UNITED STATES OF AMERICA
U.S. DEPARTMENT OF ENERGY
BEFORE THE
BONNEVILLE POWER ADMINISTRATION

2012 RATE ADJUSTMENT PROCEEDING	)))	Docket Number	BP-12

ORDER ESTABLISHING DEADLINE FOR OBJECTIONS

On May 5, 2011, Bonneville Power Administration (BPA) filed a motion[1] to strike a portion of the initial brief of Snohomish County PUD (SN).[2] A copy of BPA's motion is attached to this order.

Due to time constraints in this proceeding, any objections to the motions must be filed no later than 4:30 p.m., Pacific Time, on Tuesday, May 10, 2011.

SO ORDERED, May 5, 2011.

/s/ Samuel J. Petrillo
Samuel J. Petrillo
BP-12 Hearing Officer

[1] BP-12-M-BPA-19.
[2] BP-12-B-SN-01.

UNITED STATES OF AMERICA
U.S. DEPARTMENT OF ENERGY
BEFORE THE
BONNEVILLE POWER ADMINISTRATION

2012 RATE ADJUSTMENT PROCEEDING	)	Docket Number BP-12

BONNEVILLE POWER ADMINISTRATION'S MOTION TO STRIKE PORTIONS OF PUBLIC ULITILITY DISTRICT NO. 1 OF SNOHOMISH COUNTY'S BRIEF

Pursuant to the Bonneville Power Administration's (BPA) Rules of Procedure Governing Rate Hearings (Procedural Rules), BPA hereby submits this Motion to Strike a portion of Snohomish's initial brief.

Snohomish brief at page 14, line 18 to page 15 line 2, state as follows: In clarification and cross-examination, witnesses that supported the 10 MW demarcation could provide no tangible reason to justify a 10 MW limit other than, "it feels right." BP-12-B-SN-01, at 14-15. BPA moves to strike that sentence because it allegedly references off the record conversations made during clarification and is not supported by any evidence in the record.

While the Procedural Rules provide for the Hearing Officer scheduling transcribed clarifications sessions [Rule 1010.8 (c)], the practice over the years has been to conduct informal clarification sessions that are off the record and not transcribed or recorded. Clarification today is an informal process that allows witnesses to provide some understand of the pre-filed testimony in a question and answer format. The only way information provided during these clarification sessions can be can become part of the record is thru the submission of a data request that seeks to confirm information or response provided during clarification and the subsequent moving of the response on to the record.

Over the years, the informal clarification sessions have allowed parties, in particular, to gain a greater understanding of BPA's proposal in a setting that is not encumbered by formality and related concerns associated with a proceeding that is on the record. This process has served BPA and the parties well and Snohomish's unattributed alleged statement of a BPA witness during clarification threatens to undermine a process that served BPA and parties well for a number of years. The referenced sentence must be stricken because at this point in the proceeding, BPA cannot respond on the record and the Administrator has no way to affirm, refute or put in context any off the record statement alleged to have been made during clarification. Allowing this statement to stand could also have a chilling effect on BPA on other parties in the future if they believe that statements made during clarification could subsequently show up in briefs or testimony. Such an outcome would not be in any parties' long term interest.

While Snohomish contends in its brief that the statement was also made in cross-examination, this is a misrepresentation by Snohomish. Snohomish does not provide any citation to the transcript because there is no such statement in the transcript. Snohomish's counsel Mr. Kallstrom was the only party to cross examine the BPA panel that testified about the 10 MW limit. At no point during Mr. Kallstrom's cross examination did he ask any questions regarding the rationale behind the 10 MW limit nor did a BPA witness provide any response that would even remotely suggest that the 10 MW limit somehow 'felt right.' Consequently, Snohomish cannot point to fact that the alleged statement was made during cross examination to support for keeping the statement in the brief. Snohomish should not be allowed to falsely attribute an on the record statement by a witness as a mechanism to get any off the record statement in the record.

For the reasons stated herein BPA moves the Hearing Officer to grant this motion to strike.

Submitted this 5th day of May 2011.

/s/ Peter Burger
Peter Burger
Attorney for Bonneville Power Administration
Office of General Counsel, LP-7
Bonneville Power Administration
PO Box 3621
Portland, OR 97208-3621
(503) 230-4148
pjburger@bpa.gov

ATTACHMENT A

UNITED STATES OF AMERICA
U.S. DEPARTMENT OF ENERGY

BEFORE THE
BONNEVILLE POWER ADMINISTRATION

2012 WHOLESALE POWER RATE ADJUSTMENT PROCEEDING	**)))**	**Docket No. BP-12**

INITIAL BRIEF

OF

PUBLIC UTILITY DISTRICT NO. 1
OF SNOHOMISH COUNTY, WASHINGTON

BP-12-B-SN-01

May 2, 2011

INITIAL BRIEF
of Public Utility District No. 1 of Snohomish County, Washington

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INITIAL BRIEF
of Public Utility District No. 1 of Snohomish County, Washington

INTRODUCTION

This Initial Brief of Public Utility District No. 1 of Snohomish County, Washington ("Snohomish"), is submitted in accordance with section 1010.13(c) of the Bonneville Power Administration's ("BPA") Rules of Procedure Governing Rate Hearings,[1] as required by the Hearing Officer's November 19, 2010, *Order Establishing Schedule*,[2] and consistent with the Hearing Officer's April 14, 2011, *Order on Formatting of Briefs*.[3]

On November 18, 2010, and on December 16, 2010, BPA published a notice in the Federal Register announcing the commencement of the above-captioned consolidated rate proceedings, where BPA proposed to adopt power and transmission rates for fiscal years (FY) 2012-2013 (collectively, the "BP-12 Proceeding").[4] In these notices, BPA stated that the BP-12 Proceeding is a consolidated rate proceeding to establish power and transmission rates for FY 2012-2013.[5]

As required by section 1010.13(c) of the BPA Rules of Procedure Governing Rate Hearings and the Hearing Officer's April 14, 2011, *Order on Formatting of Briefs*, Snohomish hereby informs the Hearing Officer that this Initial Brief addresses the following issues: (1) the demand rate; (2) unanticipated load service; (3) inclusion of certain costs in the non-slice cost pool; (4) the Dispatchable Energy Resource Balancing Service charge; (5) the Variable Energy Resource Balancing Service solar rate; (6) supplemental Variable Energy Resource Balancing

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1 51 Fed. Reg. 7611 (March 5, 1986).
2 BP-12-HOO-01.
3 BP-12-HOO-62.
4 75 Fed. Reg. 70744 (Nov. 18, 2010); 75 Fed. Reg. 78690 (Dec. 16, 2010).
5 75 Fed. Reg. 70744 at 70744; 75 Fed. Reg. 78690 at 78690.

