Regional White Paper

Presentation and Analysis of Segmentation Methodology Alternatives

July 2, 2014

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I. Introduction

In the Final Record of Decision (ROD) for the BP-14 rate case, the Bonneville Power Administration's (BPA) Administrator committed the agency to engaging the region before the start of the BP-16 rate case regarding its transmission segmentation policy. The Administrator made this commitment to ensure that BPA staff and customers had sufficient time to discuss and analyze transmission segmentation alternatives prior to BPA staff's initial proposal in the BP-16 case. Staff began engaging interested customers through public meetings and informal meetings with specific customers or customer groups in January 2014. This white paper captures the various components of that discussion, which include explaining why and how BPA segments its system today as well as describing and analyzing various segmentation alternatives identified during the discussion. This white paper is not a decisional document. Rather, BPA will use this paper as an input to develop its initial proposal regarding transmission segmentation.

II. Background[1]

What Is Segmentation?

Segmentation is a part of BPA's cost allocation process in determining transmission rates. BPA performs a segmentation study that assigns specific transmission facilities (lines, substations, general plant, communications, other equipment) into defined groups, called segments. BPA's current segmentation identifies and aggregates costs into seven segments. Once each facility is assigned to one or more segments, the total investment and historical operation and maintenance (O&M) for each segment is calculated. The total investment and historical O&M for each segment become allocation factors to distribute the rate period transmission revenue requirement across the segments—total investment is used to distribute rate period depreciation and debt service costs, and historical O&M is used to distribute rate period O&M costs. The revenue requirement assigned to each segment are then used to set the various rates for each segment.

The Origins of BPA's Segmentation

From BPA's origins to the mid-1970's, transmission costs were typically bundled together with power costs and recovered through rates for power sold by BPA. As a general rule, the transmission component of BPA's bundled rates was a uniform (or postage stamp) rate. That is, the rate for transmission was the same regardless of the distance or type of facilities used to transmit power on BPA's transmission system. BPA did have a discount for deliveries within

[1] Snohomish PUD has offered comments and its perspectives on this section. This section, as included in this document, presents BPA staff's views. Because Snohomish's views are important to BPA, its comments are included in the Appendix so they can be included in this presentation, but distinguished from staff's views.

15 miles of the Federal generator bus bar but this rate was rarely, if ever, used. Beginning in the 1950's and through the 1960's (particularly when the Southern Intertie was energized), other utilities would occasionally contract with BPA to wheel non-Federal power across BPA's transmission system. BPA established rates for these uses through separate contracts. As the amount of wheeling on BPA's system grew, the rates for this service became more standardized. Generally, wheeling was charged based on the specific types of facilities used for each transaction— the number of terminals on the contract path, the number of miles between the receipt point and the delivery point, transformation between 230/500kV and 115kV, and, when called for by contract, the southern intertie. The revenues from the wheeling contracts were credited against BPA's system costs to lower the bundled rates for power sold by BPA. Use of BPA's system to wheel non-Federal power during this time was limited. The overwhelming use of BPA's transmission system during this time was to deliver Federal power at a uniform rate.

Section 6 of the Federal Columbia River Transmission System Act of 1974, 16 U.S.C. § 838 *et seq.*, provided that the BPA Administrator "make available to all utilities on a fair and nondiscriminatory basis, any capacity in the Federal transmission system which he determines to be in excess of the capacity required to transmit electric power generated or acquired by the United States." Section 10 of the Act provided that "the recovery of the cost of the Federal transmission system shall be equitably allocated between Federal and non-Federal power utilizing such system." Shortly after enactment, BPA filed its first separate "transmission" rates (i.e., Formula Power Transmission (FPT) rates that were exclusively for wheeling non-Federal power; BPA did not file new bundled power rates) with the Federal Power Commission, which was reorganized as the Federal Energy Regulatory Commission (Commission) the next year. Four years after the filing, in December 1980, the Commission remanded the rates to BPA without prejudice. The Commission requested that BPA demonstrate: 1) a rational basis for the determination of the annual cost of the transmission system; 2) a rational basis for the determination that the annual costs of the transmission system had been equitably allocated between Federal and non-Federal system users; and 3) a justification and ratemaking rationale to support the use of airline mileage billing determinants in the FPT-1 rates, as contrasted to circuit mile cost supported type rates. In addition, an explanation, including calculations, of how the revenue figures were derived in support of the proposed rate schedules was requested.

Prior to the remand order, the Commission had alerted BPA to some of the problems it was having with the transmission rates. This allowed BPA, in its 1979 power rate case, to develop more supporting information with respect to the transmission costs included in bundled power rates. BPA developed its first segmentation methodology in this case to demonstrate that power rates were recovering its appropriate share of transmission costs.

Segmentation was first applied to transmission rates in the 1981 rate case. In that case, one segmentation issue was addressed by the Commission—that BPA failed to properly segment those portions of the transmission facilities above 69kV that only serve the load of Direct Service Industrial customers (DSIs). The Commission found that BPA expected these lines to be extended to serve other substations and customers in the future. Accordingly, to assign the total cost of these lines to the delivery segment of an existing DSI would result in an inequitable over allocation of costs to the DSI service class and would distort the appropriate allocation between Federal and non-Federal transmission users.

Between 1979 and 1996, segmentation was used to establish the Network facilities and associated costs, Intertie facilities and costs, and other segment facilities and costs. Intertie costs were recovered through BPA power and wheeling uses of the Intertie segments. BPA's Network transmission costs were recovered through a combination of bundled power rates and wheeling rates, both based on a 12CP share of Network costs based on usage. All other facilities were assigned to the Fringe or three Delivery segments. The Fringe segment was comprised of facilities that were generally similar to Integrated Network facilities, but used solely for Federal power deliveries. The distinction between Fringe and Delivery facilities was, at times, inconsistent; however, this had little effect on rates—all of the costs of these other segments were recovered through bundled power rates.

Beginning in 1996, BPA's power and transmission costs were unbundled—customers paid separate power and transmission rates. Transmission facilities were no longer distinguished based upon whether they were used to deliver Federal or non-Federal power. As a result, in the 1996 rate case, staff proposed to roll the Fringe segment into the Integrated Network segment along with a portion of Delivery segment facilities. Delivery facilities at or below 34.5kV were proposed to be separately assigned to Delivery rates. BPA's initial proposal was hotly debated. IOUs disputed the roll in of the Fringe, and various parties disputed using 34.5kV as the threshold for the Integrated Network segment. Ultimately, the case resulted in a non-precedential settlement. The major segmentation-related elements of the settlement were that:

- power rates would pay for transfer agreement costs
- the Integrated Network segment would consist of non-Intertie facilities that were 34.5kV and higher (with no Fringe Segment)
- the Northern Intertie segment would be rolled into the Integrated Network segment
- BPA would endeavor to sell Utility Delivery segment facilities (defined as facilities below 34.5kV) to the local utilities to allow them to avoid the Delivery rate
- the NT rate would have a Load Shaping charge to account for peak usage; and
- the then-current Customer Service Policy for the allocation of costs of new transmission facilities would be replaced with a policy that conformed with open access principles

As a result of these changes in 1996, the purpose and need for a segmentation study changed significantly. BPA no longer needed to determine the amount of use of transmission facilities by Federal and non-Federal power since power and transmission rates were unbundled, and BPA charged the same transmission rate regardless of whether Federal or non-Federal power was being delivered. Rather, the segmentation study became a tool for assigning specific transmission facilities to defined segments and calculating their total investment and historical O&M.

Since 1996, all BPA transmission rate cases were settled until the BP-14 case. None of the settled rate cases changed the settlement-based segmentation. In the BP-14 rate case, staff proposed to continue the same segmentation methodology established by and used since the 1996 settlement. Although the facility and associated cost analysis was updated, the definitions and criteria of the segments were not. These definitions and criteria became a major issue in the BP-14 rate case with various parties disputing or defending the proposed segmentation. The primary issue was the definition of the Integrated Network segment. The issue of rolling the Fringe into the Integrated Network was renewed. The use of the 34.5kV threshold was questioned, an alternative 116kV threshold was proposed, as was assigning lower voltage costs to the utilities using facilities below that threshold. Others defended BPA's current segmentation methodology as conforming to statutory provisions for widest possible diversified use and BPA's application of uniform rates. In addition, the question of maintaining the Montana Intertie rate, a rate based on the Eastern Intertie segment, was raised.

Positions in BP-14

As part of the 2014 rate case, certain parties raised a broad range of issues about BPA's transmission segmentation policy, primarily about the use of a bright-line 34.5kV voltage threshold to separate facilities between the Integrated Network and Utility Delivery segments. This threshold results in facilities 34.5kV and above being assigned to BPA's Integrated Network segment. Facilities that fall below the 34.5kV threshold are assigned to the Utility Delivery segment. This threshold originated in the non-precedential 1996 rate case settlement and had been perpetuated through subsequent rate settlements (the settlements mooted any issues regarding the threshold until BP-14).

Also resulting from the 1996 rate case settlement, BPA implemented a policy of selling Utility Delivery facilities (transmission facilities below 34.5kV) to customers using those facilities. Purchasing these facilities allowed customers to avoid a pancaked rate (paying both Network and Utility Delivery rates) and significantly reduced BPA's investment in low voltage facilities. Currently, BPA has sold 170 of the 215 low voltage delivery facilities and retired others. The remaining facilities are included in the Utility Delivery segment. The Utility Delivery Charge (UDC) currently does not recover the full cost of the Utility Delivery segment. In the BP-14 rate case, BPA proposed to increase the UDC by 25 percent for the next two rate periods, then adopt a Use-of-Facilities Transmission (UFT) charge for remaining unsold facilities (which gradually reduces and eventually eliminates the under recovery). Setting the UDC to recover the full costs of the segment would have required an immediate UDC increase of over 100 percent.

