137 FERC ¶ 61,063
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

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

ORDER ACCEPTING AND SUSPENDING PROPOSED TARIFF REVISIONS, SUBJECT TO REFUND, AND ESTABLISHING HEARING AND SETTLEMENT JUDGE PROCEDURES

(Issued October 20, 2011)

1. On June 6, 2011, Puget Sound Energy, Inc. (Puget) filed revisions to its Open Access Transmission Tariff (OATT) Schedule 3 (Regulation and Frequency Response Service) and Schedule 13 (Regulation and Frequency Response Service for Generators Selling Outside of Control Area). Puget proposes to update the capacity rate for regulation and frequency response service under both schedules from the $5.50/kW-month capacity charge established in a black box settlement in 1998 to $12.39/kW-month. Puget also proposes to require intermittent/non-dispatchable generators exporting power from Puget's balancing authority area (BAA) to purchase an amount of regulation capacity equal to 16.77 percent of the customer's transmission reservation to reflect the regulation burden created by intermittent/non-dispatchable generators. In this order, the Commission accepts Puget's proposed Schedules 3 and 13, and suspends them for a five-month period, to become effective January 5, 2012, subject to refund. We also establish hearing and settlement judge procedures.

I. **Background**

2. Puget owns a high voltage transmission system in the state of Washington and provides service over its transmission system pursuant to its OATT. Puget also operates a BAA in which Puget anticipates significant development of wind resources, both to serve its own native load and for export to California. Puget asserts that, as of the date of this filing, there is approximately 377 MW of additional wind generation capacity in Puget's interconnection queue.

3. Puget notes that, as a balancing area operator, it is subject to the North American Electric Reliability Corporation's (NERC) Reliability Standards, including standards requiring Puget to continuously balance the output of generators to the load in its BAA. Puget states that the variable nature of wind and other intermittent/non-dispatchable generation resources strains a transmission system in ways that dispatchable generation does not. Puget claims that it must maintain significantly higher amounts of regulation reserves than the two percent of capacity currently required under Schedule 13 in order to balance the within-hour deviations of wind generation.

II. Puget's Filing

4. Puget proposes to update the capacity rate for regulation and frequency response service under Schedules 3 and 13 from the $5.50/kW-month capacity charge established in a black box settlement in 1998 to $12.39/kW-month. Puget also proposes to require intermittent/non-dispatchable generators exporting power from Puget's BAA to purchase an amount of regulation capacity equal to 16.77 percent of the customer's transmission reservation to reflect the regulation burden created by intermittent/non-dispatchable generators. Puget has not proposed a change in the purchase obligation for load and for exporting dispatchable generation resources, which would remain at two percent of the customer's transmission reservation.

5. Puget contends that the current $5.50/kW-month capacity charge no longer reflects the cost of regulation capacity because the pool of generation resources used for within-the-hour regulation service has expanded since 1998 due to constraints on the availability of Puget's hydroelectric generation and increased system variability because of wind generation. Puget claims the variability of wind generation has required Puget to reserve a larger volume of regulation reserves for intermittent/non-dispatchable generation than is required for dispatchable generation. Additionally, Puget asserts that the cost of capacity from Puget's pool of regulation resources has increased due to changes in operations and maintenance costs, increased purchase costs for Mid-Columbia hydroelectric power, and the introduction of new combined cycle generation resources into the regulation resource pool.

6. To calculate the proposed capacity charge under Schedules 3 and 13, Puget states that it uses the costs of eight generation resources that are employed on a regular basis to provide regulation capacity (i.e., the regulation resource pool). Puget explains that the annual weighted average cost of each resource in the regulation resource pool is determined by dividing the capacity of the resource by the total capacity of the pool and then multiplying that fraction by the cost in $/kW-year for that unit. Puget adds that the proposed $12.39/kW-month weighted average cost is determined by summing the annual weighted cost of each resource in the regulation resource pool and dividing the total by twelve.

7. Puget states that, to determine the costs for each resource, it uses calendar year 2011 projected Period II data (based on Puget's budgeted costs for 2011) as a test period. Puget notes that it developed the revenue requirements using Puget's actual capital structure (48 percent equity—52 percent debt) and a proposed 11.6 percent return on equity (ROE).[1] Additionally, Puget includes acquisition adjustments in two of the resources' respective revenue requirements, totaling $234 million, on a gross basis.

8. Puget states that it calculated the 16.77 percent purchase obligation for intermittent/non-dispatchable resources by using a methodology that is consistent with the approach that the Commission approved for calculating a differential regulation charge for wind resources in *Westar*.[2] According to Puget, it modified the *Westar* methodology to recognize the different market structures in the Pacific Northwest and the Southwest Power Pool (SPP).

9. Puget's methodology first compares actual wind output (in 10-minute intervals) to hourly schedules (taken as the actual output at the beginning of the previous hour) for wind plants within Puget's BAA. Puget states that 10-minute deviations from schedule are calculated as well as similar deviations for load and dispatchable generators. Puget then determines stand-alone regulation requirements to manage the within-hour variation from each source in isolation (wind, load, and dispatchable generation) using statistical analysis.[3] Puget explains that the intermittent/non-dispatchable purchase obligation is determined by dividing an adjusted regulation requirement for wind (scaled to adjust for diversity benefits between load, wind and dispatchable generator variability) by the total installed capacity of wind plants in Puget's BAA.[4]

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[1] *See* Puget June 6, 2011 Transmittal Letter at 10 (Transmittal Letter).

[2] *Westar Energy, Inc.*, 130 FERC ¶ 61,215 (2010) (*Westar*).

[3] Puget notes that the stand-alone regulation requirement amounts are determined from 95 percent confidence intervals around the expected differences between 10-minute actual and hourly scheduled MW values for wind, dispatchable generators and load. Puget indicates that this amount represents the regulation requirement to manage within-hour variations from each source in isolation from the rest of the system. *See* Lloyd C. Reed Testimony at 22-23 (Reed Testimony).

