Customer Comments on the Cost Allocation Methodologies Presented At the Transmission Cost Of Service Analysis (COSA) Workshops

From: Jack Speer [mailto:jackspeer1@mac.com]
Sent: Thursday, March 22, 2012 10:53 AM
To: Tech Forum
Subject: Cost Allocation Alternatives

In response to your request for comments from customers and other interested parties on the cost allocation methodologies presented at the Transmission Cost of Service Analysis (COSA) workshops, Alcoa urges BPA to continue to use the annual coincidental peak (1CP) method for several reasons:

1. Customers have made, and continue to make long-term decisions based on an expectation of stable and consistent BPA transmission rates. Using the same cost allocation method that has been used for many years allows customers to have confidence in the stability and consistency of future BPA transmission rates.

2. We believe that the allocation of costs should be based, as closely as possible, on cost causation (the principle that rates should be designed to recover costs from the users who are causing those costs). Since transmission systems are mostly built to withstand the largest single loads placed on them, the 1CP method meets that principle better than other methodologies.

3. We believe that the 1CP method results in rates that encourage customers to use transmission facilities more efficiently, i.e. to transmit more annual energy per unit of peak transmission capacity.

4. We believe that the 1CP method results in rates that provide better signals for energy conservation measures, by rewarding those measures that reduce annual peak usage as well as energy usage. This is especially important as Northwest utilities struggle to meet the challenges of integrating new variable energy resources in systems with limited peak capabilities.

CENTRAL LINCOLN
YOUR PUBLICLY-OWNED ELECTRIC UTILITY
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March 29, 2012

BPA Transmission Services
Via Email: techforum@bpa.gov

RE: Transmission Cost Allocation Alternatives

Central Lincoln People's Utility District ("Central Lincoln") is a consumer owned electric utility serving approximately 39,000 customers on the central Oregon Coast. Central Lincoln has historically served its entire load with BPA power and Network Transmission ("NT") service. Central Lincoln is also a member of Northwest Requirements Utilities ("NRU") and agrees with NRU's comments on BPA's Transmission Cost Allocation Alternatives. Central Lincoln also supports the NT Customer Proposal to use a 12 CP Cost Allocation Methodology for the Transmission Cost of Service Analysis ("NT Customer Proposal") submitted by NRU and others. Central Lincoln appreciates this opportunity to comment on BPA's Transmission Cost Allocation Alternatives and would like to use this opportunity to emphasize Section B of the NT Customer Proposal and add its own comments with Section C.

Central Lincoln agrees that 12CP is the most fair and appropriate cost allocation methodology as stated in the above referenced documents. 12CP is an industry accepted standard and is consistent with FERC policy and peak ratio tests. 12CP is also the best way to reflect the way in which BPA plans its transmission system reliability upgrades and thus, the best way to actually allocate BPA transmission system costs.

12CP is also the most appropriate cost allocation methodology because it will assign more costs to PTP users, which are causing more new transmission costs than NT customers. Future NT customer loads require less transmission system expansion and thus will cause less future transmission costs for BPA than PTP users. As a specific example, Central Lincoln's load has had an average annual decrease over the last 5 years. Accordingly, Central Lincoln expects no load growth for the foreseeable future. Even BPA's load forecast for Central Lincoln, which has proven overly optimistic lately, predicts anemic growth for Central Lincoln. Many NT customers are similarly situated. Central Lincoln in particular and NT customers in general are not causing additional transmission costs, and may even be opening up additional capacity for PTP use due to decreased loads.

Despite mostly flat or even decreased NT use, BPA is planning transmission expansions. These transmission expansions are largely to accommodate: (1) increased load in urban/suburban areas along the I-5 corridor largely served by IOUs; or (2) new generation interconnections which will not be serving NT load. Both of these expansion needs are required for PTP use and do not benefit NT customers. BPA will recover costs of these transmission expansions through both NT and PTP rates, not through direct assignment to those requiring the expansions. Even though Central Lincoln will be using very little of the expanded transmission network, it will nonetheless be paying a comparatively larger portion of it. Central Lincoln's argument is not that this is unfair, since there are parts of the system that Central Lincoln uses and is help paid for by others. However, continuing to use a 1CP cost allocation will put a larger portion of these "new" costs on NT customers which does not benefit them as much as PTP customers. Not only is 12CP cost allocation appropriate under each FERC test and an accepted industry standard, but it is inappropriate to place added costs on NT customers through continued use of 1CP cost allocation, when they are not causing these additional costs.

Again, Central Lincoln agrees with NRU's comments, supports the NT Customer Proposal, and appreciates the opportunity to offer its own comments to stand with others in support of a 12CP cost allocation for BPA transmission rates.

Sincerely,

Brandon Hignite
Power Analyst
Central Lincoln PUD

Clark Public Utilities
Customer-owned, customer-focused

Commissioners

Nancy E. Barnes
Carol J. Curtis
Byron H. Hanke

Chief Executive Officer/ General Manager

Wayne W. Nelson

March 30, 2012

BPA Transmission Services
VIA Email: techforum@bpa.gov

RE: Comments on Transmission Cost of Service Analysis Workshop Process

Clark would like to thank BPA for effectuating the TS-12 Transmission Settlement language providing for, among other things, "…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…" Clark appreciates the opportunity to comment on the three cost allocation methodologies identified in the Cost of Service Analysis Workshop (COSA) process. In addition to these comments we strongly support those submitted by the NT Customers.

Since 2006 Clark has waited patiently for BPA to revisit the allocation of costs between the NT and PTP transmission segments. In 2006 BPA brought it to the attention of customers that the Transmission Business Line's transmission loading pattern would support the use of a 12 CP divisor for allocating costs between the network rate classes. At that time, and contrary to cost causation principles, BPA decided against using the 12 CP methodology for allocating costs. It is now 2012 and, as the facts presented by the recent COSA process indicate, the loading pattern continues to support the use of a 12 CP divisor. In fact, based on the principles discussed in the COSA process there are no FERC or Industry accepted justifications for using anything but a 12 CP divisor for allocation of costs between BPA's network segments.

As BPA moves towards a FERC reciprocity tariff it is of the utmost importance for BPA to also put forth and adopt the most accurate FERC approved methodology for cost allocation between BPA's major transmission services. That methodology is the twelve monthly coincident peak allocation methodology or 12 CP divisor. The analysis and justification for allocation of costs based on a 12 CP system are well documented and based on widely accepted allocation principles both at FERC and within the industry. A decision to deviate from the 12 CP methodology would be a decision to continue subsidizing the PTP segment at the expense of NT customers.

BPA should adhere to cost causation principles and the facts established in the Transmission Cost of Service Analysis Workshop. Attempts to mitigate the impacts on rates to certain customer classes should be addressed in the formal rate case. To this end Clark urges BPA adopt the 12 CP allocation methodology.

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To: BPA Transmission Services

Date: March 30, 2012

RE: Transmission Cost Allocation Alternatives

Cowlitz PUD participated in BPA's Transmission Cost of Service Analysis (COSA) workshops and carefully considered the various cost allocation methodologies presented. Cowlitz believes that the methodology BPA chooses must be consistent with the principles identified by BPA and transmission customers at the outset of the COSA process. Those principles in conjunction with the facts presented by BPA throughout the COSA process strongly support a 12 CP allocation methodology. Cowlitz joined with several other NT customers in sending a letter dated February 29, 2012 urging BPA to use the 12 CP methodology and setting forth our justification for doing so. That letter is attached for your reference.

NT CUSTOMER PROPOSAL TO USE A 12 CP COST ALLOCATION METHODOLOGY FOR THE TRANSMISSION COST OF SERVICE ANALYSIS

A. Introduction.

This proposal is submitted on behalf of the following association members and individual utilities: Clark Public Utilities, Eugene Water & Electric Board, Cowlitz PUD, Northwest Requirements Utilities, PNGC Power and the Western Public Agencies Group ("NT Customers").

The NT Customers rely on the Network Integration 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.[1] 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 as part of the Transmission Cost of Service Analysis ("COSA").

BPA currently uses a modified one coincidental peak ("1 CP") allocation methodology to allocate the costs of its Network segment amongst the various wholesale transmission services for that segment. However, over the course of several COSA workshops, BPA staff has demonstrated that if BPA followed the Federal Energy Regulatory Commission's ("FERC") approach to cost allocation it would use a twelve monthly coincident peak ("12 CP") allocation methodology. In light of this information and the reasons set forth below, the NT Customers propose that BPA adopt a 12 CP methodology in the COSA on the following bases:

(1) BPA's decision to better align the terms and conditions contained in its Open Access Transmission Tariff ("OATT") with the FERC *pro forma* with the objective of making a tariff filing seeking reciprocity with FERC justifies a corresponding adoption of FERC's 12 CP methodology for allocating costs.

(2) Changes on BPA's transmission system justify the use of a 12 CP methodology including:

- BPA's large scale expansion of the transmission system to accommodate non-federal resource development by PTP customers.

- The substantial growth in the secondary transmission capacity market on BPA's system.

(3) Adoption of a 12 CP methodology is consistent with the principles enunciated by BPA and customers at the beginning of the COSA process.

[1] While some of the NT Customers take Point to Point Transmission Service ("PTP") for various reasons, each of them relies on the NT service.

The remainder of this proposal describes in detail the above justifications for the adoption of a 12 CP methodology.

B. BPA Should Adopt FERC's Approach to Cost Allocation - 12 CP.

BPA has been working for the better part of a year to bring the terms and conditions of its transmission services under its OATT in line with the terms and conditions for transmission service identified in FERC's *pro forma* OATT with an aim towards making a tariff filing seeking reciprocity with FERC by the end of March 2012. BPA's decision to adopt FERC's *pro forma* terms and conditions means that BPA should also make a corresponding move to use FERC's approach for allocating wholesale transmission costs. This is because FERC's *pro forma* OATT strikes a balance between the terms and conditions of wholesale transmission services and the allocation of costs between such services.[2] To establish terms and conditions consistent with FERC's approach and then allocate costs based on some other basis would upset that balance.

While FERC does not mandate the use of any one particular coincidental peak methodology, it has primarily affirmed the use of a 12 CP allocation method because it "believe[s] the majority of utilities plan their system to meet their twelve monthly peaks."[3] FERC does allow utilities to propose an alternative to 12 CP, but only where they can demonstrate that "such alternative is consistent with the utility's transmission system planning and would not result in over-collection of the utility's revenue requirement."[4] In evaluating such determinations, FERC uses the following three peak ratio tests:

(1) **Test No. 1** - On and Off Peak Test - This test first compares the average of the coincidental peaks in the months with the highest system peaks as a percentage of the annual system peak. Second, it compares the average of the coincidental peaks in the months with the lowest system peaks as a percentage of the annual system peak. A 12 CP allocation is considered appropriate where the difference between these two percentages is 19% or less.

(2) **Test No. 2** - Low-to-Annual Peak Test - Compares the lowest monthly peak as a percentage of the annual system peak. A range of 66% or higher is considered indicative of a 12 CP system.

(3) **Test No. 3** - Average to Annual Peak Test – Compares the average of the twelve

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[2] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21540-01, 21598 (May 10, 1996) ("Order 888") ("We agree that non-price terms and conditions cannot be designed independent of pricing and cost recovery").

[3] Order 888, 61 FR at 21599.

[4] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888-A, 62 FR 12274-01, 12321 (March 14, 1997) ("Order 888-A").

monthly peaks as a percentage of the annual system peak. A range of 81% or higher is considered indicative of a 12 CP system.[5]

Over the last several months, BPA has performed each of the above peak demand tests several times in order to determine which coincident peak allocation methodology is appropriate for its system. Each iteration of the tests used different assumptions or data to perform the calculations (e.g., total transmission system loading ("TTSL") vs. network transmission billing factors ("NTBF"), firm vs. non-firm, long term vs. short term). Nevertheless, the undeniable conclusion from BPA's numerous performances of the FERC tests is that BPA has a 12 CP system, and has had a 12 CP system since at least 2006 (the earliest year for which BPA performed the FERC tests in this COSA process).[6] As shown in the table below, this was true irrespective of which of the varying assumptions or data BPA or customers identified was actually used in the calculations.

	Test No. 1	Test No. 2	Test No. 3
Analysis for 12/5/2011 Workshop - using TTSL - Avg. result over 5 Years (2006-2010)[7]	13%	75%	88%
Analysis for 1/11/2012 Workshop - using NTBF - Avg. over result 5 Years (2006-2010)[8]	10%	84%	91%
Analysis for 2/8/2012 Workshop - using TTSL - Avg. result over 6 years (2006-2011)[9]	13%	77%	88%
Analysis for 2/8/2012 Workshop - using Long-Term NTBF - Avg. result over 6 years (2006-2011)[10]	7%	90%	94%
12 CP Condition under FERC Test	**≤ 19%**	**≥ 66%**	**≥ 81%**

[5] *Golden Spread Electric*, 123 FERC 61,047, 61,249 (2008).

[6] Indeed, BPA's conclusion in 2012 that it has a 12 CP system is fully consistent with a conclusion it reached as part of an August 16, 2006 Transmission Rate Case Workshop, which was based on data extending back as far as 1999, i.e., "TBL's transmission loading pattern would support the use of a 12CP divisor for allocating costs between the network rate classes." BPA Transmission Rate Case Workshop Handout, RE: Network Cost Allocation, dated August 16, 2006 and available upon request.

