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SUBMITTED VIA ELECTRONIC FILING

August 25, 2011

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

Re: *Puget Sound Energy, Inc*., Revisions to Open Access Transmission Tariff
Docket No. ER11-3735-000

Dear Ms. Bose:

Puget Sound Energy, Inc. ("PSE") submits for filing this Response to Deficiency Letter of August 5, 2011.

I. BACKGROUND

On June 6, 2011, PSE filed for approval with the Federal Energy Regulatory Commission ("Commission" or "FERC") proposed revisions to Schedules 3 and 13 of PSE's Open Access Transmission Tariff ("OATT") (the "June 6 Filing"). The purpose of the proposed revisions was to update PSE's existing rates for Regulation and Frequency Response Service to reflect its current costs of providing such service, and to provide for differentiated cost recovery to serve dispatchable and intermittent generators exporting power from PSE's Balancing Authority Area ("BAA"). In support of its filing, PSE included the prepared direct testimony of five witnesses, as well as full Period I and Period II cost of service support for the increased regulation rate as required by section 35.13(h) of the Commission's regulations.[1] PSE requested an effective date of August 5, 2011, or 60 days after the filing date, for the proposed tariff revisions.

On June 7, 2011, the Commission issued a Combined Notice of Filing giving interested entities until June 27, 2011 to file interventions and/or protests. On June 21, 2011, in response to a request of the American Wind Energy Association and the

[1] 18 C.F.R. § 35.13(h) (2011).

Renewable Northwest Project (collectively, "AWEA"), the Commission granted a one-week extension of time for the filing of protests. On July 5, 2011, AWEA and several other intervening entities filed pleadings protesting certain portions of PSE's filing. The protests generally requested that the Commission either reject or suspend PSE's filing for five months and set the matter for hearing and settlement procedures. On July 20, 2011, PSE filed an answer to the interventions and protests in an effort to clarify the issues and to facilitate the Commission's resolution of the proceeding ("July 20 Answer").

On August 5, 2011, the requested effective date of PSE's proposed tariff revisions, FERC Staff in the Office of Energy Market Regulation ("OEMR") issued a "Deficiency Notice Regarding Open Access Transmission Tariff Schedules 3 and 13" ("Deficiency Letter"). The Deficiency Letter requested information with respect to nine specified areas, and directed PSE to file the requested information within 30 days.

II. CONTENTS OF RESPONSE

PSE's Response consists of this transmittal letter and the following:

(1) Responses to Deficiency Letter;

(2) Appendix A, Schematic of Dynamic Transfer Options

(3) Supplemental Testimony of Lloyd C. Reed in Support of Response to Deficiency Items 3 and 5.

The filing also includes Confidential Workpapers related to the Supplemental Testimony of Mr. Reed. Those parties that have signed the Draft Protective Order included with PSE's June 6, 2011 filing in this proceeding will be provided with a copy of the confidential workpapers via overnight mail.

III. EFFECTIVE DATE AND REQUEST FOR WAIVER

The Deficiency Letter indicated that PSE's response thereto would "constitute an amendment to Puget's filing and a new filing date will be established, pursuant to *Duke Power Co.*, 57 FERC ¶ 61,215 (1991)." The Deficiency Letter further indicated that "[p]ending receipt of the [requested] information, a filing date will not be assigned to the filing." If Commission Staff determines that the information contained in this response to the Deficiency Letter cures the identified deficiencies, then presumably a later date will be established as the filing date of PSE's proposed tariff revisions.

PSE respectfully requests that the Commission permit PSE's filing to become effective on August 5, 2011, rather than at a later date. The Commission has granted waiver of the additional notice period associated with responding to a deficiency letter "if a good faith initial filing was made at least 60 days prior to the proposed effective date

and subsequently was amended to cure a Commission-identified deficiency."[2] Here, PSE's filing was made in good faith at least 60 days prior to the proposed effective date of August 5, 2011, and PSE has promptly cured the perceived deficiency in the filing. Accordingly, the Commission should exercise its discretion and allow the filing to take effect on August 5, 2011.

In the alternative, the Commission should grant waiver of the 60-day prior notice requirement associated with PSE's response to the deficiency letter for good cause.[3] In this case, good cause exists to grant waiver of the 60-days notice requirement and accept PSE's proposed tariff revisions effective August 5, 2011, the effective date requested in the June 6 Filing. PSE's June 6 Filing was made a full 60 days prior to the August 5, 2011 requested effective date, and unquestionably constituted a good faith initial filing. PSE included complete Period I and II cost support as required by the Commission's regulations and further justified the filing with detailed testimony from five witnesses. The Deficiency Letter does not direct any changes to PSE's proposed tariff revisions. As such, the information provided in the attached Response is more in the nature of a supplement than an amendment to the June 6 Filing.

Undue hardship will be imposed on PSE if a waiver is not granted and the effective date of PSE's proposed tariff revisions is delayed beyond August 5, 2011. PSE diligently worked for more than a year developing its June 14, 2010 filing of a proposed

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[2] *Niagara Mohawk Power Corp.*, 75 FERC ¶ 61,087 at p. 61,263 (1996). *See also Westar Energy, Inc.*, 130 FERC ¶ 61,215 at P 1 (2010) (accepting Westar's proposed tariff changes effective August 3, 2009, the original requested effective date, after Westar made a January 19, 2010 filing in response to a deficiency letter from Commission Staff); *Commonwealth Edison Co.*, 119 FERC ¶ 61,238 at PP 4-5 (2007) (accepting proposed tariff revisions effective May 1, 2007 after April 12, 2007 response to deficiency letter); *Midwest Independent Trans. Sys. Oper., Inc.*, 110 FERC ¶ 61,164 at PP 1, 5-14 (2005) (granting requested effective date following response to deficiency notice that included a notice of withdrawal of proposed tariff changes included in the original application); *Conectiv Bethlehem, LLC*, 106 FERC ¶ 61,272 at PP 9-11 (2004) (granting requested effective date following supplemental filing in response to deficiency letter and ordering Conectiv to refile its tariff sheets to correct any computational errors present in its original filing); *Midwest Independent Trans. Sys. Oper., Inc.*, 105 FERC ¶ 61,076 (2003) (granting requested effective date following supplemental filing in response to deficiency letter); *Illinois Power Co.*, 103 FERC ¶ 61,032 (2003) (same).

[3] The Commission grants waiver of the 60-day notice requirement upon a showing of good cause. *See Central Hudson Gas & Electric Corp.*, 60 FERC ¶ 61,106, *reh'g denied*, 61 FERC ¶ 61,089 at p. 61,354 (1992). *See also New York Independent Sys. Operator, Inc.*, 135 FERC ¶ 61,014 at P 11 n.11 (2011) (granting waiver of 60-day notice period under *Central Hudson* good cause standard); *Nevada Power Company*, 134 FERC ¶ 61,173 at P 7 (2011) (granting waiver of 60 day notice period under *Central Hudson* good cause standard); *Ameren Illinois Co.*, 134 FERC ¶ 61,159 at P 23 (2011) (granting waiver of 60-day notice period under *Central Hudson* good cause standard).

Wind Integration Within-Hour Generation Following Service in Docket No. ER10-1436-000, only to have that filing rejected outright by the Commission.[4] Thereafter, PSE elected not to seek rehearing of the Commission's order in that proceeding so that it could pursue a substantive dialogue with Staff about the direction PSE should take in a subsequent filing. Those pre-filing discussions led PSE to believe that the Commission would be comfortable with an approach to generator regulation cost recovery consistent with the approach approved by the Commission in *Westar Energy, Inc*.[5] Based on this guidance, PSE spent the better part of the last year developing the June 6 Filing, taking great care to adhere to the *Westar* methodology. The June 6 Filing was meticulously explained and justified in supporting testimony and exhibits, and PSE went to great lengths to respond to intervenors' questions and concerns in its July 20 Answer.

PSE was understandably surprised and disappointed to receive the Deficiency Letter on August 5, 2011, the last date available to the Commission to toll the effectiveness of the June 6 Filing. PSE has expended considerable time and resources during the past several years to developing a cost-supported, just and reasonable rate mechanism to recover the costs of managing the within-hour variability of intermittent generators exporting power outside of PSE's Balancing Authority Area. As PSE has explained to the Commission in this proceeding and in Docket No. ER10-1436-000, these costs are substantially under-recovered under PSE's existing ancillary service rate schedules. Absent a waiver of the 60-day notice requirement, the Deficiency Letter threatens to further delay PSE's recovery of legitimate and verifiable costs. PSE therefore respectfully requests a waiver of section 35.3 of the Commission's regulations so that tariff changes proposed in the June 6 Filing can become effective August 5, 2011, as requested.