Service; (7) the proposed committed intra-hour pilot; and (8) treatment of the Montana Intertie. The first seven of these issues relate to the Power portion of the BP-12 Proceeding. The eighth issue, BPA's treatment of the Montana Intertie, relates to the Transmission portion of the BP-12 Proceeding.

Snohomish is a member of the Public Power Council ("PPC") and has reviewed the initial brief submitted by PPC in the BP-12 Proceeding. As a result of this review, Snohomish supports and adopts the positions and legal arguments set forth in the PPC initial brief, BP-12-B-PP-01,[6] as if each of the issues raised and briefed therein were separately raised and fully briefed in Snohomish's Initial Brief. Snohomish also supports and adopts the positions and legal arguments set forth in the initial brief filed by Joint Party No. 11 and in Section II.B. of the initial brief filed by Joint Party No. 1 as if these issues and arguments were fully raised and developed in Snohomish's Initial Brief.[7]

ARGUMENT

I. CALCULATION OF THE DEMAND RATE

a. A Primary Purpose and Intent of the Demand Rate as Described in the Tiered Rates Methodology is to Send a Price Signal to Utilities

The Demand Rate was designed to provide a price signal to incent utilities to invest in energy efficiency and to reduce their power demand on BPA. BPA staff has acknowledged this goal in the Tiered Rates Methodology ("TRM") through both the TRM Record of Decision and in testimony.[8] To ensure a proper price signal, the methodology used to establish the Demand

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6 Should any positions or legal arguments raised in PPC's initial brief contradict or conflict with positions or arguments contained herein, the positions and arguments herein prevail.

7 *See* BP-12-B-JP11-01; BP-12-B-JP01-01. If and to the extent any positions or legal arguments raised in the Joint Party No. 11 and Joint Party No. 1 initial briefs contradict or conflict with positions or arguments contained herein, the positions and arguments herein prevail.

8 TRM-12-A-01 at 76; BPA-12-E-BPA-41 at 3.

Rate must correctly calculate the cost BPA would incur to acquire and provide new capacity. If BPA fails to include the proper cost components in the methodology, then the goals of the TRM will be frustrated.

b. The Demand Rate as Proposed by BPA is Too Low and Fails to Properly Capture the Cost of Acquiring a Capacity Resource

The TRM requires that the Demand Rate be based on "the annual fixed costs (capital and O&M) of the marginal capacity resource as determined in each 7(i) process."[9] While BPA staff agrees that "the intent of the TRM was to capture the entire cost of marginal capacity and not a subset of the fixed costs,"[10] the assumptions and methodology BPA has proposed omits and understates many of the fixed costs associated with the chosen capacity resource. The result is a proposed average Demand Rate by BPA of $9.57/kW/mo, which does not meet the intent of a proper price signal as envisioned by the TRM.

Joint Party No. 7 ("JP07") demonstrated that proper estimates for the annual fixed cost of the marginal capacity resource—a General Electric LMS-100 turbine—produces an average Demand Rate of $16.54/kW/mo.[11] In order to correctly implement the TRM, BPA should include the full fixed costs of the marginal resource in the Demand Rate as described by JP07.[12]

c. BPA's Methodology for Calculating the Demand Rate Should Adopt an IPP-Based Cost Estimate, as Tax-Exempt Financing for a New Marginal Capacity Resource is Unrealistic

The TRM gives BPA latitude to choose from various data sources to establish the costs associated with the marginal capacity resource, including BPA's "Resource program and/or the costs of BPA's recent capacity additions" or "third-party sources" or even "the market rate for

9 TRM-12S-A-03 at 72.
10 BP-12-E-BPA-41 at 3.
11 BP-12-E-JP07-02 at 10.
12 BP-12-E-JP07-01; BP-12-E-JP07-02

capacity if a viable capacity market develops."[13] Regardless of the source of data, the TRM is explicit that the actual costs of resources available to BPA should be used. To achieve the policy goals of the TRM, actual costs must be used to avoid misleading price signals that under-price capacity at the margin.

BPA staff's proposal relies primarily upon data and analysis from the Northwest Power and Conservation Council's ("Council") Sixth Power Plan, more specifically the Council's Microfin model, which it called "the most transparent model source for the all-in capital costs of an LMS100."[14] When "Staff ran the model for the Initial Proposal, it ran it for a municipal/PUD developer" such that "the MicroFin model has an assumption of zero property taxes."[15] (The model could have been run to include property tax.[16]) Staff also assumes that the developer would be eligible for tax-exempt debt financing, that the developer could borrow the entire cost of the resource and that the debt would have a term equal to the 30-year life of the resource.[17] Other than stating that these assumptions were the modeling choices made, BPA offers no justification for why these assumptions were chosen.

The JP07 witnesses have explained that these assumptions are "not reasonable."[18] As they have stated in testimony, a straightforward implementation of the TRM requires that BPA "should use a reasonable estimate of the financing and other costs to a private developer from which BPA could obtain needed capacity."[19] They also emphasized that "it is almost certain that the developer it [BPA] would look to would be an Independent Power Producer that is in the

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13 TRM-12S-A-03 at 72-73.
14 BP-12-E-BPA-18 at 21.
15 BP-12-E-BPA-41 at 4.
16 *See id.*
17 BP-12-E-JP07-01 at 4.
18 BP-12-E-JP07-01 at 5.
19 BP-12-E-JP07-02 at 9.

business of developing merchant plants. There is simply no evidence to suggest that entities eligible for tax-exempt financing are in the business of developing merchant resources."[20] This statement is proven true by the record of evidence presented in this proceeding.

