BP- Rate Case (Transmission Services)
Customer Responses to Scope of COSA Process, January 26, 2012

COMMENTS OF CITY OF IDAHO FALLS, CLARK PUBLIC UTILITIES, COWLITZ PUD, EUGENE WATER & ELECTRIC BOARD, NORTHWEST REQUIREMENTS UTILTIES, PNGC POWER, AND THE WESTERN PUBLIC AGENCIES GROUP ON THE BONNEVILLE POWER ADMINISTRATION'S PROPOSAL FOR THE SCOPE OF TRANSMISSION COST OF SERVICE ANALYSIS

These comments are submitted on behalf of the following association members and individual utilities: City of Idaho Falls, Clark Public Utilities, Cowlitz PUD, Eugene Water & Electric Board, Northwest Requirements Utilities, PNGC Power and the Western Public Agencies Group ("NT Customers"). They are in response to the Bonneville Power Administration's ("BPA") proposal for the scope of the Transmission Cost of Service Analysis ("COSA") process, released on January 26, 2012.

While some of the NT Customers take Point to Point Transmission Service ("PTP") for various reasons, each of them relies on the Network Transmission Service ("NT") provided by BPA to reliably deliver power to their service areas to meet the electrical needs of their retail customers at an economical rate. For this reason, the stability and predictability of the NT rate is a key element in their resource planning activities. The NT Customers have a vital interest in the method used by BPA to set the NT rate, and appreciate BPA's continuing efforts to engage all transmission customers in a dialogue on this topic.

The last time BPA fully litigated a transmission rate case was in 1996. Since that time, BPA and its transmission customers have settled every transmission rate case including the most recent BP-12 rate case. This pattern of successive settlements of transmission rates over the last fifteen years has created a concern among some BPA transmission customers that many of the 1996 assumptions behind the methodologies employed by BPA to allocate costs between the different transmission services might not accurately reflect the differences between NT and PTP service. To address this concern, parties to the BP-12 Transmission Settlement Agreement ("Settlement Agreement") agreed that BPA would perform a transmission COSA before the beginning of the BP-14 rate case, and that the outcome of that process would be used to inform BPA's initial proposal for the BP-14 rate case.

BPA has conducted a series of workshops on this topic at which there has been a considerable discussion regarding the scope of the COSA process as agreed to in the Settlement Agreement. Based on this dialogue, BPA has issued a proposal for conducting the COSA analysis that includes only the following rate development steps:

(1) Adjustments to the illustrative segmented revenue requirement (e.g., revenue credits, DSI delivery costs);

(2) Determination of the costs allocated to each transmission service and the two required ancillary services, and

(3) Allocation factors for determining the allocation of costs among Network Services.

The NT Customers understand that the third proposed step, determining the allocation factors for distributing costs among the Network Services, is at the heart of the COSA process. This will be the step in which the basis (or bases) will be identified for use in allocating costs to the Network Services. Based on comments by BPA in prior workshops, it is also the NT Customers' understanding that the basis (or bases) for this allocation will be the subject of a number of BPA workshops prior to its use in informing into BP-14 initial rate proposal. With those understandings, the NT Customers support BPA's proposed approach to the preparation of an illustrative COSA for such use in BPA's initial BP-14 rate proposal.

As part of its COSA process proposal, BPA has expressly excluded from consideration a number of topics that will undoubtedly get a thorough examination during other phases of the BP-14 rate case. These excluded topics are rate design, determination of revenue requirements, segmentation, sales forecast, and the Eastern Intertie. The NT Customers support BPA's proposal to exclude these divisive and time-consuming topics from the COSA process.

The Settlement Agreement, pursuant to which the COSA process is being conducted, stated a specific objective: to work with customers to define the parameters of a cost of service study. BPA's proposal to limit the scope of the COSA process to the three steps identified above is sufficient to meet BPA's COSA obligations under the Settlement Agreement and will provide BPA a focused opportunity to remedy any deficiencies in its current transmission cost allocation methodologies that may be identified. In addition, BPA's proposal will not open up issues that the parties never intended be part of the COSA process. The Settlement Agreement sets out those specific issues that are the subject of special pre-rate case processes. With regard to the COSA, it obliges BPA to complete an illustrative COSA in order to ensure a clear and transparent cost of service determination; it was never intended as a pre-rate case opportunity for parties to test their rate case arguments on every other rate case issue.