Respectfully submitted,

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[4] *Puget Sound Energy, Inc.*, 132 FERC ¶ 61,128 at PP 34-35 (2010). The order rejected PSE's proposed Wind Following Service rate without prejudice to PSE filing a new rate proposal consistent with the discussion in the order.

[5] 130 FERC ¶ 61,215 (2010).

Puget Sound Energy, Inc.'s Responses to
8-5-2011 Deficiency Letter

Docket No. ER11-3735-000

1. *Puget's Schedule 3 and Schedule 13 state that "a Transmission Customer must either purchase [regulation and frequency response] service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service Obligation."*[1] *What types of arrangements will Puget consider as comparable arrangements to satisfy its obligation?*

2. *Puget states that it will work with customers to facilitate a dynamic transfer into Puget's BAA of self-supplied regulation capacity or a dynamic transfer out of Puget's BAA of the generator's output. How will Puget facilitate dynamic scheduling in its BAA, and what rules and procedures will Puget use to establish dynamic transfers into and out of Puget's BAA?*

RESPONSE:

Puget Sound Energy, Inc. ("PSE") modeled its proposed Schedule 3 and Schedule 13 after the Federal Energy Regulatory Commission's ("FERC" or "Commission") *pro forma* Open Access Transmission Tariff ("OATT").[2] The "alternative comparable arrangements" language comes directly from Schedule 3 of the Commission's *pro forma* OATT, which provides that "[t]he Transmission Customer must either purchase this service from the Transmission Provider or make ***alternative comparable arrangements***

[1] Puget Sound Energy, Inc., OATT, Regulation, 008 Schedule 3 (2.0.0); Puget Sound Energy, Inc., OATT, Generator Regulation, Schedule 13 (0.0.0).

[2] See *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, *FERC Statutes and Regulations, Regulations Preambles 2006-2007* ¶31,241 at P 5, *order on reh'g*, Order No. 890-A, *FERC Statutes and Regulations, Regulations Preambles 2006-2007* ¶31,261 (2007), *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, *order on clarification*, Order No. 890-D, 129 FERC ¶61,126 (2009). A copy of the Commission's pro forma OATT is available at http://www.ferc.gov/industries/electric/indus-act/oatt-reform/order-890-B/pro-forma-open-access.doc ("*Pro Forma* OATT").

to satisfy its Regulation and Frequency Response Service obligation."[3] It is unclear how PSE's continued use of this existing tariff language can be considered a deficiency in the instant filing.

To allay the concerns expressed by certain Intervenors,[4] PSE reiterates that "alternative comparable arrangements" is not merely some "theoretical" alternative that PSE has no incentive to explore or implement. In fact, PSE would consider acceptable any reasonable comparable arrangement that effectively removes PSE's obligation to provide regulation service to its transmission customer and places that obligation on another entity. Such an arrangement, to qualify as an "alternative comparable arrangement" within the meaning of the tariff,[5] would entail either (a) a pseudo-tie of the generation output to an attaining balancing authority area ("BAA") or (b) a dynamic schedule of self-supplied regulation capacity into PSE's BAA capable of adjusting to the varying output of the third-party resource in PSE's BAA.[6] A schematic illustrating these two representative scenarios is attached to this response as Appendix A.

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[3] *See id., Pro Forma* OATT, Schedule 3 (emphasis added).

[4] *See, e.g.* NIPPC at 11 ("the words in PSE's proposed Schedule 13 stating that a generator can make 'alternative comparable arrangements' offer nothing more than an undefined, theoretical alternative.").

[5] *Puget Sound Energy, Inc.*, Docket No. ER11-3735-000, PSE Answer to Protests at 27-28 (filed July 20, 2011) ("July 20 Answer").

[6] The self-supply of regulation capacity would relieve the generator of both Schedule 13 and Schedule 9 "Generator Imbalance" charges as the arrangement would be importing energy while holding capacity at the generation source backing the import. It should be noted that regulation capacity could also be self-supplied from a generation resource physically located within the PSE BAA, in which case a dynamic transfer would not be needed.

The dynamic transfer of generation output through pseudo-tie is, in fact, an accepted practice used commonly in the Pacific Northwest to move a generator's output (including its moment-to-moment variance) from one BAA to another. The dynamic transfer can be set up in a very straight-forward method with the source and the sink Balancing Authorities ("BAs") once transmission arrangements have been made on the required paths with the approval of any intermediary BAs and transmission providers. If PSE were the source BA for a dynamic transfer, data points representing the generator output can be used as the dynamic transfer signal in the PSE Energy Management System. This signal is also sent to the sink BA's energy management system through standard communication protocols.

For a psuedo-tie, the dynamic transfer signal is included in the Area Control Error ("ACE") equations as an actual or tie-line meter. The pseudo-tie effectively moves the output of the generator from the source BAA to the sink BAA. The dynamic transfer signal can also be supplied to the intermediary BA(s) (if any) such that they can make sure the variability of the transfer is not adversely affecting the voltage and/or remedial action scheme settings on the transmission path.

Similar arrangements can be established to dynamically transfer regulation resources into a source BAA, via a dynamic schedule, for the purpose of a generator in the source BAA meeting its regulation service obligation. The generator inside PSE's BAA would contract with a unit, or BA, outside of PSE's BAA to dynamically transfer in, via a pseudo-tie, an amount of energy equal to the positive or negative deviation from schedule at a four second scan rate. For instance, if a generator in PSE's BAA scheduled 50 MW, but was generating 45 MW, the pseudo-tie arrangement would call for 5 MW to

be imported from the source unit outside of PSE's BAA. This calculation would be run every four seconds with a new signal being sent to the source unit to change its import value. This arrangement, just like a pseudo-tie out of PSE's BAA, would remove PSE's burden of supplying both regulation service and generation imbalance service.

The second deficiency item also inquires about the "rules and procedures Puget will use to establish dynamic transfers into and out of Puget's BAA." PSE has not, to date, received any third-party requests to dynamically transfer or pseudo-tie generation into or out of its BAA. If it were to receive such a request, however, in keeping with industry practice, PSE would follow the guidance given in NERC's "Dynamic Transfer Guidelines v. 2" to determine on a case-by-case basis the individual characteristics and requirements necessary to set up such an arrangement. NERC's Dynamic Transfer Guidelines provide guidance to the industry on the responsibilities, requirements, and expectations placed upon parties involved in establishing a dynamic transfer and are available at: http://www.nerc.com/docs/oc/is/IS_Dynamic_Transfer_Guidelines.pdf

In addition, the following is a summary list of requirements and protocols that may be required for the two types of arrangements referenced above:

- sufficient metering and communication equipment to establish meter values for interchange and ACE calculation purposes on a four-second scan rate
- demonstration of firm transmission capacity from source to sink and approval of intermediary BAs to allow dynamic transfers across their systems

- annual testing of resource adequacy to determine if the arrangement has fully removed PSE's provision of the ancillary service(s); actual use of the resource can be used to demonstrate this requirement
- agreement determining BA responsibilities for NERC (or other) standards
- demonstration of ability to meet all applicable NERC, WECC, and/or NAESB standards
- service election of one year or greater with a 90-day notice to ensure the BA has time to plan for any changes in reserve requirements

As Intervenors are well-aware, pseudo-tie arrangements are not "theoretical" but rather are common place in the Northwest. Indeed, PSE recently completed a pseudo-tie arrangement to import the signal for its merchant-owned Mint Farm facility into PSE's BAA. PSE also currently has similar dynamic transfer arrangements for its Goldendale, Spokane Waste, Colstrip, and Mid-Columbia generation. Thus, there are no technical barriers to implementing a pseudo-tie arrangement for generation in PSE's BAA to be moved to an attaining BAA, or for the dynamic transfer of self-supplied regulation capacity and energy into PSE's BAA, and PSE will continue to work cooperatively with its customers to achieve their desired objectives.

3. *Puget describes a study it performed to determine the 16.77 percent purchase obligation for exporting intermittent generators. However, Puget failed to provide support demonstrating that the 2.0 percent purchase obligation still accurately captures the burden imposed on Puget's system by load (under Schedule 3) and by exporting dispatchable generators (under Schedule 13). To remedy this deficiency, please provide the following information:*

    a. *Support for the proposed 2.0 percent regulation requirement for load and for exporting dispatchable generators.*

<u>RESPONSE:</u>

PSE did not propose to change the 2.0 percent purchase obligation – an effective provision of its filed tariff – in the instant filing, made pursuant to Section 205 of the Federal Power Act, as it pertains to load and dispatchable generation exports. PSE does not believe that relying upon its filed rate constitutes a deficiency.[7] Nevertheless, PSE provides the requested information and fully addresses the questions below.