Since passage of the Northwest Power Act, BPA has acquired essentially no major resource from publics other than conservation; the resources it has acquired have been from IPPs (*e.g.*, Tenaska, Klondike Wind). No party has yet offered any evidence that it is reasonable that a tax-exempt developer would supply the marginal capacity, and BPA staff has offered no explanation for its decision to assume such a developer would be available or willing to supply BPA with a marginal capacity resource at cost. The assumption of a tax-exempt developer is also inconsistent with the TRM's listing of "the market price of capacity if a viable capacity market develops in the Pacific Northwest"[21] as IPPs and other taxable entities would certainly be among the primary participants in such markets. There is no reason to believe that BPA's capacity needs could or would be met by purchases from a tax-exempt entity.

BPA also cannot reasonably assume that the marginal capacity project could be 100% debt financed, and financed for the entire 30-year estimated life of the project. As the JP07 witnesses explained, no "party would lend money to a resource developer on such terms"; at best, a 20 year period is the maximum achievable, and a 40% equity investment is likely required.[22] Substantial evidence was advanced to support these positions.[23] The JP07 witnesses supplied an estimate of the Demand Rate under these appropriate assumptions, and BPA should adopt it.[24]

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[20] BP-12-E-JP07-01 at 5.
[21] TRM-12S-A-03 at 73.
[22] *See* BP-12-E-JP07-01 at 8.
[23] *See id.* at fn 4, 5, and 6.
[24] *Id.*

d. Arguments that the Demand Rate Should be Based on the Avoided Costs of BPA's Customers are Without Merit

Section 5.3.6 of the TRM states that "BPA will base the Demand Rate on the fixed cost (capital and O&M) of the marginal capacity resource as determined in each 7(i) process."[25] As the JP07 witnesses explained, the Demand Rate should reflect "the actual fixed cost of a resource that BPA reasonably could acquire to meet its incremental capacity needs."[26]

WPAG has argued that BPA should use "avoided costs of the non-Slice customers, rather than th[ose] of BPA" for calculating the marginal cost of capacity for the Demand Rate.[27] However, the customers' avoided cost is irrelevant to the cost BPA should charge for capacity. Customers should be comparing their own cost of acquiring marginal capacity (or the cost of offsetting that need) to the cost of BPA-supplied marginal capacity. If BPA sets the Demand Rate utilizing the customer's avoided cost the customer is indifferent between self-supplying capacity and having BPA supply marginal capacity.

It is plainly not efficient to leave customers "indifferent between providing their own marginal capacity or utilizing BPA's system to supply capacity, [such that] . . . all other customers would be forced to pay higher rates if BPA recovers less than BPA's full costs."[28] BPA recognized in its Record of Decision on the TRM that the price signal should pass on to customers BPA's "actual cost of new capacity" not customer avoided costs,[29] and BPA should continue to reject the WPAG position.

[25] TRM-12S-A-03 at 72.
[26] BP-12-E-JP07-01 at 1; *see also* TRM-12-A-01 at 76 ("BPA staff testified that the price signal associated with Demand charge will pass on to customers the actual cost of capacity . . .").
[27] BP-12-E-WG-01 at 45.
[28] BP-12-E-JP07-02 at 8; *see also id.* at 5.
[29] *See* TRM-12-A-01 at 76.

e. BPA is Properly Treating Fuel Transportation and Insurance Costs

BPA staff properly recognizes that certain fuel transportation costs, incurred regardless of the operation of the resource, along with certain insurance costs, are properly included in the Demand Rate calculation of the cost of the marginal capacity. Staff correctly recognizes that such costs are part of the "capital and O&M" costs identified in § 5.3.6 of the TRM.[30] Indeed, BPA staff recognizes that unless "all of the annual fixed costs of the marginal resources" are accounted for, the rate will not send the "proper price signal."[31] Here, as elsewhere, "[f]ailure to account for all of the fixed costs would erode the value of Tier 1 and undermine the underlying theory behind BPA's tiered rates."[32]

BPA initially proposed a "'rate period average expense' for fixed fuel of $29.17/kW/yr based on mainline capacity on Northwest Pipeline at Northwest Pipeline's existing rate, although there was no such capacity."[33] In rebuttal, Staff has agreed, consistent with the Sixth Power Plan, that new plants are likely to experience incrementally-priced pipeline capacity, and has agreed to adopt this change, raising the price roughly $0.88/kW/mo.[34] BPA should adhere to this approach.

f. BPA Should use the Larger Sample Size that Includes California Energy Commission Data

In its initial proposal, BPA explained that it was departing from the Council's MicroFin model with respect to "fixed O&M cost average" by using California Energy Commission ("CEC") data.[35] According to BPA, the CEC data has a sample size of six, while the Council's

30 *See* BP-12-E-BPA-41 at 2; *see also* BP-12-E-JP07-02 at 2-3.
31 BP-12-E-BPA-41 at 2.
32 *Id.* at 3.
33 BP-12-E-JP07-01 at 8.
34 BP-12-E-BPA-41 at 7.
35 BP-12-E-BPA-18 at 21.

data is based on a single sample.[36] As a matter of elementary statistics and common sense, estimating costs from a single data point is manifestly less reliable than using all available data.

Joint Party No. 2 ("JP02") and WPAG have suggested, without evidence or explanation, that using a single data source was somehow more consistent with the TRM. As set forth above, the TRM anticipates that BPA will review a variety of data and use the best available data. Staff states there is "some merit" to using a single data source "in order to avoid the possibility of double counting costs or neglecting to include certain costs by mixing data sources."[37] But Staff provides no evidence as to the likelihood or significance of this abstract "possibility." In addition, no specific instance of "double counting" could be established by BPA staff, JP02, or WPAG.