BPA identified several difficult issues that would have to be addressed if it were to deviate from the current Utility Delivery segment definition. First, moving higher voltages into the Utility Delivery segment could cause many customers that purchased facilities to avoid a pancaked rate to again be required to pay two rates. Second, rolling the Utility Delivery segment into the Integrated Network segment could cause customers that purchased Delivery facilities to avoid the pancaked rate to believe they were misled into purchasing the facilities. They may view it as inequitable that other customers that did not take on the additional cost and responsibility of owning similar facilities would no longer pay a pancaked rate and completely escape any added cost responsibility that the purchasing utilities took on. Third, applying a functional definition rather than a bright-line voltage threshold would lead to many difficult and disputed decisions. Fourth, while alternative segmentation methodologies were proposed, there were no proposals about how to recover costs from customers affected by alternative segmentations. While these were among issues that must be resolved, customers proposing changes to segmentation did not address them with any degree of specificity in their BP-14 testimony. Furthermore, BPA's agreement with transfer customers provides that transfer costs and rates will mirror the segmentation of BPA's transmission system. Thus, changes in segmentation may result in changes to BPA's power costs and rates. BPA and the parties in the BP-14 rate case did not have sufficient time to address these issues within the strict timeframes of the BP-14 case; hence, BPA committed to engaging the region through this process in advance of the BP-16 case to address them.

In BP-14 testimony, BPA staff cited the importance of rolled in rates both in Commission policy and in BPA's history, arguments which were offered in support of the proposal to maintain the voltage threshold of 34.5kV. Staff cited cases that showed the Commission's strong preference for rolled in rates. Staff also described how the Bonneville's statutory and historical ratemaking policies to encourage the widest possible diversified use of electric power in the Northwest and to assist rural electrification was promoted through rolled in rates. BPA staff questioned whether customers' proposals to change the threshold to a level higher than 34.5kV were consistent with BPA's statutes and ratemaking policy. The larger customers responded that rural areas are now, and have been for a long time, electrified, and therefore, BPA's policies should recognize this and begin to move towards more rational cost assignments.

Some customers cited two specific functional analyses that have resulted from Commission orders. These customers suggested that such tests should be used to define what facilities should be included in BPA's Integrated Network segment. The first test referenced was the Seven Factor Test, which the Commission introduced in Order No. 888. This test is used by jurisdictional utilities to determine whether a facility is performing a transmission function (subject to Commission jurisdiction) or distribution function (subject to state jurisdiction). If a facility meets the criteria (see Appendix A) it is deemed to be a local distribution facility; thus, it is subject to state jurisdiction, not Commission jurisdiction. If a facility meets some factors but not all, the factors must be weighed against each other to determine the function of the facility.

Other customers pointed out that the Commission premised the Seven Factor Test on the lack of any wholesale activity using a facility; if there was wholesale activity, the Commission retained jurisdiction. Staff noted that all uses of BPA's Integrated Network transmission facilities are used for wholesale activities.

The other functional test that customers referenced in their argument after the evidentiary phase of the BP-14 proceeding closed is the *Mansfield* Test (see Appendix B). This test was developed in a Commission case, *Mansfield v. New England ISO*. The *Mansfield* test presumes integration and, therefore, facility costs should be rolled into network rates unless all five factors of the test are met which results in direct assignment of those costs to the customer necessitating those costs. BPA's current methodology for deciding between rolling costs into its Integrated Network or directly assigning them uses a comparable test but is not exactly the same as the *Mansfield* test, but relies on some of the same principles (the *Mansfield* and subsequent Commission decisions are considered in directly assigning costs). This issue was not explored in testimony, so the arguments made in BP-14 concerning potential application of the *Mansfield* test to BPA facilities were not based on any evidence in the record.

In BP-14, some customers cited the North American Electric Reliability Corporation's (NERC) Bulk Electric System (BES) definition of transmission and local distribution and argued that BPA should make its definition of the Integrated Network segment consistent with the BES definition. NERC currently defines the BES as any facilities operated at or above 100kV with exclusions for radial systems, local networks, generating units on the customer's side of a retail meter, and reactive power devices owned and operated by a retail customer for their own use. (This definition continues to undergo Commission and NERC review.) NERC's purpose for defining the BES is to determine which facilities are critical to the reliability of the grid. NERC developed extensive reliability standards and reporting requirements for BES facilities, and they monitor compliance. Customers arguing for the use of the BES definition also argued that the BPA application of the threshold should be raised to 116kV. No Commission cases have been found to indicate the use of the 100kV BES definition as a method for setting rates. Instead, excluding a high number of facilities using this method seems at odds with the Commission's demonstrated "roll in" preference. Furthermore, the BES definition has no mention of state-versus-Federal jurisdiction, nor does it mention wholesale activity; the BES definition was developed to determine operational jurisdiction, not ratemaking or contractual jurisdiction.

There were four main reasons staff gave for not performing a detailed functional analysis of BPA's transmission facilities for BP-14 rates. First, there were unanswered questions regarding cost recovery (*e.g.*, direct assignment, a new segment and rate, etc.) had BPA adopted a functional test that were not addressed in parties' testimony and staff did not have sufficient time within the timeframes of the BP-14 case to adequately develop and analyze a cost recovery mechanism consistent with a functional test. Second, staff reviewed the composition of facilities in the Network and Delivery segments, as modified since 1996, and determined that the 34.5kV threshold was still appropriate to recognize facilities performing a transmission rather than delivery function. Additionally, staff noted that if it were to perform a functional analysis, it was not clear which functional criteria should be used and how it should be weighted. Staff was also uncertain if the Commission tests were appropriate for BPA ratemaking purposes. Staff was not sure whether using a functional analysis would promote the widest possible diversified use of BPA's transmission consistent with BPA's statutory directives and historical ratemaking policy. Staff also noted that it was uncertain whether the use of the tests as advocated by certain customers was consistent with the Commission's strong preference for rolling in facilities,

In staff's benchmarking analysis (performed after the BP-14 case—see Industry Scan below), only two non-RTO/ISO entities have been identified as having a "sub-transmission" segment and one of those rates is being challenged before the Commission. In that case, the transmission owner is defending their sub-transmission rate, in part, by specifying that the cost of the "sub-transmission" is rolled in—it is just rolled into a different rate than the high voltage network facilities. In addition, most utilities included in the scan have only looked at changing policies going forward and do not redefine assets previously included in definition of the Integrated Network or other segments unless there are physical modifications of those facilities.

BPA's historical mandate to help with rural electrification is consistent with BPA rolling lower voltage facilities into the Network. A review of most of the 34.5kV facilities indicated that all of these lower voltage facilities are performing a transmission function, but doing so in rural areas where lower loads lead to using lower voltage infrastructure to keep costs down. Charging customers an additional sub-transmission rate may be inconsistent with BPA's mandate to facilitate widest possible diversified use and rural electrification. In BP-14, BPA argued that the proposed change would punish some rural customers for being located in areas where lower voltages are sufficient to support transmission to their service territories.

BPA stood behind these reasons to justify maintaining the 34.5kV threshold in BP-14, but did include language in its ROD that "[b]efore the next rate proceeding BPA will engage the region regarding segmentation policy. Staff and interested stakeholders should work together at the outset of these discussions to identify the framework and agenda for these discussions." This white paper is the result of those discussions.

Regional Discussion Prior to BP-16

To meet the commitment set forth in the BP-14 ROD, BPA staff initiated a regional discussion on segmentation in January 2014. In the initial public meetings, staff educated customers (at the management and staff level) about segmentation and its history in BPA ratemaking. This effort included sharing information on BPA's current segmentation and direct assignment practices as well as BPA's findings from an industry scan conducted of jurisdictional transmission providers throughout the United States.

Industry Scan

Based on the issues discussed in the BP-14 rate case, staff developed three basic questions to be answered by the industry scan:

1. ***How comparable to BPA are the other utilities' transmission facilities in size and voltage?***

BPA has over 15,000 line miles of transmission. Reviewing the size of BPA in comparison with other utilities helped BPA define the scope of the review and gave additional context to the challenges that an entity the size of BPA faces. Adding BPA to the 181 utilities reviewed using Commission Form 1 filings, BPA would rank fourth in terms of total transmission line miles. The inclusion of TVA and the other two PMAs to the list would move BPA to sixth of 185 utilities. BPA concluded that including utilities with few or no transmission facilities would not add much value to the exercise, and focusing on 100 utilities would comprise a representative pool of utilities. The 100th utility had 626 line miles, and including utilities with 500 miles or more would pick up two others, including Consolidated Edison, one of the largest utilities in the nation. Thus, a cutoff at 500 miles was used for this scan. Of the utilities excluded, 20 have between 100 and 500 miles of transmission lines, 23 have between 1 and 100 miles, and 35 have no transmission lines, including 6 RTO/ISO companies and 10 that have sold or spun off all of their transmission facilities into independent transmission companies. See Table 1 of Appendix C for a full list of utilities surveyed.

2. ***What, if any, voltage threshold do other utilities use to separate transmission from distribution?***

The table below shows BPA's staff finding from review of Form 1 submittals.

Count of Utilities	115kV	69kV	46kV	35kV	25kV
Transmission	96	82	45	30	13
Likely Transmission	1	3	6	7	4
Either	1	3	5	11	3
Likely Distribution	0	3	2	8	9
Distribution	0	3	10	29	52
Indeterminate	4	8	34	17	21
Total Population	102	102	102	102	102
Tx Probability	99%	92%	79%	50%	23%

The 35kV (the threshold used by BPA in BP-14) column of the table shows that 30 of 102 utilities include all of their 35kV facilities in transmission, 7 include most of their 35kV facilities in transmission, 11 include about half of their 35kV facilities in transmission, 8 include most of their 35kV facilities in distribution, 29 include all of their 35kV facilities in distribution, and 17 cannot be determined (these utilities have no facilities at voltages between those designated transmission and those designated distribution, e.g., 46kV is transmission and 25kV is distribution and there are no 35kV facilities). The probability that any specific 35kV facility would be designated as transmission is about 50 percent ([30+7+½ of 11] ÷ [102 –17] = 50%). The use of this threshold is reinforced by a statement by the Commission in its legal analysis of Order 888: "while there is no uniform breakout point between transmission and distribution, it appears that utilities account for facilities operated at greater than 30kV as transmission and that distribution facilities are usually less than 40kV." Order No. 888, Appendix G, FERC STATS. & REGS. ¶ 31,036 at 31,981 n.100. Thus, while the Commission does say that there is no specific threshold, BPA's BP-14 voltage threshold dividing "Integrated Network" facilities from "Utility Delivery" facilities is consistent with the median observed in the study.