[7] Transmission Cost of Service Analysis Workshop Power Point Presentation, December 5, 2011, available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Workshop_12-05-11_revised.pdf. The numbers in the table are averages over five years (2006-2010) or six years (2006-2011). However, in every case the individual calculations for each specific year also indicated that BPA has a 12 CP system without exception.

[8] FERC Coincidental Peak Test Power Point, January 11, 2012, p. 2, available at http://www.bpa.gov/corporate/ratecase/docs/FERC_Coincidental_Peak_Test.pdf.

[9] Transmission Cost of Service Analysis Workshop Power Point, February 8, 2012, p. 16, available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Workshop_2-8-12.pdf ("Feb. 8th Power Point").

[10] *Id.* at 18.

BPA staff has indicated that the basic principle enunciated by FERC staff in their discussions was that cost allocation should be based primarily on a utility's system planning.[11] This principle is consistent with FERC's justification for using 12 CP allocation methodology, i.e., because "the majority of utilities plan their system to meet their twelve monthly peaks."[12]

BPA adds transmission facilities to its transmission system to meet two primary purposes: reliability and capacity expansion.[13] With respect to reliability planning, FERC's assumption that utilities plan their systems to meet their twelve monthly peaks is also true for BPA. At the February 8, 2012 workshop, BPA staff explained in detail how BPA plans its system to meet its needs throughout the year rather than to meet one annual system peak. This is achieved by first modeling four seasonal base cases for planning purposes. The results from these four base cases are then extrapolated across the remaining months. The need to model on a seasonal basis is driven largely by the fact that resource patterns vary with each season and, therefore, the seasonal modeling and extrapolation across the remaining months ensures that BPA can meet its reliability obligations throughout the year.[14] Under FERC's approach for cost allocation this type of annual system planning, in addition to the results of the peak demand tests, indicates that BPA should be using a 12 CP allocation methodology.

C. Expansion of the System to Accommodate Resource Development by PTP Customers Warrants BPA's Use of 12 CP.

In addition to reliability, the other chief driver that causes BPA to add transmission facilities is capacity expansion.[15] In 2012 BPA expects to expend a little less than $500 million on transmission capital projects.[16] It expects to spend approximately $550 million more on transmission capital projects in 2013 and another $500+ million in 2014.[17]

Given the above, BPA is projecting an 11 percent rate increase for all Network customers in BP-14.[18] No small portion of this increase stems from BPA's Network Open Season ("NOS") process which primarily serves to expand the Network segment to accommodate non-federal resource development by PTP customers. These costs include:

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[11] *Id.* at 6.

[12] Order 888, 61 FR at 21599.

[13] Feb. 8th Power Point, p. 13.

[14] *Id.* at 9-13.

[15] *Id.* at 13.

[16] Building the Framework for the Integrated Program Review Power Point, January 31, 2012, p. 32, available at http://www.bpa.gov/corporate/pubs/letters/IPR_General-Manager-Meeting.pdf.

[17] *Id.*

[18] *Id.* at 29 (Absent a change to BPA's allocation methodology).

- Repayment of Large Generation Interconnection Agreement (LGIA) Credits;
- Precedent Transmission Service Agreement ("PTSA") Deferrals;
- Increased debt service; and
- Reduction of federal borrowing authority available for other projects.[19]

In addition to the increasing rate pressure, BPA's expansion of the system to bring these new resources online has created a substantial, real risk that BPA will not be able to recover all of the costs of that expansion from the developers that caused them. This is because many of the developers who originally entered into PTSAs with BPA under BPA's NOS process no longer want the transmission capacity. Since many of those parties are judgment proof, single project limited liability companies, in the event of default BPA will ultimately recover the costs created by those developers from its remaining Network customers, both PTP and NT.

All of BPA's customer who use the Network segment share in the costs and risks associated with the NOS projects. However, BPA's use of 1 CP means that its NT customers are shouldering a larger share of those costs than they otherwise would under a 12 CP approach. Since BPA is developing and expanding the transmission system primarily to meet the needs of PTP customers, it is only appropriate that it remedy the imbalance between its move towards FERC's *pro forma* terms and conditions of service and its currents cost allocation methodology by adopting the 12 CP allocation methodology. This will give NT customers some relief from these expansion costs that they did not cause, but would not give them any more relief than they already would have if BPA had followed the FERC approach in the first instance.

D. The Robust Secondary Capacity Market on BPA's System Justifies 12 CP.

FERC has found that allowing holders of firm transmission capacity the right to reassign capacity helps them manage the financial risks associated with their long term commitments, reduces the market power of transmission providers by allowing customers to compete, and fosters efficient capacity allocation.[20] BPA's transmission system is unique in that it has realized FERC's vision for a robust secondary market like none other in the country. According to a 2010 report by FERC staff, in 2009 there were 26,442 capacity reassignment transactions on BPA's system.[21] This accounted for approximately 79 percent of all such transactions nationwide.[22]

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[19] PTSA Reform Initiative Decision and Process Power Point, December 6, 2011, p. 17, available at http://transmission.bpa.gov/customer_forums/nos_gi_reform/ptsa_reform.pdf (All NOS 2008 & 2010 projects will have 6.6% rate impact on average over the next five years under the base case assuming no PTSA defaults or PTSA terminations).

[20] Order No. 888, 61 FR at 21575-21576.

[21] Federal Energy Regulatory Commission: Staff Report on Capacity Reassignment, p. 4 (April 15, 2010) available at http://www.ferc.gov/legal/staff-reports/04-15-10-capacity-reassignment.pdf (Reassignment Report").

[22] *Id.*

The vibrancy of the secondary PTP market on BPA's system highlights a key difference between the PTP and NT products: Whereas BPA's PTP customers can reassign their firm capacity; BPA's NT customers cannot use or reassign unused capacity during off-peak hours.[23] This means that while PTP customers have a means to ameliorate the costs of the PTP product, NT customers do not. Instead, during off-peak hours, BPA sells the unused NT capacity on either the short term firm or non-firm hourly markets. The revenues received from these sales are used to lower the rates of all Network segment customers, both NT and PTP, when BPA calculates firm Network segment rates.

Under FERC's *pro forma* OATT, the inability of NT customers to assign or sell their unused transmission capacity, and the benefit all Network segment customers receive from the resale of unused NT capacity, is balanced by the use of a 12 CP allocation methodology.[24] Consistent with the FERC *pro forma,* BPA has now provided a vibrant secondary capacity market that allows PTP customers to take full advantage of their reassignment rights. Accordingly, the time is now ripe for BPA to likewise provide NT customers the corresponding benefit they are entitled to under the *pro forma* tariff – cost allocation under a 12 CP methodology.

E. A 12 CP Allocation Methodology is Consistent with the COSA Principles.

Finally, the NT Customers' proposal that BPA adopt a 12 CP allocation methodology meets the COSA principles identified by BPA and transmission customers at the beginning of the COSA process:

- 12 CP is consistent with BPA's statutes in that it would ensure cost recovery and allocate the costs of the Network segment equitably between federal and non-federal users of the system.
- 12 CP allocates costs to customers based on their proportionate use in accordance with accepted industry practice for wholesale transmission services.
- 12 CP is simple, administrable, understandable, publicly accepted, feasible in application, durable and repeatable.

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[23] Order No. 888, 61 FR at 21576 ("We conclude that point-to-point transmission service, because it sets forth clearly defined capacity rights, should be reassignable. As for network transmission service, we conclude that there are no specific capacity rights associated with such service, and thus, network transmission service is not reassignable.")

[24] Order No. 888-A, 62 FR at 12323 ("The bottom line is that all potential transmission customers... must choose between network integration transmission service or point-to-point transmission service. Each of these services has its own advantages and risks...In choosing between network and point-to-point transmission service, the potential customer must assess the degree of risk that it is willing to accept associated with the availability of firm transmission capacity.").

- 12 CP would ensure rate stability from rate period to rate period both in regard to the level of rates and the rate design to be implemented.

- NT Customers have demonstrated a need for change from a 1 CP to a 12 CP methodology.

The one principle that the NT Customers offer no opinion on at this time is whether adoption of a 12 CP methodology would be consistent with the principle of avoiding rate shock. Per the Scope of COSA Process adopted by BPA at the February 8, 2012 Workshop, the final rate development step, rate design, is outside the scope of the COSA process.[25] This means that BPA and customers are to reserve arguments on the issue of avoidance of rate shock until the rate case.

F. Conclusion.

The NT Customers' proposal to use a 12 CP allocation methodology in the COSA is not novel; instead it is a logical extension of BPA's decision to better align itself with FERC policy. Adoption of 12 CP would mean that the terms and conditions of BPA's transmission services and the allocation of costs between such services would both be consistent with FERC policy. In addition, the move to 12 CP would recognize the changing conditions on BPA's system with respect to the expansion of the Network to accommodate resources rather than load and the vigorous secondary capacity market on BPA's system. And, that these changing conditions primarily benefit PTP customers with little benefit to NT customers. Under such circumstances, it is a modest request that BPA bring its cost allocation methodology in line with FERC practice by adopting a 12 CP methodology.

[25] Scope of COSA Process, available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Scope.pdf.

EUGENE WATER & ELECTRIC BOARD'S (EWEB) COMMENTS ON BPA'S 2012 TRANSMISSION RATE SETTLEMENT COST OF SERVICE ANALYSIS (COSA)
March 20, 2012

EWEB appreciates the opportunity to provide feedback to BPA on the implementation of the provisions of the 2012 Transmission Settlement Agreement. Our staff have been active participants in BPA's workshops. We have provided comments on BPA's proposed COSA principles, scope of the COSA analysis, and support the NT customer proposal to use a 12 CP Transmission Cost of Service Analysis.

As BPA winds down this effort and makes a cost allocation decision, EWEB would like to emphasize the importance of adhering to the both BPA's traditional rate making principles and the additional principles proposed by customers last fall:

- Consistency with BPA statutes
- Cost causation – allocating costs to customers based on proportionate use;
- Simplicity, understandability, public acceptance and feasibility of application;
- Avoidance of rate shock and rate stability from rate period to rate period; and
- Rate stability from rate period to rate period (magnitude of rates and rate design).

Three additional principles were identified by BPA's customers which include:

- Adherence to industry standards;
- Approach must be administrable, understandable, durable and repeatable; and
- Demonstrable need for change

These principles need to provide the basis for BPA's determination. Throughout the COSA workshops, BPA staff has demonstrated that if BPA followed the Federal Energy Regulatory Commission's ("FERC") approach to cost allocation it would use a twelve monthly coincident peak ("12 CP") allocation methodology. This allocation method provides better alignment of the terms and conditions contained in BPA's Open Access Transmission Tariff ("OATT") with the FERC *pro forma* and objective of making a tariff filing seeking reciprocity with FERC.

In light of this information and its consistency with the COSA principles agreed to by BPA and its customers, EWEB proposes BPA adopt a 12 CP methodology.

1. 12 CP is consistent with BPA's statutes in that it would ensure cost recovery and allocate the costs of the Network segment equitably between federal and non-federal users of the system.

2. 12 CP allocates costs to customers based on their proportionate use in accordance with accepted industry practice for wholesale transmission services.

3. 12 CP is simple, administrable, understandable, publicly accepted, feasible in application, durable and repeatable.

4. 12 CP would ensure rate stability from rate period to rate period both in regard to the level of rates and the rate design to be implemented.

5. NT Customers have demonstrated a need for change from a 1 CP to a 12 CP methodology.

The one principle not addressed above is ‘avoidance of rate shock’. EWEB strongly encourages BPA to adopt the 12 CP rate allocation method and make a separate determination to avoid rate shock, if necessary, during the rate design phase of the rate case. However, in that determination, BPA should consider the impact on total power supply costs, not just transmission. Finally, EWEB would support providing an opportunity for public power customers using point-to-point transmission to serve native load to switch to network service.

Thank you for the opportunity to provide comments.

Flathead Electric
Your Co-op
Community...Integrity...Reliability

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January 12, 2012

BPA Transmission Services
VIA EMAL: techforum@bpa.gov

Re: **Comments on Transmission Cost of Service Analysis Workshop Process**

Dear BPA Transmission Services:

BPA has been very open and forthcoming with the various data requests of the parties in this process. Flathead would like to express our appreciation to BPA for these efforts and urge BPA continue its reasonable approach to meeting the terms of the Partial Transmission Settlement Agreement. However, I would like to make a few comments on the current state of the process.

First, I think everyone in these discussions should be reminded of the terms of the partial settlement. In the settlement agreement BPA agreed to the following:

> *6. Before the start of the 2014 rate case, BPA will (a) 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, (b) complete an illustrative cost of service study using forecasted data from a recent fiscal year, and (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. (BP-12-A-02A Page 3)*

I suggest that at the next customer forum BPA include it as the first slide. Increasingly the discussion on what is or is not Cost of Service "methodology" has become an opportunity for some customers to bring up issues that were not within the scope of the settlement agreement and are more properly handled in the regular rate case process.

Second, the settling parties agreed to a cost of service study that includes "alternative methodologies for allocating demand-related costs" Clearly the focus was on peak allocation methodologies such as the 1 CP vs. the 12 CP.

Third, the settlement agreement indicates that "forecasted data" was acceptable, rather than a massive effort on the part of BPA to provide historical load data on every customer for the last five years.

Fourth, as mentioned above I think this process should be focused on the actual settlement agreement issue, but two issues that were raised are of particular concern: the suggestion that the Utility Delivery Segment should be expanded beyond the current low voltage threshold is far beyond the scope of the settlement and the suggestion that BPA should start a new Transmission rate design, especially after we are barely into the new rate design on the power side is also out of line. These issues are clearly outside the scope of the settlement.