Both the Council and CEC were trying to estimate the same "fixed O&M" costs, and the mere possibility of minor inconsistencies, if any exist, ought not to outweigh the obvious advantages of formulating vitally important pricing signals based on a more robust data set including multiple project data points. BPA should adhere to Staff's initial proposal to use the more reliable \$17.60/kw/yr fixed O&M estimates.[38]

g. The Administrator Should Adopt the Demand Rate as Described by JP07 to Properly Realize the Goals of the TRM

The Demand Rate calculated using the methodology and above assumptions, the resulting Demand Rate is \$16.54/kW/mo.[39] This Demand Rate properly captures the cost of BPA acquiring a marginal capacity resource as described in the TRM. The rate would send the proper price signal to customers and satisfy the goals and intent of the TRM.

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36 *Id.*
37 BP-12-E-BPA-41 at 5.
38 BP-12-E-BPA-01A at 101 (Power Rates Study Documentation).
39 BP-12-E-JP07-02 at 10.

h. BPA's Decision in this Proceeding Should not Influence Future Decisions Regarding the Demand Rate

Finally, to the extent BPA establishes a Demand Rate in this proceeding, BPA should make clear in its Record of Decision that this decision has no precedential impact for future rate cases. The TRM clearly states that the Demand Rate is to be calculated in the applicable 7(i) process for each rate period. In such future cases, circumstances will certainly be different, and a functioning market for capacity may have developed or BPA may have actually purchased the output of a capacity resource.

Joint Party No. 1 ("JP01") has also included discussion of the appropriate calculation of the Demand Rate in Section II.B. of its initial brief, BP-12-B-JP01-01. To the extent those arguments are not inconsistent with the positions or arguments taken by Snohomish herein, Snohomish supports the arguments raised by JP01 in these sections and adopts and incorporates them as if raised and fully briefed herein.

II. UNANTICIPATED LOAD SERVICE

BPA initially proposed to offer firm requirements power under an FPS Unanticipated Load Service ("ULS") rate in the event certain Customer-Owned Utilities ("COUs") experienced a delay to the online date of their new, non-Federal Specified Resources. BPA subsequently expanded the ULS for the same subset of COUs: 1) to cover permanent loss or failure of a COU's new resource during the rate period; and 2) to prevent potentially subjecting a COU to high transmission congestion management charges if no Firm Network Transmission capacity is available from source to sink at the time the power deliveries were to begin under the Regional Dialogue contract and Secondary (non-firm) Network Transmission had to be used instead. The FPS-12 rate for ULS is designed to recover the cost of the "unanticipated load" placed on BPA by the COU during the FY 2012-2013 rate period that had not been requested, and therefore was not forecast when setting the rates for that rate period."[40]

Snohomish opposes: 1) offering ULS to a COU for the delay in a new resource coming online intended to serve the COU's load growth above its rate period high water mark ("Above-RHWM load"); 2) offering ULS in the event the COU experiences a permanent loss or failure of the new resource during the rate period intended to serve the COU's Above-RHWM load; and 3) limiting ULS to COUs who are Transfer customers of BPA and contract for the Load Following product, and have requested Firm Network Transmission service for their new, non-Federal resource and only Secondary Network Transmission capacity is available, which could potentially expose the COU to "high transmission congestion management (TCMS) charges."

a. Snohomish Does Not Support ULS for Either Permanent Loss or Failure, or a Delay in the Online Date, of a New, Non-Federal Specified Resource

i. BPA Should Not Offer ULS for the Permanent Failure of a New, Non-Federal Specified Resource Intended to Serve the COU's Above-RHWM Load.

It is inappropriate for BPA to offer ULS to COUs who experience permanent loss or failure of their new resource during a rate period. The Northwest Power Act explicitly addresses the permanent loss or failure of a resource and requires BPA to treat the resource as continuing to serve firm load until the resource is determined to be permanently lost, or until such use is discontinued with the consent of the Administrator.[41] Until this determination is made by the Administrator, the COU's Above-RHWM load falls outside the circumstances described in section 10.1 of the TRM.[42]

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[40] BP-12-E-BPA-21 at 16.
[41] 16 U.S.C. § 839c(b)(1).
[42] *See* TRM-12S-A-03 at 90. As stated above, if BPA or any other party wishes to expand the definition of unanticipated load to cover these circumstances, they must follow the process set out in section 13 of the TRM.

Section 10.1 of the TRM limits unanticipated loads to those “loads that BPA is obligated to serve under the Northwest Power Act, but of which BPA has not had the notice to serve as required by the CHWM Contract or the General Rate Schedule Provisions.”[43] If a utility provides BPA with notice, as required under the Regional Dialogue Contract, that it intends to serve a portion of its firm load with either a specified or unspecified non-Federal resource, then under the express terms of the Northwest Power Act, *BPA is no longer obligated to serve that portion of the utility’s load*.[44] Snohomish therefore objects to BPA offering ULS to a COU for the permanent loss or failure of its new resource — within or beyond the rate period — as the method by which the resource is replaced until the Administrator’s decision on permanent loss or discontinuance of the resource is made.

The utility has several ways to can mitigate the loss of its resource intended to serve its Above-RHWM load. It can purchase replacement power from the short-term market or from a different resource for the period, or purchase business interruption insurance to mitigate the lost revenue or replacement power costs associated with loss or failure of the resource.[45] All three of these options are available on a near-term basis in the Northwest wholesale marketplace without BPA needing to offer ULS for this purpose.

ii. BPA Should Not Offer ULS for the Delay in a New, Specified Resource Coming Online to Serve the COU’s Above-RHWM Load

ULS is not necessary in the event a COU’s new, non-Federal Specified Resource is delayed in reaching commercial operation. BPA states in its testimony, “[a] customer should know well in advance that a resource is not going to come online and be able to pursue different replacement options…either of these options would not involve the customer taking ULS and

[43] TRM-12S-A-03 at 90.
[44] *See* 16 U.S.C. § 839c(b)(1)(B).
[45] *See* BP-12-E-SN-04 at 5; *see also* BP-12-E-BPA-40 at 10.