3. Do the utilities differentiate transmission rates by voltage or other criteria?

Staff found that 66 utilities roll all transmission facilities into their network rates (Point-to-Point and Network Integration), 35 utilities differentiate their network transmission rates into bulk system rates and sub-transmission rates based on a voltage basis. Table 2 in Appendix C lists the 35 utilities with a brief description of the rate design (most of these 35 utilities differentiate based on ISO/RTOs requirements, which comprise eight separate entities). Table 3 of Appendix C shows the six utilities which have facility-differentiated transmission rates, usually due to interties connecting their systems to other areas.

Information on treatment of radial lines was gathered through discussions with select utilities since treatment of such lines is not clear in Commission Form 1 data. In these discussions, BPA found that the entities interviewed had significantly different practices:

- Duke Energy is in the process of revising its treatment of radial lines. In the past, Duke would roll in the cost of its radial lines into its network transmission rates. A customer would construct a radial line between Duke's network and the customer's load and then be repaid through transmission credits. Duke's new policy directly assigns its radial lines and would not give credits to customers for radial lines. Duke Carolinas implemented this treatment several years ago; Duke Progress began implementing this policy in January 2014. In both cases, the policy is not retroactive—Duke did not remove existing radials from its network rates and continues applying credits for customer-owned facilities built prior to the new treatment.
- The Southern Company directly assigns radial lines that are serving only wholesale or only retail functions to the user of such lines. Radial lines with mixed usage (both retail and wholesale customers) are included in the network. Southern' s wheeling customers challenged their direct assignment policy, which included some retail function radials in the network. Their customers argued this was not providing customers comparable treatment. Southern settled the dispute and changed its policy. Pursuant to the settlement, radial lines constructed between 2003-2010 were removed from its network segment.

- Southern California Edison and Pacific Gas & Electric generally assign radial wholesale lines to the customer served from the radial. In 2004, Edison changed its direct assignment policy for some breakers based on a Commission ruling. Edison now includes in its network the costs associated with ring breakers to integrate generation. Previously these costs were directly assigned to the integrating party; Edison did not retroactively apply this change, but applies the new practice whenever new equipment is added to an older station.
- Members of the Southwest Power Pool are required to remove single-customer radial lines from the costs submitted for inclusion in SPP bulk system transmission rates.

After sharing this preliminary information, BPA asked participants to develop proposals for alternative Segmentation methodologies for analysis. BPA has performed analysis on six proposals received (five Network alternatives and one Montana Intertie alternative) as well as the status quo. These proposals and associated analyses are discussed in Section III of this paper.

BPA's Segmentation Principles

BPA developed principles for the segmentation analysis which will be used to evaluate each of the proposals. These principles were shared with customers and reflect customer input.

1. Consistent with statutory requirements

a. Full and timely cost recovery

b. BPA's rates are based on total system costs

c. Equitable cost allocation between Federal and non-Federal uses of the transmission system

d. Encourages the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles

2. Consistent with ratemaking principles

a. Cost causation

b. Simplicity, understandability, public acceptance and feasibility of application

c. Avoidance of rate shock

d. Rate stability from rate period to rate period

3. Considers a regional perspective

a. Alternatives include how costs are allocated and recovered

b. BPA asks that proponents of alternatives explain how the region benefits from the alternative compared to the status quo

c. Historically BPA has applied uniform rates to achieve widest possible diversified use

III. Analysis of Proposed Alternatives

Using the status quo as a benchmark, BPA staff evaluated the proposed alternatives. Participants were asked to include in their segmentation alternatives how transmission system costs would be allocated and recovered under their segmentation. This required customers to identify in their proposals not only the guidelines for changing the segmentation of facilities, but also outline a rate design for how the segment costs would be recovered from customers. Recognizing that a change in segmentation could introduce rate shock to some customers, some participants identified rate mitigation strategies as part of their proposals.

All analysis shown in this paper is based on BP-14 Final Proposal revenue requirement and forecast sales and is "decision quality" analysis. When BPA performs the segmentation analysis for the initial proposal for the BP-16 case, the best data available for FY 2016 and FY 2017 will be used. In addition, for alternatives where BPA simplified data or discussion purposes (i.e., the Revenue Requirement "Rule of Thumb"), BPA will use the actual data based on its repayment, revenue requirement, and rates models for the Initial Proposal. Thus, for the alternative chosen for the initial proposal in BP-16, the results will likely differ somewhat from the analysis of that alternative contained in this paper.

Network Segment Alternatives

Network Alternative 0 – Status Quo

BPA's transmission rates currently identify and allocate costs to seven segments: Generation Integration, Integrated Network, Southern Intertie, Eastern Intertie, Utility Delivery, Direct Service Industry (DSI) Delivery, and Ancillary Services. The BP-14 Final Proposal documentation contains information on how these numbers were developed. Facilities are divided between the Integrated Network and the Utility Delivery segment based on a 34.5kV bright-line threshold; all transmission facilities not in other segments that are 34.5kV or higher are placed in the Integrated Network segment.

The status quo is offered as an alternative for consideration in this process. The fact that BPA is undertaking a review of its segmentation alternative does not mean that BPA must or should change its segmentation methodology. However, because the status quo alternative was generated from a non-precedential rate settlement, the status quo should not be considered the presumptive alternative where other alternatives must demonstrate conditions necessitating a change in segmentation. The status quo is offered as another alternative being considered. However, in the analysis of the various alternatives, the status quo is used as a measure of cost shift because it is the basis for rates today.

Status Quo Justification from BP-14

The status quo use of a bright-line voltage threshold at 34.5kV appears to be solidly in the center of the practice that jurisdictional utilities across the country use to distinguish between transmission and distribution. The Commission's preference is to roll transmission facilities into network rates unless cause is shown to separately recover costs from ratepayers; the status quo alternative is aligned with the Commission's preference. Because the facilities currently in the Utility Delivery segment are transmission facilities, they could be rolled into the Integrated Network segment under the Commission's preference. However, there may be good policy reasons to retain the Utility Delivery segment. This policy is examined in more detail in the discussion on Alternative 1 and Alternative 2.

Evaluation Based on BPA Principles (based on arguments made in BP-14)

1. Consistent with statutory requirements

a. Status quo results in full recovery of BPA costs.

b. Revenue requirement is based on total system costs and recovers these costs from the current segments.

c. Customers/facilities on the system with Federal and non-Federal uses are responsible for comparable costs on BPA's system.

d. Uniform rates for transmission facilities encourage the widest use among the largest group of customers.

2. Consistent with rate making principles

a. Delivery service is more costly, so Delivery customers are assigned costs associated with delivery service. The BPA Network operates as a whole to provide reliable, stable service at least cost to all customers. Customers benefit from the whole system, not just from the specific identifiable facilities. Sharing the costs associated with the Network over all the customers is consistent with the cost causation principle.

b. BPA has been using the current Segmentation methodology for almost 20 years so it is certainly understandable, simple, and feasible to apply.

c. Status quo maintains similar rate levels and proposes to limit rate increases to Utility Delivery to avoid rate shock during the next rate period.

d. This is consistent with the methodology used for almost 20-years and has resulted in small rate shifts in the previous rate periods. This is a tested method that has proven to be very stable.

3. Considers a regional perspective

a. It is clear how all costs are allocated and recovered among BPA's customers.

b. Not applicable

c. Maintains this approach to encourage the widest use

Network Alternative 1 – Roll In Utility Delivery Segment - Proposed by PNGC

Roll all facilities currently in the Utility Delivery (UD) segment into the Network segment. The UD rate would be eliminated and costs associated with former UD facilities are recovered through the Network rates.

PNGC Justification

BPA instituted the UD Charge (UDC) in 1997 in part to incent customers to purchase the wholesale substations that BPA had previously provided. When the UDC was put in place, it was recognized that at some point the UDC would become unsustainable. We have now reached the point of unsustainability, given the number of UD facilities that have been sold, and the costs, billing determinants, and the “un-purchasable” nature of the remaining UD facilities.

Rolling the UD facilities into the Network segment is consistent with BPA’s statutory responsibility to set power and transmission rates that encourage “the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles.” (Federal Columbia River Transmission System Act at 16 U.S.C. § 838g).

Doing so will result in minimal rate impact to Network segment transmission rates (approximately 0.6% for the PTP rate and 0.3% for the NT rate), while avoiding an unnecessarily severe impact on transmission rates for those who would otherwise pay the UDC.

Further, the UDC has outlived its original purpose of incenting utilities to purchase the UD facilities. Since the implementation of the UDC, BPA has sold 158 out of 203 of the UD facilities. The remaining 45 substation are not likely to be sold, even if BPA follows through with plans to increase the UD rate 84 percent over the next several rate cases. There are several reasons that many of the remaining substations are “un-purchasable” from the utilities’ point of view:

- The remaining transformers are very old (average age 58.2 years, with 17 transformers over 70 years old) and customers are wary of purchasing such old equipment, particularly given the possible reliability consequences and costs associated with equipment failure.
- 16 facilities are not segmented 100 percent to the UD segment, which significantly complicates a possible sale (BPA typically would not sell elements of a multi-segmented substation).
- 14 facilities are shared by multiple customers, which significantly complicates a possible sale.
- Acquisitions of high voltage equipment have potential staffing, training, and reliability implications well beyond the price of the delivery substation.
- At a time when many small utilities are deregistering from ERO compliance obligations, adding high voltage equipment to their systems could unnecessarily endanger those efforts.