The basis for the 2.0 percent purchase obligation for load under Schedule 3 of the PSE OATT was a settlement between Commission Staff and PSE in Docket No. ER97-4468-000.[8] The Prepared Direct Testimony of Jerald A. Smith on behalf of Commission Staff explained the derivation of the 2.0 percent regulation percentage as follows:

Step 1:	Calculate the absolute values of hour-to-hour load deviations using the Puget Sound's hourly load data provided in Puget Sound's response to Staff-57 (this information is in electronic format).
Step 2:	Calculate the average of the deviations and divide the average by 2.
Step 3:	Divide the number calculated in step 2 by Puget Sound's 12-CP load.
Step 4:	Express the number calculated in step 3 as a percentage. Consider the percentage thus calculated as the percent of regulation reserve.[9]

Calculated thusly using PSE load data from calendar year 1996 yielded a regulation reserve percentage of 1.68%.[10] The 1.68% purchase obligation was later

[7] *See, e.g.*, *Atlantic City Ele. Co.*, 295 F.3d 1, 10 (D.C. Cir. 2002) ("The courts have repeatedly held that FERC has no power to force public utilities to file particular rates unless it first finds the existing filed rates unlawful.").

[8] *Puget Sound Energy, Inc.*, 97 FERC ¶ 61,309 (2001) (letter order approving settlement that included 2.0 percent Schedule 3 regulation purchase obligation).

[9] *Puget Sound Energy, Inc.*, Docket No. ER97-4468-000, Prepared Direct Testimony of Jerald A. Smith on Behalf of FERC Staff at 9 (filed Feb. 27, 1998).

[10] *Id*. at 10.

rounded up to 2.0% in a black box settlement with FERC Staff.[11] The 2.0% figure was used again as a reasonable approximation of the regulation requirement associated with dispatchable generation exports when PSE amended its OATT to include Schedule 13 in 2010.[12] This method of approximating the regulation burden associated with generation exports using the same purchase obligation associated with load is consistent with the methodology used by Entergy and other transmission providers who have implemented generator regulation charges.[13]

In response to Commission Staff's August 5, 2011 Deficiency Letter, PSE hereby provides the attached Supplemental Testimony of PSE witness Lloyd C. Reed which re-calculates the regulation percentage using the calendar year 2010 hour-to-hour variability of load in PSE's BAA in the same manner described by Commission Staff Witness Jerald A. Smith in Docket No. ER97-4468.[14] The resulting regulation percentage of 1.54% supports and closely approximates the existing 2.0 percent purchase requirement for load and dispatchable generation exports.[15]

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[11] *See* Puget Sound Energy, Inc., Docket No. ER97-4468-000, Letter from Linda Lee, Commission Staff Counsel, to the Honorable Raymond M. Zimmet (dated April 10, 1998) (notifying ALJ Zimmet that PSE and FERC Staff had reached a settlement with respect to certain tariff provisions related to ancillary services); see also *Puget Sound Energy, Inc*., 97 FERC ¶ 61,309 (2001) (letter order approving settlement that included 2.0 percent Schedule 3 regulation purchase obligation).

[12] *Puget Sound Energy, Inc*., Letter Order, Docket No. ER10-723-000 (Apr. 12, 2010) (accepting PSE's OATT modifications, including implementation of Schedule 13 generator regulation service with 2.0% regulation requirement).

[13] *See, e.g., Entergy Servs. Inc*., 120 FERC ¶ 61,042 at PP 62-66 (2007); *Florida Power Corp.*, 89 FERC ¶ 61,263 (1999).

[14] *See* Exh. PSE-101, Supplemental Testimony of Mr. Lloyd C. Reed, at 4.

[15] *Id*.

Mr. Reed also explains in his supplemental testimony that he has calculated the regulation purchase obligation of load and dispatchable generation, respectively, using the same portfolio-wide analysis that was used to calculate the 16.77% purchase obligation for intermittent generation exports.[16] Using the portfolio-wide analysis, which takes into account offsetting system diversity, the regulation percentage for load would be 1.21% and 0.38% for dispatchable generation.[17] While PSE does not propose to revise the 2.0% regulation percentage for load or dispatchable generation exports under Schedules 3 and 13 of its filed tariff in this proceeding, it provides this information to be fully responsive to Commission Staff's deficiency letter. If the Commission wishes to adopt regulation percentages for load and exporting dispatchable generators that are based on the same portfolio-wide methodology used to develop the 16.77% regulation purchase obligation for exporting intermittent generation, these percentages developed by Mr. Reed in his portfolio-wide study would be reasonable to apply.

b. Please explain whether the purchase obligation in Schedule 3 is based only on load deviations within the BAA or deviations of both load within the BAA and generation used to serve that load.

RESPONSE:

Please refer to PSE's response to item 3(a) above. As described in the testimony of FERC Staff Witness Jerald A. Smith in Docket No. ER97-4468-000, the 2.0 percent purchase obligation reflected in Schedule 3 is based solely on the hour-to-hour load deviations on PSE's system during calendar year 1996 and therefore reflects only the

[16] *See id*. at 5.

[17] *Id*. at 6.

load deviations in the PSE BAA.[18] It does not reflect the deviations of generation used to serve that load.

> c. *Further, to the extent the 2.0 percent regulation requirement in Schedule 3 does not reflect the deviations of the generation serving the load within the BAA, please explain how the regulation costs for those deviations are recovered and explain whether it is unduly discriminatory to charge generators serving load outside of the BAA for regulating capacity based on their dispatchability but not similarly charge generators serving load within the BAA based on their dispatchability.*

RESPONSE:

As discussed in response to items 3(a) and (b) above, the 2.0 percent regulation requirement in Schedule 3 does not reflect or recover the cost of deviations of the generation serving the load within PSE's BAA. It is based solely on load deviations. Therefore, PSE does not recover the cost of providing regulation service to generation resources that are committed to serving load in PSE's BAA under either Schedule 3 or Schedule 13. Instead, the regulation costs associated with such generation deviations are currently being passed through to PSE's retail and wholesale customers through their bundled rates. There is therefore no need to distinguish between generators serving load inside PSE's BAA based on dispatchability because all of the generators are serving the same customers and those customers are paying for all of the related regulation costs.

In contrast, PSE has no means of recovering regulation costs associated with generators that serve load outside of PSE's BAA other than through Schedule 13 of its OATT. These generators are not serving or benefiting load in PSE's BAA and are

[18] *Puget Sound Energy, Inc.*, Docket No. ER97-4468-000, Prepared Direct Testimony of Jerald A. Smith on Behalf of FERC Staff at 9 (filed Feb. 27, 1998).

instead participating in external markets for their own benefit. Such generators should be responsible for paying the costs associated with the incremental burden they impose on the system. Mr. Reed's Supplemental Testimony demonstrates that the incremental burden associated with intermittent generation is nearly 45 times greater than that imposed by dispatchable generation.[19]

It is therefore entirely appropriate, and not unduly discriminatory, for PSE to charge generators serving load outside the PSE BAA based on dispatchability while not charging generators serving load within the PSE BAA. The Commission recognized this in *Westar*, where it approved a regulation purchase obligation for exporting generation based on dispatchability while not requiring Westar to charge generation serving load inside the Westar BAA for regulation service under its existing Schedule 3 or proposed Schedule 3A.[20]

4. *Puget does not provide sufficient information regarding how Puget would account for the costs associated with regulating Puget's Wild Horse wind facility. Please demonstrate whether and/or how the increased variability from the Wild Horse facility is included in the computation of regulation reserve capacity under Schedule 3.*

RESPONSE:

As noted above in response to items 3(a) – (c), the computation of the 2.0% regulation reserve capacity obligation under Schedule 3 was performed in Docket No. ER97-4468-000 by FERC Staff witness Jerald A. Smith. Mr. Smith calculated the

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[19] Exh. PSE-101, Supplemental Testimony of Lloyd C. Reed at 6-7 (16.77 / 0.38 = 44.13).

[20] *See Westar Energy, Inc*., 130 FERC ¶ 61,215 at P 35 (2010) ("*Westar*") (finding that "Westar's proposed Balancing Agreement and Schedule 3A will allow Westar to charge for generation regulation resulting from transactions involving exports of power out of the Westar balancing area.").

average hour-to-hour load deviations on PSE's system using 1996 data provided by PSE, and ultimately divided such average deviation by PSE's 12 CP demand to arrive at a load regulation percentage. The variability of PSE's generation resources was not measured or otherwise factored in to the determination of the 2.0 percent load regulation percentage in Docket No. ER97-4468-000. The 2.0 percent is a load-only deviation factor, and no generation deviations are accounted for in it. As discussed above, generation deviations serving load in PSE's balancing area are absorbed and paid for by the load in the area.