would not leave the customer subject to a UAI."[46] Similar to a permanent loss of a resource, the utility can either procure: 1) replacement power from the short-term market; 2) output from a different resource for the period; or 3) business interruption insurance.[47] Any of these alternatives allows the customer to avoid an Unauthorized Increase ("UAI") or other BPA charges.[48] With these and other options available, there is no need for BPA to devote its limited resources to create, administer, and manage ULS on behalf of the affected COUs. Further, because the COU provided BPA with notice that it would serve a portion its firm load with the new resource, the circumstances BPA proposed in the GRSPs for unanticipated load under the FPS-12 rate schedule is load BPA is not obligated to serve under the Northwest Power Act, and therefore would not be eligible for ULS.[49]

iii. BPA is Not Responsible for Mitigating a COU's New, Non-Federal Resource Development Risk with ULS

As proposed, the applicable FPS-12 General Rate Schedule Provisions (GRSPs) offer ULS for certain COUs who formally notify BPA of the non-Federal generating resources they will use to serve load their Above-RWHM load.[50] BPA's Regional Dialogue Contract states, "…policies and deadlines were negotiated, reviewed, and established and were known by the customers when they made their power purchase commitments. As such, these policies and deadlines are not grounds for BPA relieving customers of their contractual obligations through rate schedules or general rate schedule provisions."[51]

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[46] BP-12-E-BPA-40 at 10.

[47] *See* BP-12-E-SN-04 at 5; *see also* BP-12-E-BPA-40 at 10.

[48] *See id.*

[49] *See* 16 U.S.C. § 839c(b)(1)(B); *see also* TRM-12S-A-03 at 90 (permitting BPA to serve unanticipated load only where "BPA has not had the notice to serve as required by the CHWM Contract or the General Rate Schedule Provisions").

[50] BP-12-E-BPA-40 at Attachment 3, page 3-1 (setting forth revised language for ULS in the GRSPs); *see also* Tr. at 17, *BP-12 Cross Examination Transcripts* (Mar. 28, 2011).

[51] BP-12-E-BPA-40 at 6.

If a COU elects to meet its load growth with market purchases, a new, non-Federal resource, and/or a product from BPA priced at the Tier 2 rate, and provided formal notice to BPA of the same, then BPA is in no way responsible to help the COU mitigate its potential delivery risks with the ULS. Having accepted the responsibility to plan for its future load growth, the COU is also responsible to follow through on that contractual commitment. This includes being responsible for pursuing available alternatives to replace the new resource if its online date is delayed or lost — independent of seeking a BPA-provided GRSP that delegates this responsibility back to BPA, thereby mitigating the COU's resource development risk.

Encouraging utilities to develop or acquire non-Federal resources has been a fundamental objective of both the TRM and Regional Dialogue policies. BPA's support to expand the conditions to mitigate such risks for COUs through ULS undermines this objective.

b. ULS Should be Available to all BPA Transfer Customers who Cannot Secure Firm Network Transmission Service in Time to Match their Non-Federal Power Deliveries may Require ULS

i. ULS as Proposed Treats COUs who are Transfer Customers of BPA Inequitably

BPA has proposed that only a subset of its preference customers or COUs would be eligible to purchase ULS in the event they have formally applied for, but cannot secure, Firm Network Transmission service to deliver energy from their non-Federal specified resource to their load.[52] BPA staff stated that the intent was to provide ULS only to those COUs who were Transfer customers *and* had contracted for the Load Following product to serve their Tier 1 load.[53] BPA cited its interest in mitigating Transfer customers' exposure to high TCMS charges. Exposure to costs for securing transmission and ancillary services to facilitate energy deliveries

[52] *See* BP-12-E-BPA-40 at Attachment 2, page 3-1.
[53] *See* Tr. at 17, lines 8-25.

from a resource to a COU's load is common to BPA's Transfer customers, not just those contracting for the Load Following product.

During the Regional Dialogue process, the region agreed to transition to tiered rates during the FY2012-2014 period. Utilities and BPA also agreed COUs would be responsible for serving their future load growth above their Contract HWM load each rate period. Snohomish believes it is inappropriate for BPA to restrict eligibility for ULS to only a subset of its Transfer customers. There are COUs who contracted for the Slice/Block product who rely on transfer service who also face situations where firm transmission is unavailable for delivery of their firm requirements power to serve their native load.[54] BPA cannot use the product under the Regional Dialogue Contract the COU selected as the criteria to determine which COU will or will not be eligible for ULS. BPA's Transfer customers face unique challenges in serving their load. Such actions represent inequitable treatment of BPA's Transfer customers.

ii. BPA Must Provide the Rationale or Analysis as to Why ULS is Capped at 10 MW

In testimony BPA proposed to "to expand ULS FPS eligibility to new Specified Resources that either fail to come online or experience permanent failure during the rate period and that are 10 MW or less in nameplate rating."[55] However, BPA provided no rationale for proposing this limit. ~~In clarification and cross-examination, witnesses that supported the 10 MW~~

[54] For example, assume a Transfer customer in Idaho who contracts with BPA for the Slice/Block product and requires 1 MW from the wholesale energy market to serve its load. Such a utility has three alternatives: 1) purchase 1 MW from the wholesale energy market and pay the Pacificorp Balancing Authority Area the required transmission costs; 2) purchase energy from the UAMPS pool and also pay the Pacificorp transmission costs; or 3) do not supply the 1 MW of energy and pay Pacificorp's Balancing Authority Area imbalance energy charges.

[55] BP-12-E-BPA-40 at 9.

~~demarcation could provide no tangible reason or evidence to justify a 10 MW limit other than, "it feels right."~~

iii. BPA Should Provide ULS to COUs who are Transfer Customers Regardless of the Regional Dialogue Product the COU Selected to Serve its Load up to its RHWM During a Rate Period

Snohomish supports BPA providing relief, on a temporary basis through ULS under the FPS-12 rate, *to all Transfer customers* who have applied for, but cannot secure the necessary Firm Network Transmission service in a timely manner to deliver a market purchase or new, non-Federal specified resource needed to serve their native load. ULS is a seemingly appropriate solution for *all* of BPA's Transfer customers under these circumstances. Such transmission constraints are widely known and affect many of BPA's Transfer customers, regardless of the product they select when purchasing Tier 1 power from BPA.