Of the remaining 45 UD substations, 39 face at least one of the above challenges. Many face more than one of these challenges. In short, the vast majority of the remaining substations are “un-purchasable” no matter how high the UDC goes. Consequently, retaining the UD segment, and increasing the UDC by 25 percent in the next rate case, will not result in substantial sales of the UD facilities. It will, however, result in a UD rate higher than the current NT transmission rate. At that point, customers subject to the UDC would essentially pay a pancaked transmission rate that amounts to two times the NT rate. We have arrived at the point where the most logical action is to roll the remaining UD facilities into the Network segment.

PNGC Evaluation based on BPA Principles

1. Consistent with Statutory Requirements

a. Roll in would ensure widest possible use at lowest possible rates to consumers consistent with sound business principles
b. Would ensure full and timely cost recovery
c. Rates would be based on system costs
d. Would maintain equitable allocation between federal and non-federal uses

2. Consistent with Ratemaking Principles

a. These facilities were put in as wholesale points of delivery, and are part of system needed to transmit wholesale power to wholesale customers
b. It’s simple, understandable, easy to apply, and would be acceptable to many customers
c. Avoids rate shock to all parties
d. Does provide stability, especially vis-à-vis alternatives (scheduled rate increases)

3. Considers a Regional Perspective

a. By fulfilling BPA’s statutory directive to provide the widest possible use at the lowest possible cost to consumers, the roll-in alternative promotes an economically healthy rural segment of our region
b. Without a roll-in of the UD segment into the Network segment, many rural areas will pay approximately double for transmission service, thereby negatively impacting economic well-being in these areas; alternatively, rolling-in the UD segment will have minimal impact on the Network segment while avoiding rate shock for the current UD customers
c. Provides level playing field to all sellers of power
d. Retains uniform rates
e. Respects past BPA policies which provided these substations

Network Alternative 2 – Maintain Adjusted Utility Delivery Charge – Proposed by NRU

As part of the BPA Transmission Segmentation review, NRU recommends a fundamental revision in the methodology for determining the Utility Delivery Charge (UDC). The application of the proposed new UDC methodology beginning in FY 2016 would result in a UDC that is generally comparable to the current level in the FY 2014/2015 rates after the 25 percent increase for delivery service. In this proposal the Utility Delivery segment is eliminated in FY 2016 and beyond, the adjusted revenue requirement is rolled into the Network, and the revenue from the new UDC is credited to the Network Segment revenue requirement. The UDC is applied as a uniform charge to all utilities taking delivery from BPA substations below 34.5kV.

The proposed NRU staff methodology for deriving a new UDC is illustrated in Appendix E Table 1 and Table 2. It displays the existing BPA methodology and shows revisions to develop the new charge.

The key components of change are as follows:

- The UDC would include the direct O&M cost of Lines and Substations but would exclude the O&M Overhead charges (see discussion that follows). As a result, the cost recovery for O&M is reduced to about 57 percent of the current level for the Utility Delivery segment.
- The financial value of the FCRTS Investment Base (Net Plant) of about $21 million for Utility Delivery is reduced to 20 percent of its current level based on NRU members' assessment of the actual remaining value of the assets. For example, the average age of utility transformers since their date of manufacture is 55 years and 42 years since their installation (new or used). The BPA Depreciation Study in 1984, 1989 and 2004 identifies 37 years as the life of substation equipment. The situation will vary from facility to facility, but generally NRU members believe these facilities are "old" and over-valued.
- Based on the revised 20 percent value of Utility Delivery Net Plant, the direct depreciation calculation is reduced proportionately. However, we depreciate BPA's General Plant, which supports the delivery of O&M, at 100 percent. This results in a total depreciation cost of about 49 percent of the current level.
- This 49 percent is then applied to the Net Interest Expense and Planned Net Revenue figures because these numbers are a product of the revised net plant investment.
- When the O&M and other costs are combined the Utility Delivery revenue requirement becomes 56 percent of the current amount, reduced from about $6.4 million to $3.6 million.
- NRU did not adjust the reported Revenue Credits of about $240,000 accruing to the Utility Delivery segment but recognizes that they could change.

- Finally, NRU reduces the level of Transmission financial reserves applied in the BP-14 rate case to offset the UDC, based on a lower overall recommended cost for delivery service.
- When these elements are combined, the UDC recovers the cost of the utility delivery facilities.
- In future rate cases, the UDC would increase commensurate with the average change in rates for PTP and NT Network service (on a percentage basis).

NRU Justification

In the BP-14 rate case, BPA raised the Utility Delivery rate by 25 percent, from $1.119 per kW per month to $1.399 per kW per month. Using current cost recovery methodologies, BPA identified an under recovery of the Utility Delivery segment, and absent corrective action, this sets the stage for continuing significant UDC increases in the future. This could have a dramatic impact on utilities with delivery facilities. For example, if BPA again increased the Utility Delivery rate by another 25 percent, the rate for delivery service would essentially be equal to the current $1.741 per kW per month rate for Network Transmission. The customers using low voltage delivery facilities effectively would be paying double the NT rate compared to other customers. In contrast to the Utility Delivery rate of $1.399 per kW per month, the GTA Delivery rate, which applies to customers that purchase federal power that is delivered over non-federal low voltage facilities operated below 34.5kV is at a rate of $0.820 per kW per month. Our understanding is that the GTA Delivery rate recovers the actual cost for delivery service where such costs are imposed by the GTA provider. The GTA Delivery rate of $.0820 per kW per month is less than 59 percent of the Utility Delivery rate. While we have not analyzed the financial components of the rate charged by the GTA providers, this raises questions regarding BPA's delivery rate, and if a revised methodology for BPA cost recovery would result in a more equitable charge for BPA Transmission's delivery customers.

Rationale for Revisions in O&M Costs

In reviewing the Direct O&M numbers for the Utility Delivery segment substations compared to the Integrated Network Facilities, the differences are quite dramatic. For the Integrated Network, the Substations have a reported investment of $2.182 B and O&M at $85.25 million. O&M activities represent about 3.9 percent of the investment value for Network Substations. The Utility Delivery Facilities have a reported investment of $29.575 million and O&M at $1.85 million. O&M activities represent about 6.3 percent of the reported investment value for Delivery Substations. The O&M for Delivery Substations is 62 percent higher based on investment than for Network Substations. This implies that BPA's delivery facilities are in relatively poor condition compared to Network substations, requiring more time for maintenance. If the delivery substations were of higher quality, the station specific O&M would be lower which would reduce the overhead costs assigned to those facilities. NRU proposes that

Utility Delivery customers continue to pay all direct O&M costs (those directly associated with the Utility Delivery facilities) but recommend other revisions in the calculation of the charge.

The Overhead categories applied to O&M (Table 2 of Appendix E) represent about 43 percent of the total O&M cost. The categories of Marketing, Business Support, Systems Engineering, and Corporate together account for about $1.5 million or close to 25 percent of the overall cost for the current Utility Delivery rate. While overhead charges to O&M are often used to recover full costs of service, for the current Utility Delivery rate they are duplicative and should be eliminated; Network Transmission customers are already paying the full cost of each kilowatt of power transmitted to them from BPA through their NT rates. The NT rate captures all of BPA's indirect overheads for transmission service. It is inappropriate to effectively double charge a Utility Delivery customer for O&M overheads. When power is scheduled to loads that are served over both Network and Delivery facilities, there are no additional transmission paths that must be identified. The Network and Delivery segments are combined into one transmission path, with the Delivery segment covering the costs of legacy low voltage facilities. Therefore, the cost of service for Utility Delivery service should be limited to the direct cost of the program rather than adding on administrative overheads, which result in a double collection of costs from Utility Delivery customers.

Discussion of Impact on Other Customers

There is no impact on other customers by adopting this proposed UDC because the UDC would recover approximately the same amount as the current rates. The revenue from the new UDC would become a component of the overall $650 million revenue requirement for the Network Segment. To the extent that any of the proposed calculations of the UDC are not 100 percent accurate, any revisions would not have a material impact on the rate for the Network, because the revenue shortfall from the UDC with the current methodology is less than 0.5 percent of the Network Revenue Requirement. While the total exposure from the proposed changes to the Utility Delivery segment for the Network revenue is nominal, the impact of not making a change for the remaining Utility Delivery customers is significant.

Effects of Changes to the UDC Over Time

Once the UDC is set, NRU recommends that it be adjusted over time commensurate with the average change in rates for PTP and NT Network service. In other words, once the methodology for determining the charge is agreed to, the UDC rate would be adjusted each rate period commensurate with the average change in the PTP and NT Network service rates. This would be more administratively efficient for BPA than trying to track all of the numbers for this declining base of facilities, and equally important, it would provide more certainty to the customers as to what they may expect regarding future costs.

Equity Between Utilities that Have and Have Not Purchased Utility Delivery Facilities

By preserving a UDC and setting it no higher than its current level of cost recovery, an incentive remains for utilities to purchase Delivery facilities to avoid the charge. Equally important, for those utilities that have recently purchased or are considering purchasing facilities, maintaining a UDC at the current level should not invalidate the overall business case for their decision.

Summary of Justification

The BPA Low Voltage Delivery Charge needs to be re-examined with the assumption that there is no continuing business need for BPA to maintain a Utility Delivery segment for purposes of rate making. Based on the analysis and methodology explained in this paper, the current level of the UDC would recover the actual costs of the service. NRU notes the significant discrepancy between the BPA UDC and the charge from the GTA providers. Other methodologies have the potential for a lower UDC than $1.399 per kW per month and should be explored by BPA staff and the customers in advance of the BP-16 transmission rate case.