As described in its response to item 3(c) above, the costs associated with regulating the variability of Wild Horse and any other facility dedicated to serving load within PSE's BAA are recovered not through Schedules 3 or 13 of the PSE's OATT but rather are recovered from PSE's retail and wholesale customers through bundled rates. PSE fully recovers the cost of regulating Wild Horse - and all of its other generation - from the parties who benefit from its output - PSE's bundled retail and wholesale customers.

PSE notes that this situation is identical to that considered and accepted by the Commission in *Westar*. As Westar explained in that case:

> [T]here is no need to distinguish between generators serving load inside Westar's Balancing Area based on dispatchability because all of the generators are serving the same customers and those customers are paying for all of the related regulation costs.
>
> This is entirely different from the situation being addressed with the proposed Schedule 3A charge, where dispatchable generators are not Designated Resources for and are never used to serve load inside the Balancing Area. Westar's customers receive no benefit from the sales these generators make and should not be responsible for the regulation burden they impose on the system. [21]

[21] Westar Response to Deficiency Letter, Docket No. ER09-1273 (Jan. 19, 2010) at 10.

5. *In calculating the deviations for dispatchable generators that are used in determining the intermittent purchase obligation, Puget only uses data from six of its dispatchable generators. Please explain why Puget excludes part of its dispatchable generation fleet from its calculations of deviations for determining the intermittent purchase obligation. Please also explain how the data from these six dispatchable generators are used to calculate a "portfolio-wide" system diversity ratio, and if not used, please explain how the system diversity ratio was calculated.*

RESPONSE:

In determining the intermittent purchase obligation under Schedule 13 using the portfolio-wide approach approved by the Commission in *Westar*, PSE sought to incorporate into the analysis the benefits of any offsetting variability associated with PSE's dispatchable generators. But first, PSE had to overcome a data problem. As explained in the direct testimony of Mr. Reed, PSE has detailed data on generator output within the hour.[22] What PSE does not have is a record of dispatch instruction or generator set point to compare the generator output to so as to measure the unit's variability.[23] For example, Westar's portfolio-wide study included a group of dispatchable generators that were set to the code RBASE during a given interval, meaning that the generator received a dispatch instruction from the Southwest Power Pool, Inc. ("SPP") every ten minutes.[24] Westar was then able to compare the actual

[22] Exh. PSE-100 at 14 ("PSE has detailed, 4-second interval generation records for its Dispatchable Plants extending back for several years.").

[23] *Id*. at 23-24.

[24] *See Westar Energy, Inc*., Docket No. ER09-1273-000, Responses to Deficiency Letter at 2-3 (filed Jan. 19, 2010). Westar noted that it had similar data problem as PSE with respect to its dispatchable generators that were not set to code RBASE, explaining that "SPP provides dispatch instructions to dispatchable generators on a different basis

output from the generator set to code RBASE with the dispatch instruction from SPP to determine the variability of the unit.[25]

As Mr. Reed explained, unlike Westar, PSE's dispatchable generation units do not receive a dispatch instruction from a third party operator, and PSE does not create and maintain a complete set of revised, hour-ahead schedules in real time for its dispatchable units.[26] It was therefore necessary for Mr. Reed to review the actual output data from PSE's dispatchable generation units in order to create a proxy generation schedule to measure against the units' actual output. As Mr. Reed described, this was a labor-intensive process:

> the operation of each [ ] plant[] was analyzed across calendar year 2010 to determine the periods when the plant was operated in a steady-state mode. All hours in which the plant was: (1) not being intentionally ramped up or down, or (2) was not being limited by a partial or full unit forced outage were considered to be steady-state periods. Next, a set of 60-minute before-the-hour persistence forecasts were created for each representative plant. A cross-check was then performed to ensure that each 60-minute persistence forecast was determined at a point in time when the plant was operating in a steady-state mode. The hourly levelized forecasts created from the previous step were then ramped across the last 10 minutes of each hour and the first 10 minutes of the next hour in order to be consistent with the top of the hour ramping procedure used in the WECC. Finally, the difference between the hour-ahead ramped forecasts and the actual generation for each representative plant were computed across each 10-minute period for all of the steady-state hours for that particular

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than for wind generators; therefore, Westar is not able to simulate dispatch instructions for the purposes of its study as it did with the wind generators." *Id*. at 2.

[25] *Id*. at 3.

[26] Exh. PSE-100, Testimony of Lloyd C. Reed at 25.

plant during calendar year 2010.[27]

Creating even one year-long data set for a single generation plant using this onerous process was quite time-consuming. Therefore, Mr. Reed elected to simplify the process by evaluating six representative plants rather than repeating the process for PSE's entire suite of dispatchable resources. He selected two plants each from the representative categories of coal-fired steam (Colstrip 1&2 and Colstrip 3&4), combined cycle/combustion turbine/miscellaneous (Goldendale and Sumas), and hydro generation (Upper Baker and Lower Baker), and created 12-month data sets in the manner described in the block quote above.[28]

The Deficiency Letter next asks how the data from these six representative units was used to perform the portfolio-wide analysis. The first step was to scale up the variability of the six representative units to match the size of PSE's entire dispatchable generation fleet.[29] Mr. Reed explained the process as follows:

> The 10-minute interval scheduled versus actual deviations as measured across all of the steady-state hours during each month of calendar year 2010 were scaled up by the ratio of the total amount of monthly energy production from all Dispatchable Plants within that class (coal-fired steam, CCCT/CT/Misc, or hydro) that were electrically located within the PSE BAA, divided by the total monthly energy production of the two representative Dispatchable Plants.[30]

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[27] Id. at 24-25.

[28] *Id*. at 24-25.

[29] The PSE generating units that were continuously operated on Automatic Generation Control during 2010 were excluded from the scaling process since these units were providing, rather than using, regulation capacity.

[30] *Id*. at 27.

The scaled-up 10-minute deviations for all three of the PSE plant classes were then combined with the 10-minute PSE load deviations and the 10-minute wind deviations in order to determine PSE's overall within-the-hour regulation requirement.[31]

In short, Mr. Reed determined the variability of PSE's dispatchable generation units by scaling up the variability of six representative units to approximate the entire fleet because of the labor-intensive manipulations required to create the data set for each plant. This scaled up approximation was not done with the intent of disadvantaging intermittent generators in any way. As PSE explained in its July 20 Answer, "[i]f PSE had actually measured and included the variability of each individual dispatchable generating unit on its system, there would have been additional diversity benefits among PSE's fleet of dispatchable units and this piece of the pie likely would have shrunk – thereby increasing the size of Invenergy's piece of the pie in the portfolio-wide analysis."[32]

Nevertheless, in response to the Deficiency Letter, Mr. Reed now has formulated the 12-month data sets for seven additional dispatchable resources. With these additional seven dispatchable units included, Mr. Reed's updated portfolio-wide study accounts for approximately 97% of the actual generation from all of the dispatchable plants that were electrically located within the PSE BAA during calendar year 2010.[33] Mr. Reed's supplemental testimony explains that the results of this updated portfolio-wide study result in a regulation purchase obligation for exporting intermittent generators of 17.15%,

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[31] *Id*.

[32] July 20 Answer at 18.

[33] See Exh. PSE-101, Supplemental Testimony of Lloyd C. Reed, at 10.

which is consistent with (and as predicted, slightly higher than) Mr. Reed's original portfolio-wide approach that used scaling to approximate the variability of PSE's dispatchable units based on six representative units.[34] Therefore, PSE does not propose to revise the 16.77% purchase obligation determined using Mr. Reed's original portfolio-wide analysis.

6. *In calculating the proposed capacity charges, Puget only uses data from eight generation resources. Please explain why Puget excludes part of its generation fleet and purchases from its calculations of the cost of providing regulation service and explain why it selected these particular eight generation resources.*

RESPONSE:

The Prepared Direct Testimony of Michael V. Tongue, included with PSE's initial filing as Exhibit PSE-200, explains the selection of eight resources for PSE's regulation resource pool and the exclusion of PSE's remaining generation resources from the pool.[35] Mr. Tongue explained that certain PSE generation resources are "regularly used on an integrated basis to respond to system imbalances within the scheduling hour and should therefore be included in [ ] PSE's regulation resource pool."[36] These resources include:

1. Mid-Columbia Hydro – Jointly Contracted Hydro
2. Upper Baker River – PSE Owned Hydro
3. Lower Baker River – PSE Owned Hydro
4. Encogen – PSE Owned Natural Gas Combined Cycle

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[34] *Id*..