Finally, there seems to be propensity of some customers who want BPA to do things like FERC "industry" standards suggest, but only if it suits them for their current needs. Every utility employee wants what costs the least and offers the most for their stakeholders. It is ironic that the same folks that want BPA to seek reciprocity object to BPA using the FERC standard test for 12 CP cost allocation. Flathead pays BPA for Power and for Transmission for almost all our needs and all the unnecessary FERC-mandated separation and processes simply costs our members more. Flathead and others have had to bend to the FERC winds and now it is time for the FERC advocates to bear the same wind.

Thank you for the opportunity to comment.

Sincerely,

Russ Schneider
Regulatory Analyst

March 30, 2012

<u>Via Electronic Submission</u>
Bonneville Power Administration
techforum@bpa.gov

Re: Comments of Iberdrola Renewables & PacifiCorp on Bonneville Power Administration's Cost Allocation Alternatives

On March 13, 2012 Bonneville Power Administration ("Bonneville") issued a request for comments regarding positions on annual peak (1 Coincidental Peak or 1 CP), annual average monthly peak (12 Coincidental Peak or 12 CP), the average of the 3 monthly peaks in the highest quarter (3 Coincidental Peak or 3 CP) or Non-Coincidental Peak (NCP). Bonneville should use either 1 NCP or 1 CP.

BPA's transmission system is built to meet peak demand requirements of the users. In accordance with the philosophy that the creators of the costs should pay the costs, the users should be required to pay based on their share of the peak demand. This demand occurs on an annual basis, thus the use of 1CP is consistent with cost causation principles. Changing to a 12CP method simply creates a cost shift or subsidy between customer classes, where some classes pay more than their peak share and others pay less.

To illustrate the dramatic cost shift that would result from moving from a 1CP to 12 CP rate calculation in its March 7, 2012 presentation titled "Transmission Cost of Service Analysis Workshop", BPA calculates that moving from 1CP to 12 CP, *while holding revenue constant*, would decrease the NT rate by 14.6% and increase the PTP rate by 4.2%.

In an alternative calculation by BPA in its January 11, 2012 COSA presentation, where revenue requirements were increased, BPA anticipates a 5.4 percent rate increase for point-to-point ("PTP") customers and a 0.2% rate increase for NT customers using 1 CP. Bonneville also anticipates a 9.8 percent rate increase for PTP customers and a 14.4 percent rate <u>decrease</u> for network ("NT") customers if rates are calculated using12 CP. Use of 12 CP shifts costs from the NT customers to other transmission customers, particularly the PTP customers.

To the extent that Bonneville needs to curtail transmission on its system, under certain conditions, Bonneville maintains its NT schedules and cuts PTP. Moreover, Bonneville has recently suggested that the quality of PTP service on its system may be of significantly lesser quality than PTP service on other transmission providers systems. For example, in its Interim Environmental Redispatch and Negative Pricing Policies Record of Decision ("Environmental Redispatch Rod") issued in May 2011, Bonneville suggested that it has very broad statutory authority to curtail even long-term firm PTP service. *See, e.g.*, Environmental Redispatch Rod at 12 (stating: "The Northwest Power Act provides that transmission access and services are to be provided subject to any existing legal obligations and without substantial interference with the Administrator's power marketing program.")

From: Fred Rettenmund [mailto:fredr@inlandpower.com]
Sent: Wednesday, March 21, 2012 11:08 AM
To: Tech Forum
Subject: BPA Transmission Cost Allocation Alternatives

Inland Power and Light Company appreciates the opportunity to comment on the cost allocation methodologies presented at the Transmission Cost of Service Analysis (COSA) workshops. Inland Power is a cooperative utility using Network Transmission (NT) to serve its approximately 39,000 members in eastern Washington and northern Idaho.

Inland Power firmly believes that BPA should employ the 12 coincident peak cost allocation method in the COSA for the FY 2014-2015 transmission rate case. The 12 CP allocation method has long been used by the Federal Energy Regulatory Commission (FERC). The 12 CP method clearly meets all of the FERC tests when applied to the load characteristics and planning criteria for the BPA Network segment. The 12 CP method will result in the equitable allocation of costs of the Network between federal and non-federal users of the transmission system as well as between the various transmission services involving use of the Network segment.

Thank you for considering these comments.

Kris Mikkelsen

CEO

Inland Power and Light Company

March 30, 2012

<u>Via Electronic Submission</u>

Bonneville Power Administration
techforum@bpa.gov

Re: Comments of Listed PTP Customers[1] on Bonneville Power Administration's Cost Allocation Alternatives

On March 13, 2012, Bonneville Power Administration ("BPA") issued a request for comments regarding positions on annual peak (1 Coincidental Peak or 1 CP), annual average monthly peak (12 Coincidental Peak or 12 CP), the average of the 3 monthly peaks in the highest quarter (3 Coincidental Peak or 3 CP) and Non-Coincidental Peak (NCP). As discussed below, BPA (i) should not rely on the FERC cost allocation test and (ii) should use 1 NCP (or perhaps 1 CP) for allocation of BPA transmission costs.

The BPA transmission system is built to meet peak demand requirements of the users. In accordance with the principles of cost-causation, the users should be required to pay based on their share of the peak demand.

Particularly in light of the uniqueness of transmission service as currently offered by BPA and the statutory scheme under which BPA operates, the equitable allocation of BPA's transmission costs should not be determined through a mechanical application of FERC's cost allocation test. It is apparent that the NT service offered by BPA differs substantially from, and is superior to, *pro forma* NT service. For example, BPA's Network Resources are not required to be undesignated to provide power for off-system sales of less than a year.[2] In short, BPA should not rely on the results of the FERC cost allocation tests to determine BPA's cost allocation methodology.

[1] The Listed PTP Customers are comprised of Avista Corporation, Puget Sound Energy, Inc., Portland General Electric Company, Tacoma Power, Powerex Corporation, Snohomish County Public Utility District No. 1, Public Utility District No. 1 of Franklin County, and Public Utility District No. 1 of Benton County.

[2] Allowing off-system sales with a duration of less than a year from Network Resources is not consistent with FERC's pro forma tariff and fails to free up and make transfer capability fully available for transmission sales by BPA to others. Among other things, such foregone transmission sales result in increased BPA PTP transmission rates.

In the 1996 rates decision, BPA identified 1 NCP method as superior because it permits BPA to price all firm Network service on a similar basis, using "equivalent" billing determinants for NT and PTP customers (NCP for NT and contract demand for PTP):

> BPA proposed to allocate firm Network rate classes using annual contract demands or their equivalents. For customers without contract demands (NT rate customers and 1981 Power Sales Contract customers under the NRP rate), the sum of their forecasted noncoincidental peaks is used as the contract demand equivalent. Woerner, *et al.*, WP-96-E-BPA-85, at 7-8. BPA identified three reasons to support the use of normal peaks, as opposed to cold weather peaks. First, BPA planning criteria are based primarily on meeting annual peak loading conditions with contingencies under normal weather conditions. Second, it is not clear that wheeling customers have adequate contract demand to cover cold weather peaks since they utilize significant amounts of nonfirm transmission during cold snaps. Finally, NT customers deserve some recognition for their inability to use or assign unused capacity during off-peak hours. Metcalf, *et al*., WP-96-E-BPA-115, at 8-11. This cost allocation method permits BPA to price all firm Network service on a similar basis.

1996 Wholesale Power and Transmission Rate Proposal, Administrator's Record of Decision, WP-96-A-02, at page 426. It has not been shown that BPA plans its system primarily on the basis of meeting its twelve monthly peaks.[3] For example, BPA does plan to meet a system "super peak," which occurs on an annual or less frequent basis. (This would perhaps support use of 1 CP.) In any event, there is no indication that circumstances have drastically changed since 1996 so as to warrant a change from the 1 NCP cost allocation method. Therefore, 1 NCP should be the starting point, from which BPA should deviate only for sound and demonstrated reasons.

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[3] In Order No. 888, FERC expressly stated that it was confirming the use of 12 CP for utilities that plan their systems to meet their twelve monthly peaks but declined to require the use of 12 CP for other utilities:

> We are reaffirming the use of a twelve monthly coincident peak (12 CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks. Utilities that plan their systems to meet an annual system peak (e.g., ConEd and Duke) are free to file another method if they demonstrate that it reflects their transmission system planning. Moreover, we recognize that alternative allocation proposals may have merit and welcome their submittal by utilities in future rate applications. They will be evaluated on a case-by-case basis and decided on their merits.

Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036, at P 31,737 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

Changing to a 12CP method simply creates an unwarranted cost shift between customer classes. To illustrate the dramatic cost shift that would result from moving from a 1 CP to 12 CP rate calculation in its March 7, 2012 presentation titled "Transmission Cost of Service Analysis Workshop", BPA anticipates that moving from 1 CP to 12 CP, *while holding revenue constant*, would decrease the NT rate by 14.6% and increase the PTP rate by 4.2%. With an increase in revenue requirements, BPA anticipates that

(i) NT rates would *increase* 0.2% using 1 CP but *decrease* 14.4% using 12 CP; and

(ii) PTP rates would *increase* 5.4% using 1 CP but *increase* 9.8% using 12 CP.

In summary, use of 12 CP shifts costs from the NT customers to other transmission customers, particularly the PTP customers. BPA should not rely on the FERC cost allocation test and should use 1 NCP (or perhaps 1 CP) for allocation of transmission costs.

As requested, these preliminary comments address the use of peak load cost allocation methodologies in the development of BPA's transmission rates. The Listed PTP Customers look forward to providing further comments on this and other topics leading up to BPA's Initial Proposal for the BP-14 rate period.

The Listed PTP Customers appreciate 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.

From: Jim Webb [mailto:jim@lvenergy.com]
Sent: Saturday, March 24, 2012 7:01 PM
To: Tech Forum
Subject: Cost Allocation Alternatives

Cost Allocation Alternatives:

Thank you for the opportunity to submit comments on the cost allocation methodologies presented at the Transmission Cost of Service Analysis (COSA) workshops. As a BPA Network Transmission (NT) customer the use of the appropriate cost allocation methodology can have a significant impact on the transmission rates that Lower Valley Energy and our 26,000 members in eastern Idaho and western Wyoming are required to pay.

Lower Valley strongly encourages BPA to employ the 12 coincident peak (12 CP) cost allocation method in the COSA for the FY 2014-2015 transmission rate case. We believe that use of the 12 CP cost allocation methodology is consistent with FERC requirements and standard industry practices. Adoption of 12 CP methodology by BPA would result in the equitable allocation of the cost of BPA's transmission system between federal and non-federal users as well as between the various transmission services involving use of the network segment.

We would appreciate your consideration of our comments concerning transmission cost allocation alternatives and hope you will adopt the use of the 12 CP methodology.

Jim Webb

President/CEO

Lower Valley Energy

Afton, Wyoming

NT CUSTOMER PROPOSAL TO USE A 12 CP COST ALLOCATION METHODOLOGY FOR THE TRANSMISSION COST OF SERVICE ANALYSIS

A. Introduction.

This proposal is submitted on behalf of the following association members and individual utilities: Clark Public Utilities, Eugene Water & Electric Board, Cowlitz PUD, Northwest Requirements Utilities, PNGC Power and the Western Public Agencies Group ("NT Customers").

The NT Customers rely on the Network Integration 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.[1] 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 as part of the Transmission Cost of Service Analysis ("COSA").

BPA currently uses a modified one coincidental peak ("1 CP") allocation methodology to allocate the costs of its Network segment amongst the various wholesale transmission services for that segment. However, over the course of several COSA workshops, BPA staff has demonstrated that if BPA followed the Federal Energy Regulatory Commission's ("FERC") approach to cost allocation it would use a twelve monthly coincident peak ("12 CP") allocation methodology. In light of this information and the reasons set forth below, the NT Customers propose that BPA adopt a 12 CP methodology in the COSA on the following bases:

(1) BPA's decision to better align the terms and conditions contained in its Open Access Transmission Tariff ("OATT") with the FERC *pro forma* with the objective of making a tariff filing seeking reciprocity with FERC justifies a corresponding adoption of FERC's 12 CP methodology for allocating costs.

(2) Changes on BPA's transmission system justify the use of a 12 CP methodology including:

- BPA's large scale expansion of the transmission system to accommodate non-federal resource development by PTP customers.

- The substantial growth in the secondary transmission capacity market on BPA's system.

(3) Adoption of a 12 CP methodology is consistent with the principles enunciated by BPA and customers at the beginning of the COSA process.

[1] While some of the NT Customers take Point to Point Transmission Service ("PTP") for various reasons, each of them relies on the NT service.

The remainder of this proposal describes in detail the above justifications for the adoption of a 12 CP methodology.

B. BPA Should Adopt FERC's Approach to Cost Allocation - 12 CP.

BPA has been working for the better part of a year to bring the terms and conditions of its transmission services under its OATT in line with the terms and conditions for transmission service identified in FERC's *pro forma* OATT with an aim towards making a tariff filing seeking reciprocity with FERC by the end of March 2012. BPA's decision to adopt FERC's *pro forma* terms and conditions means that BPA should also make a corresponding move to use FERC's approach for allocating wholesale transmission costs. This is because FERC's *pro forma* OATT strikes a balance between the terms and conditions of wholesale transmission services and the allocation of costs between such services.[2] To establish terms and conditions consistent with FERC's approach and then allocate costs based on some other basis would upset that balance.