[4] Puget explains that, to adjust for diversity benefits, a system diversity ratio is determined by calculating a combined "portfolio-wide" within-hour regulation requirement that simultaneously accounts for load, wind and dispatchable generator deviations and dividing this figure by the sum of the stand-alone regulation requirements for load, wind and dispatchable generators. Puget states that this ratio is 0.637. Puget

(continued …)

10. Puget notes that its methodology for calculating wind generator deviations differs from Westar's. Puget explains that, while Westar calculated scheduled vs. actual output deviations using differences between 10-minute actual output and 10-minute persistence forecasts (i.e., actual output from the beginning of the previous 10 minute interval), Puget calculates deviations between 10-minute actual output and proxy 60-minute persistence forecasts (i.e., output from the beginning of the previous hour). Puget argues that its use of 60-minute persistence forecasts is reasonable because the Pacific Northwest operates in an hourly scheduled, bilaterally traded market structure, while generators in SPP are given new dispatch signals every 10 minutes.[5]

11. On August 5, 2011, Commission staff issued a deficiency letter requesting further information regarding Puget's filing, as discussed below.

III. Notice of Filings and Responsive Pleadings

12. Notice of Puget's filing was published in the *Federal Register*, 76 Fed. Reg. 34,223 (2011), with interventions or protests due on or before June 27, 2011. On June 16, 2011, the American Wind Energy Association (AWEA) and the Renewable Northwest Project (RNP)[6] jointly filed a motion for extension of time to file motions to intervene, comments, and protests. On June 21, 2011, the Commission granted the extension of time to and including July 5, 2011. Avista Corporation, Bonneville Power Administration (Bonneville), and NextEra Energy Resources, LLC filed timely motions to intervene. AWEA, Invenergy Wind North America LLC (Invenergy), the Northwest and Intermountain Power Producers Coalition (NIPPC), and Pacific Gas and Electric Company (PG&E) filed timely motions to intervene and protests. The Large Public Power Council (LPPC),[7] Powerex Corp. (Powerex), and the Public Generating Pool (PGP)[8] filed timely motions to intervene and comments. Puget filed an answer.

13. Notice of Puget's response to the deficiency letter was published in the *Federal Register*, 76 Fed. Reg. 56,747 (2011), with interventions or protests due on or before

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adds that the system diversity benefit is allocated to wind by multiplying the ratio by the stand-alone regulation requirement for wind. *See* Reed Testimony at 28-31.

[5] *See* Transmittal Letter at 11-12.

[6] For the purposes of this order, we will refer to these joint filers as "AWEA."

[7] LPPC is an association of 25 municipal and state-owned utilities.

[8] PGP is comprised of ten consumer-owned electric utilities.

September 15, 2011. AWEA, Invenergy and PG&E filed timely comments. Powerex filed comments out of time. Puget filed an answer.

A. Comments and Protests

14. LPPC and PGP support Puget's effort to revise its tariff to allow Puget to reflect the full costs of balancing wind resources on its system. LPPC believes Puget's approach is consistent with recent Commission direction regarding recovery of regulation service costs, including *Westar*.[9] PGP argues that Puget's proposal is consistent with cost causation principles because exporting intermittent/non-dispatchable generators are likely to pass the additional regulation service costs through to the end-use customers and those customers will cause and/or benefit from the required increase in regulation service.[10]

15. AWEA argues that Puget should not rely upon *Westar* as precedent because: (1) Puget's proposal is not an interim measure; (2) there is no foreseeable creation of a unified balancing area and ancillary services market that would obviate the need for such a charge; and (3) Westar's transmission customers have the ability to schedule transmission at 5-minute intervals through the SPP energy imbalance market.[11] NIPPC and PG&E also point out that the permanent nature of Puget's proposed Schedule 13 renders reliance on *Westar* inappropriate. They also complain that Puget does not commit to provide annual reports or an updated filing after three years.[12] NIPPC believes that Puget's proposal should be an interim measure, subject to the availability of an imbalance market.[13] Invenergy also argues that there are significant differences between Puget's proposal and the proposal accepted in Westar (e.g., SPP was implementing significant reforms to reduce regulation capacity requirements; SPP operates a 5-minute energy imbalance market; and, in Westar, the differential between the regulation capacity obligation for intermittent/non-dispatchable and conventional generators was significantly less than Puget's proposal).

16. AWEA argues that Puget's Schedule 13 charge is unjust and unreasonable because Puget has not enacted grid operating reforms to reduce the proposed charge (such as the

[9] LPPC Comments at 2-3 (citing *Westar*, 130 FERC ¶ 61,215 at P 35-36; *Puget Sound Energy*, 132 FERC ¶ 61,128, at P 34 (2010)); *see also* PGP Comments at 3-5.

[10] PGP Comments at 3-5.

[11] AWEA Protest at 10-13.

[12] NIPPC Protest at 4, 12; PG&E Protest at 4-5.

[13] NIPPC Protest at 5.

ability for customers to change schedules on an intra-hourly basis; implementation of a wind energy forecast program; and use of that forecast to minimize the amount of regulation capacity procured based on actual system conditions).[14] To support its argument, AWEA points to the Commission's notice of proposed rulemaking regarding integration of variable energy resources (VER NOPR) and data from an Avista Wind Integration Study and a National Renewable Energy Laboratory study.[15] AWEA claims that its analysis confirms that obsolete grid operating practices alone have increased Puget's calculated regulation charge beyond what it would have been if sub-hourly scheduling were in place.[16] AWEA, NIPPC, and Invenergy argue that failure to implement intra-hourly transmission scheduling at intervals of less than 15 minutes will result in regulation charges that are excessive and not just and reasonable for many different types of transmission customers.[17]

17. NIPPC disagrees with Puget's assertion that it cannot implement intra-hour scheduling because it is not practiced in the Pacific Northwest. NIPPC points out that: Bonneville has implemented 30-minute scheduling; ColumbiaGrid is developing (with Northern Tier Transmission Group and West Connect) the Joint Initiative for Intra-Hour Transaction Accelerator Platform; and Puget has adopted an intra-hour scheduling business practice.[18] Similarly, AWEA claims that Puget's proposed regulation charge is

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[14] AWEA Protest at 2-3.

[15] *Id.* at 4-6 (citing *Integration of Variable Energy Resources*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,664, at P 22-25, 31, 34-35, n.95 (2010) (VER NOPR)); n.11 (citing Avista Corp., *Wind Integration Study* at 48 (2007), *available at* http://www.uwig.org/AvistaWindIntegrationStudy.pdf); n.12 (citing Milligan, Kirby, King, Beuning (2011), "Operating Reserve Implication of Alternative Implementations of an Energy Imbalance Service on Wind Integration in the Western Interconnection," NREL Technical Report, as presented at UWIG Spring Meeting, April 2011). *See also id.* at 8 (citing Increasing Renewable Resources: How ISOs and RTOs Are Helping Meet This Public Policy Objective, ISO/RTO Council (Oct. 16, 2007), *available at* http://www.isorto.org/atf/cf/%7B5B4E85C6-7EAC-40A0-8DC3-003829518EBD%7D/IRC_RENEWABLES_REPORT_101607_FINAL.pdf).