As an example of how far afield the COSA process could be taken, some parties have suggested that the COSA process should include an examination of BPA's segmentation policy. However, there was no agreement in the Settlement Agreement, either express or implied, to revisit BPA's segmentation methodology either in the COSA process or otherwise outside the rate case. Segmentation is a sufficiently important issue that if parties had intended to discuss it in the COSA process, it would have been expressly called out in the Settlement Agreement. In fact, this is exactly what the parties did for the Eastern Intertie, which is a sub-issue in the overall segmentation discussion. Section 2.b of the Settlement Agreement expressly provides that BPA will make available a forum during the rate period for interested customers to discuss the Eastern Intertie and associated rates. It is illogical to assume that the parties to the Settlement Agreement implicitly agreed by their silence on the topic to include segmentation in the COSA process, while in the same document expressly calling out the need for a separate workshop to discuss the Eastern Intertie. Accordingly, BPA's proposal to exclude issues concerning its segmentation policy is appropriate and consistent with the intent of the Settlement Agreement.

The NT Customers appreciate this opportunity to comment on the critical COSA process. We are encouraged by BPA's efforts to conduct an open and collaborative process on this topic. The NT Customers look forward to working with BPA in the spirit of reaching a fair and equitable conclusion regarding the allocation of costs for Network Services.

To: Techforum@bpa.gov; Rebecca Fredrickson (by E-mail)

From: Henry Tilghman on behalf of EDP Renewables (EDPR)

Date: February 2, 2012

Re: COSA Process Comments

Tilghman Associates submits the following comments on behalf of EDPR. EDPR appreciates the opportunity to provide these comments on the *Cost of Service Analysis Scope* document posted by Bonneville on January 26, 2012.

EDPR concurs with the ratemaking principles Bonneville has proposed;

- Consistency with BPA statutes
- Costs should be allocated to customers based on proportionate use
- Simplicity and feasibility

As the *Cost of Service Analysis Scope* document notes, Section 6 of the BP-12 Transmission Settlement Agreement requires BPA to "work with interested transmission customers in an open and collaborative forum to define the parameters of a cost of service study that includes consideration of alternative methodologies for allocating demand-related costs and that determines the costs of BPA's major transmission services." It also requires BPA to "complete an illustrative cost of service study using forecasted data from a recent fiscal year" which will be shared with customers, with the methodology from the study to be used for BPA's initial proposal for the BP-14 rate case.

In the workshops leading up to the Transmission Settlement Agreement, many parties, including EDPR, expressed concern that Bonneville's then-current rates were not based on an appropriate allocation of costs between rate segments. Anecdotally, EDPR understands that a full segmentation study has not been conducted since before 1996 – since then segmentation issues have been included in rate case settlements between the parties. Furthermore, the initial allocation of costs between Point to Point (PTP) and Network (NT) Rates in 1996 was itself the result of a settlement agreement. It is significant to note that EDPR was not a customer in 1996, did not become a PTP customer until 2002, and has never participated in a rate case examination of segmentation issues.

In many cases it appears that customers with NT service receive a higher level of service than PTP customers. See the attached presentation of Snohomish County PUD dated September 15, 2010. Consistent with cost causation principles facilities, programs, and employees that benefit NT customers should be allocated to those customers based on their proportionate use. Such a direct assignment of facilities and program costs to a specific customer class is consistent with the rationale which resulted in direct assignment of Wind Integration Team costs to the VERBS Rate.

EDPR understood the quoted language from the Transmission Settlement Agreement to include review and discussion of Segmentation issues; specifically including the allocation of costs between PTP and NT Rates and review of the other Network Segments. Accordingly, EDPR agrees that the COSA Process must include Segmentation related to the Network Segments. EDPR, however, also agrees that issues and costs associated with the Southern Intertie and Eastern Intertie (including the Montana Intertie) should not be a included in the COSA Process.

As part of the review related to Segmentation issues set out in the Transmission Settlement Agreement, EDPR believes that Bonneville must examine, with customer input, whether the existing Network Segments need to be modified and whether additional Network Segments should be added. For example:

- In Section 2 of the Proposed COSA Scope, Bonneville omits the Generation Integration (GI) segment. GI costs should be included in the discussion.
- The Utility Delivery Segment (UD) should be examined. EDPR believes that some facilities above 34.5kV may be used exclusively for NT service. If so, and consistent with the cost causation principles articulated by Bonneville, these facilities should not be allocated to the Network segment shared by NT and PTP customers.
- Bonneville should consider creating a Dynamic Transfer Capacity segment for customers with historic dynamic transfer rights. Unfortunately, Bonneville's dialogue with customers on dynamic transfers to date has been limited to new, incremental usage. All NT, and some PTP, customers however are consuming existing dynamic capacity on the Bonneville system. Many PTP customers (likely the majority) do not have a dynamic component to their service – and if

