro	2.3	0.4%	1.1	0.4%	0.0	0.0%
Copco 2 - 1	Hydro	0.5	0.1%	0.2	0.1%	0.0	0.0%
Copco 1 - 1	Hydro	0.4	0.1%	0.2	0.1%	0.0	0.0%
Copco 1 - 2	Hydro	2.0	0.3%	0.9	0.3%	0.0	0.0%
Swift 2	Hydro	0.0	0.0%	0.0	0.0%	0.0	0.0%
Currant Creek	Gas	109.7	18.8%	64.5	20.7%	45.1	17.3%
Lake Side	Gas	49.4	8.5%	29.1	9.3%	20.3	7.8%
Hermiston	Gas	65.9	11.3%	30.9	9.9%	34.9	13.4%
Gadsby 4 CT	Gas	5.0	0.9%	2.9	0.9%	2.1	0.8%
Gadsby 6 CT	Gas	4.9	0.8%	2.9	0.9%	2.0	0.8%
Gadsby 5 CT	Gas	4.1	0.7%	2.4	0.8%	1.7	0.7%
Gadsby 3	Gas	3.1	0.5%	1.8	0.6%	1.3	0.5%
Gadsby 2	Gas	1.8	0.3%	1.1	0.3%	0.7	0.3%
Gadsby 1	Gas	1.2	0.2%	0.7	0.2%	0.5	0.2%
Cholla 4	Coal	26.3	4.5%	15.5	5.0%	10.8	4.2%
Hunter 3	Coal	23.2	4.0%	13.7	4.4%	9.6	3.7%
Hunter 1	Coal	19.0	3.3%	11.2	3.6%	7.8	3.0%
Huntington 2	Coal	11.6	2.0%	6.8	2.2%	4.8	1.8%
Naughton 3	Coal	6.2	1.1%	3.6	1.2%	2.6	1.0%
Huntington 1	Coal	16.4	2.8%	9.7	3.1%	6.8	2.6%
Hunter 2	Coal	14.4	2.5%	8.5	2.7%	5.9	2.3%
Naughton 2	Coal	1.9	0.3%	1.1	0.4%	0.8	0.3%
DJ 4	Coal	0.2	0.0%	0.1	0.0%	0.0	0.0%
Naughton 1	Coal	0.6	0.1%	0.3	0.1%	0.2	0.1%
Carbon 2	Coal	0.2	0.0%	0.1	0.0%	0.1	0.0%
Carbon 1	Coal	0.2	0.0%	0.1	0.0%	0.1	0.0%
DJ 3	Coal	0.1	0.0%	0.0	0.0%	0.0	0.0%
Bridger	Coal	0.0	0.0%	0.0	0.0%	0.0	0.0%
DJ 1	Coal	0.0	0.0%	0.0	0.0%	0.0	0.0%
DJ 2	Coal	0.0	0.0%	0.0	0.0%	0.0	0.0%
Monsanto	Contract	0.0	0.0%	0.0	0.0%	0.0	0.0%
Nucor	Contract	0.0	0.0%	0.0	0.0%	0.0	0.0%
MagCorp	Contract	0.0	0.0%	0.0	0.0%	0.0	0.0%
Cool Keeper	Contract	0.0	0.0%	0.0	0.0%	0.0	0.0%
SCL	Contract	0.0	0.0%	0.0	0.0%	0.0	0.0%
Totals		**582.2**	**100%**	**311.8**	**100%**	**260.4**	**100%**