c. If BPA Proceeds to Expand and Implement ULS as Proposed, the GRSPs Must be Revised

i. BPA Must Adequately Price Unanticipated Load Service to Avoid Cost Shifts

As stated above, Snohomish opposes ULS for the permanent loss or failure, or delays to the online date of a new, non-Federal Specified Resource noticed to serve the COU's Above-RHWM load. However, if BPA elects to adopt ULS as proposed under revisions to the FPS-12 rate schedule attached to BP-12-E-BPA-40, then BPA must ensure that COUs purchasing ULS pay the full cost BPA incurs to provide the service. BPA staff stated in testimony and again during cross-examination that it intends to establish a price for ULS that fully recovers BPA's costs to provide ULS "to avoid cost shifts to customers that do not take such service."[56] BPA staff has proposed language in the GRSPs allowing BPA to adjust the energy rate if the applicable diurnal period forecast market price (plus any additional costs incurred by BPA) is

[56] *See* BP-12-E-BPA-40 at 9-10; Tr. at 21, lines 15-20.

higher than the rate listed in the GRSPs.[57] However, BPA would make such adjustments only if ULS is taken for more than one year, with the adjustment occurring mid-rate period.[58]

To adequately recover the full costs incurred by BPA and to avoid cost shifts to other BPA customers, BPA must revise the GRSP language for ULS under the FPS-12 Rate Schedule so it can adjust the listed price on two (and possibly more) occasions as follows: (1) at the time each contract for ULS is entered into, allowing BPA to include the actual purchase price if BPA has made all or part of the purchase at the outset; and (2) at the time BPA makes additional purchases to provide ULS service under any particular contract.

ii. BPA Must Ensure there are no Stranded Costs in the Event ULS is Required by a COU who also Purchases Transmission Congestion Management Services from BPA-Power Services

If a COU elects to purchase ULS because of difficulties it faces obtaining Firm Network Transmission service to serve its above-RHWM load, BPA must revise the GRSP language to allow recovery of any stranded costs that could be created by the COU switching from TCMS to ULS. By its terms, ULS is only available under the FPS-12 rate schedule to mitigate transmission service difficulties if the utility also faces "high TCMS charges."[59] If a customer elects TCMS, the TRM requires BPA to "go to the market to provide the [TCMS] service,"[60] and the charge is set to recover BPA's full costs.

If the COU subsequently elects to contract with BPA for ULS under the FPS-12 rate, then BPA must ensure it does not incur stranded costs from that customer who would no longer be taking TCMS service (e.g., in the event of permanent resource failure or loss). BPA hinted at the possibility of stranded costs when it stated that it "…believes there would still be limited cost

[57] *See* BP-12-E-BPA-40 at Attachment 3, page 3-2.
[58] *See id.* at 9.
[59] BP-12-E-BPA-40 at Attachment 3, page 3-1 (setting forth revised language for ULS in the GRSPs).
[60] *See* TRM-12-A-02 at 80 (section 8.3).

risk to BPA and other customers if the eligibility [of ULS] is expanded. That risk would be further reduced in all instances if BPA reserves the right to adjust the rate year-to-year when the customer requests ULS for more than one year of the rate period."[61]

III. NON-SLICE COST POOL

JP02 has suggested that BPA's proposal to include certain costs in the Non-Slice Cost Pool is potentially inconsistent with the TRM.[62] These costs were Balancing Augmentation, Transmission Losses, and Unused RHWM.[63] BPA staff addressed this charge in rebuttal testimony and concluded that the costs noted by JP02 were properly allocated and consistent with the TRM.[64] Joint Party No. 8 ("JP08") also addresses these concerns, supporting that BPA acted appropriately in this instance.[65] Snohomish agrees with BPA staff that the costs described above were adequately noticed, have been properly allocated, and that no further change is necessary or warranted.

IV. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE RATE

a. BPA Should Not Adopt the Dispatchable Energy Resource Balancing Service Rate as Proposed

In this proceeding, BPA has proposed a Dispatchable Energy Resource Balancing Services ("DERBS") rate in an attempt to capture the costs of providing balancing reserves to non-Federal thermal generators. BPA has defined a "dispatchable energy resource" to mean "any non-Federal thermally based generating resource that schedules its output or is included in BPA's Automatic Generation Control systems."[66] While Snohomish agrees the cost of providing balancing reserve capacity should be charged to those generators consuming them, BPA has not

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61 BP-12-E-BPA-40 at 9.
62 BP-12-E-JP02-01 at 3, 14-15.
63 *Id.* at 14.
64 BP-12-E-BPA-36 at 6-7.
65 BP-12-E-JP08-02.
66 See Attachment 1, ACS-12 Rate Schedule.

adequately demonstrated it is not already collecting for a variety of ancillary services for thermal generators that are behind a customer's meter. Therefore until such time that BPA can clearly demonstrate that it is not double collecting, the DERBS rate should not be implemented.

Snohomish has two behind-the-meter non-Federal thermal generators that would be subject to the proposed DERBS rate – the Kimberly-Clark and Hampton Lumber Mill cogeneration facilities.

If BPA ignores Snohomish's concerns that the DERBS rate may duplicate charges already being assessed on behind-the-meter generators and proceeds to implement the rate, then at a minimum there are modifications which Snohomish believes would help the rate achieve its intended objective.

b. The DERBS Rate Should be Comprised of a Base Charge and a Variable Charge

BPA has proposed two different rate designs for its product DERBS.[67] The first rate is comprised of a base charge for 2 MW of balancing reserve capacity equal to twenty percent of the DERBS revenue requirement and a variable charge for reserve capacity above 2 MW which will recover the remaining eighty percent of the DERBS revenue requirement.[68] The alternative rate also provides 2 MW of balancing reserve capacity for each non-Federal thermal generator, but recovers 100% of the DERBS revenue requirement through the variable charge for reserve capacity above 2 MW.[69]

Snohomish prefers the first rate design over the alternative. This rate recovers twenty percent of the DERBS revenue requirement through the base charge and the remainder of the revenue requirement through the variable charge. This improves certainty for both customers and

[67] BP-12-E-BPA-47.
[68] *Id.* at 2.
[69] *Id.* at 3.