While FERC does not mandate the use of any one particular coincidental peak methodology, it has primarily affirmed the use of a 12 CP allocation method because it "believe[s] the majority of utilities plan their system to meet their twelve monthly peaks."[3] FERC does allow utilities to propose an alternative to 12 CP, but only where they can demonstrate that "such alternative is consistent with the utility's transmission system planning and would not result in over-collection of the utility's revenue requirement."[4] In evaluating such determinations, FERC uses the following three peak ratio tests:

(1) **Test No. 1 -** On and Off Peak Test - This test first compares the average of the coincidental peaks in the months with the highest system peaks as a percentage of the annual system peak. Second, it compares the average of the coincidental peaks in the months with the lowest system peaks as a percentage of the annual system peak. A 12 CP allocation is considered appropriate where the difference between these two percentages is 19% or less.

(2) **Test No. 2** - Low-to-Annual Peak Test - Compares the lowest monthly peak as a percentage of the annual system peak. A range of 66% or higher is considered indicative of a 12 CP system.

(3) **Test No. 3** - Average to Annual Peak Test – Compares the average of the twelve

[2] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21540-01, 21598 (May 10, 1996) ("Order 888") ("We agree that non-price terms and conditions cannot be designed independent of pricing and cost recovery").

[3] Order 888, 61 FR at 21599.

[4] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888-A, 62 FR 12274-01, 12321 (March 14, 1997) ("Order 888-A").

monthly peaks as a percentage of the annual system peak. A range of 81% or higher is considered indicative of a 12 CP system.[5]

Over the last several months, BPA has performed each of the above peak demand tests several times in order to determine which coincident peak allocation methodology is appropriate for its system. Each iteration of the tests used different assumptions or data to perform the calculations (e.g., total transmission system loading ("TTSL") vs. network transmission billing factors ("NTBF"), firm vs. non-firm, long term vs. short term). Nevertheless, the undeniable conclusion from BPA's numerous performances of the FERC tests is that BPA has a 12 CP system, and has had a 12 CP system since at least 2006 (the earliest year for which BPA performed the FERC tests in this COSA process).[6] As shown in the table below, this was true irrespective of which of the varying assumptions or data BPA or customers identified was actually used in the calculations.

	Test No. 1	**Test No. 2**	**Test No. 3**
Analysis for 12/5/2011 Workshop - using TTSL - Avg. result over 5 Years (2006-2010)[7]	13%	75%	88%
Analysis for 1/11/2012 Workshop - using NTBF - Avg. over result 5 Years (2006-2010)[8]	10%	84%	91%
Analysis for 2/8/2012 Workshop - using TTSL - Avg. result over 6 years (2006-2011)[9]	13%	77%	88%
Analysis for 2/8/2012 Workshop - using Long-Term NTBF - Avg. result over 6 years (2006-2011)[10]	7%	90%	94%
12 CP Condition under FERC Test	**≤ 19%**	**≥ 66%**	**≥ 81%**

[5] *Golden Spread Electric*, 123 FERC 61,047, 61,249 (2008).

[6] Indeed, BPA's conclusion in 2012 that it has a 12 CP system is fully consistent with a conclusion it reached as part of an August 16, 2006 Transmission Rate Case Workshop, which was based on data extending back as far as 1999, i.e., "TBL's transmission loading pattern would support the use of a 12CP divisor for allocating costs between the network rate classes." BPA Transmission Rate Case Workshop Handout, RE: Network Cost Allocation, dated August 16, 2006 and available upon request.

[7] Transmission Cost of Service Analysis Workshop Power Point Presentation, December 5, 2011, available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Workshop_12-05-11_revised.pdf. The numbers in the table are averages over five years (2006-2010) or six years (2006-2011). However, in every case the individual calculations for each specific year also indicated that BPA has a 12 CP system without exception.

[8] FERC Coincidental Peak Test Power Point, January 11, 2012, p. 2, available at http://www.bpa.gov/corporate/ratecase/docs/FERC_Coincidental_Peak_Test.pdf.

[9] Transmission Cost of Service Analysis Workshop Power Point, February 8, 2012, p. 16, available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Workshop_2-8-12.pdf ("Feb. 8th Power Point").

[10] *Id.* at 18.

BPA staff has indicated that the basic principle enunciated by FERC staff in their discussions was that cost allocation should be based primarily on a utility's system planning.[11] This principle is consistent with FERC's justification for using 12 CP allocation methodology, i.e., because "the majority of utilities plan their system to meet their twelve monthly peaks."[12]

BPA adds transmission facilities to its transmission system to meet two primary purposes: reliability and capacity expansion.[13] With respect to reliability planning, FERC's assumption that utilities plan their systems to meet their twelve monthly peaks is also true for BPA. At the February 8, 2012 workshop, BPA staff explained in detail how BPA plans its system to meet its needs throughout the year rather than to meet one annual system peak. This is achieved by first modeling four seasonal base cases for planning purposes. The results from these four base cases are then extrapolated across the remaining months. The need to model on a seasonal basis is driven largely by the fact that resource patterns vary with each season and, therefore, the seasonal modeling and extrapolation across the remaining months ensures that BPA can meet its reliability obligations throughout the year.[14] Under FERC's approach for cost allocation this type of annual system planning, in addition to the results of the peak demand tests, indicates that BPA should be using a 12 CP allocation methodology.

C. Expansion of the System to Accommodate Resource Development by PTP Customers Warrants BPA's Use of 12 CP.

In addition to reliability, the other chief driver that causes BPA to add transmission facilities is capacity expansion.[15] In 2012 BPA expects to expend a little less than $500 million on transmission capital projects.[16] It expects to spend approximately $550 million more on transmission capital projects in 2013 and another $500+ million in 2014.[17]

Given the above, BPA is projecting an 11 percent rate increase for all Network customers in BP-14.[18] No small portion of this increase stems from BPA's Network Open Season ("NOS") process which primarily serves to expand the Network segment to accommodate non-federal resource development by PTP customers. These costs include:

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[11] *Id.* at 6.

[12] Order 888, 61 FR at 21599.

[13] Feb. 8th Power Point, p. 13.

[14] *Id.* at 9-13.

[15] *Id.* at 13.

[16] Building the Framework for the Integrated Program Review Power Point, January 31, 2012, p. 32, available at http://www.bpa.gov/corporate/pubs/letters/IPR_General-Manager-Meeting.pdf.

[17] *Id.*

[18] *Id.* at 29 (Absent a change to BPA's allocation methodology).

- Repayment of Large Generation Interconnection Agreement (LGIA) Credits;
- Precedent Transmission Service Agreement ("PTSA") Deferrals;
- Increased debt service; and
- Reduction of federal borrowing authority available for other projects.[19]

In addition to the increasing rate pressure, BPA's expansion of the system to bring these new resources online has created a substantial, real risk that BPA will not be able to recover all of the costs of that expansion from the developers that caused them. This is because many of the developers who originally entered into PTSAs with BPA under BPA's NOS process no longer want the transmission capacity. Since many of those parties are judgment proof, single project limited liability companies, in the event of default BPA will ultimately recover the costs created by those developers from its remaining Network customers, both PTP and NT.

All of BPA's customer who use the Network segment share in the costs and risks associated with the NOS projects. However, BPA's use of 1 CP means that its NT customers are shouldering a larger share of those costs than they otherwise would under a 12 CP approach. Since BPA is developing and expanding the transmission system primarily to meet the needs of PTP customers, it is only appropriate that it remedy the imbalance between its move towards FERC's *pro forma* terms and conditions of service and its currents cost allocation methodology by adopting the 12 CP allocation methodology. This will give NT customers some relief from these expansion costs that they did not cause, but would not give them any more relief than they already would have if BPA had followed the FERC approach in the first instance.

D. The Robust Secondary Capacity Market on BPA's System Justifies 12 CP.

FERC has found that allowing holders of firm transmission capacity the right to reassign capacity helps them manage the financial risks associated with their long term commitments, reduces the market power of transmission providers by allowing customers to compete, and fosters efficient capacity allocation.[20] BPA's transmission system is unique in that it has realized FERC's vision for a robust secondary market like none other in the country. According to a 2010 report by FERC staff, in 2009 there were 26,442 capacity reassignment transactions on BPA's system.[21] This accounted for approximately 79 percent of all such transactions nationwide.[22]

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[19] PTSA Reform Initiative Decision and Process Power Point, December 6, 2011, p. 17, available at http://transmission.bpa.gov/customer_forums/nos_gi_reform/ptsa_reform.pdf (All NOS 2008 & 2010 projects will have 6.6% rate impact on average over the next five years under the base case assuming no PTSA defaults or PTSA terminations).

[20] Order No. 888, 61 FR at 21575-21576.

[21] Federal Energy Regulatory Commission: Staff Report on Capacity Reassignment, p. 4 (April 15, 2010) available at http://www.ferc.gov/legal/staff-reports/04-15-10-capacity-reassignment.pdf (Reassignment Report").

[22] *Id.*

The vibrancy of the secondary PTP market on BPA's system highlights a key difference between the PTP and NT products: Whereas BPA's PTP customers can reassign their firm capacity; BPA's NT customers cannot use or reassign unused capacity during off-peak hours.[23] This means that while PTP customers have a means to ameliorate the costs of the PTP product, NT customers do not. Instead, during off-peak hours, BPA sells the unused NT capacity on either the short term firm or non-firm hourly markets. The revenues received from these sales are used to lower the rates of all Network segment customers, both NT and PTP, when BPA calculates firm Network segment rates.

Under FERC's *pro forma* OATT, the inability of NT customers to assign or sell their unused transmission capacity, and the benefit all Network segment customers receive from the resale of unused NT capacity, is balanced by the use of a 12 CP allocation methodology.[24] Consistent with the FERC *pro forma,* BPA has now provided a vibrant secondary capacity market that allows PTP customers to take full advantage of their reassignment rights. Accordingly, the time is now ripe for BPA to likewise provide NT customers the corresponding benefit they are entitled to under the *pro forma* tariff – cost allocation under a 12 CP methodology.

E. A 12 CP Allocation Methodology is Consistent with the COSA Principles.

Finally, the NT Customers' proposal that BPA adopt a 12 CP allocation methodology meets the COSA principles identified by BPA and transmission customers at the beginning of the COSA process:

- 12 CP is consistent with BPA's statutes in that it would ensure cost recovery and allocate the costs of the Network segment equitably between federal and non-federal users of the system.

- 12 CP allocates costs to customers based on their proportionate use in accordance with accepted industry practice for wholesale transmission services.

- 12 CP is simple, administrable, understandable, publicly accepted, feasible in application, durable and repeatable.

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[23] Order No. 888, 61 FR at 21576 ("We conclude that point-to-point transmission service, because it sets forth clearly defined capacity rights, should be reassignable. As for network transmission service, we conclude that there are no specific capacity rights associated with such service, and thus, network transmission service is not reassignable.")

[24] Order No. 888-A, 62 FR at 12323 ("The bottom line is that all potential transmission customers… must choose between network integration transmission service or point-to-point transmission service. Each of these services has its own advantages and risks…In choosing between network and point-to-point transmission service, the potential customer must assess the degree of risk that it is willing to accept associated with the availability of firm transmission capacity.").

- 12 CP would ensure rate stability from rate period to rate period both in regard to the level of rates and the rate design to be implemented.

- NT Customers have demonstrated a need for change from a 1 CP to a 12 CP methodology.

The one principle that the NT Customers offer no opinion on at this time is whether adoption of a 12 CP methodology would be consistent with the principle of avoiding rate shock. Per the Scope of COSA Process adopted by BPA at the February 8, 2012 Workshop, the final rate development step, rate design, is outside the scope of the COSA process.[25] This means that BPA and customers are to reserve arguments on the issue of avoidance of rate shock until the rate case.

F. Conclusion.

The NT Customers' proposal to use a 12 CP allocation methodology in the COSA is not novel; instead it is a logical extension of BPA's decision to better align itself with FERC policy. Adoption of 12 CP would mean that the terms and conditions of BPA's transmission services and the allocation of costs between such services would both be consistent with FERC policy. In addition, the move to 12 CP would recognize the changing conditions on BPA's system with respect to the expansion of the Network to accommodate resources rather than load and the vigorous secondary capacity market on BPA's system. And, that these changing conditions primarily benefit PTP customers with little benefit to NT customers. Under such circumstances, it is a modest request that BPA bring its cost allocation methodology in line with FERC practice by adopting a 12 CP methodology.

[25] Scope of COSA Process, available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Scope.pdf.

NRU

Northwest Requirements Utilities

(503) 233-5823
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jsaven@pacifier.com

825 NE Multnomah, Suite 1135
Portland, Oregon 97232

To: BPA Tech Forum

Date: March 29, 2012

RE: Cost Allocation Alternatives

Northwest Requirements Utilities provides the following comments on the cost allocation methodology to be used in the development of BPA's cost of service studies for the FY 2014/2015 transmission rate case. NRU represents 50 load following customers of BPA, all of whom purchase transmission under the Network Integration rate schedule. The choice of an allocation methodology will directly affect our membership as a result of the rate impacts that will result.

NRU was a party to the February 29, 2012 joint comments of the NT customers and agrees with the positions taken in that document. As stated there: "The NT Customers' proposal to use a 12 CP allocation methodology in the COSA is not novel; instead it is a logical extension of BPA's decision to better align itself with FERC policy. Adoption of 12 CP would mean that the terms and conditions of BPA's transmission services and the allocation of costs between such services would both be consistent with FERC policy." In summary, now is the time to move to a 12 CP approach to cost allocation for the transmission rate case for FY 2014/2015.