> they desire to add it they will have to pay an incremental rate for the service. EDPR believes it is appropriate to identify the facilities and programs used to support the historic levels of dynamic transfers and allocate the associated costs to those customers who receive the benefit of those services. In workshops, Bonneville staff has stated that load consumes dynamic transfers differently from generators; this assertion, however has not been supported with evidence. In fact, an NT customer with a mostly residential load probably does consume dynamic capacity much differently from a generator or from an NT customer with large industrial or commercial loads. The dynamic requirements of large industrial loads and irrigation loads may actually be more similar to generators than to residential loads. Customers who currently consume existing dynamic transfer capacity should pay for that service in proportion to their use. EDPR concedes that all customers benefit from facilities that provide voltage support for reliability, but notes that customers with a dynamic component to their service benefit disproportionately.

EDPR agrees that the COSA process should include allocation factors for determining the allocation of costs among Network services. Where feasible, Bonneville's cost allocations should be consistent with FERC policy.

From: ann@annfisherlaw.com [mailto:ann@annfisherlaw.com] **On Behalf Of** Ann Fisher
Sent: Thursday, January 26, 2012 4:46 PM
To: Tech Forum
Subject: COSA Process Comments

Thank you for putting together the COSA scoping document. After talking to M-S-R's technical consultant, it would appear that in order for the scoping to be meaningful, we will need the following back up information and responses ot questions indicated:

1. a sufficient level of disaggregation as part of the Segmentation provided

2. Does BPA do its accounting by FERC Uniform System of Accounts for Plant & Expenses? (All BPA work papers should be in Excel spreadsheets. Documentation of sources is very important so that the study could be replicated.)

3. Need a solid engineering basis or definition of transmission facilities, (Generation Interconnection, Lines, & Substations).

(This will form the basis for breaking out gross plant in service.)

4. A break out the dollars and costs for those portions of the Transmission system that are being excluded from the analysis.

5. Detailed vintage (yrs) data on facilities for figuring out depreciation rates

6. methodology of Transmission O&M available for review.

7. cost for BPA's FTE and contractors that work on Transmission and the basis for allocation of A&G costs (Acctg and IT staffing and other Executive Overhead).

8. A detailed accounting of BPA Treasury Debt which is solely attributable to the transmission investments being studied.

Ann L. Fisher
Legal & Consulting Services
Mail to: PO Box 25302
Portland, Oregon 97298
located at: 4800 SW Griffith Ave, Ste 125
Beaverton, Oregon 97005
503-721-0181; facsimile 503-291-1556

PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

February 2, 2012

Bonneville Power Administration
Transmission Services
P.O. Box 64019
Vancouver, WA 98666-1409

Submitted to: techforum@bpa.gov

Re: **COSA Process Comments**

By email dated January 26, 2013 BPA requested comments on their proposal for the scope of the Transmission Cost of Service Analysis (COSA) process as outlined in section 6 of the BP-12 Transmission Settlement Agreement. PacifiCorp appreciates BPA's efforts to "work with interested customers in an open and collaborative forum" and we look forward to continuing this effort both in these COSA workshops and in the BP-14 transmission rate case workshops to follow. While PacifiCorp appreciates the opportunity to provide these comments, although we note that the COSA Workshop process remains ongoing. As appropriate, PacifiCorp may submit additional comments at a later date.

BPA has presented how they currently develop their segmented revenue requirement. However, customers need greater clarity on the development and use of customer peak data both for cost allocation and the calculation of rates. PacifiCorp anticipates that these remaining issues will be addressed in further workshops.

PacifiCorp looks forward to reviewing BPA's segmented revenue requirement model with the accompanying peak cost allocators and billing factors. This review will allow PacifiCorp to perform necessary scenario analysis and increase our understanding of various proposals.

PacifiCorp appreciates BPA's consideration of these comments.

Sincerely,

Phil Obenchain
Director, Bonneville Regional Affairs PacifiCorp

February 2, 2012
U.S. Department of Energy
Bonneville Power Administration
Transmission Services
P.O. Box 64019
Vancouver, WA 98666-1409

Via Email: techforum@bpa.gov

Re: Comments of Puget Sound Energy, Inc. on the Presentation Entitled "Cost of Service Analysis Scope," distributed January 26, 2012

Dear Ladies and Gentlemen:

In this letter, Puget Sound Energy, Inc. ("PSE") comments on the document entitled "Cost of Service Analysis Scope," distributed on January 26, 2012 (the "COSA Scope Presentation"). PSE thanks Bonneville Power Administration ("BPA") for the opportunity to comment and to work cooperatively with BPA on these issues.