[16] *Id*. at 12-13.

[17] AWEA Protest at 9-10 (citing VER NOPR, FERC Stats. & Regs. ¶ 32,664 at P 31, 33); NIPPC Protest at 8; Invenergy Protest at 5.

[18] NIPPC Protest at 6-7.

excessive because it assumes hourly scheduling intervals instead of the 30-minute scheduling intervals that may be in effect in Puget's business practices or OATT.[19]

18. Powerex states that it supports Puget's response to the deficiency letter regarding intra-hour scheduling. Although Powerex agrees that mandatory use of intra-hour schedule adjustment practices should reduce a transmission provider's regulation burden, Powerex argues that Puget's regulation burden will not be reduced until it knows whether, or to what extent, its customers will use intra-hour scheduling. Powerex explains that, if a transmission provider does not know whether its customers will submit intra-hour schedules, it cannot decrease the amount of regulation reserves it holds for those customers and cannot correspondingly decrease its costs.

19. As for wind energy forecasting, AWEA contends that, because utility transmission providers have implemented their own wind energy forecasting programs, Puget has no compelling reason not to do so.[20] NIPPC and Invenergy argue that the Commission should not accept Puget's proposed Schedule 13 until Puget has implemented power production forecasting to ensure that regulation capacity is procured efficiently.[21]

20. AWEA asserts that Puget's proposal does not assign conventional generators their full integration costs.[22] AWEA states that integration costs include the cost of contingency reserves, power system inefficiency that results from variability and uncertainty in natural gas markets being passed through to the electricity system as a result of inflexibility in the natural gas purchasing process, and increased ramping and cycling requirements imposed by inflexible baseload generators. AWEA argues that large conventional generators do not pay the cost of maintaining the contingency reserves (under Schedules 5 and 6 under the OATT) that are needed to maintain grid reliability in the event that one of those conventional generators trips offline. AWEA asks the Commission to require Puget to assign non-Schedule 13 integration costs to the

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[19] AWEA Protest at 14-15 (citing Bonneville, "Intra-Hour Scheduling: Transmission Provider Discussion," Apr. 13, 2011, *available at* http://transmission.bpa.gov/customer_forums/bpa_oatt/documents/intra-hour_scheduling.pdf).

[20] *Id*. at 8 (citing Porter, K. and J. Rogers. 2010. *Status of Centralized Wind Power Forecasting in North America*. NREL/SR-550-47853. Golden, CO: National Renewable Energy Laboratory).

[21] NIPPC Protest at 9; Invenergy Protest at 5.

[22] AWEA Protest at 15-19.

generators that cause them. AWEA also asks the Commission to pursue this issue on a generic level (via technical conference and/or rulemaking) to ensure that integration costs are allocated in a non-discriminatory manner.[23]

21. AWEA contends that Puget's proposal should be rejected or, in the alternative, suspended for the maximum five-month period subject to hearing and hold the hearing and settlement judge procedures in abeyance to give the parties the opportunity to resolve the issues through informal settlement discovery before a Commission-appointed administrative law judge.[24]

1. Self-Supply Option

22. AWEA argues that transmission customers should be given the option to self-supply reserves at a lower cost than Puget proposes to charge them. AWEA asserts that denying transmission customers this option would inhibit competition on the power system, cause the inefficient operation of the power system, and impose costs that are not just and reasonable.[25] NIPPC contends that, to enable self-supply, the Commission should require Puget to publish procedures and technical requirements for dynamic scheduling.[26]

23. Similarly, Powerex contends that Puget should: (1) specify the types of arrangements Puget will consider as "alternative comparable arrangements" under Schedules 3 and 13 and (2) provide transparent and non-discriminatory rules and procedures for establishing dynamic transfer limits and for allocating dynamic scheduling capability.

2. Curtailment

24. PG&E states that Puget's proposed tariff language is unclear as to whether exporting generators that have paid the new regulation service charges will be curtailed "to the extent necessary to maintain system reliability" rather than "to the extent it is physically feasible to provide regulation service from Puget's resources or from resources available to it," as contemplated by the Commission in the VER NOPR.[27] PG&E seeks

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[23] *Id.* at 19.

[24] AWEA Protest at 9.

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

[26] NIPPC Protest at 11.

[27] *Id.* at 7 (citing VER NOPR, FERC Stats. & Regs. ¶ 32,664 at P 21).

additional information to determine whether wind resources that pay the Schedule 13 regulation service charge may still be subject to curtailment and Puget's estimated magnitude and frequency of such curtailments.[28]

25. If wind generators in Puget's BAA are subject to curtailment in these circumstances, Powerex argues that the portion of their output that is curtailable must be e-tagged using an "interruptible" or "non-firm" generation product code to ensure that the sinking balancing authorities know the energy they are receiving may be curtailed and can make the necessary planning decisions to maintain reliability.[29]

3. Methodology for Determining the Differential Impact Attributed to Intermittent/Non-dispatchable Generation

26. AWEA and Invenergy argue that Puget's proposed 16.77 percent regulation capacity obligation substantially overstates the amount of regulation capacity that Puget is required to maintain because: (1) Puget excludes hours from its calculation of deviations between actual and scheduled output for dispatchable generators and half of its generation fleet from its calculations of deviations for dispatchable generators; (2) Puget compares the actual output of dispatchable generators to fictitious ramped hourly schedules, which understates their regulation burden; (3) Puget does not provide enough data to evaluate the scaling methods used to calculate regulation burden imposed by dispatchable generators; and (4) data from the Vantage plant are based on only three months of operational data and corresponds to a startup period in which variability may be higher.[30]

27. AWEA and Invenergy contend that Puget created arbitrary groupings of resources in its calculation of the intermittent/non-dispatchable purchase obligation, which leads to significantly larger charges for resources placed into smaller groups, such as wind. AWEA and Invenergy suggest that, instead, Puget should calculate the regulation burden with and without the wind resources in order to determine the incremental variability impacts.[31]

28. AWEA contends that Puget's proposed "portfolio-wide" methodology is portfolio-wide in name only and that the Commission should find that it fails to take into account

[28] *Id*. at 9.