NRU Evaluation based on BPA Principles

1. Consistent with statutory requirements

a. This proposal provides for full cost recovery of the actual costs of all of the low voltage delivery facilities and applies sound business principles in determining the level of the charge.

b. The rate proposed for utility low voltage delivery service is determined by a thorough review and revision of BPA's cost allocation methodology for assigning utility delivery costs in the context of BPA overall Network system costs.

c. This proposal makes no distinction between federal and non-federal power supply. Both federal and non-federal power flow over the low voltage facilities in the current Utility Delivery segment.

d. This proposal encourages the widest possible diversified use of electric power at the lowest possible rates by not making utility delivery service for facilities below 34.5kV prohibitively expensive in the long term, while simultaneously not increasing the currently collected costs from the other customers in the Network. Conversely, if the UDC continues to increase by 25 percent every rate period, the customers using low voltage delivery facilities will be paying double the NT rate compared to other customers, which would violate this principle. The NRU proposal is also consistent with sound business principles because it continues to provide an incentive for utilities to buy the low voltage facilities by retaining a UDC, which promotes BPA's goal of getting out of the low voltage delivery business.

2. Consistent with rate making principles

a. The proposal recovers all costs for low voltage utility delivery service using an updated cost recovery methodology as described herein using BPA data from the BP-14 rate case.

b. The proposal is easy to understand, straightforward to administer, and should be acceptable to BPA transmission customers because it protects customers taking low voltage delivery service from excessive increases, while shielding other customer groups from cost increases. Utilities that have already purchased such facilities should not object because a BPA charge for low voltage delivery service is maintained.

c. By limiting future increases in the utility delivery charge to the overall average increase in rates for Network service (NT and PTP), customers paying the delivery charge are shielded from rate shock. Other customer groups are not impacted by this proposal compared to the status quo.

d. This proposal achieves rate stability from rate period to rate period for both Network customers and customers with low voltage delivery facilities. Conversely, this principle will be violated if customers taking low voltage delivery service continue to experience 25 percent rate increases every rate period.

3. Considers a regional perspective

a. The NRU proposal fully describes how costs are allocated and recovered.

b. The region benefits from this alternative compared to the status quo for three primary reasons. First, by resolving the issue of the cost basis for the UDC and basically removing it from future transmission rate cases, the transmission rate case should be less contentious between BPA and the customer groups, as well as the potential GTA related issues for the power rate cases. Second, BPA can avoid imposing a disproportionately high increase in the UDC that has a questionable analytical foundation of cost recovery, and can do so without adversely impacting other customer groups. Third, the proposed UDC maintains an incentive for utilities to purchase these facilities, while simultaneously not imposing steep cost increases for those utilities that may not be in a position to acquire these facilities to avoid the charge.

c. The NRU proposal does not change BPA's application of uniform rates for transmission service.

Network Alternative 3 – Develop a "Radial" Segment – Proposed by Snohomish

<u>Proposal Overview</u>

Snohomish proposes identifying radial facilities on BPA's system and recovering the costs associated with those facilities from customers who utilize the identified radial facilities. There are two ways these costs could be recovered: 1) create a new segment comprised of the identified radial facilities and create a rate to recover costs associated with this segment, to be charged to customers using the identified facilities or 2) the radial facilities would remain in the Network segment, and BPA could then identify costs associated with the radial facilities and develop a charge for customers using those facilities.

Snohomish's proposal seeks to achieve a segmentation methodology that is both durable and technically justifiable. By only identifying radially-operated facilities based on a discrete set of criteria, the proposal satisfies a robust engineering and functional analysis, keeps to a limited scope and makes "radial" facilities easier to identify, allowing the function of facilities to be determined simply.

Definition of "Radially-Operated Facilities"

Snohomish defines "Radially-Operated Facilities" as Radial systems and Radial Open Loops.[2] Radial Systems are a group of contiguous transmission elements that emanate from a single point of connection; power flows in one direction from the substation to the load. Radial Open Loops are two or more Radial Systems that are connected by a Normally Open Switch (in effect, creating a gap between the Radial Systems). Radial Open Loops are, operationally, almost identical to Radial Systems. Based on feedback from BPA, analysis limited to Radial Systems is more technically manageable.

Criteria for Identifying Radial Facilities

BPA staff and Snohomish worked together to clarify what criteria would be used to identify radial facilities for removal from the Integrated Network segment (see Appendix F). Facilities not identified as radial facilities that are currently in the Integrated Network segment will remain in that segment.

The criteria for identifying radial facilities are listed below:

Radial facilities:

a. Radial line where BPA owns connected station
b. Radial line where customer owns connected station
c. Looped service with a normally open switch
d. Facilities connected by a common bus that serve looped lines (lines originate on the same bus and deliver to the same bus where power only flows to the load and not back out to the BPA system)

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[2] Snohomish believes that local networks are non-integrated. However, Snohomish has decided not to include local networks in its proposal.

Exception for radial facilities with generation:

a. Generation that exists on a radial line that is either wheeled or scheduled across BPA's system or flows back to BPA's system may be excluded. BPA will consider these on a case by case basis.

This analysis of radial facilities is a strictly functional analysis; voltage is not considered in radial identification.

Snohomish, as a separate proposal, also suggests a revision of BPA's Direct Assignment Policy for clarity and to assure equitable allocation of future costs. Revising the Direct Assignment Policy will ensure equitable allocation of new transmission projects.

Snohomish Evaluation based on BPA Principles

1. Consistent with statutory requirements

a. Snohomish's proposal will allow BPA to fully and timely collect its revenue requirement.

b. BPA's rates will continue to be based on total system costs.

c. This proposal equitably allocates costs to users of the Transmission system, regardless of whether federal or non-federal power is being transmitted. This proposal should result in equitable rates because it reflects cost causation.

d. The Snohomish proposal does not affect actual deliveries of power; therefore, the use of electric power does not change. The proposal will provide lower rates to all transmission customers for use of the Integrated Network segment by removing radially-operated facilities from the Integrated Network segment. The creation of a new segment consisting of only radially-operated facilities will provide the lowest possible rates for those customers who receive transmission service over those facilities. Non-radially-operated facilities will be excluded. Snohomish's proposal is consistent with sound business principles because it is based on cost causation and thus provides a better price signal than an arbitrary 34.5kV test that will promote efficient transmission facility decisions.

2. Consistent with rate making principles

a. The core of the Snohomish proposal is cost causation; the costs of radially-operated transmission facilities are separated and assigned to those who benefit from those facilities.

b. This proposal would result in either a new segment or a separate charge for radial facilities. Such a charge, based on a straightforward radial test, should be simple, understandable, and feasible to apply.

c. As stated as part of the Segmentation public process, any complete proposal will include a mitigation plan to avoid rate shock. Snohomish has included a preliminary proposal to mitigate rate shocks.

d. Because of the radial nature of facilities on BPA's system, rates should be relatively stable from rate period to rate period.

3. Considers a regional perspective

a. This proposal addresses how costs are allocated and recovered.
b. This proposal should be superior to the status quo because the proposal should result in rates based on the function of facilities used by BPA to provide various services and should result in rates that are more closely aligned with cost causation than an arbitrary 34.5kV threshold test.
c. This proposal should not affect the diversified use of electricity in the region. This proposal, which is based on a functional (radial versus non-radial) analysis, is based on principles of cost causation and provides uniform rates within the proposed segments across BPA's Transmission system.

Rate Mitigation

Throughout the Segmentation workshops, Snohomish has stated that its primary goal is a transparent, technically justified approach to segmenting the BPA Transmission System. While Snohomish recognizes that a change in the Segmentation method will result in a new allocation of costs, it is not Snohomish's intent to cause rate shock among BPA's transmission customers. Snohomish recognizes the need for rate mitigation as a result of the Radial Service proposal and submits two possible alternatives:

Mitigation Plan 1: Phased-in Approach

- Phases-in costs of radial service over ten rate periods; 10 percent of the overall revenue requirement would be applied in each successive rate period
- Results in the full identified $33 million Radial Service Revenue Requirement being collected at the end of the phase-in

Mitigation Plan 2: Phased-in Approach with Revenue Requirement Cap

- Phases-in costs of radial service over ten rate periods; 5 percent of the overall revenue requirement would be applied in each successive rate period
- Results in only 50 percent of the total identified Radial Service Revenue Requirement being collected at the end of the phase-in

As stated previously, Snohomish is primarily interested in achieving an engineering-based, technically-justified and transparent Segmentation methodology. If BPA decides to adopt the Radial Service proposal, Snohomish is open to a range of potential alternatives to mitigate rate shock. The options outlined above are simply two out of many possibilities available for consideration.

Between these two options, Snohomish prefers Mitigation Plan 1, which results in fully recovering the Radial Service Revenue Requirement at the end of the phase-in. However, if BPA sees the need for further mitigation beyond what is outlined in Mitigation Plan 1 in order to successfully adopt the Radial Service proposal, Snohomish is also receptive to further mitigation as described in Mitigation Plan 2.

Network Alternative 4 – Develop transformation charge – Proposed by IOU/Large public coalition: Puget, Seattle City Light, Pacificorp, PGE, Powerex, Tacoma, Avista, Ibedrola, Benton County PUD

The coalition proposes that BPA develop a rate associated with transformation through the following process:

1. Identify intertie, generation integration, delivery, ancillary service, and direct assignment facilities. (Any changes to BPA's methodologies for identifying facilities in these segments is beyond the scope of this particular proposal.)
2. Network segment facilities are those remaining transmission facilities not falling into the segments in item 1 above.
3. Develop a voltage-differentiated rate for transmission on BPA's Network segment, depending upon the transformation provided.
    a. Determine the average depreciated cost of substation transformation facilities, differentiated by voltage class, on BPA's Network segment. Also, determine the average depreciated cost of lines and other, non-substation facilities, regardless of voltage, on BPA's Network segment.
    b. The concept is to compute rates based on
        i. the average costs of voltage-differentiated substation facilities determined in item a. above, plus
        ii. the costs of non-voltage differentiated non-substation facilities on BPA's Network segment determined in item a. above.
    c. This results in transmission rates based on the service received with respect to transformation services and "postage stamp" rates with respect to other services. Each BPA customer served over the Network segment would pay costs consisting of
        i. a uniform, "postage stamp" charge for Network segment customers based on the cost of non-transformation facilities, plus
        ii. a voltage-differentiated charge for transformation based on the average cost of transformation facilities of the voltage levels used by the particular customer.