BPA, and reduces the risk that BPA will not be able to fully recover the costs it incurs to provide balancing reserves.[70]

c. The DERBS Rate Billing Determinant Should be Based Upon a "Demonstrated Maximum Peak Capacity"

Through its testimony BPA proposes to tie the base charge to the non-Federal thermal generator's nameplate rating.[71] There are numerous instances where conditions and operating restrictions limit a resource from generating at or near its full nameplate rating.[72] Such conditions and restrictions can include fuel, boiler, machinery, and other similar constraints placed upon the generator.[73] If BPA proceeds with implementing a DERBS rate for FY2012-13, Snohomish has argued that the billing determinant for the base charge be on the resource's "demonstrated maximum peak capacity." Snohomish proposed to define "demonstrated maximum peak capacity" the generator's maximum one-minute output (in megawatts) during the previous three years of operation.[74]

Snohomish advocated that BPA require supporting documentation that shows the demonstrated maximum peak capacity and the limitations or constraints on the resource that keep it from reaching its nameplate rating. Adopting this change recognizes the reality that some generators cannot achieve their full nameplate capacity, and will allow BPA to capture any physical or operating restrictions on the generator. Further, basing the DERBS billing determinant on a demonstrated peak will more fairly and accurately apportion costs based on the actual reserve quantity the generator could require.

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70 *See* BP-12-E-SN-06 for additional discussion.
71 BP-12-E-BPA-47 at 2.
72 BP-12-E-SN-06 at 3.
73 *Id.*
74 *Id.*

d. The Balancing Reserves Provided to each Generator Should be Increased From 2 MW to 3 MW

BPA proposed that 2 MW of balancing reserve capacity be provided to each generator. Snohomish also recommended that this amount be increased to 3 MW. This revision better aligns with BPA's criteria that applies the DERBS rate to Dispatchable Energy Resources 3 MW nameplate capacity or greater.

e. BPA Must Structure the DERBS Rate Such That There Are Not Duplicative Charges

In its testimony BPA has failed to fully explain how the DERBS rate, which includes three within hour components (regulating reserves, following reserves, and imbalance reserves), is not already being collected for the regulating component that is embedded in the Regulation and Frequency Response ("RFR") rate. The RFR rate is already being assessed on loads and behind-the-customer-meter resources inside the BPA BAA.

BPA applies the forecasted cost of providing RFR against the average BAA load, resulting in a mill per kilowatt-hour charge. This charge is then applied to the total load a customer (like Snohomish) is responsible for. Snohomish's monthly transmission invoice shows that BPA derives total load from Snohomish's metered load (in/out) plus the sum of generation from "behind-the-meter" non Federal generating resources (hydro and thermal). This results in the billing determinant to which BPA applies the RFR rate.

The way BPA accesses the RFR rate, a customer like Snohomish cannot compare the costs recovered for the regulating reserves set aside for load following from the regulating reserves set aside for non-Federal thermal resources. Since the two rates recover costs based on different and perhaps even contradictory billing determinants, there is no standard for comparison.

For this reason, we do not believe BPA has adequately demonstrated there is no double-collection of the regulating reserve component within DERBS and RFR as applied to non-Federal thermal resources, and therefore should not imposed the DERBS rate at this time.

V. VARIABLE ENERGY RESOURCE BALANCING SERVICE – SOLAR RATE

BPA has proposed a VERBS rate for solar generating resources within BPA's BAA. Snohomish agrees that establishing a rate for providing balancing reserve capacity for solar resources inside BPA's BAA is appropriate. However, as stated in Snohomish's testimony, BPA's proposed VERBS rate for solar generators could collect more revenues than needed to offset the cost of providing balancing reserves.[75]

The risk of establishing an improper rate is exacerbated in situations, as is the case here, where BPA lacks necessary data. BPA staff admits: "We do not have any scheduling data [from solar projects]."[76] A rate that is higher than necessary could be a disincentive for future solar projects in BPA's BAA, while a rate that is set too low could create costs shifts. Currently, there are no utility-scale solar projects installed in the BPA,[77] but BPA forecasts it expects up to 34 MW of solar generating resources by the end of the rate period.[78] Given the danger of setting the precedence with a VERBS rate for solar generators that is half of the rate of the VERBS rate for wind, Snohomish has recommended that BPA at least strive to establish a VERBS solar rate at a level no greater than necessary to fully recover costs.

To overcome the lack of data noted by BPA staff, Snohomish proposed BPA take a similar approach to that taken for small wind projects of less than 20 MW nameplate capacity in

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75 *See* BP-12-E-SN-02 at 1-2; BP-12-E-SN-07 at 1-2.
76 BP-12-E-BPA-47 at 5.
77 BP-12-E-SN-02 at 1-2.
78 BP-12-E-BPA-47 at 45.

the FY 2010-11 rate period.[79] In order to "get it right," Snohomish proposes BPA exempt solar projects of less than 20 MW AC nameplate capacity from the VERBS solar rate during fiscal year 2012. This would allow BPA a full year to collect the minute-by-minute generation and hourly schedule data to more accurately determine the solar balancing capacity reserve requirements for northwest solar resources. BPA could then develop and implement in fiscal year 2012, a VERBS solar rate that fairly and accurately collects BPA's costs for providing reserves.

VI. SUPPLEMENTAL VARIABLE ENERGY RESOURCE BALANCING SERVICE

BPA has proposed an optional service for customers with variable energy resources located within the BPA Balancing Authority Area ("BAA"). This optional service "supplements" the existing Variable Energy Resource Balancing Service ("VERBS"). VERBS Supplemental Service provides customers with an additional amount of non-Federal balancing reserve capacity to decrease the number of DSO-216 curtailment events the customer's variable energy resource could be subject to.[80] Snohomish generally supports BPA's approach in the development of the Supplemental Service rate that the cost of providing the VERBS Supplemental Service from a third party's non-Federal resource should be recovered solely from the customers requesting the service, with no cost shifts to other customers.[81]

In testimony BPA did not go into the details about how it will access any third-party reserves it purchases from non-Federal resources to provide the VERBS Supplemental Service. In the event BPA procures and subsequently deploys third-party *inc* reserves within the hour so a customer's project avoids DSO-216 curtailments, energy and capacity must be transmitted or delivered from the third-party to a BPA interconnection point. Doing so incurs additional costs not currently included in the Supplemental VERBS rate. Examples of such costs include the cost