[29] Powerex Comments at 6.

[30] AWEA Protest (referencing Kirby Aff.); Invenergy Protest at 7-8.

[31] AWEA Protest (referencing Kirby Aff.); Invenergy Protest at 7.

the diversity in deviations among all system resources and load. AWEA argues that, because Puget's calculation of regulation burden and costs are allocated according to the stand-alone variability of each group, the flaws that the Commission identified in Westar's stand-alone methodology are also present in Puget's proposed methodology.[32]

29. PG&E contends that Puget needs to provide additional information regarding how load and import/export generation will be charged for the regulation service they require. PG&E is concerned that Puget has allocated capacity costs to dispatchable plants based only upon the "steady-state mode" operation of those plants, which excludes forced outages, without similarly excluding forced outages from the calculation of regulation needs for intermittent/non-dispatchable generation.

30. PG&E states that it cannot independently verify some of the calculations included in testimony and requires additional information to do so. For example, PG&E asserts that it cannot verify the 296.41 MW of installed wind capacity used to calculate the purchase obligation under Schedule 13.[33] PG&E also asserts that, using Puget's data provided in the original filing, it estimated a need for flexible capacity of 317 MW for Puget's load, which is different than the 71 MW that Puget calculated.

31. PG&E argues that Puget calculated the regulation requirements by creating a 60-minute persistence forecast for wind generation and then compared it against actual generation. PG&E points out that Puget admits in its deficiency response that because Puget did not have historic scheduling records for its dispatchable facilities, it had to create data to determine the regulation needs of these resources. PG&E asserts that, without actual historic schedules and forecasts, it is difficult to tell whether the deviations are a good proxy for the actual deviations.

32. Powerex argues that Puget should modify its proposed charges under Schedules 3 and 13 to require transmission customers to procure reserves commensurate with the generator's on-line nameplate capacity, rather than the customer's reserved point-to-point transmission capacity.[34] Powerex supports the use of nameplate capacity because transmission customers may reserve transmission capacity in excess of the amount they ultimately use, which may not be consistent with cost causation principles.

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[32] AWEA Protest at 20-21.

[33] PG&E Protest at 11-12 (citing Reed Testimony at 31:16).

[34] Powerex Comments at 8.

4. Derivation of the Regulation Capacity Charge

33. NIPPC and AWEA assert that Puget has not provided testimony or evidence that the eight resources included in its generator regulation costs will actually provide generator regulation service or that these resources are on automatic generation control, which is required to provide such service. NIPPC contends that, without this information, it is not possible to discern the true cost Puget incurs in providing generator regulation service. NIPPC states that Puget could be relying on its own hydro generation and short-term purchases of low-cost Mid-Columbia power to provide generator regulation service.[35]

34. AWEA argues that Puget may be overstating the cost of providing regulation service by giving too much weight to high cost resources that are infrequently used to provide regulation service and/or giving too little weight to low cost resources that are more frequently used to provide regulation.[36] Invenergy also argues that Puget is not using the correct pool of generation resources to calculate its cost of service and that resources should be weighted based on their actual use in providing regulation service rather than their net plant capability.[37]

35. Invenergy asserts that Puget included $140 million in regulatory asset costs in the calculation of the revenue requirement for a number of generating resources used in the determination of its Schedule 3 and 13 rates that should only be included in Puget's retail rates and not in its Schedule 3 and 13 rates. Furthermore, Invenergy contends that Puget included acquisition adjustments for two of its generating resources without justifying their inclusion, and that Puget's proposed 11.6 percent return on equity appears to be excessive.[38]

36. PG&E argues that Puget's use of the total fixed revenue requirements for a specific set of resources as a proxy for determining regulation cost does not appear to account for the fact that resources in Puget's balancing authority area provide multiple functions. PG&E asserts that the risk of duplicative recovery exists if the benefits to Puget's native load and generation from units assumed to provide regulation service are not considered when estimating the proposed regulation charge. PG&E states that it

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[35] NIPPC Protest at 13.

[36] AWEA Protest (referencing Kirby Aff.).

[37] Invenergy Protest at 11-12.

[38] *Id*. at 14-16, 18.

seeks to evaluate whether the generation capacity costs proposed for collection under Schedule 13 are separate, distinct, and incremental from the capacity costs collected from Puget's native load customers.[39]

5. <u>Undue Discrimination</u>

37. NIPPC and PG&E argue that Puget's proposal gives preferential treatment to intermittent/non-dispatchable generators that sink in Puget's BAA because these generators pay for regulation service under Schedule 3 with a billing determinant of two percent of reserved transmission service, while exporting intermittent/non-dispatchable generators must take regulation service under Schedule 13 with a billing determinant of 16.77 percent of reserved transmission service.[40] Invenergy asserts that Puget's proposed rate under Schedule 13 will have zero impact on Puget but an enormous impact on wind generators exporting from Puget's BAA. PG&E is also concerned that Puget's proposal could result in undue discrimination because only exporting intermittent/non-dispatchable generators are subject to the differential charge under Schedule 13.[41]

B. <u>Puget's Answers</u>

38. Puget argues that the Commission should not impose a five-month suspension because protestors have not shown that 10 percent or more of Puget's proposed regulation capacity rate increase is excessive.[42] Puget adds that such a suspension would be contrary to Commission precedent because it would lead to inequitable results by denying Puget legitimate cost recovery during the five-month suspension.[43]

39. Puget notes that the VER NOPR proposals requiring transmission-owning utilities to adopt voluntary 15-minute scheduling protocols, implement centralized generation forecasting, and collect a year's worth of generator output data with these practices in place before filing for differentiated generator regulation rates are preliminary and do not

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[39] PG&E Protest at 8-9.

[40] NIPPC Protest at 15; PG&E Protest at 10.

[41] PG&E Protest at 7.

[42] Puget Answer at 3 (citing *W. Tex. Utils. Co.*, 18 FERC ¶ 61,189 (1982); *see also Midwest Indep. Transmission Sys. Operator, Inc.*, 134 FERC ¶ 61,242, at P 26 (2011); *N. States Power Co.*, 131 FERC ¶ 61,188, at P 36 & n.7 (2010)).