For example, rural and urban BPA transmission customers receiving deliveries of requirements power from BPA at delivery voltages at 34.5kV would all pay the same rate, regardless of location in the region.

d. BPA customers would be able to redirect transmission regardless of the voltage at the redirected POD (perhaps a different approach for "permanent redirects").
e. Charging for average losses on BPA's Network segment would continue, i.e., loss calculations would not change in the voltage-differentiated rate.

The coalition proposes that after the charges are developed that the average increase in the Network segment rate for any rate period for each voltage class (for example, the average rate increase for any voltage class is to be no more then 20 percent). Spread the costs of such limit pro rata to other Network segment rates, so that to the extent practicable no such voltage class experiences an average Network segment rate increase greater than 20 percent (for example) for any rate period. This limit mitigates any "rate shock" that may otherwise occur.

Coalition Justification

This approach more closely aligns with cost causation because it reflects different charges based on the cost of transformation services received from BPA, essentially treats customers using Network facilities at a given voltage the same regardless of their location within the region, and should not be unduly complicated to implement.

Coalition Evaluation Using BPA Principles

These BPA proposed principles are set forth below, together with some observations set forth in italics regarding the voltage-differentiated rate proposal in the context of those proposed principles.[3]

1. Consistent with statutory requirements

a. The issue is not whether BPA will fully and timely recover its costs. The issue is which customers will pay for which facilities. This proposal attempts to provide a methodology that is relatively easy to implement while at the same time more closely aligning BPA's rates with cost causation.
b. Under the voltage-differentiated rate proposal, all of BPA's Network segment costs are allocated to rates for users of such segment. BPA should achieve cost recovery of its total Network segment costs.
c. Under the voltage-differentiated rate proposal, Network segment rates are more closely aligned with cost causation than an arbitrary 34.5kV segmentation test because they reflect different charges based on the cost of transformation services received from BPA.

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[3] Proponents of this alternative have noted that not all of these principles are applicable to segmentation of BPA's facilities and that these principles may not be determinative in a BPA rate proceeding.

This is particularly appropriate in light of the fact that BPA's lower-voltage Network facilities are used predominately to serve a subset of BPA's transmission customers. The voltage-differentiated Network segment rate would apply to BPA customers regardless of whether Federal or non-Federal power is being transmitted, yet should be equitable insofar as it would better reflect cost causation and collect the cost of lower-voltage Network facilities from the subset of BPA Network customers that are served with such facilities.

d. Under the voltage-differentiated rate proposal, Network segment rates are more closely aligned with cost causation because they include different charges based on the transformation services received from BPA. Such rates send a better price signal than a rate that is not voltage differentiated and are limited to collecting the Network segment revenue requirement—therefore, they should promote efficient transmission facility decisions and should be consistent with this principle. Indeed, BPA's scan of industry practices indicates that about one-third of the utilities reviewed have voltage-differentiated rates.

2. Consistent with rate making principles

a. Under the voltage-differentiated rate proposal, BPA's Network segment rates more closely align with cost causation because they reflect different charges based on the cost of transformation services received from BPA.

b. Under the voltage-differentiated rate proposal, BPA's Network segment rates reflect different charges based on the cost of transformation services received from BPA but are otherwise unchanged from BPA's current Network segment rate structure. The "BPA Segmentation Review Industry Practices Scan" dated January 2014 indicates that about a third of the roughly 100 utility systems analyzed have voltage-differentiated rates. In other words, the voltage-differentiated rate proposal has some precedent. However, it should be noted that BPA's system seems relatively unique insofar as BPA's lower-voltage Network facilities are used predominately to serve a subset of BPA's transmission customers, while other BPA transmission customers—investor-owned utilities and larger preference agencies—provide their own lower-voltage facilities. Because of this fact, the voltage-differentiated rate proposal is particularly appropriate for BPA's system.

c. Under the voltage-differentiated rate proposal, mitigation of potential "rate shock" is addressed as discussed above.

d. Under the voltage-differentiated rate proposal, the transformation provided to a particular customer and the average cost of transformation facilities by voltage class on BPA's Network segment should be relatively stable, and the voltage-differentiated rate proposal should result in Network rates that are relatively stable fro*m rate period to rate period.*

3. Considers a regional perspective

a. Alternative includes how costs are allocated and recovered

c. Under the voltage-differentiated rate proposal, all Network segment costs are allocated to BPA Network segment rates and should therefore be recovered. The voltage-differentiated rate proposal is superior to the status quo because it provides i) a uniform, "postage stamp" charge for Network segment customers based on the cost of non-transformation facilities, plus ii) a voltage-differentiated charge for transformation based on the cost of transformation facilities of the voltage costs used by the particular customer (which thus is better aligned with cost causation). BPA has not always applied uniform rates, [4] nor has it shown that uniform rates achieve the widest possible diversified use consistent with sound business principles.

Network Alternative 4a (Considered but not studied) – Apply Seven Factor Test to Create Segment Based on Function – Proposed by IOU/Large public coalition: Puget, Seattle City Light, Pacificorp, PGE, Powerex, Tacoma, Avista, Ibedrola, Benton County PUD

The coalition proposes that BPA perform an analysis of the functions performed by BPA's facilities through the following method:

1. Identify intertie, generation integration, ancillary service, and direct assignment facilities. (Any changes to BPA's methodologies for identifying facilities in these segments are beyond the scope of this particular proposal.)
2. Network segment facilities and delivery facilities are those remaining transmission facilities not falling into the segments in item 1 above.
3. Segment remaining transmission or delivery facilities using an analysis of the functions performed by BPA's facilities.
   a. As discussed below, BPA's system seems relatively unique insofar as BPA's lower-voltage Network facilities are used predominately to serve a subset of BPA's transmission customers, while other BPA transmission customers—investor-owned utilities and larger preference agencies—provide their own lower-voltage facilities. Because of this fact, segmenting BPA's system using the FERC seven-factor test or similar functional test is particularly appropriate.
4. After the segmentation and to the extent practicable, limit the proposed average increase in the Network segment rate and the distribution segment rate for any rate period (for example, the average rate increase in each rate is to be no more than 20 percent). Spread the cost of such limit pro rata to the Network segment rate and the distribution segment

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[4] *See, e.g.,* BP-14-B-JP06-01, pp. 16-18.

rate, so that to the extent practicable neither rate experiences an average rate increase greater than 20 percent (for example) for any rate period. This limit mitigates any "rate shock" that may otherwise occur.

Coalition Justification

This approach more closely aligned with cost causation because it should result in rates based on the function or usage of the various BPA facilities and should not be unduly complicated to implement.

Coalition Evaluation Based on BPA Principles

BPA has developed "BPA's Final Segmentation Principles" dated March 20, 2014. These BPA principles are set forth below, together with some observations set forth in italics regarding segmentation of BPA's facilities based on function in the context of those proposed principles.[5]

1. Consistent with statutory requirements

a. The issue is not whether BPA will fully and timely recover its costs. The issue is which customers will pay for which facilities. This proposal attempts to provide a methodology that is relatively easy to implement while at the same time more closely aligning BPA's rates with cost causation.

b. Under the proposal for segmentation of BPA's facilities based on function, all of BPA's Network and delivery segment costs are allocated to rates for users of such segments. BPA should achieve cost recovery of its total Network and delivery segment costs.

c. Under the proposal for segmentation of BPA's facilities based on function, Network and delivery segment rates are more closely aligned with cost causation than an arbitrary 34.5kV segmentation test because such segmentation should result in rates based on the function of facilities used by BPA to provide various services. This is particularly appropriate in light of the fact that BPA's lower-voltage Network facilities are used predominately to serve a subset of BPA's transmission customers. The segmentation of BPA's facilities based on function would apply regardless of whether Federal or non-Federal power is being transmitted, yet should be equitable insofar as it would better reflect cost causation and result in rates based on segmentation of facilities reflecting the function of those facilities.

d. Under the proposal for segmentation of BPA's facilities based on function, Network and delivery segment rates are more closely aligned with cost causation because they include different charges based on the function of facilities used by BPA to provide

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[5] Proponents of this alternative have noted that not all of these principles are applicable to segmentation of BPA's facilities and that these principles may not be determinative in a BPA rate proceeding.

various services. Such rates send a better price signal than an arbitrary 34.5kV segmentation test and are limited to collecting the Network and delivery segment revenue requirements—therefore, they should promote efficient transmission facility decisions and be consistent with this principle.

2. Consistent with rate making principles

a. Under the proposal for segmentation of BPA's facilities based on function, Network and delivery segment rates are more closely aligned with cost causation because they include different charges based on the function of facilities used by BPA to provide various services.

b. Under the proposal for segmentation of BPA's facilities based on function, BPA's Network and delivery segment rate structures would remain unchanged (but would likely reflect the transfer of facilities from one segment to another).

c. Under the proposal for segmentation of BPA's facilities based on function, mitigation of potential "rate shock" is addressed as discussed above.

d. Under the proposal for segmentation of BPA's facilities based on function, the function performed by various BPA facilities should be relatively stable, and the proposal for segmentation of BPA's facilities based on function should result in Network and delivery segment rates that are relatively stable from rate period to rate period.