[35] Exh. PSE-200, Testimony of Michael V. Tongue at 8-10.

[36] *Id*. at 9.

5. Goldendale – PSE Owned Natural Gas Combined Cycle
6. Mint Farm – PSE Owned Natural Gas Combined Cycle
7. Sumas – PSE Owned Natural Gas Combined Cycle
8. Colstrip – Jointly Owned Coal[37]

The common theme among these eight generation resources is that they have relatively high capacity factors compared to PSE's other resources, and are therefore online and available for commitment to both incremental and decremental regulation capacity. These resources form the backbone of PSE's dispatchable thermal and hydro units and, in the experience of the Manager of PSE's Load Office, Mr. Tongue, are used most frequently to provide regulation reserves.[38]

PSE excluded its small hydroelectric run-of-river facilities from its regulation resource pool because these resources have limited storage capability, and are therefore generally not able to be dispatched in response to system variability. These run-of-river facilities include Snoqualmie Falls and Electron.[39] Among its thermal units, PSE excluded its simple cycle combustion turbine natural gas units from the regulation resource pool. These include the Whitehorn 2&3 units, Fredrickson 1&2, and Fredonia units 1-4. These units all have very high operating costs compared to the eight resources in PSE's regulation resource pool, and are therefore generally not online and available to

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[37] *Id.*

[38] *Id.*

[39] PSE also excluded its purchased hydro run-of-river facilities from the regulation resource pool for the same operational reasons, as well as contractual limitations associated with these purchases: Nooksack, North Wasco, Koma Kulshan, Twin Falls, Weeks Falls, and other small QF hydro purchases.

provide incremental and decremental regulation capacity. Indeed, the 2010 annual capacity factors of the Whitehorn, Frederickson and Fredonia plants ranged between 0.6% and 2.3%. As Mr. Tongue explained, the high operating costs of these units make them better suited to providing "10-minute non-spin contingency reserves rather than regulation capacity."[40] PSE also excluded four of its combined cycle combustion turbine generation facilities from the regulation resource pool because PSE does not have dispatch control, or has limited dispatch control, over the facilities: March Point 1, March Point 2, Tenaska, and Fredrickson I. The March Point and Tenaska facilities have physical and contractual limitations that limit their ability to provide regulation reserves The Fredrickson I combined cycle unit is jointly owned with EPCOR, and the joint ownership agreement restricts PSE's ability to operate the plant to provide regulation capacity. Finally, PSE excluded its approximately 3 MW Crystal Mountain internal combustion engine generator and a small PURPA QF purchase from a municipal solid waste incinerator. Like the other units excluded, these resources have contractual or operational limitations on PSE's ability to dispatch them up or down that make them poorly suited to provide the regulation capacity needed to respond to within-the-hour system variability.

The Commission rejected PSE's proposed proxy unit pricing methodology in Docket No. ER10-1436-000 in part because the capacity rate was not based on the cost of the units actually used to provide the service.[41] In this proceeding, therefore, PSE selected the generation resources that, in the experience of the system operator Mr.

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[40] Exh. PSE-200, Prepared Direct Testimony of Michael V. Tongue at 9.

[41] *See generally Puget Sound Energy, Inc.*, 132 FERC ¶ 61,128 (2010).

Tongue, are actually used to provide regulation capacity, and developed the capacity rate reflected in Schedules 3 and 13 using the weighted average cost of these resources.

7. *Puget uses nameplate capacity when calculating the 16.77 percent purchase obligation for exporting intermittent generators but applies the resulting charge based on transmission reservation. Please provide justification for this differing treatment and explain why Puget should be allowed to use nameplate capacity in calculating the 16.77 percent intermittent purchase obligation for exporting intermittent generators under Schedule 13, while applying the resulting charge based on transmission reservation.*

RESPONSE:

Mr. Reed used the nameplate capacity of dispatchable and intermittent generators to perform the portfolio-wide study that resulted in the 16.77 percent purchase obligation for intermittent generators for two reasons. First, the six dispatchable generation resources used in the study, as well as the Wild Horse wind facility, are all owned or controlled by PSE and used to serve PSE retail or wholesale customers. These resources do not have point-to-point transmission reservations. Mr. Reed therefore elected to use the nameplate capacity of these resources, and to be consistent, did the same for the Vantage facility. Second, this approach appears to be consistent with Westar's final portfolio-wide study, which was also performed using the nameplate capacity of the included generation facilities.[42]

[42] Westar's January 19, 2010 response to Commission Staff's deficiency filing used the average peak generation or maximum observed generation for the generation facilities in the portfolio study. *See Westar Energy, Inc.*, Docket No. ER09-1273-000, Response to Deficiency Letters, Supplemental Testimony of Paul A. Dietz at 8 (filed January 19, 2010). Westar's subsequent compliance filing included lower values for the wind and dispatchable generation regulation percentages than what was reflected in Mr. Dietz's January 19, 2010 portfolio study. *See Westar Energy, Inc.*, Docket No. ER09-1273-000, Compliance Filing, Clean Schedule 3A (filed April 19, 2010). Mr. Reed learned through conversations with Mr. Dietz that the reduced values in the April 19 compliance filing were the result of using the nameplate capacity of the generators in the

Unlike Westar, however, PSE has not proposed to charge transmission customers under Schedule 13 according to the nameplate capacity of the generation facility that is being exported. Rather than entering a "Balancing Area Services Agreement" as a means of charging generators directly for Schedule 13 regulation service, as Westar does under its Schedule 3A, PSE currently collects Schedule 13 generator regulation charges directly from the transmission customer that delivers energy from the exporting generator to a sink outside the control area. Because PSE charges the transmission customer and not the generator under Schedule 13, it seems logical to charge the customer based on its transmission reservation and not the nameplate capacity of the exported generation facility. PSE saw no reason to amend this previously filed (and currently operative) component of Schedule 13 in this proceeding. However, PSE does not object to revising Schedule 13 to use nameplate capacity as the billing determinant for generator regulation service if that is the preferred approach.

It should be noted that the apparent inconsistency between the portfolio-wide study and the Schedule 13 billing determinant actually works to the advantage of Invenergy's Vantage wind facility. Vantage's firm point-to-point transmission reservation is 90 MW, while its nameplate capacity is 96 MW. If PSE were to amend Schedule 13 to provide for a charge based on a percentage of Vantage's 96 MW installed capacity, Vantage would pay a higher monthly charge.

8. *In its calculation of the 16.77 percent purchase obligation, Puget uses 60-minute persistence forecasts in calculating all of the deviations for intermittent generators. As of June 28, 2011, transmission customers were able to change*

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portfolio study at the urging of Commission Staff, rather than maximum observed or average peak generation values.

their schedules on an intra-hourly basis. Please explain whether Puget's calculation of the 16.77 percent purchase obligation accounts for the possibility that resources would utilize intra-hour transmission scheduling now that it is available, and if not, why not.

RESPONSE:

PSE's calculation of the 16.77 percent purchase obligation does not presently account for the possibility that resources may in the future change their schedules on an intra-hourly basis and PSE does not believe it can or should. Mr. Reed used the most recent calendar-year 2010 variability data from the load and generation in the PSE BAA to perform his portfolio-wide regulation study. While PSE has offered voluntary intra-hour schedule adjustments on the half-hour since June 1, 2010,[43] the Deficiency Letter correctly notes that Bonneville Power Administration ("BPA") did not offer half-hour schedule adjustments for wheel-through customers until June 28, 2011. To be effective, intra-hour schedule adjustments must be available for each leg of the journey. As a result, exporting generators like Invenergy's Vantage facility that must pass through BPA's transmission system were unable to utilize half-hour schedule adjustments during calendar year 2010. As such, Mr. Reed's portfolio study and the resulting 16.77% regulation purchase obligation does not reflect the availability of half-hour schedule adjustments.[44]

PSE cannot speculate as to the possible future impact of half-hour schedule

[43] See NIPPC Protest, Attachment A.