The "COSA process" should help BPA's customers understand a number of important elements of BPA's ratemaking process in the period prior to the commencement of the BP-14 rate proceeding. In that regard, it will be particularly helpful for BPA's customers to receive a functional cost of service model and have the ability to work with such model to understand the algorithms contained within the model. Additionally, BPA should discuss with its customers the principles to be relied upon in the allocation of costs within the cost of service model.

BPA has indicated that a number of rate development steps are "outside the scope of the COSA process". Reasonable limitations on the scope of the "COSA process" are understandable, in light of BPA's need to produce a cost of service model for use by BPA's customers in advance of the BP-14 rate proceeding. Of course, PSE recognizes that the cost of service model will be subject to review and possible revision during the course of the BP-14 rate proceeding.

Given the exclusion of certain rate development steps from the "COSA process," BPA should, in parallel with the "COSA process," conduct workshops and provide information to its customers on such rate development steps, including, for example, the functionalization of BPA's revenue requirement between power and transmission and rate design.

PSE appreciates BPA's review of these comments and consideration of the recommendations contained herein. By return e-mail, please confirm BPA's receipt of these comments.

Very truly yours,

Puget Sound Energy, Inc.

By: ________________________
Title: ________________________

February 2, 2012

Bonneville Power Administration
Attn: Ms. Rebecca Fredrickson
P.O. Box 3621
Portland, Oregon 97208

Re: Comments on BPA Proposed Scope of Transmission Cost of Service Analysis

Dear Ms. Fredrickson,

The Public Utility District No. 1 of Snohomish County, Washington ("Snohomish"), submits this letter in response to BPA's January 26, 2012 request for comments on the scope of the Transmission Cost of Service Analysis ("COSA") process required in Section 6 of the BP-12 Transmission Settlement Agreement ("Settlement Agreement"). Snohomish appreciates BPA's effort to further define the scope of the COSA. However, without further expansion in the scope as discussed below, Snohomish is unable to consent to the proposal.

Revenue Requirements

Snohomish proposes that the COSA process begin with an explanation of the segmented revenue requirements as it is critical to fully understanding BPA's current transmission cost of service analysis and determining whether an alternative to that analysis is warranted. Snohomish is unclear as to how BPA determines which facilities and associated costs of the transmission system (e.g., intra-agency costs, overhead costs) fall into the relevant segments. As BPA has previously noted, because a rates settlement was reached, BPA's draft segmentation study was not published. BPA can assist customers by producing the raw data, the relevant FERC accounts and the model BPA used in its draft segmentation study. The model should be in an Excel format to allow customers to evaluate different scenarios.

To the extent BPA believes that allowing customers to fully understand the determination of the segmented revenue requirements is outside the scope of the COSA process, we disagree. The first step in a cost of service study under traditional ratemaking is to understand the revenue requirement. In addition, the Settlement Agreement states that BPA will work with its customers "to define the parameters of a cost of service study that ***includes*** consideration of alternative methodologies for allocating demand-related costs and that determines the costs of BPA's major transmission services." The term "includes" does not restrict the parameters of a cost of service study to only cost allocation and the costs of transmission services. Snohomish does not intend to challenge the costs included in the revenue requirements, but only to understand how those costs are divided between the relevant segments.

2320 California Street • Everett, WA • 98201 / *Mailing Address:* P.O. Box 1107 • Everett, WA • 98206-1107
425-783-1000 • Toll-free in Western Washington at 1-877-783-1000 • www.snopud.com

Revenue Credits

Snohomish is unclear as to (i) what constitutes a revenue credit (e.g., only short-term sales, long-term and short-term sales, or prepayments that certain categories of customers make for transmission service), (ii) how that credit is applied, i.e., to the total revenue requirement or to each segmented revenue requirement, and (iii) why it may be more appropriate to apply a revenue credit to each segmented revenue requirement than to the total revenue requirement.

Assignment of Costs to Each Transmission/Ancillary Service

Snohomish is unclear as to the relationship between the segments and the categories of service. Snohomish requests that BPA clarify (i) whether each segment has different categories of service, (ii) what types of costs within each segment are directly assigned to the various services, and (iii) what criteria BPA applies in determining what types of costs are assigned.

Survey of Rate Methodologies

Snohomish believes that a survey of the cost of service methodologies used by other federal power marketing agencies like Western Area Power Administration and Tennessee Valley Authority and other non-public utilities would be helpful in evaluating which methodology is appropriate for BPA.

Relationship between BPA Power and BPA Transmission

Snohomish is interested in understanding the intra-agency costs between BPA Power and BPA Transmission. If there are costs, how are they assigned to the different segments?