For over a decade BPA's transmission rates have been fairly stable as a result of settlements that occurred over that period. From time to time, BPA and the customers have looked at different cost allocation methodologies. For example, we have attached a 2006 BPA study that suggests, based on information from 1999 to 2005, a 12 Coincident Peak approach to cost allocation was warranted. In the end, this approach was not implemented. It has been clear for many years that BPA passes the tests necessary for the agency to move to the industry standard 12 CP approach to transmission cost allocation prescribed by the FERC. However, we have stayed with the resulting "Modified 1 CP" approach due to the fact that BPA's transmission rate cases have been the result of settlement agreements since the 1996 rate case. Now is the time for change.

We are also aware that, as BPA has shown, the rate impacts of this change will not be equivalent between NT and PTP customers. All other things being equal, NT rates will go down and PTP rates will go up if BPA moves to 12 CP cost allocation. NRU is not averse to other groups proposing ways to mitigate the PTP rate increase within the context of the upcoming rate proceeding. However, any such discussion should occur during the rate case workshops or rate case proceedings and *not* part of the cost of service analysis. The COSA should be strictly a cost allocation exercise and follow the 12 CP methodology.

The Tiered Rate Methodology has resulted in more prescriptive and stable ratemaking for BPA Power Services rates. It is our hope that adoption of the industry standard 12 CP FERC approach to cost allocation for BPA transmission ratemaking, coupled with a resolution of the Utility Delivery Charge issue, will do much to bring long term stability to BPA's transmission rate making practices.

Network Cost Allocation

1996 Transmission Rate Case

BPA's rate construct was to set the PTP rate, the IR rate, and the Base Charge for the NT and NTP rates equal to each other. Given its different rate design, FPT was treated as a revenue credit to Network cost.

Network allocation factors were annual contract demands (PTP/IR) or their equivalent (NT/NTP); i.e., a 1NCD (non-coincidental demand) cost allocation method.

- The contract demand equivalent for the load-based services of NT and NTP (service under the 1981 power sales contract) was the sum of the forecasted annual noncoincidental peak demands.

The portion of the NT/NTP allocation factor that represented the difference between the classes' coincidental peak demand and their annual noncoincidental peak demands was the basis for the Load Shaping allocation factor. The remaining portion of the NT/NTP allocation factor was included in the determination of the Base Charge.

The rate case was settled at negotiated rate levels that maintained the rate construct but changed the results of the 1CP Network cost allocation.

2002, 2004 and 2006 Transmission Rate Cases

In its 2002 initial rate proposal, TBL proposed a 1CP (coincidental peak) Network cost allocation methodology. Usage patterns of the Federal transmission system would have supported using a 12CP method, consistent with FERC standards for jurisdictional utilities. (See below). Given the cost shifts among the Network services that would have resulted from the use of 12CP, TBL proposed the 1CP method. However, the 2002 final rates were based on a negotiated settlement that specified rate levels.

The 2004 transmission rates are also based on a negotiated settlement that increased most rates by a uniform percentage adder.

The 2006 transmission rates are also based on a negotiated settlement although in the 2006 rate case, rates were adjusted by segment (rather than a uniform rate increase) moving the cost allocation closer to a 1CP cost allocation.

FERC Guidance

In Order 888, FERC states:

> . . . we will allow all firm transmission rates, including those for flexible point-to-point service, to be based on adjusted system monthly peak loads. The adjusted system monthly peak loads consist of the transmission provider's total monthly firm peak load minus the monthly coincident peaks associated with *all* firm point-to-point service customers plus the monthly contract demand reservations for *all* firm point-to-point service.

Translating this guidance for the FCRTS, the unit charge for Network service (PTP/IR) =

$$\frac{\text{Network Cost}}{CP_{\text{Network firm/nonfirm}} - CP_{\text{PTP/IR}} + \text{Contract Demands}_{\text{PTP/IR}}}$$

- PTP includes firm and nonfirm service.
- Forecasted short-term PTP converted to annual equivalents.
- FPT not included in this calculation.
- Network cost not recovered through PTP/IR would be basis for NT rate.

FERC has defined certain "tests" to determine when it is appropriate to use a 12CP method, which is used by most utilities. These tests are:

1. **Test 1**: Compare the lowest monthly peak as a percentage of the annual peak. If this ratio is **greater than 71%**, FERC has adopted 12CP.
2. **Test 2**: Compare the average of the 12 monthly peaks to the annual peak. If this ratio is **greater than 84%**, FERC has adopted 12CP.

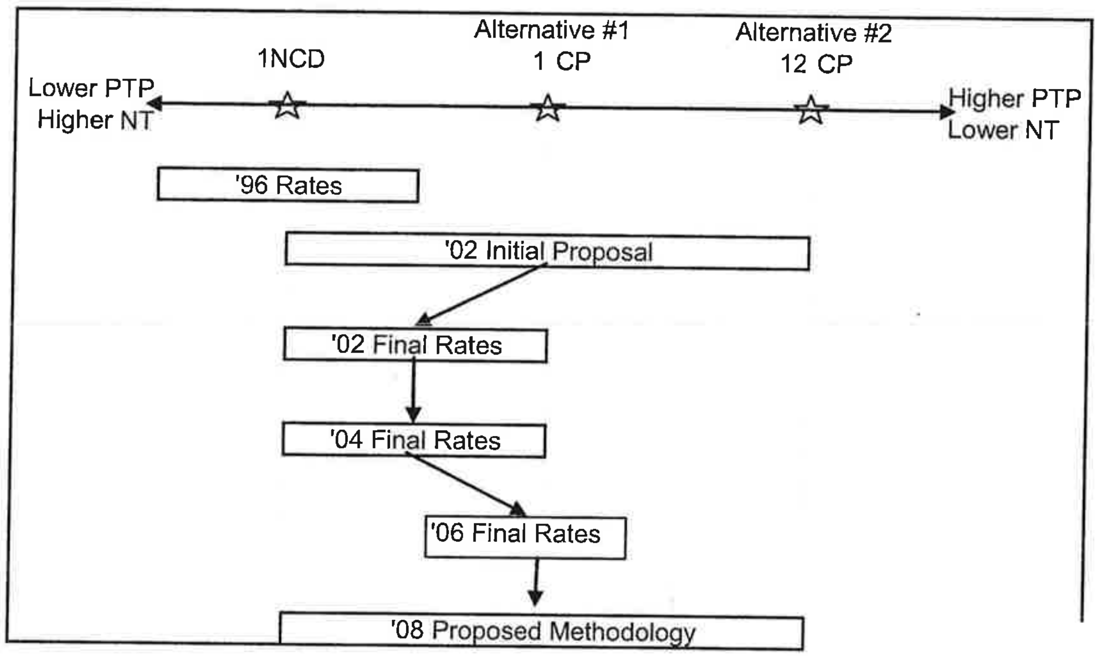
The results of applying these tests to the Federal transmission system are shown here:

CY	(a) **Lowest Monthly Tx Peak** (MW)	(b) **Avg of 12 Monthly Tx Peaks** (MW)	(c) *Annual Peak* (MW)	(d) **Test 1: Col (a)/ Col (c)** (%)	(e) **Test 2: Col (b)/ Col (c)** (%)
1999	21,213	24,844	27,070	78.4	91.8
2000	19,723	23,607	27,139	72.7	87.0
2001	16,660	20,125	24,035	69.3	83.7
2002	18,587	21,362	23,463	79.2	91.0
2003	18,126	20,959	22,700	79.9	92.3
2004	18,077	20,467	22,998	78.6	89.0
2005	18,519	20,713	22,231	83.3	93.1

<u>TBL's transmission loading pattern would support the use of a 12CP divisor for allocating costs between the network rate classes.</u>

Recommendation:

Though BPA would like to move towards the 12CP allocation we feel there would be a considerable cost shift in the FY08/09 rate period therefore we propose to continue with the 1CP allocation approach.



NORTHERN WASCO COUNTY PUD
PEOPLE'S UTILITY DISTRICT

March 30, 2012

BPA Tech Forum

Subject: COSA Cost Allocation Alternatives

Northern Wasco County People's Utility District (NWCPUD) appreciates the opportunity to comment on the cost allocation methodologies presented at the Transmission Cost of Service Analysis (COSA) workshops. NWCPUD is a publicly-owned utility using Network Transmission (NT) to serve its approximately 9,780 retail customers.

BPA currently uses a modified one coincidental peak ("1 CP") allocation methodology to allocate the costs of the Network segment to the various classes of wholesale transmission services using that segment. However, over the course of several COSA workshops, BPA staff has demonstrated that if BPA followed the Federal Energy Regulatory Commission's ("FERC") approach to cost allocation it would use a twelve monthly coincident peak ("12 CP") allocation methodology. As stated in the Northwest Requirements Utilities comments and NT Customer Proposal, the 12 CP method clearly meets all of the FERC tests when applied to the load characteristics and planning criteria for the BPA Network transmission segment.

NWCPUD firmly believes that BPA should allocate Network segment transmission costs using the 12 coincident peak cost method in the COSA for the FY 2014-2015 transmission rate case. The 12 CP allocation method has long been used by the Federal Energy Regulatory Commission (FERC) for allocation of demand related costs. The 12 CP method will result in the equitable allocation of costs of the Network between federal and non-federal users of the transmission system as well as between the various transmission services involving use of the Network segment.

Thank you for considering these comments.

Sincerely,

Kurt J. Conger
Director of Power Supply, Transmission and Regulatory Policy

To: BPA Tech Forum

Date: March 30, 2012

Re: Transmission Cost Allocation Alternatives

PNGC Power is a generation and transmission cooperative serving the net requirements of its 14 rural electric distribution cooperative members[1]. PNGC and its members hold a Network Integration Transmission Service (NT) contract. We have been active participants in the Cost of Service process (COSA) and will continue to participate in the BPA rate proceedings as we have a direct and substantial interest in BPA's transmission rates. We appreciate this opportunity to comment on the cost allocation alternatives as part of the COSA process.

Today, BPA filed its OATT at FERC and asked for approval on a reciprocity basis. We believe BPA's efforts to align its transmission service better with FERC standards should be carried over into the transmission COSA. BPA's system justifies the use of the 12 coincident peak (12 CP) methodology and has for at least a decade. Now is the time for BPA to use the 12 CP cost allocation methodology.

PNGC and other NT customers sponsored the February 29, 2012 letter urging BPA to use the 12 CP methodology in its COSA. We refer BPA to this letter for detailed support of our choice of the 12 CP cost allocation methodology.

The results of any cost of service study are the starting point for rate design, not the final result. It is important that cost of service results be accurately reported so that movements away from them can be made deliberately in the rate design process. We recognize that BPA's rate principles create tension in implementation and may result in a modification of pure cost of service results. The merits of any modifications should be the subject of a rate case in which all competing rate principles can be considered.

[1] PNGC's members are Blachly Lane Electric Cooperative, Central Electric Cooperative, Clearwater Power Company, Consumers Power Inc., Coos Curry Electric Cooperative, Douglas Electric Cooperative, Fall River Electric Cooperative, Lane Electric Cooperative, Lincoln Electric Cooperative, Northern Lights, Inc., Okanogan Rural Electric Cooperative, Raft River Rural Electric Cooperative, Umatilla Electric Cooperative, and West Oregon Electric Cooperative.

Pacific Northwest Generating Cooperative
711 NE Halsey • Portland, OR 97232-1268
(503) 288-1234 • Fax (503) 288-2334 • www.pngcpower.com

From: Ray Grinberg [mailto:Ray@penlight.org]
Sent: Monday, March 26, 2012 12:02 PM
To: Tech Forum
Subject: Cost Allocation Alternatives

Peninsula Light Company appreciates the opportunity to comment on the cost allocation methodologies presented at the Transmission Cost of Service Analysis (COSA) workshops. Peninsula uses Network Transmission (NT) to serve its 30,000 members in Pierce County, Washington.

Peninsula Light Company supports the position of NRU and other NT Customers and urges BPA to employ the 12 coincident peak cost allocation method in the COSA for the FY 2014-2015 transmission rate case. The 12 CP allocation method has long been prescribed by the Federal Energy Regulatory Commission (FERC). The 12 CP method clearly meets all of the FERC tests when applied to the load characteristics and planning criteria for the BPA Network segment. The 12 CP method will result in the equitable allocation of costs of the Network between federal and non-federal users of the transmission system as well as between the various transmission services involving use of the Network segment.

Thank you for considering these comments.

Ray Grinberg

Power Resources Director

March 30, 2012

Via Electronic Submission
Bonneville Power Administration
techforum@bpa.gov

Re: Comments of Point to Point Customers Coalition on Bonneville Power Administration's Cost Allocation Alternatives

The Point to Point Customers Coalition ("Coalition") thanks the Bonneville Power Administration ("BPA") for the opportunity to submit these comments in response to the March 13, 2012 request for comments on the cost allocation methodologies presented at the Transmission Cost of Service Analysis ("COSA") workshops. The Coalition includes Benton County Public Utility District No. 1, EDP Renewables, Franklin County Public Utility District No. 1, M-S-R Public Power Agency, Pend Oreille Public Utility District No. 1, Powerex, Seattle City Light, Snohomish County Public Utility District No. 1, and Tacoma Power. The Coalition is a non-homogenous group of point-to-point ("PTP") customers of BPA, including public agencies, an independent power producer and a power marketer.