[43] *Id*. at 4 (citing *Allegheny Power Sys. Operating Cos.*, 111 FERC ¶ 61,308, at P 51 (2005)).

disturb the Commission's existing practice of considering utilities' proposals to recover generator regulation service costs on a case-by-case basis.[44] Puget contends that, as in *Westar*, the issue before the Commission is not regional reforms but whether Puget's proposal is just and reasonable.[45]

40. Puget argues that calculating the true incremental system impact of wind generation would unfairly assign all the benefits of offsetting system variability to wind generation and not to other resources of variability on the system like load and dispatchable generation. Puget notes that, in *Westar*, the Commission found that the "portfolio-wide approach appropriately shares the diversity benefits among generators and load, and does not inappropriately allocate costs to any one customer."[46]

41. Puget disagrees with AWEA's objection to the manner in which Puget determined the dispatchable component of its system variability.[47] Puget argues that excluding the ramping periods of dispatchable generators does not assume, as suggested, that there is no regulation burden associated with dispatchable generators during this period. Puget contends that, instead, it appropriately assumes that the regulation burden during ramping periods is the same as that during steady state operation (i.e., that the generator is meeting its dispatch instructions during ramping periods with the same accuracy as it does during steady state operation).[48] Puget adds that the exclusion of forced outage periods from the assessment of the dispatchable regulation requirement is appropriate because forced outages trigger contingency reserves and therefore do not need to be managed with regulation service. Puget explains that no adjustments for forced outages on wind plants were made in the computation of the wind regulation requirement because there were no high speed cutout events at the Wild Horse facility during calendar year 2010 or at the Vantage plant during the October – December 2010 period that would have qualified for use of Puget's contingency reserves.[49]

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[44] *Id*. at 6.

[45] *Id.* at 7 (citing *Westar*, 130 FERC ¶ 61,215 at P 42).

[46] *Id*. at 14 (quoting *Westar*, 130 FERC ¶ 61,215 at P 37).

[47] *Id.* at 17 (citing Kirby Aff. at 2-3).

[48] *Id*. at 17.

[49] *Id*. at 17-18 (citing Reed Testimony at 26-27).

42. Puget disagrees that it should not have included $142,547,560 in regulatory assets related to the Rock Island and Rocky Reach PPA in its rate base.[50] Puget states that the regulatory assets are directly attributable to and reflect the actual fixed costs of purchasing the capacity under the PPA, the prudence and accounting treatment of which was approved by the Washington Utilities and Transportation Commission (Washington Commission).

43. Puget argues that it is also appropriate to include the net positive acquisition adjustments in its revenue requirement totaling $234 million related to the acquisition of the Mint Farm and Encogen generation facilities.[51] Puget disagrees with Invenergy's suggestion to pass along to ratepayers the benefits of the bargain purchase of the Goldendale and Sumas facilities collectively for $205 million less than book value and the associated negative acquisition adjustments, while denying Puget cost recovery of the positive acquisition adjustments associated with the more costly purchases of Mint Farm and Encogen.[52]

44. Puget challenges as specious Invenergy's objection to its proposal to recover an 11.6 percent ROE because Puget recently filed a retail rate proposal with the Washington Utilities and Transportation Commission (Washington Commission) seeking an ROE of 10.8 percent. Puget explains that the reason for the discrepancy between the two amounts is that the Washington Commission and the Commission use different rate-setting methodologies to determine ROE.[53]

45. Puget argues that it is not unduly discriminatory for it to impose a differentiated purchase obligation on generators exporting wind generation but not on wind generation that sinks in Puget's BAA. Puget claims that its proposed revisions to Schedules 3 and 13 followed as closely as possible the Commission-accepted tariff provisions set forth in Westar's accepted Schedule 3A, which imposed a generator regulation charge on generator exports but not generation sinking in Westar's control area.[54]

46. Puget states that it will not curtail any generator (wind or otherwise) for economic reasons. Puget explains that, to the extent there is a shortfall of reserves identified by the

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[50] *Id.* at 22 (citing Invenergy Protest at 14-15).

[51] *Id*. at 23 (citing Invenergy Protest at 15-16).

[52] *Id*. at 24.

[53] *Id*. at 25.

[54] *Id*. at 26 (citing *Westar*, 130 FERC ¶ 61,215 at P 35).

reliability coordinator, all Puget transmission customers (whether load, wind, third party wind, or dispatchable generation) will be treated on a non-discriminatory basis to the extent practicable and consistent with Good Utility Practice. While Puget does not expect it to happen, it argues that curtailment for reliability reasons must be an option available to the system operator if and when the reliability of the system is in jeopardy.[55] Puget states that, unlike Bonneville's current (and proposed WP-12 rate case) wind balancing service, Puget is not proposing to limit the amount of regulation service that it makes available to wind plants to any pre-determined MW amount. Puget also notes that it currently allows exporting wind plant schedules to be tagged as "firm" pursuant to current Western Electricity Coordinating Council scheduling procedures.[56]

47. Puget explains that Schedules 3 and 13 require the transmission customer to either purchase regulation service from Puget or "make alternative comparable arrangements."[57] Puget states that the "alternative comparable arrangement" provision existed prior to Puget filing and was not modified because Puget does not believe the necessary arrangements lend themselves at this time to a more definitive statement or detailed provisions of the type that Powerex proposes.

IV. Deficiency Letter and Puget's Response

48. On August 5, 2011, Commission staff issued a deficiency letter requesting further information regarding Puget's filing. In the deficiency letter, staff directed Puget to provide support for its two percent purchase obligation for load and for exporting dispatchable generators. Staff also asked Puget to explain how the regulation costs for generators serving load within the Puget BAA are recovered and whether it is unduly discriminatory to charge generators serving load outside of Puget's BAA for regulating capacity based on their dispatchability but not similarly charge generators serving load within Puget's BAA based on their dispatchability. Additionally, staff directed Puget to demonstrate whether and/or how the increased variability from its Wild Horse wind generation facility (Wild Horse facility), an intermittent/non-dispatchable generator serving load in Puget's BAA, is included in the computation of regulation reserve capacity under Schedule 3.

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[55] *Id*. at 29 (citing PG&E Comments, Docket No. RM10-11-000 at 20 ("Curtailment of VER generation should always be available as an option to maintain system reliability in over-generation situations.")).

[56] *Id*. at 29.

[57] *Id*. at 27.