Table D
2011 Study Results
Schedule 3 and 3A, Following Reserves

		Total 10-Minute Reserves		Load Following Available		Load Following Reserves Net of 10-Minute Reserves	
Plant	**Type**	(aMW)	% of Total	(aMW)	% of Total	(aMW)	% of Total
MidColumbia	Hydro	68.5	11.8%	68.5	7.7%	0.0	0.0%
Swift 1	Hydro	84.8	14.6%	84.1	9.4%	0.0	0.0%
Yale	Hydro	34.5	5.9%	44.2	4.9%	9.7	3.1%
Cutler 2	Hydro	6.7	1.1%	6.5	0.7%	0.0	0.0%
Cutler 1	Hydro	5.1	0.9%	5.1	0.6%	0.0	0.0%
Oneida 1	Hydro	4.2	0.7%	4.2	0.5%	0.0	0.0%
Merwin	Hydro	0.0	0.0%	0.0	0.0%	0.0	0.0%
Oneida 2	Hydro	3.9	0.7%	3.9	0.4%	0.0	0.0%
Oneida 3	Hydro	3.9	0.7%	3.9	0.4%	0.0	0.0%
Copco 2 - 2	Hydro	2.3	0.4%	2.4	0.3%	0.1	0.0%
Copco 2 - 1	Hydro	0.5	0.1%	0.5	0.1%	0.1	0.0%
Copco 1 - 1	Hydro	0.4	0.1%	0.4	0.0%	0.0	0.0%
Copco 1 - 2	Hydro	2.0	0.3%	2.1	0.2%	0.1	0.0%
Swift 2	Hydro	0.0	0.0%	0.0	0.0%	0.0	0.0%
Currant Creek	Gas	109.7	18.8%	240.5	26.9%	130.9	41.7%
Lake Side	Gas	49.4	8.5%	119.9	13.4%	70.5	22.5%
Hermiston	Gas	65.9	11.3%	97.3	10.9%	31.4	10.0%
Gadsby 4 CT	Gas	5.0	0.9%	5.9	0.7%	0.9	0.3%
Gadsby 6 CT	Gas	4.9	0.8%	5.7	0.6%	0.8	0.3%
Gadsby 5 CT	Gas	4.1	0.7%	5.2	0.6%	1.1	0.4%
Gadsby 3	Gas	3.1	0.5%	6.9	0.8%	3.8	1.2%
Gadsby 2	Gas	1.8	0.3%	3.0	0.3%	1.2	0.4%
Gadsby 1	Gas	1.2	0.2%	1.7	0.2%	0.5	0.2%
Cholla 4	Coal	26.3	4.5%	48.0	5.4%	21.7	6.9%
Hunter 3	Coal	23.2	4.0%	35.3	4.0%	12.1	3.9%
Hunter 1	Coal	19.0	3.3%	30.1	3.4%	11.1	3.5%
Huntington 2	Coal	11.6	2.0%	19.5	2.2%	7.9	2.5%
Naughton 3	Coal	6.2	1.1%	7.6	0.9%	1.4	0.4%
Huntington 1	Coal	16.4	2.8%	21.4	2.4%	5.0	1.6%
Hunter 2	Coal	14.4	2.5%	16.5	1.8%	2.1	0.7%
Naughton 2	Coal	1.9	0.3%	1.1	0.1%	0.0	0.0%
DJ 4	Coal	0.2	0.0%	0.5	0.1%	0.2	0.1%
Naughton 1	Coal	0.6	0.1%	0.8	0.1%	0.3	0.1%
Carbon 2	Coal	0.2	0.0%	0.5	0.1%	0.4	0.1%
Carbon 1	Coal	0.2	0.0%	0.4	0.0%	0.2	0.1%
DJ 3	Coal	0.1	0.0%	0.1	0.0%	0.1	0.0%
Bridger	Coal	0.0	0.0%	0.0	0.0%	0.0	0.0%
DJ 1	Coal	0.0	0.0%	0.1	0.0%	0.0	0.0%
DJ 2	Coal	0.0	0.0%	0.1	0.0%	0.0	0.0%
Monsanto	Contract	0.0	0.0%	0.0	0.0%	0.0	0.0%
Nucor	Contract	0.0	0.0%	0.0	0.0%	0.0	0.0%
MagCorp	Contract	0.0	0.0%	0.0	0.0%	0.0	0.0%
Cool Keeper	Contract	0.0	0.0%	0.0	0.0%	0.0	0.0%
SCL	Contract	0.0	0.0%	0.0	0.0%	0.0	0.0%
Totals		**582.2**	**100%**	**894.1**	**100%**	**313.6**	**100%**

Table E
2011 Study Results for all plants
Schedule 3 and 3A, Contribution Ratio

		Load Following Credit Incremental to Spin	
Plant	Type	(aMW)	% of Total
MidColumbia	Hydro	0.0	0.0%
Swift 1	Hydro	0.0	0.0%
Yale	Hydro	0.0	0.0%
Cutler 2	Hydro	0.0	0.0%
Cutler 1	Hydro	0.0	0.0%
Oneida 1	Hydro	0.0	0.0%
Merwin	Hydro	0.0	0.0%
Oneida 2	Hydro	0.0	0.0%
Oneida 3	Hydro	0.0	0.0%
Copco 2 - 2	Hydro	0.0	0.0%
Copco 2 - 1	Hydro	0.0	0.0%
Copco 1 - 1	Hydro	0.0	0.0%
Copco 1 - 2	Hydro	0.0	0.0%
Swift 2	Hydro	0.0	0.0%
Currant Creek	Gas	0.0	0.0%
Lake Side	Gas	0.0	0.0%
Hermiston	Gas	0.0	0.0%
Gadsby 4 CT	Gas	0.0	0.0%
Gadsby 6 CT	Gas	0.0	0.0%
Gadsby 5 CT	Gas	0.0	0.0%
Gadsby 3	Gas	0.0	0.0%
Gadsby 2	Gas	0.0	0.0%
Gadsby 1	Gas	0.0	0.0%
Cholla 4	Coal	0.0	0.0%
Hunter 3	Coal	0.0	0.0%
Hunter 1	Coal	0.0	0.0%
Huntington 2	Coal	0.0	0.0%
Naughton 3	Coal	0.0	0.0%
Huntington 1	Coal	0.0	0.0%
Hunter 2	Coal	0.0	0.0%
Naughton 2	Coal	0.0	0.0%
DJ 4	Coal	0.0	0.0%
Naughton 1	Coal	0.0	0.0%
Carbon 2	Coal	0.0	0.0%
Carbon 1	Coal	0.0	0.0%
DJ 3	Coal	0.0	0.0%
Bridger	Coal	0.0	0.0%
DJ 1	Coal	0.0	0.0%
DJ 2	Coal	0.0	0.0%
Monsanto	Contract	81.1	36.8%
Nucor	Contract	38.5	17.5%
MagCorp	Contract	85.3	38.7%
Cool Keeper	Contract	0.4	0.2%
SCL	Contract	15.0	6.8%
Totals		**220.4**	**100%**