[44] Mr. Reed's portfolio analysis actually used 60 minute persistence forecasts in lieu of Vantage's next-hour generation schedule (a) to be consistent with the treatment of PSE's own generation resources, for which no hourly schedule was available; and (b) because the 60-minute persistence forecast was more accurate than Vantage's submitted generation schedules. *See* July 20 Answer at 14-17.

adjustments – a practice which was not yet available as of the date of PSE's June 5, 2011 filing in this proceeding, and was not in use during Mr. Reed's 2010 study period – and then try to incorporate such speculation into its proposed regulation rate schedules. The Commission only permits utilities to recover the "legitimate and verifiable costs" of providing service.[45]

The cost impacts of the recent availability of half-hour schedule adjustments are not legitimate or verifiable at this time. Half-hour schedule adjustments are not mandatory under the BPA scheduling program or under PSE's intra-hour scheduling business practice. Highlighting the voluntary nature of intra-hour schedule adjustments in the region is the fact that Vantage's hourly generation schedule has been updated only once on the half-hour since BPA's intra-hour scheduling program went live.[46] Without certainty that a generator will revise its schedule on the half hour, the system operator must still plan to have regulation capacity available based on the likelihood of deviation from the original hourly schedule. BPA noted recently that "[h]alf-hour scheduling is currently voluntary, so BPA cannot assume any reduction in the need to carry balancing reserves."[47] As a BA subject to civil penalties of up to $1,000,000 per violation per day

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[45] *See, e.g. Rumford Power Associates, L.P.*, 97 FERC ¶ 61,159 at 61,704 (2001) ("Since only legitimate and verifiable costs may be recovered and since Central Maine has not specifically addressed or supported the basis for the Contribution Margin in its answer, the Commission finds the Contribution Margin is unsupported and directs Central Maine to refund the $1.1 million to Rumford within 30 days of the date of this order with interest computed in accordance with Section 35.19 of the Commission's regulations.").

[46] See July 20 Answer at 10.

[47] BPA Wind Integration Team Initiatives, Update to WIT email list, June-July 2011.

for violations of NERC's mandatory reliability standards, PSE cannot justifiably afford to make the resource decisions needed to balance its system in advance of the operating hour based on the fact that a transmission customer may or may not adjust its schedule on the half-hour. Further, absent a liquid intra-hour market for buying and selling capacity or energy, PSE, even in the presence of expected half-hour schedule adjustments, would still need to make resource decisions during the time-frame when energy is commonly, and reliably, available in the market – 60 minutes before the start of the operating hour.

However, PSE recognizes the possibility that widespread or mandatory use of intra-hour schedule adjustment practices, or full intra-hour scheduling for all generation, loads, and transmission resources in the future, particularly in conjunction with a liquid intra-hour market for energy and capacity in the Pacific Northwest, might reduce PSE's regulation burden and therefore reduce an intermittent generator's purchase obligation under Schedule 13. PSE therefore would propose to file an informational report, consistent with the Commission's order in *Westar*,[48] on an annual basis describing the status of intra-hour scheduling in the region and in PSE's BAA, along with an assessment of whether the increased use of such scheduling (if it occurs) reduces the regulation burden on PSE. Any regional operating practices that reduce the regulation requirement of intermittent resources will be incorporated into the informational report.

9. Please explain Puget's use of 10-minute intervals to measure actual wind output.

RESPONSE:

[48] *See Westar* at P 43 ("we will require Westar to make an informational report on an annual basis … The annual informational report should include updated data.").

Mr. Reed described PSE's use of 10-minute intervals to measure actual wind output at pages 8-9 of his prepared direct testimony.[49] He explained that PSE has detailed, 4-second interval actual generation records for the Wild Horse wind plant extending back to 2006, and for the Vantage wind plant dating back to mid-2010. PSE aggregated the base 4-second data into 1-minute interval data, and Mr. Reed then aggregated the 1-minute data into 10-minute interval data for calendar year 2010.[50]

Mr. Reed's decision to use 10-minute interval data to measure the intra-hour variability of wind output was based primarily on the Resource and Demand Balancing ("BAL") Reliability Standards of the North American Electric Reliability Corporation ("NERC"). In particular, NERC Standard BAL-005-0 requires balancing authorities like PSE to maintain sufficient regulating reserves to balance their system,[51] while BAL-001-0.1a requires the actual balancing of supply and demand in real-time necessary for reliable operation of the grid. To avoid a violation of these requirements, PSE closely monitors the extent of its Area Control Error ("ACE") in real-time to rebalance supply and demand such that the compliance metric, known as Control Performance Standard-2 ("CPS-2") (the 12-month rolling average) will indicate compliance. Under CPS-2, PSE must maintain the balance between scheduled generation and actual generation output in its BAA such that its ACE does not exceed a certain percentage during at least 90 percent

[49] Exh. PSE-100, Testimony of Lloyd Reed at 8-9.

[50] *Id*.

[51] NERC Standards BAL-005-0.1b – Automatic Generation Control, *available at* http://www.nerc.om/files/BAL-005-0_1b.pdf.

of the 10-minute intervals of each month, on a rolling twelve-month average.[52]

The use of 10-minute intervals to measure the deviations between the actual generation output and scheduled output of generation and load is therefore consistent with NERC's performance metrics for balancing authorities. A less granular interval –30 minutes, for example – might not capture all relevant intermittent generator variability. For example, it is conceivable that a wind generator might ramp up to 15 MW above its scheduled output during the first 15 minutes of the 30 minute interval, and then ramp back down to its scheduled output during the second 15 minutes of the 30 minute interval. Measuring the output at 0 and 30 minutes would show zero variability, but NERC's CPS-2 criteria would have required PSE to provide 10 MW of decremental regulation capacity during the first 10 minutes, 5 MW of decremental and 5 MW of incremental capacity during the second 10 minutes, and 10 MW of incremental regulation capacity during the final 10 minutes of the 30 minute interval. Using 10-minute interval output data therefore better allows PSE to capture the variability that it must respond to under NERC's Reliability Standards. The use of 10-minute interval data is also consistent with the approach to measuring generation and load variability approved by the Commission in *Westar*.[53]

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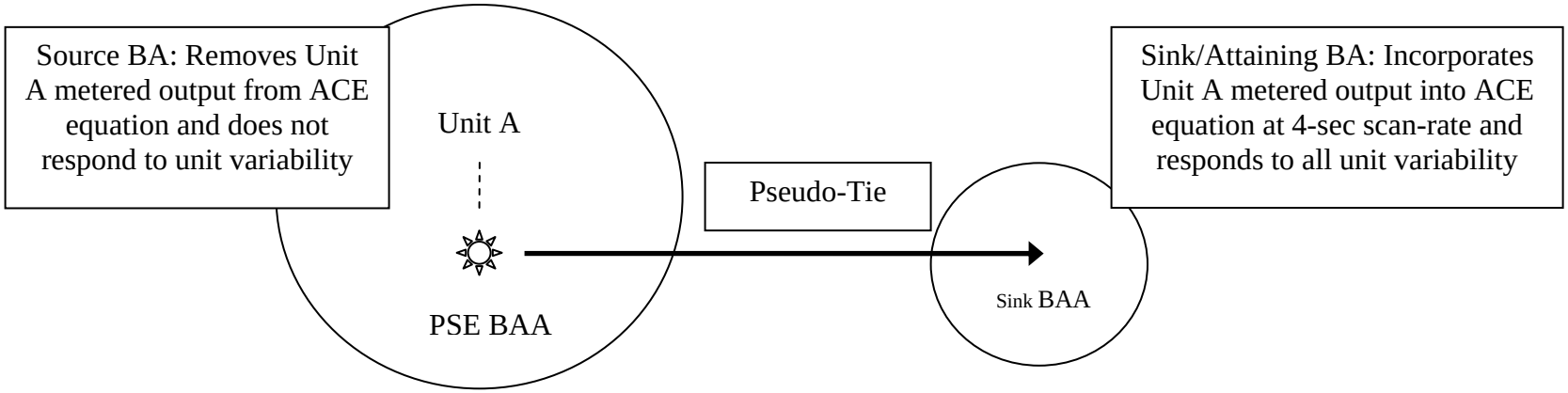
[52] See NERC Standards BAL-001-0.1a – Real Power Balancing Control Performance, *available at* http://www.nerc.com/files/BAL-001-0_1a.pdf.