49. Staff noted that Puget only uses data from six of its dispatchable generators in calculating the deviations for dispatchable generators that are used in determining the intermittent/non-dispatchable purchase obligation and requested that Puget explain why it excludes part of its dispatchable generation fleet from the calculation. Staff also noted that Puget uses nameplate capacity when calculating the intermittent/non-dispatchable purchase obligation but applies the resulting charge based on transmission reservation. Staff requested that Puget provide justification for this differing treatment and explain why Puget should be allowed to use nameplate capacity in the purchase obligation calculation while applying the resulting charge based on transmission reservation.

50. Additionally, staff noted that, as of June 28, 2011, transmission customers were able to change their schedules on an intra-hourly basis. Staff asked Puget whether its calculation of the intermittent/non-dispatchable purchase obligation accounts for the possibility that resources would utilize intra-hour transmission scheduling now that it is available, and, if not, why not.

51. In response to the deficiency letter, Puget explains that the two percent purchase obligation for load was settled on in a black box settlement in 1998. Puget adds that it used the two percent figure again as a reasonable approximation of the regulation requirement associated with dispatchable generation exports when Puget amended its OATT to include Schedule 13 in February 2010. Puget argues that 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 Services, Inc. and other transmission providers who have implemented generator regulation charges.[58]

52. Puget states that it is not proposing to change the two percent purchase obligation as it pertains to load and dispatchable generation exports. However, to be responsive to the deficiency letter, Puget provides additional information. Specifically, Puget recalculated the purchase obligation of load and dispatchable generation using the same portfolio-wide analysis that was used to calculate the 16.77 percent purchase obligation for intermittent/non-dispatchable generation exports. Puget states that the recalculation resulted in a purchase obligation of 1.21 percent for load and 0.38 percent for dispatchable generation. Puget states that, while it does not propose to revise the purchase obligation for load and dispatchable generation exports, it would be reasonable to apply these new percentages if the Commission seeks regulation percentages for load and exporting dispatchable generators that are based on the portfolio-wide methodology.

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[58] Puget Deficiency Response at 7 (citing *Entergy Servs. Inc.*, 120 FERC ¶ 61,042 (2007); *Florida Power Corp.*, 89 FERC ¶ 61,263 (1999)).

53. Puget states that it does not recover the cost of providing regulation service to generation resources that are committed to serving load in Puget's BAA under either Schedule 3 or Schedule 13. Puget explains that, instead, the regulation costs associated with such generation deviations are currently passed through to Puget's retail and wholesale customers through their bundled rates. Therefore, Puget asserts there is no need to distinguish between generators serving load inside Puget's BAA based on dispatchability because all of the generators are serving the same customers and those customers are paying all the related regulation costs.

54. Puget states that, in contrast, it has no means of recovering regulation costs associated with generators that serve load outside of Puget's BAA other than through Schedule 13. Puget argues that this approach is similar to the approach taken in *Westar* where the Commission 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.[59]

55. Puget explains that it used the most recent calendar year 2010 data to perform its portfolio-wide regulation study and that intra-hour scheduling was not available at that time. Puget states that the calculation of the 16.77 percent purchase obligation does not account for the possibility that resources may, in the future, change their schedules. Puget adds that, because intra-hour scheduling has only been available since June 28, 2011 and is voluntary, there is no certainty that a generator will revise its schedule. However, Puget states that it recognizes that widespread use of intra-hour schedule adjustment practices might reduce Puget's regulation burden and therefore reduce an intermittent/non-dispatchable generator's purchase obligation under Schedule 13. Therefore, Puget proposes to file informational reports on an annual basis describing the status of intra-hour scheduling in the region and in Puget's BAA, along with an assessment of whether the increased use of such scheduling reduces the regulation burden on Puget.

56. Puget also states that it only included six of its dispatchable generators in its calculation of the intermittent/non-dispatchable purchase obligation to overcome a data problem. Puget explains that it has detailed data on generator output within the hour but does not have a record of dispatch instruction or generator set point to compare to generator output to measure the unit's variability. Puget states that, while it creates and maintains day-ahead schedules for its dispatchable generating plants, it does not create and maintain a complete set of revised, hour-ahead schedules in real-time. Therefore, Puget states that, through a labor-intensive process, it created a proxy generation schedule

[59] Puget Deficiency Response at 10 (citing *Westar*, 130 FERC ¶ 61,215 at P 35).

to measure against the unit’s actual output. Puget states that, in order to simplify the process, it evaluated six representative plants rather than repeating the process for Puget’s entire suite of dispatchable resources.

57. Nevertheless, Puget states that, in response to the deficiency letter, it included seven additional dispatchable units in its portfolio-wide study, which now accounts for 97 percent of the actual generation from all of the dispatchable plants that were electrically located within the Puget BAA during calendar year 2010. Puget states that the result of this updated portfolio-wide study increases the intermittent/non-dispatchable purchase obligation from 16.77 percent to 17.15 percent. In spite of the increase, Puget does not propose to revise the 16.77 percent purchase obligation determined using the original portfolio-wide analysis.

58. Puget explains that it elected to charge transmission customers under Schedule 13 based on transmission reservation because Puget collects generator regulation charges directly from the transmission customer that delivers energy from the exporting generator to a sink outside Puget’s BAA. Puget contends that, because it charges the transmission customer and not the generator, it seemed logical to charge the customer based on its transmission reservation and not the nameplate capacity of the exported generation facility. Puget adds that its currently-effective Schedule 13 charges transmission customers based on transmission reservation. Puget is not seeking to amend this component of Schedule 13.

V. Discussion

A. Procedural Matters

59. Pursuant to Rule 214 of the Commission’s Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2011), the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. We will also accept Powerex’s late comments.

60. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2011), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept Puget’s answers because they have provided information that assisted us in our decision-making process.

B. Substantive Matters

61. In Order No. 890, the Commission revised the *pro forma* OATT to clarify and expand the obligations of transmission providers to ensure that transmission service is

provided on a non-discriminatory basis.[60] In Order No. 890-A, the Commission further clarified that "transmission providers may propose to assess regulation charges to generators selling in the control area, as well as generators selling outside the control area, and the Commission will consider such proposals on a case-by-case basis."[61] In addition, the Commission has accepted utilities' proposals for separate regulation charges for generators.[62]

62. Puget's proposed Schedule 13 will require transmission customers who are delivering energy outside of Puget's BAA from intermittent/non-dispatchable generators to purchase a different volume of generator regulation reserves than dispatchable generator resources. In addition to assessing a different volume of reserves to intermittent/non-dispatchable and dispatchable generators, Puget's proposed Schedules 3 and 13 increase its capacity rate for regulation and frequency response service.