NERC Costs

Snohomish requests that BPA clarify (i) how transmission costs associated with NERC compliance are currently allocated to the services within each segment, and (ii) what NERC-related activities BPA provides to specific types of services.

Canadian Entitlement

Under the Columbia River Treaty, a significant amount of power is delivered from the United States to Canada. Snohomish requests that BPA explain how BPA recovers the costs associated with that delivery of power.

Effects of Order No. 1000

BPA is currently working with Snohomish and other members of ColumbiaGrid to help ColumbiaGrid meet FERC's directives in Order No. 1000. What is BPA's opinion of how Order No. 1000 will affect BPA's cost allocation for transmission? Under what circumstances does BPA bring a new transmission line to ColumbiaGrid for cost allocation purposes?

BPA's Viewpoint

Snohomish believes it would be helpful for customers to understand what BPA considers as the biggest drivers of transmission rates and where the most judgment is applied in developing COSA studies.

Sales Forecast

Snohomish understands that the sales forecast methodology is outside the scope of the COSA process. However, we would like to confirm that customers can review the sales forecast as part of the rate case. If not, Snohomish would like to know in what forum customers will have an opportunity to perform such a review.

Regulatory History

Finally, Snohomish believes that in order for customers to put the COSA process in context, a review of the regulatory history of BPA's transmission cost of service is necessary. Snohomish understands that under previous rate cases customers have raised issues regarding transmission costs. Snohomish is interested in knowing whether these issues were resolved and if so, under what rationale.

Sincerely,

Giuseppe Fina

for Dana A. Toulson
Assistant General Manager
Power, Rates & Transmission Management

Tacoma Power's Comments on BPA's Scope of COSA Process

Tacoma Power makes the following comments on the "Scope of COSA process" that BPA put out for comment on January 26, 2011. Tacoma Power expects that this process will produce a fully functional transparent spreadsheet Transmission COSA model that BPA will use in its WP-14 Initial Proposal. The public workshop process around the rebuild of the Power Rates Analysis Model prior to the WP-12 case to implement the TRM should serve as a model for what we hope to achieve on the Transmission side. This will fulfill the requirements of Section 6(c) of the Settlement which stated:

> *c) share the cost of service model with customers to ensure clear and transparent cost of service determinations. BPA will use the methodology from the study in the initial proposal for the 2014 rate case to prepare rate designs and allocate costs among rate classes.*

We believe that the Transmission cost of service model should be much simpler than the RAM to build, maintain, and use given that BPA's Transmission rate calculations are relatively simpler than its Power rate calculations. The goal would be to create a model that will be user friendly and transparent, and includes all the necessary detailed input data to create allocation factors and perform all other necessary calculations internally in order to understand and track the derivation of every Transmission rate.

We recommend that the modeling should start with detailed expenses and all other revenue requirement elements. These inputs must be reconcilable to the Integrated Program Review. The model should also include inputs of forecasts of revenue credits, detail monthly loads forecasts, and all other inputs necessary to derive each segments' rates. The model should have the following steps and data inputs (page numbers refer to the Presentation from the Dec 5th workshop):

- Detail total Transmission revenue requirement inputs reconcilable to the IPR (showing both Transmission direct and corporate allocation amounts and allocation methodologies)
- Detail monthly load forecasts for cost allocation and rate design purposes (PPT p51, and 33-34)
- The Segmentation step (PPT p7-32)
- The Allocation and Rate Design Steps (PPT p35-45)

The model should be built with the ability to directly assign or allocate in a different manner any necessary costs or revenue credits to a particular rate class (e.g. PTP, NT, IR, etc) within a segment. For instance it might be more equitable to assign Planned Net Revenues for Risk" differently among rate classes. There may be many more examples for the necessity to directly assign or allocate costs to a particular rate class so this capability should be built into the model.

At this time Tacoma Power has no issues with the design of the particular Segments. We will address that issue in the rate case process if it proves necessary.

Finally, rate design discussions should not be outside the Scope of the COSA process. We believe they were intended to be within the Scope as reflected by the language in Section 6(c) of the Settlement Agreement. The rate design step is a fundamental part of the COSA model as we describe above. A general concept in ratemaking and rate design is that higher load factors (high and even utilization of the system across the year) should result in lower unit rates. Arguably a 1CP billing factor or ratchet demand for NT may be more equitable because it reflects the value of a higher load factor for any individual customer within the NT class. Currently, a 100% load factor NT customer pays the same unit rate that a 50% load factor customer does. We feel it would be more fruitful to have any necessary rate design discussion within this process.

Tacoma Power appreciates the opportunity to comment on the Scope of the COSA. If you have any questions about these comments, please contact Jim Russell at 253-502-8395.