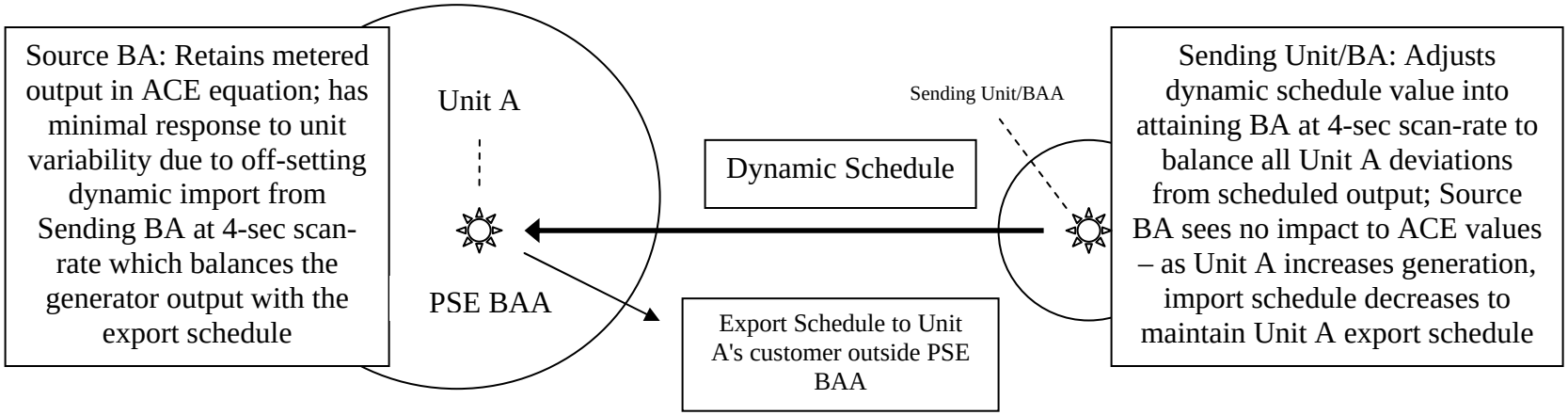
[53] See *Westar Energy, Inc.*, Docket No. ER09-1273, Response to Deficiency Letter, Supplemental Testimony of Paul A. Dietz at 10 (filed Jan. 19, 2010) ("We looked at the 10-minute instantaneous meter observations from Westar's Energy Management System ("EMS") that occurred during the study period for the five sources of variance discussed above and determined the deviation of that source for each interval.").

Appendix A – Schematic of Two Representative Dynamic Transfer Arrangements for the Self-Supply of Regulation Service.

Opt. 1: Pseudo-Tie Out



Opt. 2: Dynamic Schedule In



UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Puget Sound Energy, Inc.	)	Docket No. ER11-3735-000

PREPARED SUPPLEMENTAL DIRECT TESTIMONY OF
LLOYD C. REED
ON BEHALF OF PUGET SOUND ENERGY, INC.

SECTION I - INTRODUCTION

Q. Please state your name and business address.

A. Lloyd C. Reed, 10025 Heatherwood Lane, Highlands Ranch, Colorado 80126.

Q. Are you the same Lloyd Reed that previously testified in this matter?

A. Yes.

Q: What is the purpose of your supplemental testimony?

A: PSE asked me to perform two additional analyses to respond to concerns expressed in deficiency items 3 and 5 of the August 5, 2011 Letter of Deficiency that PSE received from the Commission Staff regarding PSE's June 6, 2011 proposed revisions to Schedule 3 and Schedule 13 of its open access transmission tariff in Docket No. ER11-3735-000. Specifically, PSE asked me to: (1) provide additional support demonstrating that the 2.0 percent purchase obligation still accurately captures the burden imposed on PSE's system by load (under Schedule 3) and by exporting dispatchable generators (under Schedule 13); and (2) to perform an updated PSE system-wide regulation analysis that incorporates additional historical data for PSE's dispatchable generation resources. I will first address

the issue of the existing 2.0% purchase obligation for load and dispatchable exports, and then I will address the updated PSE system-wide regulation requirement analysis.

SECTION II – SUPPLEMENTAL TESTIMONY IN SUPPORT OF RESPONSE TO DEFICIENCY ITEM 3

Q. How was the 2.0% regulation purchase obligation for load that is specified in PSE's currently effective Schedule 3 originally determined?

A. The 2.0% regulation purchase requirement was originally established in 1998 as part of a "black box" rate case settlement agreement ("Settlement Agreement") between PSE and the Commission Staff in Docket No. ER97-4468-000. The basis of the 2.0% figure was a computation performed by Staff witness Jerald A. Smith, dated February 18, 1998. Using hourly load data from calendar year 1996, Mr. Smith applied the following computational methodology, as described in his Direct Testimony, when computing the PSE regulation percentage:

Step 1: Calculate the absolute values of hour-to-hour load deviations using the Puget Sound's hourly load data provided in Puget Sound's response to Staff-57 (this information is in electronic format).

Step 2: Calculate the average of the deviations and divide the average by 2.

Step 3: Divide the number calculated in step 2 by Puget Sound's 12-CP load.

Step 4: Express the number calculated in step 3 as a percentage. Consider the percentage thus calculated as the percent of regulation reserve.

Q. What was the result of Mr. Smith's 1998 PSE regulation analysis?

A. Using 1996 load data and applying the methodology described above, Mr. Smith computed PSE's load regulation requirement to be 1.68%. This percentage was subsequently rounded up to 2.0% as part of the Settlement Agreement.

Q. In response to deficiency item 3.b., please explain whether the 2.0 percent purchase obligation in Schedule 3 is based on load deviations within the PSE balancing authority area ("BAA") or deviations of both load within the BAA and generation used to serve that load?

A. Mr. Smith's 1998 analysis was based solely upon deviations in load within the PSE Balancing Authority Area ("BAA") during calendar year 1996.

Q. Was the 2.0% figure also adopted for use in PSE's currently effective Schedule 13 for generation exports?

A. Yes. As part of a filing submitted to the Commission in Docket No. ER10-723-000, PSE proposed to adopt the 2.0% figure as the Schedule 13 regulation percentage for generation exports. The Commission accepted for filing PSE's proposed Schedule 13 tariff, including the 2.0% regulation percentage, on April 12, 2010.

Q. Have you performed an updated analysis in support of the existing 2.0% regulation percentage for load and dispatchable generation exports?

A. Yes. PSE asked me to perform a new analysis to confirm the reasonableness of this figure. I subsequently computed the regulation percentage using up-to-date PSE load data

from calendar year 2010 while employing the same computational methodology that was used by Mr. Smith in 1998 in his determination of the original 2.0% figure.

Q. What were the results of your updated analysis?

A. Using hourly PSE BAA load deviations from calendar year 2010 and employing the same methodology used by Mr. Smith in 1998, I determined the PSE load regulation percentage to be 1.54%. This result approximates Mr. Smith's originally computed load regulation percentage of 1.68%. Using the same rounding convention that was utilized in the 1998 Settlement Agreement, the updated 1.54% figure would be rounded up to 2.0%, which is the same regulation percentage as specified in PSE's currently in effect Schedules 3 and 13. I therefore conclude that the existing 2.0% load regulation percentage figure remains reasonable given the application of Mr. Smith's computational methodology. Details regarding my updated PSE load regulation analysis are included in the confidential work papers submitted in conjunction with my supplemental testimony.

Q. Is it possible to determine a regulation percentage to be applied to load and dispatchable generation under PSE's Schedules 3 and 13 using the same portfolio-wide approach that you used to determine the 16.77 percent purchase obligation for exporting intermittent generators, rather than the methodology employed by Mr. Smith to determine the 2.0% load regulation percentage in 1998?

A. Yes. In the *Westar* proceeding, witness Paul Dietz submitted supplemental testimony in response to a deficiency letter from Commission Staff in which he determined load and dispatchable resource regulation percentages based upon a system-wide approach that utilized a 95% confidence interval and that allocated system diversity benefits among the multiple sources of deviation within the Westar BAA.

Q. Have you performed a system-wide analysis similar to Westar's regulation study that could be used to determine the regulation percentages for load and dispatchable generating resources located within the PSE BAA?

A. Yes. The same analysis that I performed in support of PSE's proposed Schedule 13 intermittent resource regulation requirement of 16.77% could also be used to determine load and dispatchable generation regulation requirements. That analysis, described in detail in my direct testimony and supporting work papers, employed the same 95% confidence interval and system diversity allocation methodology that was used by Westar witness Paul Dietz in Westar's Schedule 3A proceeding. While the primary purpose of my direct testimony was to establish the regulation percentage to be applied to intermittent generating resources located within the PSE BAA, that same analysis could be used to determine regulation percentages for load and dispatchable generating resources as well.

Q. How can the results of your previous PSE system-wide regulation analysis be used to determine regulation percentages for load and dispatchable generating resources located within the PSE BAA?