BPA must adopt a cost allocation methodology that equitably allocates costs of the Federal transmission system between Federal and non-Federal power users.[1] To this end, the Coalition urges BPA to adopt a 1 non-coincident peak ("NCP") or to continue with a 1 CP cost allocation methodology. As discussed below, the 12 CP methodology that other customers have suggested would create unjustifiable cost shifts and is not appropriate for BPA's transmission system.

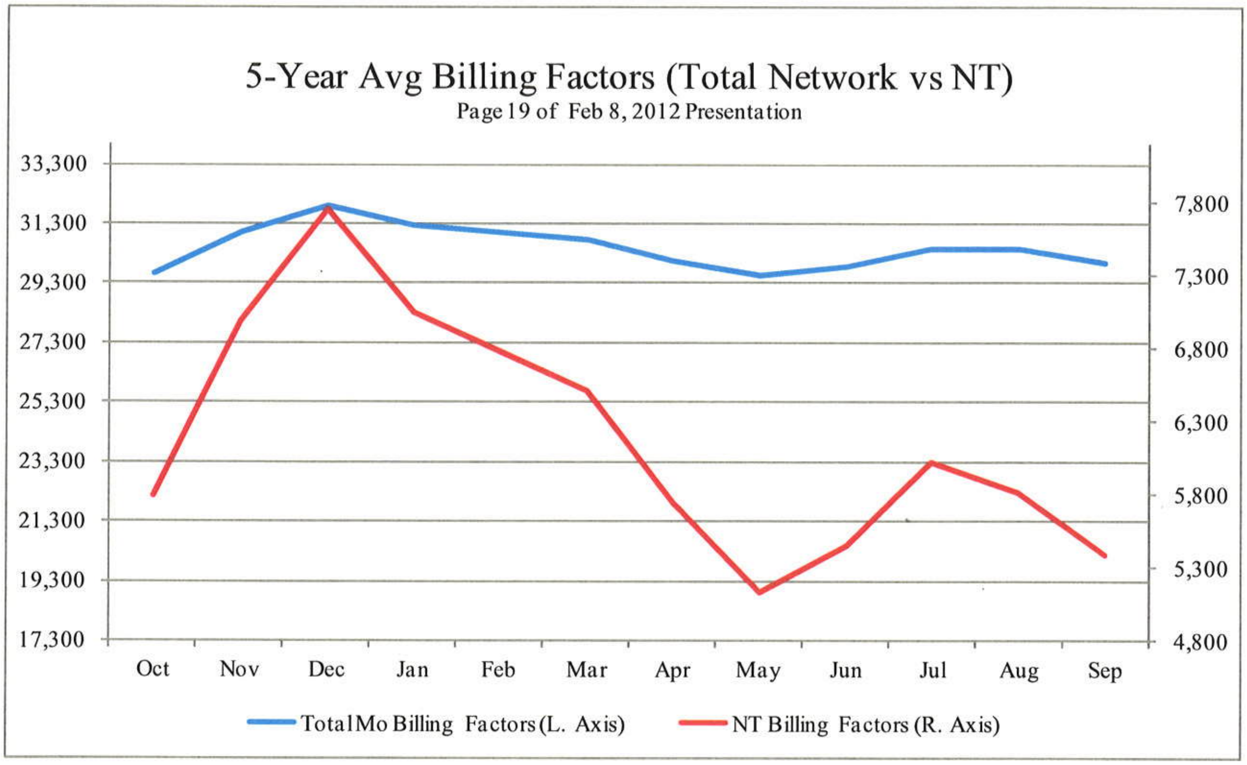
I. BPA Should Not Allocate Demand Costs on a 12 CP Basis.

A. The FERC Cost Allocation Tests Have Been Proven Inapplicable.

The Coalition has supported BPA's investigation of the FERC cost allocation tests for possible guidance on how BPA and its customers could develop a more appropriate cost allocation methodology. The Coalition recognizes the fact that the FERC tests 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. Now that the investigation has concluded, it is clear that these tests do not take into account the uniqueness of BPA's arrangements. Approximately 80% of BPA's transmission customers are 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

[1] 16 U.S.C. § 838h.

CP methodology. As the following graph illustrates, 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.



In fact, the Coalition's analysis demonstrates that if the tests only accounted for BPA's network customers, the tests would justify a 1 CP method under the FERC cost allocation tests.

NT Billing Factors (BPA's "Historical Billing Factor" Spreadsheet)

	Annual	Annual	Avg 11 off	Annual	|--------- **NT Results** ---------|		
Year	Peak	Average	Peak	Min	Test 1	Test 2	Test 3
2006	6,825	5,866	5,779	4,971	15%	73%	86%
2007	8,322	6,441	6,270	5,006	25%	60%	77%
2008	7,722	6,283	6,152	5,253	20%	68%	81%
2009	8,797	6,150	5,910	4,950	33%	56%	70%
2010	9,767	6,221	5,898	5,152	40%	53%	64%
				5-Yr Average	27%	62%	76%
				12 CP Condition	<19%	>66%	>81%
				12CP or 1CP?	**1CP**	**1CP**	**1CP**

This is consistent with the fact that BPA's transmission system has been built to meet the annual anticipated peak demand, plus a margin, for its customers. Therefore, it does not make sense for

BPA to rely on the results of the FERC cost allocation tests for allocating the costs of its network segment among its customers.

Moreover, while the FERC tests are based upon load, service to NT customers on the BPA system is directed by the BPA Memorandum of Agreement for the Management of Network Integration Transmission Service for Delivery of Federal Power to Network Customer Loads, September 30, 2011 ("NT MOA"). The NT MOA ensures NT customers access to 65% of the aggregated nameplate capacity of designated BPA network resources (including network resources and non-federal designated network resources) and firm transmission necessary to deliver such. The Coalition believes that the access to designated resources should be considered as a proxy for reserved capacity for NT customers.

B. 1 NCP Should Be the Starting Point for Cost Allocation Discussions.

In its 1996 decision, BPA identified the 1 NCP method as superior because it created "equivalent" demands for NT and PTP customers. In other words, equivalency in terms of cost allocation could be achieved by recognizing that BPA formally reserves capacity for PTP/IR/FPT customers and informally reserves capacity for NT customers (i.e., NCP for NT and contract demand for PTP). Since then, BPA and its customers have implemented transmission rates achieved through settlement agreements. Those settlement agreements have no precedential value. Therefore, the coalition believes that 1NCP should be the starting point for BPA's current COSA process.

It is important to note that in 1996, BPA chose 1 NCP even though others argued for the adoption of the 12 CP method. There is no indication from what we have learned through the COSA workshops that circumstances have changed since 1996 in a manner that would warrant a change to this cost allocation method. In fact, according to the FERC cost allocation tests, BPA has effectively met a 12 CP test since 1996. However, that cost allocation method has been rejected and adopting it now would ignore the fact that BPA stands by, ready to transmit power to its public power customers under various load, weather and system conditions.

If BPA were to divert from 1 NCP, then it would need to adjust the demands for the NT class of customers upward in some way to ensure equitable treatment and adherence to cost causation principles.

C. A 12 CP Cost Allocation Methodology Will Inappropriately Shift Costs From NT Customers to PTP Customers.

Cost causation requires that costs be borne by those who cause them or benefit from them. From this perspective, 1 CP or 1 NCP is more consistent with traditional cost causation principles than the 12 CP approach for BPA. Changing to a 12 CP method without recognizing BPA practices simply creates an inappropriate cost shift or cross-subsidization between customer classes, where some classes pay more than their share and others pay less.

As illustrated in BPA's January 11, 2012 presentation titled "Transmission Cost of Service Analysis Workgroup," BPA anticipates a 5.4 percent rate increase for PTP customers and a 0.2 percent rate increase for NT customers using a 1 CP methodology. By contrast, BPA anticipates a 9.8 percent rate increase for PTP customers and a 14.4 percent rate decrease for NT customers using a 12 CP methodology. Use of the 12 CP methodology without adjustments to recognize BPA practices inappropriately shifts costs from the NT customers to other transmission customers, particularly the PTP customers.

The cost shift results in large part because the 12 CP method does not properly incorporate the system flexibility set aside by BPA per the NT MOA and inappropriately allocates a portion of the short-term transmission sales revenues to NT customers. The 12 CP method typically uses monthly coincidental peak use for customer classes as the basis for cost allocation. However, in this case, using the NT coincident monthly peak use is inappropriate as BPA is setting aside transmission to ensure access to 65% of the aggregated nameplate capacity of designated network resources. The appropriate monthly allocator for NT customers under 12 CP is the greater of NT coincident monthly peak use or the set aside capacity.

The load shaping charge is the rationale behind which *both* PTP and NT customers benefit from BPA's short-term sales revenues. Without a load shaping charge, there is no logical foundation for including short-term sales in the denominator when calculating NT rates, because NT customers no longer have a claim on the inventory BPA uses to make short-term sales. Eliminating the load-shaping charge without correspondingly allocating a higher proportionate share of short-term sales revenues to PTP rates is wrong computationally and results in an unjustifiable cost shift to PTP customers.

BPA should also consider the risk that the resultant rate disparity, which would occur by using the 12 CP methodology, may trigger conversion requests from PTP customers and undermine the anticipated result. A change from 1 NCP to 12 CP would constitute a fundamental change in the "rules of the road" that PTP customers were unaware of when executing their PTP contracts. The same "rules of the road" were the cost allocation method expectations under which NT customers signed their contracts.

II. BPA Should Ensure that Transmission Costs Are Equitably Allocated Between Transmission Customers.

Section 10 of the Transmission System Act allows for uniform rates and specifies that the costs of the Federal transmission system be equitably allocated between Federal and non-Federal power utilizing the system.[2] This is the rate standard that BPA is required to meet. The Coalition is deeply concerned that certain transmission customers may be paying the same or

[2] 16 U.S.C. § 838h.

greater rate than other transmission customers without having caused a particular cost or received any benefits from that cost. Such a disparity would be contrary to traditional cost causation principles and the Transmission Act's cost allocation standard.[3] The Coalition strongly urges BPA to ensure that transmission costs are directly assigned to those customers that cause or benefit from these costs.

While it is fair for BPA to charge transmission customers a proportionate share of the embedded cost of the entire transmission system, it is not fair for one group of customers to subsidize another. The Coalition requests that BPA confirm that the following service costs are appropriately allocated between NT and PTP classes of customers or transmission customers in general.

- Redispatch service[4]
- Secondary network service[5]
- Determination of firm transmission commitments[6]
- Planning of transmission system improvements[7]
- Staffing for NERC compliance activities[8]
- Staffing to comply with NAESB standards for NT service[9]
- Staffing to establish a new Network Integration Transmission Service Model[10]

III. Topics for Further Investigation

A. Assignment of Plant to Segments and Plant Replacements

The Coalition wishes to understand how the assignment of lines carrying voltages of 34.5 kV or less to the Utility Delivery Segment aligns with FERC ratemaking tests distinguishing between distribution and transmission, as well as NERC's reliability definition and functional

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[3] The "equitable allocation" seems to suggest that costs be allocated between PTP and NT in the same manner, i.e., either allocated upon "use" for both services or, "reservation" for both purpose. This "rate-making" standard is not inconsistent with public utilities' interest in BPA adopting, as closely as reasonable, terms and conditions that embrace open-access.

[4] Attachment M to BPA Open Access Transmission Tariff

[5] NT MOA, Section 10(a).

[6] NT MOA, Section 6(a).

[7] NT MOA, Section 6(d).

[8] See Exhibit A, p. 1.

[9] See Exhibit A, p. 3.

[10] See Exhibit A, p. 3.

test of what constitutes the bulk electric system. We would like the opportunity for our engineers to review the color-coded one-line diagrams that are used to determine whether certain facility costs should be included as part of BPA's transmission system costs and confirm that the network segment consists of only those lines and equipment associated with providing transmission service to the network.

In addition, we wish to understand how BPA ensures that the color-coded one-line diagrams are kept up to date. Are the drawings audited on a periodic basis? How are plant replacements captured?

BPA identified some issues concerning the financial accounting for plant retirements. Does BPA have any plans for addressing these issues? Will they be addressed before the next rate case?

B. General Plant

Staff has informed the Coalition that general plant for corporate services was allocated equally between transmission and power rates. Now, it appears that 65% will be allocated to transmission and 35% to power rates. Why was general plant for corporate services allocated equally in the past and what circumstances have changed to warrant this significant change in the allocation of these costs?

IV. BPA Should Establish Protocols to Provide Transmission Cost Information to Customers In Advance of Transmission Rate Cases.

The Coalition thanks BPA staff for providing the models that comprise the cost of service analysis – the Revenue Requirement model, the investment model, and the general plant spreadsheet.[11] In addition, members found staff's explanation of the models particularly helpful and appreciated BPA staff's commitment to transparency in our discussions. The models are easy to follow and easily replicable. Given the benefits of the models to customers, the Coalition requests that these models become standard documents filed as part of staff's initial proposal in all future rate cases and that the costs used in the models be subject to audit.

Also, staff provided another spreadsheet which was a list of detailed Integrated Program Review ("IPR") costs by category/program that served as the base detail input into the revenue requirement model. This table should be addressed in the IPR process as the beginning point for the rate case COSA. The Coalition recommends that in the IPR, each category/program and their costs should be paired with the customer segment(s) who will ultimately be assigned these costs, and the method that will be used to assign the category/program costs should be clearly set

[11] We understand that the collection of these models is included in BPA's Annual Revenue Requirement Study.

forth during the IPR. This will permit customers to know before the costs are incurred how recovery will be achieved, e.g., from the network or from the delivery segment.