3. Considers a regional perspective

a. Under proposal for segmentation of BPA's facilities based on function, all Network and delivery segment costs are allocated to BPA Network or delivery segment rates and should therefore be recovered.

b. The proposal for segmentation of BPA's facilities based on function is superior to the status quo because the proposal should result in rates based on the function of facilities used by BPA to provide various services and should result in rates that are more closely aligned with cost causation than an arbitrary 34.5kV segmentation test.

c. BPA has not always applied uniform rates,[6] nor has it shown that uniform rates achieve the widest possible diversified use consistent with sound business principles. The proposal for segmentation of BPA's facilities based on function is superior to BPA's practice "[h]istorically," which was based on an arbitrary 34.5kV segmentation test that arose in a 1996 transmission rate case settlement. As discussed above, the proposal should result in rates based on the function of facilities used by BPA to provide various services and should result in rates that are more closely aligned with cost causation and more consistent with sound business principles than an arbitrary 34.5kV segmentation test.

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[6] *See, e.g.,* BP-14-B-JP06-01, pp. 16-18.

BPA Rate Analysis

Rates analysis was not developed for this alternative. The initial analysis of this alternative was delayed because the proposal was somewhat similar to Snohomish's proposal. Later in the process, no specific criteria to apply the seven factors to facilities were developed. Without developed criteria and due to time constraints BPA was not able to conduct this analysis. BPA notes that one of the criteria—serves a wholesale purpose—is true for very nearly all BPA's facilities.

Network Alternative 5 – Establish a Subtransmission Segment and Rate Based on Voltage Threshold – Proposed by Seattle City Light

Seattle City Light requests that BPA review BPA's transmission facilities in the Network segment as of BP-14 and establish a new Sub-Transmission Segment based on the following:

1. Retain transmission facilities above 145kV in the Network.

Transmission facilities at 145kV and above are most likely to facilitate system-to-system transactions of bulk power, used for marketing transactions, and support regional transfers. These uses are most akin to network services

2. For facilities below 145kV, excluding the Delivery Segment, establish a new Sub-Transmission Segment.

Facilities at less than 145kV are most likely used to deliver power to end users. The new rate would be applied to customers taking service from BPA's transmission system at point(s) of delivery less than 145kV.

Seattle City Light Justification

This approach provides for improved comparability of service and uses between the segments. Frequently referred to as a "bright line" the alternative is simple to apply.

Evaluation Based on BPA Principles

BPA has developed "BPA's Final Segmentation Principles" dated March 20, 2014. The alternative has similarities and differences with the current conditions, which are evaluated.

1. Consistent with statutory requirements

a. The alternative includes all facilities and attendant costs, and proposes no changes to BPA's policies and practices regarding cost recovery. Consequently, the alternative should provide for the same cost recovery as the current conditions.

b. The proposal establishes a new segment within the system, which, combined with existing segments, will encompass BPA's entire transmission system. The alternative does not include any change to BPA's cost recovery policies and practices. Consequently, all transmission segment rates should be based on total system costs.
c. The new alternative does not make any changes to the allocation between federal and non-federal uses of the transmission system from the current conditions.
d. This topic has three concepts (use, rates, and business), which are not entirely consistent with each other or defined in law. The new alternative entails a cost and rate shift from customers not using the proposed segment to customers that do. In discussions to date, no parties have provided information that the cost shifts will affect consumption. As BPA's industry scan shows, utilities take a variety of approaches to segmentation, including the proposed alternative.

2. Consistent with rate making principles
a. The new alternative recognizes differences in service and subsequent cost causation. The alternative more closely aligns service, cost, and subsequent rates, and as such is an improvement, compared to the status quo.
b. The new alternative adds one segment based on voltage level. BPA already established the Delivery Segment based on voltage, so an additional voltage-based segment should be similarly understandable. The new segment will have more customers than the Delivery Segment although less than the Network segment, so it is feasible to apply. A sub-Transmission Segment is used by other utilities in the region and country. BPA's customers will understand the new segment.
c. This is a newly proposed alternative. As of June 1, 2014 BPA has not yet estimated revenue requirements and rates so rate shock is unknown. If BPA chooses to implement the alternative, tools to lessen rate increases, such as a phase in, may be applied if needed.
d. If adopted, the new alternative would be a change to one rate period. After adoption, the segment itself should be stable.

3. Considers a regional perspective
a. The alternative is specifically intended to ensure that costs are allocated and recovered according to the service provided.
b. The alternative is a change in cost allocation, and as such the region is no better or worse off.
c. Uniform rates typically are called "postage stamp" rates meaning the distance from generation to load is not a factor in determining the rate, and the new alternative does not change this practice. If necessary rate shocks will be mitigated, so the new alternative should have no effect on the use of power.

Montana Intertie Alternatives

IM Alternative 1 – Status Quo – Proposed by PPC

Currently services supported by the Eastern Intertie segment (including TGT, IM, and IE) are charged a rate separate from Network service. For TGT and IM this rate is developed based on $12.5 million of costs identified in the Montana Intertie Agreement recovered on a pro rata share of Long Term sales over the Eastern Intertie (currently 1,746 MW). The Eastern Intertie Hourly rate is based on the Eastern Intertie segmented costs ($9.9 million in BP-14) over possible Eastern Intertie sales (1,930 MW).

<u>PPC Justification</u>

Retention of the current rates for recovery of Eastern Intertie costs is consistent with BPA's statutory requirements and rate directives. Conversely, elimination of the IM firm transmission rate and inclusion of Eastern Intertie costs in the Network segment face broad opposition and create significant legal and policy risks for the agency. These include, without limitation:

- Creation of a precedential rate treatment for intertie facilities that is contrary to the current segmentation and recovery of intertie facility costs from users;
- Treatment of a radial transmission facility used exclusively for generation interconnection in a manner inconsistent with treatment of other similar facilities;
- Unduly discriminatory treatment of Eastern Intertie users who currently pay the TGT rate for the same services on the same facilities;
- Imposition of existing and future costs on Network customers without commensurate offsetting benefits to those customers in contravention of well-established rate-making principles.

<u>PPC Evaluation Using BPA Principles</u>

Summary of Previous Eastern Intertie Segmentation Litigation

BPA has maintained a separate rate segment for the Eastern Intertie since 1983, when the facility came into service and rates were set for its use. The Eastern Intertie is a radial transmission facility. Its primary use is to transmit the output of Colstrip generation for five customers. There are no requests in BPA's transmission service request queue for new long-term firm service over that path. In the BP-14 rate case, the Administrator found that "[t]hese factors indicate that the Eastern Intertie should remain a separate segment" and that "other reasons to roll in BPA's Eastern Intertie capacity have not been established."[7]

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[7] Administrator's Final Record of Decision, *2014 Wholesale Power and Transmission Rate Adjustment Proceeding*, BP-14-A-02, ("BP-14 ROD") at 160-161.

Based on the evidence in the record in the BP-14 case, the Administrator made other, more definitive findings:

- "[R]oll-in of BPA's Eastern Intertie capacity would not encourage development of renewable generation in the Pacific Northwest."[8]
- "There is a significant risk of additional costs from roll-in of BPA's Eastern Intertie capacity that has not been refuted. Because of that risk, it has not been demonstrated that roll-in would be consistent with sound business principles."[9]
- "It cannot be determined on this record whether roll-in of the Eastern Intertie would be a precedent for roll-in of the Southern Intertie."[10]

1. Consistent with Statutory Requirements

Retaining the Eastern Intertie segment ensures full and timely cost recovery. BPA has been recovering the costs of those facilities from Eastern Intertie users for decades. BPA has asserted and FERC has agreed that the BPA transmission rates as a whole, including the Eastern Intertie rates, are set at a level sufficient to recover BPA's costs. Only the costs of the Eastern Intertie facilities, net of costs recovered through the TGT rates, form the basis of the current IM rate and we do not propose to change this arrangement.

BPA does not use the Eastern Intertie facilities for delivery of federal power as part of its federal power-marketing program. Vigilante Electric's load is served with federal power over a line and transformer bay out of the Garrison substation, but those facilities are segmented to the Network and not to the Eastern Intertie. Rather, the Eastern Intertie was built solely to import non-federal electric power from generation in Montana and this remains the sole function of the line. Were additional generation to be interconnected to the Eastern Intertie facilities and delivered to loads in the Pacific Northwest, as rate case parties have asserted, the use of the line would remain unchanged; its function would remain a non-federal power import facility that interconnects with the BPA network at Garrison.

Rolling the Eastern Intertie costs into the Network rates would not encourage the "widest possible diversified use of electric power." There is no evidence that Montana wind development is being impeded by the existence of the current rates. This is particularly the case given that Montana wind generation is already competitive with Pacific Northwest wind generation and is asserted by some parties to be of higher quality.

BPA's rates for the Montana Intertie are currently based on the cost of those facilities and, therefore, are the lowest reasonable rates.

It must also be noted that other rate case parties have argued that rolling in the IM rate, without roll-in of the TGT rate, might be unduly discriminatory. Colstrip parties

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[8] BP-14 ROD, at 162.
[9] *Id*. at 163.
[10] *Id*. at 164.

have raised this argument and it must be considered. Rolling in the TGT costs, as well as IM costs, is not a palatable option; doing so would significantly increase Network rates in a manner that is inequitable to Network customers and create concerns similar to those noted in this and the following section.

2. Consistent with Rate-Making Principles

Retention of the Eastern Intertie segment and rates satisfies the cost causation principle by allocating the costs of the facilities to the users of those facilities. The only foreseeable new users of the facilities would be non-federal generation and those parties should pay the costs of the facilities, as do the current customers who use the facilities to transmit Colstrip power into the Pacific Northwest. A proposal to allocate these Eastern Intertie costs to Network customers would violate cost causation by allocating costs to Network customers in the absence of any certain, meaningful economic benefit commensurate with the costs. A generalized regional benefit is not a sufficient rationale to support imposition of costs on Network customers. Moreover, sufficient evidence has not been produced demonstrating even a generalized regional benefit.

PPC's proposal requires BPA to take no action and as such is simple, understandable and feasible. No change is required from the rates that have been in effect in one form or another for more than twenty years. Given that these rates have been acceptable for that period up until the BP-12 case, that nothing has happened to warrant changing these rates and that proposals to eliminate these rates and roll the costs into the Network received strong and broad opposition, retention of the rates should be considered to have broad public acceptance.