A. One of the final steps in my previous PSE system-wide regulation analysis was to compute the 2010 annual regulation requirement, measured in megawatts, of the three main sources of deviation on the PSE system - load, intermittent generation, and dispatchable generation - while taking into account system diversity benefits. That computation resulted in the following regulation requirements: (1) Load – 45.34 MW, (2) intermittent generation – 49.72 MW, and (3) dispatchable generation – 11.20 MW. The 49.72 MW figure for intermittent generation was divided by the total installed capacity of

the wind plants located within the PSE BAA to arrive at the proposed Schedule 13 Wind Purchase Obligation percentage of 16.77%. Dividing the 45.34 MW load regulation figure by PSE's 12 month coincident peak load ("12-CP") would yield the load regulation percentage while dividing the 11.20 MW dispatchable plant figure by the total installed capacity of all dispatchable plants included in the study would yield the dispatchable plant regulation percentage.

Q. What is the result of the PSE load regulation percentage computation that you mention above?

A. Using the same hourly PSE BAA load data that I previously utilized in my original PSE system-wide regulation analysis, the 12-CP figure, based on calendar year 2010 load data, would be 3,742.6 MW. Dividing the PSE load regulation requirement of 45.34 MW by the 12-CP figure of 3,742.6 MW yields a load regulation percentage of 1.21%.

Q. Please describe the result of the PSE dispatchable plant regulation percentage computation that you performed?

A. Using the dispatchable plant generation data that I previously utilized in my original PSE system-wide regulation analysis, the total installed capacity of all dispatchable plants located within the PSE BAA (excluding those plants that are continuously operated on automatic generation control and therefore are not dispatched to a fixed set point) would be 2,947.8 MW. Dividing the dispatchable plant regulation requirement of 11.20 MW by the total installed capacity figure of 2,947.8 MW yields a dispatchable plant regulation percentage of 0.38**%.**

Q. Did PSE propose to modify its currently effective 2.0% regulation percentage for load and dispatchable plants under Schedules 3 and 13?

A. PSE did not propose to modify the currently effective 2.0% regulation requirement for load and dispatchable generating resources in its June 6, 2011 Schedule 3 & 13 tariff filing with the Commission. However, should the Commission wish to have PSE adapt Schedule 3 and 13 regulation percentages for load and dispatchable generator exports that are based on the same system-wide methodology that was used to develop the 16.77% regulation purchase obligation for exporting intermittent generators, it would be reasonable for the Commission to also adopt the 1.21% load regulation purchase obligation and the 0.38% dispatchable plant regulation purchase obligation. All three of these regulation purchase obligations were determined as part of an integrated system-wide PSE regulation study that equitably allocates system diversity benefits among the three sources of deviation within the PSE BAA, using the same allocation methodology as was employed by Westar.

SECTION III - SUPPLEMENTAL TESTIMONY IN SUPPORT OF RESPONSE TO DEFICIENCY ITEM 5

Q. In response to deficiency item 5, please describe how dispatchable generating plants were incorporated into your original PSE system-wide regulation analysis.

A. The PSE system-wide regulation analysis that I conducted in support of PSE's original June 6, 2011 Schedule 13 tariff filing incorporated three sources of regulation requirements on the PSE system: (1) load, (2) intermittent generating resources, and (3) dispatchable generating resources. As I described in my testimony, I was able to compute the regulation requirements of load and intermittent generating plants using readily available historical data, combined with a set of derived load and generation forecasts based upon 60-minute persistence. However, for the dispatchable plant category, I found

that deriving a set of historical hour-ahead forecasts for these plants was problematic given that PSE generally did not maintain records of the next-hour and within-the-hour dispatch points for its dispatchable plants. Unlike Westar, PSE does not receive dispatch instructions from a third party operator that might be used to determine a dispatchable plant's next hour generation forecast. All plants within PSE's BAA, except for two third-party plants, are adjusted in real time to meet system or unit needs from temperature to fuel delivery to load requirements and there has not been a reason to date to track all of the within-hour or next-hour changes from day-ahead operating plans.

Q. Given the data issue that you describe above, how did you incorporate PSE's dispatchable plants into your original PSE system-wide regulation analysis?

A. Due to the lack of historical dispatch instruction data, I chose to simplify the process by analyzing in detail two representative plants from each of the three classes of dispatchable plants that PSE operates. The representative plants were: 1) Colstrip 1&2 and Colstrip 3&4 (coal-fired steam plants), 2) Goldendale and Sumas (gas-fired CCCTs and CTs), and 3) Upper Baker and Lower Baker (hydroelectric). I then acquired 2010 1-minute historical generation data for these six plants from PSE and analyzed this data to determine the periods when the plants were either being operated in a steady-state mode (*i.e.* flat dispatch across an hour) or when the plants were being intentionally ramped up or down or had experienced a forced outage event. From this analysis, I then derived a set of 60-minute persistence forecasts that incorporated the impacts of intentional ramping events and forced outages. I next computed the stand alone regulation requirement for each of the six representative plants by comparing the next-hour forecasts against the plant's actual generation. The computed regulation requirements for each of

the three categories of plants were then scaled up on an hourly basis so that the final dispatchable plant regulation requirement used in the system-wide regulation study reflected all of PSE's dispatchable plants.

Q. Deficiency item five suggests that PSE "exclude[d] part of its dispatchable generation fleet from its calculations of deviations for determining the intermittent purchase obligation." Is this characterization accurate?

A. No. My original PSE system-wide regulation study incorporated the impacts of all of PSE's dispatchable plants. The scaling process was used to reasonably simplify the inclusion of dispatchable plants in the system-wide regulation study given the aforementioned data availability issue. As I described above, the stand-alone regulation requirements of the six representative plants were scaled up from a total of 12.86 MW to 18.05 MW to reflect PSE's overall dispatchable plant regulation requirement. The PSE dispatchable plants that were continuously operated on AGC during 2010 were *supplying* regulating capacity rather than *using* regulation capacity; therefore, those plants were appropriately not included in the scaling process.

Q. To respond to the concern expressed in deficiency item 5, have you performed a new "portfolio-wide" study using historical data from substantially all of PSE dispatchable generating plants?

A. Yes. In response to deficiency item five, I have expanded my study of dispatchable plants in the original system-wide regulation study in order to demonstrate that the original scaling process resulted in a reasonable result. Using PSE's historical 2010 1-minute generation data for seven additional dispatchable plants, I incorporated this data into an updated PSE system-wide regulation analysis. With the addition of the seven new plants,

on top of the six dispatchable plants that were included in my original analysis, the updated analysis incorporated a set of plants that accounted for approximately 97% of the actual generation from all of the dispatchable plants that were electrically located within the PSE BAA during calendar year 2010.[1] The updated analysis, therefore, did not utilize any scaling factors.

Q. What were the results of your updated PSE system-wide regulation analysis that incorporated historical data for the seven additional dispatchable plants?

A. In the updated analysis that incorporated historical data for the seven additional dispatchable plants, PSE's overall system-wide regulation requirement was determined to be 106.02 MW. This compares to a 106.27 MW overall regulation requirement from my original study. The updated Wind Purchase Obligation percentage was determined to be 17.15%, which compares to 16.77% from my original analysis. These results confirm the reasonableness of the proposed 16.77% Wind Purchase Obligation, which was derived using the six representative dispatchable plants and the use of scaling factors. Details regarding my updated PSE system-wide regulation analysis are included in the confidential work papers submitted in conjunction with my supplemental testimony

Q. Does this conclude your supplemental testimony?

A. Yes.

[1] The remaining 3% (two thermal units, five small hydro units, and four simple cycle combustion turbines) were excluded because of their small size and very low load factors. A sensitivity analysis demonstrated that including these plants in the system-wide PSE regulation study would have had virtually no impact on the MW magnitude of PSE's regulation requirement.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Puget Sound Energy, Inc.	)	**Docket No. ER11-3735-000**

AFFIDAVIT OF LLOYD C. REED

Lloyd C. Reed, being first duly sworn, deposes and states that he is the Lloyd Reed referred to in the document entitled "Prepared Supplemental Direct Testimony of Lloyd C. Reed on Behalf of Puget Sound Energy, Inc.," that any exhibits accompanying that document were prepared by him or under his direction, that he has read such testimony and is familiar with the contents thereof, and that the facts set forth therein are true and correct to the best of his knowledge, information and belief in this proceeding.

Lloyd C. Reed

SUBSCRIBED AND SWORN TO before me, the undersigned notary public, this 25th day of August, 2011.

Notary Public

My Commission Expires: APRIL 15 2012

LIZ REICHERT NOTARY PUBLIC STATE OF COLORADO

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused to be served the foregoing document upon all parties on the official service list compiled by the Secretary of the Commission in this proceeding.

Dated at Washington, D.C., this 25th day of August, 2011.

*/s/ Justin P. Moeller*_____

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