The Coalition hopes that BPA will adopt these recommendations going forward. The Coalition believes these recommendations are essential for customers to understand the nexus between costs and rates and to allow them to work with staff to develop a consensus around those rates.

V. Conclusion

The Coalition urges BPA to maintain either the 1 NCP or 1 CP cost allocation methodology for setting transmission rates. BPA should reject any suggestions for a 12 CP methodology because as discussed in these comments, such a methodology would unjustifiably shift transmission costs and not equitably allocate those costs, as required by the Transmission Act, and would not be appropriate for BPA's transmission system. BPA must also ensure that transmission costs used in the cost allocation methodology are equitably allocated between transmission customers. The Coalition thanks BPA for its consideration of these comments and looks forward to continuing the discussion.

Sincerely,

Dana A. Toulson

Dana Toulson
Assistant General Manager
Power, Rates, and Transmission Management
Snohomish County PUD No. 1

Representative of the Point to Point Customers Coalition

w/Attachment

EXHIBIT A

FY12-FY13 Transmission Staffing Scenario

As part of the IPR process, Transmission received customer comments on a number of staffing issues. These included:

- Recommending BPA implement a succession planning initiative for the key Transmission Services areas.
- Ensuring there is sufficient staffing to efficiently perform in key areas, such as policy and rates, reliability compliance and operations.
- Validating there is sufficient staff to work on NERC standard compliance and operations. Includes ensuring a coordinated approach to NERC standard compliance, between BPA and its customers.
- Provide continuity in staff working on NT policy development
- Maintaining continuity in staffing and preservation of expertise in order to enable Transmission (and the customers) to move forward on pressing issues rather than spend time re-training staff.
- Dedicating sufficient resources to the interconnection process, the implementation of new operational capabilities, and important policy decisions, in order to avoid delays in new renewable energy investment.
- Prioritizing and increasing spending levels for the Wind Integration Team (WIT) and other advances in transmission and ancillary services operations. Adding an 10-15 additional FTE are required to fully reach the potential of WIT.
- Committing more resources towards achieving FERC reciprocity status.

Based on this feedback, Transmission reviewed its staffing levels and has the following proposal.

	Organization	IPR Program Area	CFTE	BFTE	TERM	Capital / Expense	Justification of Need for Position
							Compliance
1	Transmission Internal Operations	External Reimbursable Services	4			Reimbursable Expense	Develop new internal processes, ongoing program documentation and system enhancements to support ongoing customer coordination for NERC compliance associated with the Joint Registration Organization (JRO). This program supports up to 60 customers. Risk is non-compliance for BPA and its customers for those customers who elect the JRO option.
2	Transmission Engineering	Regulatory & Regional Association Fees		1		Expense	Additional support needed to provide advice and guidance to customers for NERC/CIP compliance associated with communications interphases - fiber, relays, etc. This is new ongoing core work specifically to provide customer support. Risk is non-compliance for BPA and its customers for those customers who elect the JRO option.
3	Transmission Customer Service Engineering	External Reimbursable Services	2			Reimbursable Expense	Provide ongoing annual technical coordination, review and certification for load serving entity (LSE) and distribution provider (DP) registered customers for NERC compliance. Risk is non-compliance for BPA and its customers.

	Organization	IPR Program Area	CFTE	BFTE	TERM	Capital / Expense	Justification of Need for Position
							Compliance
4	Marketing & Sales	Regulatory & Regional Association Fees	1			Expense	Technical modifications are required to BPA's webTrans system that only OATI can perform in order for BPA to be FERC compliant. The risk is that BPA won't meet the effective date for the NERC ATC Standards.
5	Transmission Commercial Systems	Regulatory & Regional Association Fees		2		Expense	Additional support needed to maintain additional commercial IT systems required under the NERC ATC Standards and Reciprocity. This includes integration with existing commercial systems, new enhancements, documentation, and new certification requirements. The risk is that BPA is non-compliant.
6	Transmission Account Services	Regulatory & Regional Association Fees			1	Expense	Additional support needed to process JRO Agreements. The risk is that BPA is non-compliant.
							Wind Integration
7	Transmission Planning	Internal Reimbursable Services	1			Reimbursable	Support for completing studies required for wind integration. Risk is non-compliance with LGIP.
8	Transmission Operations	Capital Program			1	Capital	Improving wind integration process with control center system environment and to respond to customer's needs. Risk is delay of project energization.
9	Transmission Engineering	Capital Program			2	Capital	Additional project managers are needed for wind integration projects. Risk is failure to execute projects.
10	Transmission Policy Development & Analysis	Scheduling Technical Support			1	Expense	Additional support needed to improve ancillary services required to implement the wind integration initiatives and to respond to customer needs. The risk is decreased reliability to the FCRPS.

	Organization	IPR Program Area	CFTE	BFTE	TERM	Capital / Expense	Justification of Need for Position
11	Transmission Policy Development & Analysis	Marketing Business Strategy	1			Expense	Additional support needed to improve customer access to existing and new intertie capacity, increase Dynamic Transfer Capability (DTC) between regions, reduce the risk of negative Northwest prices, and shift balancing service responsibilities to California Balancing Authority Areas (BAA). Risks include the inability to export surplus wind power out of the region during periods of high water or non-power constraints on hydro operation, thereby creating a risk of negative prices, and inability to shift balancing service responsibilities to California BAAs due to lack of DTC.
							NT Service
12	Transmission Marketing & Sales	Scheduling Technical Support		1		Expense	Conversion of MBA Coop Student. Additional support needed to maintain additional commercial IT systems required under the NAESB NT Standards, which includes the Network Integration Transmission Service (NITS). This includes a new transacting system for just NT service, integration with existing commercial systems, new enhancements, and customer support. The risk is that BPA is non-compliant in implementing new industry standards for NT Service.
13	Transmission Commercial Systems	Scheduling Technical Support		3		Expense	Additional support needed to maintain additional commercial IT systems required under the NAESB NT Standards, which includes the Network Integration Transmission Service (NITS). This includes a new transacting system for just NT service, integration with existing commercial systems, new enhancements, and customer support. The risk is that BPA is non-compliant in implementing new industry standards for NT Service.
14	Transmission Commercial Systems	Scheduling Technical Support	3			Expense	Additional support needed to setup the new Network Integration Transmission Service (NITS) model. This includes data population, testing, integration with other commercial systems, troubleshooting before the model is ready to be commercially available, and customer support. The risk is that BPA is non-compliant in implementing new industry standards for NT Service.
		TOTAL	12	7	5		

FY12 Staffing Cost Rule of Thumb:	
BFTE	$102,000
CFTE	$129,846

CAPITAL:

Capital FTE are already covered in the FY12-13 capital program and there is no resulting incremental IPR program increase. There are 3 Term BFTE added in lieu of CFTE. Although the budget rule of thumb for CFTE is $129,846, for most engineering functions the annual CFTE cost is typically $150-300K.

EXPENSE:

The incremental expense FTE is 14 with an associated annual expense program increase is $1,567,230. There are 2 Term BFTE and 7 permanent BFTE added in lieu of CFTE. These BFTE are added because the positions are inherently governmental and/or cost of CFTE significantly exceeds BFTE.

REIMBURSABLE EXPENSE:

Seven of the FTE are for reimbursable services and would be rate neutral.

	EXPENSE FTE			CAPITAL FTE	
5	Expense CFTE	$649,230	0	Capital CFTE	$0
7	Expense BFTE	$714,000	0	Capital BFTE	$0
2	Expense Term BFTE	$204,000	3	Capital Term BFTE	$306,000
	Total annual cost	$1,567,230		Total annual cost	$306,000

RATE IMPACT

Rule of thumb rate impact for **expense program $6.2M = 1% change**	Rule of thumb for **capital program $66M = 1% change**
Rate Impact: 0.25%	**Rate Impact: Not applicable**

BPA Financial Disclosure Information: This information has been made publicly available by BPA on August 20, 2010 and does not contain Agency-approved Financial Information.

COMMENTS OF THE WESTERN PUBLIC AGENCIES GROUP IN SUPPORT OF A 12 CP COST ALLOCATION METHODOLOGY FOR THE TRANSMISSION COST OF SERVICE ANALYSIS

The utilities that comprise the Western Public Agencies Group ("WPAG") appreciate this opportunity to reaffirm their support of the NT Customer Group[1] proposal (submitted on February 29, 2012 to Tech Forum, a copy of which is attached hereto) that the Bonneville Power Administration ("BPA") adopt a 12 Coincidental Peak ("CP") methodology for the Transmission Cost of Service Analysis ("NT Customer Proposal"). These comments are intended to supplement and support that earlier submittal and, to the extent necessary, the NT Customer Proposal is expressly incorporated herein.

On March 28, 2012, BPA sent an email via Tech Forum to all "Transmission Customers and Interested Parties" stating that "BPA's team has concluded work on its Open Access Transmission Tariff" and that BPA expects that it "will announce the submission of the tariff [to the FERC] on or about March 30."

At base, BPA's announcement means that BPA has made a final decision to bring the terms and conditions of its transmission services closer in line with the terms and conditions for such services contained in the Federal Energy Regulatory Commission's ("FERC") *pro forma* Open Access Transmission Tariff ("OATT"). The WPAG utilities offer no opinion in this process as to the wisdom of BPA's decision or as to whether BPA's movement towards the terms and conditions in the FERC *pro forma* is what is best for BPA, its customers or the region. Rather, the WPAG utilities simply recognize that BPA has made its decision and that there are natural implications stemming from it.

One such implication is cost allocation in setting transmission rates and charges. As FERC itself has recognized "non-price terms and conditions cannot be designed independent of pricing and cost recovery."[2] Accordingly, in light of BPA's move toward the terms and conditions of the *pro forma*, BPA should not allow its current wholesale transmission cost allocation methodology to remain stagnant, but instead should make a parallel move towards the FERC *pro forma's* methodology for cost allocation. This would allow BPA to approach the *pro forma's* intended parity between the terms and conditions of transmission services and cost allocation.

This means that, consistent with the NT Customer Proposal, BPA should use a 12 CP methodology to allocate the costs of its Network segment amongst the various wholesale transmission services for that segment rather than the modified 1 CP methodology it currently uses. This conclusion is amply supported by the demonstrations made by BPA staff in the COSA

[1] The parties participating in the February 29, 2012 proposal included the following association members and individual utilities: Clark Public Utilities, Eugene Water & Electric Board, Cowlitz PUD, Northwest Requirements Utilities, PNGC Power and WPAG.

[2] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21540, 21598 (May 10, 1996).

workshops showing that if BPA were to follow FERC's allocation methodology it would use 12 CP to allocate costs.[3]

The WPAG utilities appreciate the considerable time and obvious effort that BPA staff has put into the COSA process. These workshops have been conducted in a professional manner and were effective in facilitating a meaningful dialogue between BPA and its customers on how BPA should allocate its wholesale transmission costs between the various transmission services. However, the undeniable and unchallenged conclusion from the workshops is that BPA has a 12 CP system and should use a 12 CP allocation methodology. To date, no party has provided either a scintilla of proof or a credible argument to the contrary. Therefore, based on the information above and in the NT Customer Proposal, and because all of the evidence and analysis in this process has been overwhelmingly one sided in favor of 12 CP, we urge BPA to adopt 12 CP for the COSA.

[3] See, Transmission Cost of Service Analysis Workshop Power Point Presentation, December 5, 2011, available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Workshop_12-05-11_revised.pdf; FERC Coincidental Peak Test Power Point, January 11, 2012, p. 2, available at http://www.bpa.gov/corporate/ratecase/docs/FERC_Coincidental_Peak_Test.pdf; Transmission Cost of Service Analysis Workshop Power Point, February 8, 2012, pp. 16 & 18 , available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Workshop_2-8-12.pdf.

ATTACHMENT

NT CUSTOMER PROPOSAL TO USE A 12 CP COST ALLOCATION METHODOLOGY FOR THE TRANSMISSION COST OF SERVICE ANALYSIS

A. Introduction.

This proposal is submitted on behalf of the following association members and individual utilities: Clark Public Utilities, Eugene Water & Electric Board, Cowlitz PUD, Northwest Requirements Utilities, PNGC Power and the Western Public Agencies Group ("NT Customers").

The NT Customers rely on the Network Integration 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.[1] 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 as part of the Transmission Cost of Service Analysis ("COSA").

BPA currently uses a modified one coincidental peak ("1 CP") allocation methodology to allocate the costs of its Network segment amongst the various wholesale transmission services for that segment. However, over the course of several COSA workshops, BPA staff has demonstrated that if BPA followed the Federal Energy Regulatory Commission's ("FERC") approach to cost allocation it would use a twelve monthly coincident peak ("12 CP") allocation methodology. In light of this information and the reasons set forth below, the NT Customers propose that BPA adopt a 12 CP methodology in the COSA on the following bases:

(1) BPA's decision to better align the terms and conditions contained in its Open Access Transmission Tariff ("OATT") with the FERC *pro forma* with the objective of making a tariff filing seeking reciprocity with FERC justifies a corresponding adoption of FERC's 12 CP methodology for allocating costs.

(2) Changes on BPA's transmission system justify the use of a 12 CP methodology including:

- BPA's large scale expansion of the transmission system to accommodate non-federal resource development by PTP customers.

- The substantial growth in the secondary transmission capacity market on BPA's system.

(3) Adoption of a 12 CP methodology is consistent with the principles enunciated by BPA and customers at the beginning of the COSA process.