63. As protesters have pointed out, there are differences between the proposal before us here and the proposal accepted in *Westar*. Those differences, however, do not require the Commission to reject Puget's proposal outright. Currently, the Commission considers proposals to assess generator regulation charges on a case-by-case basis and, as such, evaluates each case on its own merits to determine whether the proposal is just and reasonable.

64. We find that several issues before us can be decided on the merits, while others raise issues of material fact that cannot be resolved based upon the record before us and are more appropriately addressed in the hearing and settlement judge procedures ordered below.

65. We disagree with protesters' arguments that the differential charge under Schedule 13 for intermittent/non-dispatchable generators should be rejected because Puget has not implemented grid operating reforms (such as intra-hourly scheduling; implementation of a wind energy forecast program; and use of that forecast to minimize

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[60] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 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 (2009) *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[61] Order No. 890-A, FERC Stats & Regs. ¶ 31,261 at P 313.

[62] *See Florida Power Corp.*, 89 FERC ¶ 61,263; *Entergy Services Inc.*, 120 FERC ¶ 61,042 at P 66; *Westar*, 130 FERC ¶ 61,215.

the amount of regulation capacity procured based on actual system conditions) to reduce the proposed charge. While the Commission is examining the reforms protesters advocate in the *Integration of Variable Energy Resources* rulemaking proceeding in Docket No. RM10-11-000, the Commission does not currently require transmission providers to implement those operating procedure reforms.[63] Therefore, we find that the protesters' arguments are not a basis for rejecting Puget's proposal.

66. We find that AWEA's arguments regarding Puget's assignment of integration costs to conventional generators, the cost of contingency reserves (under Schedules 5 and 6 of the OATT) and power system inefficiency that results from variability and uncertainty in natural gas markets are not before the Commission in this proceeding. Here, the issue before the Commission is whether Puget's proposed capacity rate and differentiated purchase obligation for exporting intermittent/non-dispatchable and dispatchable generation resources are just and reasonable. Therefore, we reject AWEA's arguments as being beyond the scope of this proceeding.[64]

1. Self-Supply Option

67. We disagree with protesters' contention that Puget does not offer the option of self-supply under Schedules 3 and 13. Both schedules state that "a 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."[65] We find that this provision is consistent with the language in the *pro forma* OATT and that no further modifications to Puget's tariff are necessary with regard to the option to self-supply. Accordingly, we reject protesters' claim that Puget's

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[63] We also note that all public utility transmission providers, including Puget, will be required to make the necessary changes to be in compliance with any final rule the Commission issues in the *Integration of Variable Energy Resources* rulemaking proceeding; this order does not exempt Puget from complying with any such final rule.

[64] If AWEA is concerned that Schedules 5 and 6 do not appropriately capture the costs of contingency reserves, it can bring this issue to the Commission's attention under section 206 of the Federal Power Act (16 U.S.C. § 824e (2006)).

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

proposal fails to provide transmission customers with an option to self-supply regulation service.[66]

2. Curtailment

68. Protesters argue that it is unclear whether wind resources that pay the Schedule 13 regulation service charge may still be subject to curtailment and request Puget's estimated magnitude and frequency of any such curtailments. In its July 20, 2011 answer, Puget clarifies whether wind resources that pay the Schedule 13 regulation service charge may still be subject to curtailment. In that answer, Puget states that it will not curtail any generator, wind or otherwise, for economic reasons and that its proposal does not limit the amount of regulation service that it makes available to wind resources. We find this clarification satisfactory.

3. Hearing and Settlement Judge Procedures

69. Puget's proposed capacity charge and purchase obligation raise issues of material fact that cannot be resolved based upon the record before us and that are more appropriately addressed in the hearing and settlement judge procedures ordered below.

70. Our preliminary analysis indicates that Puget's proposed rates have not been shown to be just and reasonable and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. In *West Texas Utilities Company*,[67] the Commission explained that, when its preliminary examination indicates that the proposed rates may be unjust and unreasonable and may be substantially excessive, as defined in *West Texas Utilities Company*, the Commission would generally impose a five-month suspension. In this proceeding, we find that the proposed rates may be substantially excessive. Therefore, we will accept Puget's proposed Schedules 3 and 13 for filing, suspend them for a five-month period, make them effective January 5, 2012,[68] subject to refund, and set them for hearing and settlement judge procedures, as discussed below.

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[66] While Puget indicates that it has received no requests for dynamic scheduling (*see* Puget Deficiency Response at 4), we note that a transmission customer that is unable to arrange for dynamic scheduling in order to "make alternative comparable arrangements" may bring this issue to the Commission's attention under section 206 of the Federal Power Act (16 U.S.C. § 824e).

[67] 18 FERC at 61,374.

[68] While Puget's filing was completed on August 25, 2011, the original June 6, 2011 filing with its original August 5, 2011 requested effective date gave notice of a

(continued …)

71. In calculating the proposed 16.77 percent intermittent/non-dispatchable purchase obligation, Puget states that it employs a portfolio-wide methodology. Puget explains that there is no within-hour market for capacity reserves in the Pacific Northwest and any amount of capacity that is reserved by Puget for regulation service cannot be used for any other purpose until the next scheduling hour. Therefore, Puget uses 60-minute persistence forecasts in determining the purchase obligation. Puget adds that intra-hour scheduling and forecast data are not currently available for use in computing the purchase obligation for regulation reserves, even though intra-hour scheduling was implemented in the Pacific Northwest on June 28, 2011. We find the use of hourly data to be acceptable in the interim, until intra-hourly data become available. To account for intra-hourly scheduling, Puget proposes to make informational reports on an annual basis describing the status of intra-hour scheduling in the region and in Puget's BAA, along with an assessment of whether the increased use of such scheduling reduces the regulation burden on Puget. We will accept Puget's use of hourly data conditioned on Puget submitting these annual informational filings.[69]

72. While we agree with Puget that a portfolio-wide approach that shares diversity benefits among generators and loads is appropriate here, the record is insufficient to determine whether the methodology has been implemented in such as way that diversity benefits are appropriately shared among generators and loads and does not inappropriately allocate costs to any one customer. We further find that the datasets used in Puget's portfolio-wide methodology raise issues of material fact that cannot be resolved based upon the record before us. For example, protesters argue that they cannot verify that Puget's use of 60-minute persistence forecasts instead of actual hour-ahead forecasts reduces the computed purchase obligation, as Puget claims. Protesters also assert that they are unable to verify some of the data Puget used in its portfolio-wide analysis. We believe the ordered hearing is the appropriate forum to explore all issues related to the inputs into the datasets Puget uses in its portfolio-wide methodology to calculate the purchase obligations for load under Schedule 3 and for dispatchable and intermittent/non-dispatchable generation resources under Schedule 13.

