September 19, 2012

Via Electronic Submission
Bonneville Power Administration
techforum@bpa.gov

Re: Comments of Point to Point Customers Coalition to Transmission Rate Schedules.

The Point-to-Point Customers Coalition ("PTP Coalition") submits these comments in response to the proposed changes to the transmission rate schedules discussed during the September 12, 2012 workshop. BPA has stated that it plans to propose a 12 non-coincidental peak ("NCP") method for allocating network costs. For avoidance of doubt, however, the PTP Coalition makes clear that we do not support the 12 NCP method and believe BPA should adopt a 1 NCP method. The PTP Coalition also believes that BPA should develop a full cost of service study before determining transmission rates.

Cost Allocation

BPA staff states that a 12 NCP approach is appropriate based upon: (i) system usage profile; and (ii) system planning. The PTP Coalition disagrees with the underlying assumptions of BPA's staff's rationale.

First, reliance on the relative flatness of BPA's system usage is inappropriate. The FERC tests that BPA uses to make this finding were designed for utilities that serve native load with only a very small percentage, if any, of PTP or third party transactions, which is not at all the case for BPA. Approximately 80% of BPA's transmission revenues are from PTP, integration of resources rate ("IR") and Formula Power Transmission rate ("FPT") customers. This means that about 80% of the BPA's transmission service is associated with reserved capacity as opposed to usage. This ratio between reservation- and usage-based customers biases the FERC test results toward a 12 NCP methodology. It is the non-network transmission ("NT") customers that are creating the relatively flat overall BPA peak load profile, thus skewing the FERC tests to a 12 CP result. If the tests only account for BPA's network customers, the tests would justify a 1 NCP method.

Second, a 12 NCP method is not in line with the way BPA plans for transmission. BPA stated in its 1996 reciprocity petition for declaratory order to FERC that a 1 NCP method was appropriate in part because it reflected how BPA planned its system. BPA stated:

> BPA planning studies look at a winter condition with loads equal to the sum of the utilities' annual noncoincidental demands. BPA also plans for a summer peak on the parts of the FCRTS where peak loading conditions occur in the summer.[1]

BPA summarized its transmission planning process during BP-14 workshops and this summary did not identify any important departures from the planning process described in 1996. BPA plans its system using its internal criteria consistent with NERC reliability standards and WECC powerflow base cases, which are modeled to account for summer and winter seasonal peaks, heavy and light load hour variations, and spring cases with surging hydro conditions. This process determines boundary conditions that reveal system adequacy and transfer capability. As a result of this type of planning, the Northwest today has a transmission system that can, for example, reliably meet peak winter demand which may cover a four- to five-month period lasting from the start of November through the end February. Accordingly, BPA's 1996 rationale for using a 1 NCP cost allocation method still has valid application today.

Finally, the PTP Coalition emphasizes that it does not view 12 NCP as an agreed upon compromise.

Segmentation

BPA should develop a full cost of service study, including a segmentation study, before determining transmission rates. In the 1996 Final Record of Decision, BPA stated that:

> BPA operates and maintains the FCRTS to provide various transmission services throughout the PNW region. Because many services do not require the use of the entire system, the Segmentation Study categorizes the facilities of the FCRTS according to the types of services they provide. The Segmentation Study produces the segmented historical FCRTS investment base and the segmented averages of the last 3 years' actual operations and maintenance (O&M) expenses. *This provides the basis for segmenting the transmission revenue requirements used to develop rates.*[2]

BPA also made clear that the transmission rates should meet FERC's comparability standard.

> Bonneville and its customers have been guided throughout the rate proceeding (and the terms and conditions proceeding) by a desire to arrive at rates, terms and conditions for access to the FCRTS that would conform to the policies announced in the Pricing Guidelines, the NOPR, and ultimately, the Final Rule adopted in Order 888.[3]

The PTP Coalition presented on August 22 a detailed analysis (based upon information available to the PTP Coalition experts) of the network segment as it would look today, based upon current FERC and NERC requirements. The PTP presentation is both consistent with current regulation as well as the methodology employed in the 1996 segmentation study. The study stated that:

> BPA facilities are segmented on the basis of voltage and function. The final determination of segmentation of the network for this proceeding incorporates the Settlement Agreement.[[4]] The segmentation study developed in prior rate

[2] 1996 Final Record of Decision (WP-96-A-02) at 409 (emphasis added).

[3] *Id.* at 31.

[4] The 1996 Transmission Settlement allowed certain facilities to be allocated to different segments or made other concessions. Those concessions have no precedential value and demonstrate that BPA modified the segmentation study to the extent necessary to support the Settlement.

proceedings is the starting point for the Final Study. In order to identify the facilities and the associated costs that provide a specific type of service, the segmentation process was originally based upon:

- Power flow studies, on-line diagrams and other technical data that indicate the operating voltage of each facility and type of service.
- Contracts and rate structures.
- Work orders under which each of the facilities were constructed, standard costing procedures and accounting principles; and standard utility business practices.

In determining the cost of each segment, the following sources were used:

- The accounting records maintained by BPA's Plant Investment Section;
- The equipment catalogue from BPA's Division of Materials and Procurement;
- The cost studies of the Division of Substation and Control Engineering. These studies provide the relationship of equipment cost to the total cost, including installation and costs associated with specific accessory equipment that form integral units such as line terminals;
- Standard costing procedures and accounting principles; and
- Actual and forecasted data from the Corps and the Bureau.[5]

It is noteworthy that included in the list of Tables were a summary of the BPA plant investment 9/30/95, Summary of Investment 9/30/95, Summary of Segmented Corps Plant, Summary of Segmented Bureau Plant, and Summary of Segmented 3 year average O&M. Taken together it is clear that BPA has historically required a segmentation study before determining transmission rates.

Conclusion

We urge BPA to have an open mind during the upcoming transmission rate case. We request that BPA provide certainty as to when it will update the 1996 cost of service study and segmentation analysis.

Sincerely,

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On behalf of: Benton County Public Utility District No. 1; EDP Renewables; Franklin County Public Utility District No. 1; M-S-R Public Power Agency; Seattle City Light; Snohomish County Public Utility District No. 1; Tacoma Power

[5] Final Segmentation Study at 5 (June 1996).