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[79] *See* WP-10-A-02/TR-10-A-02 at 9.
[80] *See* BP-12-E-BPA-45.
[81] BP-12-E-BPA-47.

of the reserved firm transmission capacity to the BPA interconnection point, real power losses, any ancillary services, and administrative overhead required for BPA to implement this service.[82] Neglecting to include such costs in the Supplemental VERBS rate will cause cost shifts to BPA's other customers.[83]

Snohomish stated in its surrebuttal testimony its concerns regarding the unintended consequences of BPA procuring supplemental balancing capacity through Requests for Proposals with six-month terms, while providing the option for customers to purchase Supplemental VERBS for an individual month. Snohomish proposed that BPA can solve this problem, and avoid incurring stranded costs, by aligning its notice provisions for Supplemental VERBS with its other Balancing Service Elections.[84]

VII. COMMITTED INTRA-HOUR PILOT

Snohomish opposes BPA's proposed Committed Intra-Hour Scheduling pilot ("CIH Pilot") as it discriminates against at least one group of BPA's customers with variable energy resources. One such customer group is those who contracted with BPA under the Regional Dialogue contracts for the Block/Slice product.

The Regional Dialogue contract for the Slice product is based on the presumption that the hourly scheduling arrangements that have existed in the Pacific Northwest for decades would be the same in the future.[85] Snohomish, like BPA's other Slice customers, pays its share of the costs of the Federal Base System for each percentage share of the system it contracts for. In

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[82] *Id.* at 3.
[83] *See id.* (containing additional discussion of how these costs may arise).
[84] BP-12-E-SN-07.
[85] Section 2(a)(8) of Exhibit E of the Snohomish Slice contract states that: "All Transactions shall be stated in the time zone specified by WSCC and shall be in 'hour-ending' format." Section 2(a)(9) of Exhibit E states: "All Schedules, except Dynamic Schedules, will be implemented on an hourly basis using the standard ramp as specified by WSCC procedures."

exchange, Snohomish receives its percentage share of the output and flexibility inherent in the Federal Base System with which to serve its load and balance its resources.

Limiting a Slice customer's participation in the CIH pilot means the fundamental structure of the Slice product and the value derived from the flexibility inherent in the Federal Base System that Slice customers are paying for is compromised.

VIII. TREATMENT OF THE MONTANA INTERTIE

Some rate case parties have proposed that BPA roll costs currently recovered by the Montana Intertie rate into the rates for BPA's general transmission network.[86] Snohomish understands that this action is not expected to have any impact on BPA's general transmission rates for the fiscal year 2012-13 rate period, but is concerned that about the potential for greatly increased costs in future rate periods due to the need to expand the transmission system to accommodate future uses. As a result of these concerns, and for the additional reasons stated in the initial brief of Joint Party No. 11, BP-12-B-JP11-01, Snohomish strongly opposes rolling costs recovered by the Montana Intertie rate into rates for BPA's general transmission network. Snohomish adopts and incorporates the arguments regarding the Montana Intertie set out in BP-12-B-JP11-01 as if raised and fully briefed herein.

CONCLUSION

For all of the reasons stated herein, the Administrator should take action consistent with the recommendations described above.

Respectfully submitted,

PUBLIC UTILITY DISTRICT NO. 1
OF SNOHOMISH COUNTY, WASHINGTON

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[86] *See*, *e.g.*, BP-12-E-NG-03.

s/ Jeffrey R. Kallstrom
Anne L. Spangler, General Counsel
Jeffrey R. Kallstrom, Associate General Counsel
(425) 783-8250 / (425) 267-6416 (fax)
jkallstrom@snopud.com

Counsel for Public Utility District No. 1 of Snohomish County, Washington

Dated: May 2, 2011

ATTACHMENT A

EXHIBIT LIST

Pursuant to the Hearing Officer's November 19, 2010, Order establishing and titled *Special Rules of Practice to Govern these Proceedings*,[1] and the Hearing Officer's April 14, 2011, *Order on Formatting of Briefs*,[2] the following is a revised exhibit list reflecting the status of all of Snohomish's exhibits, including those admitted, withdrawn, and rejected during the hearing, for the BP-12 consolidated proceeding.

File Code	*Exhibit*	*Status*
BP-12-E-SN-01	Snohomish Direct Testimony	Admitted
BP-12-E-SN-02	Snohomish Direct Testimony[3]	Admitted
BP-12-E-SN-03	Snohomish Rebuttal Testimony	Admitted
BP-12-E-SN-04	Snohomish Rebuttal Testimony	Admitted
BP-12-E-SN-05	Snohomish Surrebuttal Testimony	Admitted
BP-12-E-SN-06	Snohomish Surrebuttal Testimony	Admitted
BP-12-E-SN-07	Snohomish Surrebuttal Testimony	Admitted
BP-12-E-SN-08	Snohomish Surrebuttal Testimony	Admitted
BP-12-E-SN-09	Affidavit of Anna J. Miles	Admitted
BP-12-E-SN-10	Affidavit of Linda A. Finley	Admitted
BP-12-E-SN-11	Affidavit of Ian R. Hunter	Admitted
BP-12-E-SN-12	Affidavit of Jeffrey D. Deren	Admitted
BP-12-E-SN-13	Response to Data Request SN-BPA-35	Withdrawn[4]
BP-12-Q-SN-01	Statement of Qualifications of Anna J. Miles	Admitted
BP-12-Q-SN-02	Statement of Qualifications of Linda A. Finley	Admitted
BP-12-Q-SN-03	Statement of Qualifications of Ian R. Hunter	Admitted
BP-12-Q-SN-04	Statement of Qualifications of Jeffrey D. Deren	Admitted

[1] BP-12-HOO-02 at 5
[2] BP-12-HOO-62.
[3] As modified by the errata found at BP-12-E-SN-02-E01.
[4] Response to Data Request SN-BPA-35 was admitted into evidence on BPA's motion on April 13, 2011. *See* BP-12-HOO-61, *Order Admitting Evidence – Transmission*.