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proposed rate change despite certain deficiencies in the filing's underlying support. *See Niagara Mohawk Power Corp.*, 126 FERC ¶ 61,173 (2009). As such, the statutory 60-day prior notice was provided, and the Commission has determined that in this case the five-month suspension period will begin on the August 5, 2011 requested effective date. *Id*.

[69] This filing will be for informational purposes only. Therefore, the filing will not be publicly noticed in the *Federal Register* and the Commission will not act on it.

73. Additionally, the currently-effective two percent purchase obligation in Schedule 13 is applicable to both dispatchable and intermittent/non-dispatchable generation exports and is therefore representative of the collective regulation burden placed on Puget's system by all types of exporting generation. Because Puget now proposes to differentiate between the types of generation being charged under Schedule 13, it is inherently proposing two new charges, and Puget must accurately reflect the regulation burden imposed on its system by each type of exporting generation resource. It follows that Puget must also accurately reflect the regulation burden imposed on its system by load under Schedule 3. In its response to the deficiency letter, Puget states that "[i]f 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 percent regulation purchase obligation for exporting intermittent generation, [the] percentages developed by Mr. Reed in his portfolio-wide study would be reasonable to apply."[70] Therefore, we direct Puget to revise the purchase obligation for dispatchable generation exports under Schedule 13 and for load under Schedule 3 using the same portfolio-wide methodology it uses to calculate the purchase obligation for intermittent/non-dispatchable generation exports. Because the same datasets are used to determine the purchase obligation for load, dispatchable generation resources, and intermittent/non-dispatchable generation resources, the inputs into the datasets for these calculations are also part of the ordered hearing.

74. With respect to the arguments protesters raise regarding the existence of undue discrimination between exporting generators and those serving internal load, we do not have sufficient information before us to determine whether Puget's charges under Schedule 13 are discriminatory. Puget asserts that, contrary to protester's arguments, it does not recover the cost of providing regulation service to generation resources sinking in Puget's BAA under Schedule 3 or Schedule 13. Puget states that, instead, the regulation costs associated with such generation deviations are currently passed through to Puget's retail and wholesale customers through their bundled rates. Based on the record before us, we cannot determine whether this rate treatment is comparable to the rate treatment intermittent/non-dispatchable generators have under Schedule 13. We believe the ordered hearing is the appropriate forum to explore this matter.

75. The hearing should also explore all cost-of-service matters with regard to Puget's proposed $12.39/kW-month regulation capacity charge, including, but not limited to, which pool of generation resources to use in the derivation of the charge, the costs associated with each generation resource, and the return on equity.

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[70] Puget Deficiency Response at 8.

76. While we are setting these matters for a trial-type evidentiary hearing, we encourage the parties to make every effort to settle their dispute before hearing procedures are commenced. To aid the parties in their settlement efforts, we will hold the hearing in abeyance and direct that a settlement judge be appointed pursuant to Rule 603 of the Commission's Rules of Practice and Procedure.[71] If the parties desire, they may, by mutual agreement, request a specific judge as the settlement judge in the proceeding; otherwise the Chief Judge will select a judge for this purpose.[72] The settlement judge shall report to the Chief Judge and the Commission within 30 days of the date of the appointment of the settlement judge, concerning the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions or provide for commencement of a hearing by assigning the case to a presiding judge.

The Commission orders:

(A) Puget's proposed Schedules 3 and 13 are hereby accepted for filing and suspended for a five-month period, to become effective January 5, 2012, subject to refund, as discussed in the body of this order.

(B) Pursuant to the authority contained in and subject to the jurisdiction conferred upon the Federal Energy Regulatory Commission by section 402(a) of the Department of Energy Organization Act and by the Federal Power Act, particularly sections 205 and 206 thereof, and pursuant to the Commission's Rules of Practice and Procedure, and the regulations under the Federal Power Act (18 C.F.R. Part I), a public hearing shall be held concerning Puget's tariff revisions. However, the hearing shall be held in abeyance to provide time for settlement judge procedures, as discussed in Ordering Paragraphs (C) and (D) below.

(C) Pursuant to Rule 603 of the Rules of Practice and Procedure, 18 C.F.R. § 385.603 (2011), the Chief Administrative Law Judge is directed to appoint a settlement judge in this proceeding within fifteen (15) days of the date of this order. Such settlement judge shall have all powers and duties enumerated in Rule 603 and shall convene a settlement conference as soon as practicable after the Chief Judge designates

[71] 18 C.F.R. § 385.603 (2011).

[72] If the parties decide to request a specific judge, they must make their joint request to the Chief Judge by telephone at (202) 502-8500 within five days of this order. The Commission's website contains a list of Commission judges and a summary of their backgrounds and experience (http://www.ferc.gov/legal/adr/avail-judge.asp).

the settlement judge. If the parties decide to request a specific judge, they must make their request to the Chief Judge within five (5) days of the date of this order.

(D) Within thirty (30) days of the appointment of the settlement judge, the settlement judge shall file a report with the Commission and with the Chief Judge on the status of settlement discussions. Based on this report, the Chief Judge shall provide the parties with additional time to continue their settlement discussions, if appropriate, or assign this case to a presiding judge for a trial-type evidentiary hearing, if appropriate. If settlement discussions continue, the settlement judge shall file a report at least every sixty (60) days thereafter, informing the Commission and the Chief Judge of the parties' progress toward settlement.

(E) If settlement judge procedures fail and a trial-type evidentiary hearing is to be held, a presiding judge, to be designated by the Chief Judge, shall, within fifteen (15) days of the date of the presiding judge's designation, convene a prehearing conference in these proceedings in a hearing room of the Commission, 888 First Street, NE, Washington, DC 20426. Such a conference shall be held for the purpose of establishing a procedural schedule. The presiding judge is authorized to establish procedural dates, and to rule on all motions (except motions to dismiss) as provided in the Rules of Practice and Procedure

By the Commission. Commissioner Spitzer is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.