[1] While some of the NT Customers take Point to Point Transmission Service ("PTP") for various reasons, each of them relies on the NT service.

The remainder of this proposal describes in detail the above justifications for the adoption of a 12 CP methodology.

B. BPA Should Adopt FERC's Approach to Cost Allocation - 12 CP.

BPA has been working for the better part of a year to bring the terms and conditions of its transmission services under its OATT in line with the terms and conditions for transmission service identified in FERC's *pro forma* OATT with an aim towards making a tariff filing seeking reciprocity with FERC by the end of March 2012. BPA's decision to adopt FERC's *pro forma* terms and conditions means that BPA should also make a corresponding move to use FERC's approach for allocating wholesale transmission costs. This is because FERC's *pro forma* OATT strikes a balance between the terms and conditions of wholesale transmission services and the allocation of costs between such services.[2] To establish terms and conditions consistent with FERC's approach and then allocate costs based on some other basis would upset that balance.

While FERC does not mandate the use of any one particular coincidental peak methodology, it has primarily affirmed the use of a 12 CP allocation method because it "believe[s] the majority of utilities plan their system to meet their twelve monthly peaks."[3] FERC does allow utilities to propose an alternative to 12 CP, but only where they can demonstrate that "such alternative is consistent with the utility's transmission system planning and would not result in over-collection of the utility's revenue requirement."[4] In evaluating such determinations, FERC uses the following three peak ratio tests:

(1) **Test No. 1 -** On and Off Peak Test - This test first compares the average of the coincidental peaks in the months with the highest system peaks as a percentage of the annual system peak. Second, it compares the average of the coincidental peaks in the months with the lowest system peaks as a percentage of the annual system peak. A 12 CP allocation is considered appropriate where the difference between these two percentages is 19% or less.

(2) **Test No. 2** - Low-to-Annual Peak Test - Compares the lowest monthly peak as a percentage of the annual system peak. A range of 66% or higher is considered indicative of a 12 CP system.

(3) **Test No. 3** - Average to Annual Peak Test – Compares the average of the twelve

[2] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 FR 21540-01, 21598 (May 10, 1996) ("Order 888") ("We agree that non-price terms and conditions cannot be designed independent of pricing and cost recovery").

[3] Order 888, 61 FR at 21599.

[4] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888-A, 62 FR 12274-01, 12321 (March 14, 1997) ("Order 888-A").

monthly peaks as a percentage of the annual system peak. A range of 81% or higher is considered indicative of a 12 CP system.[5]

Over the last several months, BPA has performed each of the above peak demand tests several times in order to determine which coincident peak allocation methodology is appropriate for its system. Each iteration of the tests used different assumptions or data to perform the calculations (e.g., total transmission system loading ("TTSL") vs. network transmission billing factors ("NTBF"), firm vs. non-firm, long term vs. short term). Nevertheless, the undeniable conclusion from BPA's numerous performances of the FERC tests is that BPA has a 12 CP system, and has had a 12 CP system since at least 2006 (the earliest year for which BPA performed the FERC tests in this COSA process).[6] As shown in the table below, this was true irrespective of which of the varying assumptions or data BPA or customers identified was actually used in the calculations.

	Test No. 1	**Test No. 2**	**Test No. 3**
Analysis for 12/5/2011 Workshop - using TTSL - Avg. result over 5 Years (2006-2010)[7]	13%	75%	88%
Analysis for 1/11/2012 Workshop - using NTBF - Avg. over result 5 Years (2006-2010)[8]	10%	84%	91%
Analysis for 2/8/2012 Workshop - using TTSL - Avg. result over 6 years (2006-2011)[9]	13%	77%	88%
Analysis for 2/8/2012 Workshop - using Long-Term NTBF - Avg. result over 6 years (2006-2011)[10]	7%	90%	94%
12 CP Condition under FERC Test	**≤ 19%**	**≥ 66%**	**≥ 81%**

[5] *Golden Spread Electric*, 123 FERC 61,047, 61,249 (2008).

[6] Indeed, BPA's conclusion in 2012 that it has a 12 CP system is fully consistent with a conclusion it reached as part of an August 16, 2006 Transmission Rate Case Workshop, which was based on data extending back as far as 1999, i.e., "TBL's transmission loading pattern would support the use of a 12CP divisor for allocating costs between the network rate classes." BPA Transmission Rate Case Workshop Handout, RE: Network Cost Allocation, dated August 16, 2006 and available upon request.

[7] Transmission Cost of Service Analysis Workshop Power Point Presentation, December 5, 2011, available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Workshop_12-05-11_revised.pdf. The numbers in the table are averages over five years (2006-2010) or six years (2006-2011). However, in every case the individual calculations for each specific year also indicated that BPA has a 12 CP system without exception.

[8] FERC Coincidental Peak Test Power Point, January 11, 2012, p. 2, available at http://www.bpa.gov/corporate/ratecase/docs/FERC_Coincidental_Peak_Test.pdf.

[9] Transmission Cost of Service Analysis Workshop Power Point, February 8, 2012, p. 16, available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Workshop_2-8-12.pdf ("Feb. 8th Power Point").

[10] *Id.* at 18.

BPA staff has indicated that the basic principle enunciated by FERC staff in their discussions was that cost allocation should be based primarily on a utility's system planning.[11] This principle is consistent with FERC's justification for using 12 CP allocation methodology, i.e., because "the majority of utilities plan their system to meet their twelve monthly peaks."[12]

BPA adds transmission facilities to its transmission system to meet two primary purposes: reliability and capacity expansion.[13] With respect to reliability planning, FERC's assumption that utilities plan their systems to meet their twelve monthly peaks is also true for BPA. At the February 8, 2012 workshop, BPA staff explained in detail how BPA plans its system to meet its needs throughout the year rather than to meet one annual system peak. This is achieved by first modeling four seasonal base cases for planning purposes. The results from these four base cases are then extrapolated across the remaining months. The need to model on a seasonal basis is driven largely by the fact that resource patterns vary with each season and, therefore, the seasonal modeling and extrapolation across the remaining months ensures that BPA can meet its reliability obligations throughout the year.[14] Under FERC's approach for cost allocation this type of annual system planning, in addition to the results of the peak demand tests, indicates that BPA should be using a 12 CP allocation methodology.

C. Expansion of the System to Accommodate Resource Development by PTP Customers Warrants BPA's Use of 12 CP.

In addition to reliability, the other chief driver that causes BPA to add transmission facilities is capacity expansion.[15] In 2012 BPA expects to expend a little less than $500 million on transmission capital projects.[16] It expects to spend approximately $550 million more on transmission capital projects in 2013 and another $500+ million in 2014.[17]

Given the above, BPA is projecting an 11 percent rate increase for all Network customers in BP-14.[18] No small portion of this increase stems from BPA's Network Open Season ("NOS") process which primarily serves to expand the Network segment to accommodate non-federal resource development by PTP customers. These costs include:

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[11] *Id.* at 6.

[12] Order 888, 61 FR at 21599.

[13] Feb. 8th Power Point, p. 13.

[14] *Id.* at 9-13.

[15] *Id.* at 13.

[16] Building the Framework for the Integrated Program Review Power Point, January 31, 2012, p. 32, available at http://www.bpa.gov/corporate/pubs/letters/IPR_General-Manager-Meeting.pdf.

[17] *Id.*

[18] *Id.* at 29 (Absent a change to BPA's allocation methodology).

- Repayment of Large Generation Interconnection Agreement (LGIA) Credits;
- Precedent Transmission Service Agreement ("PTSA") Deferrals;
- Increased debt service; and
- Reduction of federal borrowing authority available for other projects.[19]

In addition to the increasing rate pressure, BPA's expansion of the system to bring these new resources online has created a substantial, real risk that BPA will not be able to recover all of the costs of that expansion from the developers that caused them. This is because many of the developers who originally entered into PTSAs with BPA under BPA's NOS process no longer want the transmission capacity. Since many of those parties are judgment proof, single project limited liability companies, in the event of default BPA will ultimately recover the costs created by those developers from its remaining Network customers, both PTP and NT.

All of BPA's customer who use the Network segment share in the costs and risks associated with the NOS projects. However, BPA's use of 1 CP means that its NT customers are shouldering a larger share of those costs than they otherwise would under a 12 CP approach. Since BPA is developing and expanding the transmission system primarily to meet the needs of PTP customers, it is only appropriate that it remedy the imbalance between its move towards FERC's *pro forma* terms and conditions of service and its currents cost allocation methodology by adopting the 12 CP allocation methodology. This will give NT customers some relief from these expansion costs that they did not cause, but would not give them any more relief than they already would have if BPA had followed the FERC approach in the first instance.

D. The Robust Secondary Capacity Market on BPA's System Justifies 12 CP.

FERC has found that allowing holders of firm transmission capacity the right to reassign capacity helps them manage the financial risks associated with their long term commitments, reduces the market power of transmission providers by allowing customers to compete, and fosters efficient capacity allocation.[20] BPA's transmission system is unique in that it has realized FERC's vision for a robust secondary market like none other in the country. According to a 2010 report by FERC staff, in 2009 there were 26,442 capacity reassignment transactions on BPA's system.[21] This accounted for approximately 79 percent of all such transactions nationwide.[22]

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[19] PTSA Reform Initiative Decision and Process Power Point, December 6, 2011, p. 17, available at http://transmission.bpa.gov/customer_forums/nos_gi_reform/ptsa_reform.pdf (All NOS 2008 & 2010 projects will have 6.6% rate impact on average over the next five years under the base case assuming no PTSA defaults or PTSA terminations).

[20] Order No. 888, 61 FR at 21575-21576.

[21] Federal Energy Regulatory Commission: Staff Report on Capacity Reassignment, p. 4 (April 15, 2010) available at http://www.ferc.gov/legal/staff-reports/04-15-10-capacity-reassignment.pdf (Reassignment Report").

[22] *Id.*

The vibrancy of the secondary PTP market on BPA's system highlights a key difference between the PTP and NT products: Whereas BPA's PTP customers can reassign their firm capacity; BPA's NT customers cannot use or reassign unused capacity during off-peak hours.[23] This means that while PTP customers have a means to ameliorate the costs of the PTP product, NT customers do not. Instead, during off-peak hours, BPA sells the unused NT capacity on either the short term firm or non-firm hourly markets. The revenues received from these sales are used to lower the rates of all Network segment customers, both NT and PTP, when BPA calculates firm Network segment rates.

Under FERC's *pro forma* OATT, the inability of NT customers to assign or sell their unused transmission capacity, and the benefit all Network segment customers receive from the resale of unused NT capacity, is balanced by the use of a 12 CP allocation methodology.[24] Consistent with the FERC *pro forma,* BPA has now provided a vibrant secondary capacity market that allows PTP customers to take full advantage of their reassignment rights. Accordingly, the time is now ripe for BPA to likewise provide NT customers the corresponding benefit they are entitled to under the *pro forma* tariff – cost allocation under a 12 CP methodology.

E. A 12 CP Allocation Methodology is Consistent with the COSA Principles.

Finally, the NT Customers' proposal that BPA adopt a 12 CP allocation methodology meets the COSA principles identified by BPA and transmission customers at the beginning of the COSA process:

- 12 CP is consistent with BPA's statutes in that it would ensure cost recovery and allocate the costs of the Network segment equitably between federal and non-federal users of the system.

- 12 CP allocates costs to customers based on their proportionate use in accordance with accepted industry practice for wholesale transmission services.

- 12 CP is simple, administrable, understandable, publicly accepted, feasible in application, durable and repeatable.

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[23] Order No. 888, 61 FR at 21576 ("We conclude that point-to-point transmission service, because it sets forth clearly defined capacity rights, should be reassignable. As for network transmission service, we conclude that there are no specific capacity rights associated with such service, and thus, network transmission service is not reassignable.")

[24] Order No. 888-A, 62 FR at 12323 ("The bottom line is that all potential transmission customers… must choose between network integration transmission service or point-to-point transmission service. Each of these services has its own advantages and risks…In choosing between network and point-to-point transmission service, the potential customer must assess the degree of risk that it is willing to accept associated with the availability of firm transmission capacity.").

- 12 CP would ensure rate stability from rate period to rate period both in regard to the level of rates and the rate design to be implemented.

- NT Customers have demonstrated a need for change from a 1 CP to a 12 CP methodology.

The one principle that the NT Customers offer no opinion on at this time is whether adoption of a 12 CP methodology would be consistent with the principle of avoiding rate shock. Per the Scope of COSA Process adopted by BPA at the February 8, 2012 Workshop, the final rate development step, rate design, is outside the scope of the COSA process.[25] This means that BPA and customers are to reserve arguments on the issue of avoidance of rate shock until the rate case.

F. Conclusion.

The NT Customers' proposal to use a 12 CP allocation methodology in the COSA is not novel; instead it is a logical extension of BPA's decision to better align itself with FERC policy. Adoption of 12 CP would mean that the terms and conditions of BPA's transmission services and the allocation of costs between such services would both be consistent with FERC policy. In addition, the move to 12 CP would recognize the changing conditions on BPA's system with respect to the expansion of the Network to accommodate resources rather than load and the vigorous secondary capacity market on BPA's system. And, that these changing conditions primarily benefit PTP customers with little benefit to NT customers. Under such circumstances, it is a modest request that BPA bring its cost allocation methodology in line with FERC practice by adopting a 12 CP methodology.

[25] Scope of COSA Process, available at http://www.bpa.gov/corporate/ratecase/docs/COSA_Scope.pdf.