PPC's proposal would not cause the rate levels to increase or the costs to be uncertain. The customers that currently pay that rate would continue to do so but no additional customers would pay the costs or the rate unless they requested transmission service over the Eastern Intertie. No potential for rate shock is created by the proposal.

The proposal would not cause a change in the way the rate is calculated or in the costs. The rate is stable from rate period to rate period to the same extent it has always been. There would not be any greater unpredictability in the rate level beyond what is already experienced.

As a general matter, transmission capacity is available on the Eastern Intertie and existing and potential customers may request it, yet no requests have been made. Given our understanding that this is the case and that no new wind plants or transmission interconnections with BPA facilities are in the permitting or construction stage, the issue of rolling-in of the IM or other Eastern Intertie rates is not ripe. As a matter of policy and administrative law, BPA should not decide to change the current rate structure based on speculation that customers for a facility's use might somehow be created.

3. Considers a regional perspective

PPC proposes that BPA continue to allocate its share of Eastern Intertie costs to users of the Eastern Intertie facilities. The proposal does not affect cost allocation in regard to any other part of the FCRTS.

Lastly, were BPA to roll-in the Eastern Intertie costs as proposed by some parties, it would risk creating a precedent that could be used by other parties to argue for rolling into the Network the costs of other, currently segmented transmission facilities. Rolling in the Eastern Intertie costs could be seen as an invitation to roll-in the costs of generation interconnection facilities which are even more closely co-located with the network. It would be imprudent to believe that other, future rate case parties would not look for similarities between the Eastern and Southern Interties to argue for BPA to roll-in its Southern Intertie facilities. PPC does not support such proposals but the risk that they could be made should be a key consideration in BPA's decision on this issue.

IM Alternative 2 – Roll IM Rate into the Network – Proposed by Gaelectric

Gaelectric proposes that the IM rate associated with Montana Intertie service over the Eastern Intertie be rolled into Network rates. Gaelectric did not propose a specific method for rolling in the IM-rate so BPA identified two methods to achieve IM roll in:

Method 1: The Eastern Intertie remains a separate segment. TGT revenues continue to be collected and credited to the Eastern Intertie segment. Over/under collection of costs associated with the Eastern Intertie are allocated to all segments based on Net Plant Investment. BPA will serve the current 16 MW subscription, and if sold the additional 184 MW it has rights to, over the Montana Intertie as part of the Network. Costs associated with IM service (defined as the pro-rata share of use over the Eastern Intertie) will be assign to the Network Segment and recovered through Network rates.

Method 2: The facilities associated with the Eastern Intertie are rolled into the Network and recovered through Network rates. The IM rate is no longer charged to IM customers. TGT revenues continue to be collected and are credited to the Network segment. This treatment means that any under/over recovery of the current "Eastern Intertie" segment would be attributed solely to the Network.

<u>Gaelectric Justification</u>

The IM rate has resulted in 184 MW of capacity on the Montana Intertie being stranded for over 25 years and as a result of RNP calling attention to this issue in the 2012 and 2014 rate setting processes, BPA eliminated certain contract terms with the other Colstrip transmission system owners. This shifted the stranded costs to those parties while retaining the capacity and associated rate pancake. This means while the costs are no longer stranded from BPA's perspective (they are now a cost of the Colstrip transmission system owners), the continuing rate pancake is creating a barrier so that the remaining capacity continues to be stranded. We have attempted to work with parties to address concerns about the precedent set by rolling in the Montana Intertie, but the opposition continued with the same arguments brought up in previous discussions and no progress was made.

We have listened to discussions on other Segmentation issues and notes that the proposed roll in of the UD segment would result in a 0.6 percent impact on Network rates—smaller than the 0.2 percent impact that is expected if the IM rate is rolled in.

During the permitting of the MT Intertie facilities, BPA made extensive arguments in Montana that the need for these facilities for regional reliability was at least as great as the need to integrate the Colstrip facilities identified in the then-current NWPP regional plan as “regional supply”. This is in conflict with the opposition’s arguments that the MT Intertie facilities serve only one purpose and that is to integrate extra-regional facilities.

Gaelectric Evaluation based on BPA Prinicples

The elimination of the MT Intertie rate pancake is completely consistent with BPA’s segmentation principles. Indeed, continuing the status quo is inconsistent with those principles.

1. Consistent with statutory requirements

a. The Eastern Intertie investment has long since been paid for, and while there are always ongoing capital and maintenance costs associated with any facility properly maintained, the continuing costs associated with the MT Intertie are negligible in comparison to the costs of the FCRTS in total. BPA Staff analysis indicated that the impact of simply including the stranded 184 MW of capacity into rates would be 0.2 percent at the most, with the acknowledgement that there were no additional revenues included in the analysis from the potential increased use of the tie. Assuming even a 30 percent usage of the stranded capacity would make this change a net benefit from a rate perspective.

b. Except for a specific 90 mile segment of double circuit 500kV transmission under the status quo.

c. It’s never been clear to me where FERC authority begins and ends with regard to Bonneville, but FERC (i.e. national) policy under both Republican and Democrat administrations has been clear since 1996 that transmission is intended to be full open access without distinction between customers. Is it “federal” use anytime a county PUD or a customer-owned utility uses the system, or only when they are taking their BPA preference supply? What about secondary sales/purchases of energy? This principle is so severely blurred as to obscure any cost element associated with the MT Intertie rate elimination.

d. The current status of the MT Intertie is in complete violation of this principle. Despite BPA's pleadings in the original permitting hearings regarding reliability of the total grid, the position in recent years has been that the Townsend-Garrison segment was built for a single, specific purpose. As a result, a certain amount of capacity has been stranded for over 20 years. That is an egregious violation of the most basic asset management principles, not to mention this segmentation principle.

2. Consistent with rate making principles

a. Again, I note that BPA's own testimony in the permitting phase of construction of the Townsend-Garrison segment noted the critical interest this segment played in system reliability. I'm long enough in the tooth to have lived through the nearly monthly splitting and islanding of the western grid during the mid-1980s that was solved with the completion of the entire 500kV system across Montana. With the segment between Townsend and Garrison open, we would be in the same soup we were in 30 years ago.

b. Nothing could be more simple, understandable or feasible than eliminating a completely separate rate class for 90 miles of double circuit line. As for public acceptance, any reasonable party considering the entire spectrum of segmentation issues would agree that this insignificant change is acceptable.

c. Prior opponents of eliminating the MT Intertie pancake are maintaining that a 0.6 percent increase in rates is insignificant when it involves rolling distribution facilities into the transmission grid, but in their past opposition, they felt that the 0.2 percent increase associated with eliminating the MT Intertie rate pancake was egregious. That inconsistency is neither helpful nor reasonable. I simply note that for over 20 years those that oppose this change were paying the costs that we seek to eliminate, and they didn't even know it. That speaks volumes about avoidance of rate shock.

d. This will have no impact one way or another on rate stability.

3. Considers a regional perspective

a. This has been covered in prior points hereunder.

b. Everyone benefits from efficient management of transmission resources. Leaving 184 MW of capacity stranded for over 20 years is poor management of assets at the very least. Planning process are purportedly looking for low cost transmission increments as evidenced through BPA's own NOS processes and various sub-regional planning processes. There is no lower hanging fruit than making use of stranded capacity. It is the transmission equivalent of conservation, which is widely embraced by virtually every reasonable party.

c. The status quo violates any reasonable perspective of achieving the widest possible diversified use. The status quo is clear: this segment can never be used for any purpose other than integrating Colstrip's coal fired production.

IV. Rate and Customer Impact Analyses of Segmentation Alternatives

Network Alternative 0 – Status Quo

The Status Quo is based on the results of the BP-14 rate case. The rates and customer loads used in the customer impact analyses are taken from the final Transmission Rates Study. Elements of transmission costs, specifically costs for the transfer of Federal power to BPA customers served through third-party transmission, are taken from the final Power Rates Study. The proportions each customer pays for transmission-related costs contained in power rates are taken from the final Oversupply rate case.

The Status Quo case maintains the current criteria for determining the segments. As discussed above, the criterion for separating between them (the 34.5kV bright-line threshold) was established through a non-precedential settlement of the 1996 rate case. However, the non-precedential settlement does not rule out selecting the threshold for use going forward, but the Status Quo should not be considered the presumptive case against which other alternatives must demonstrate a superior basis and result. The Status Quo does represent the rates that customers are paying during the current rate period and are thus presented as a standard measure of comparison of cost shifts.

BPA staff notes that none of the alternatives presented in the Segmentation Review are outside the bounds of reasonable ratemaking practices, and we recognize the important role that cost of service plays in ratemaking. We have attempted to implement each alternative as proposed in a manner that represents the intent of those that have proposed the alternative. However, given the time constraints of this process, not every element of each proposal may be fully integrated into the analyses. We believe that the results of the analyses are well within the bounds of reasonableness to produce a fair representation of the customer impacts of each alternative.

The summary of customer impacts displayed below consists of two views of the Status Quo. The first view compares the alternative to the existing BP-14 rates. However, the existing BP-14 rates have limited the level of the Utility Delivery rate to a level that produced a 25 percent rate increase compared to the BP-12 Utility Delivery rate. This resulted in a rate that under-recovered costs allocated to the Utility Delivery segment. This under-recovery was reallocated to other segments, primarily the Network segment. The second view compares the alternative to a set of rates that assumes that the Utility Delivery rate fully recovers the costs allocated to the Utility Delivery segment, all other aspects of rate development held constant.

Network Alternative #1 - Roll Utility Delivery Segment into Network

To give proper context to this alternative, BPA assessed the two views of the Status Quo case discussed above. Alternative #1 is modelled assuming all Utility Delivery costs are assimilated into the Network and the Utility Delivery is eliminated. The alternative proposes no changes to the DSI Delivery segment and rates, and none are modelled.

The table below shows rates under Alternative #1 compared to BP-14 and the UD Full Recovery scenarios.

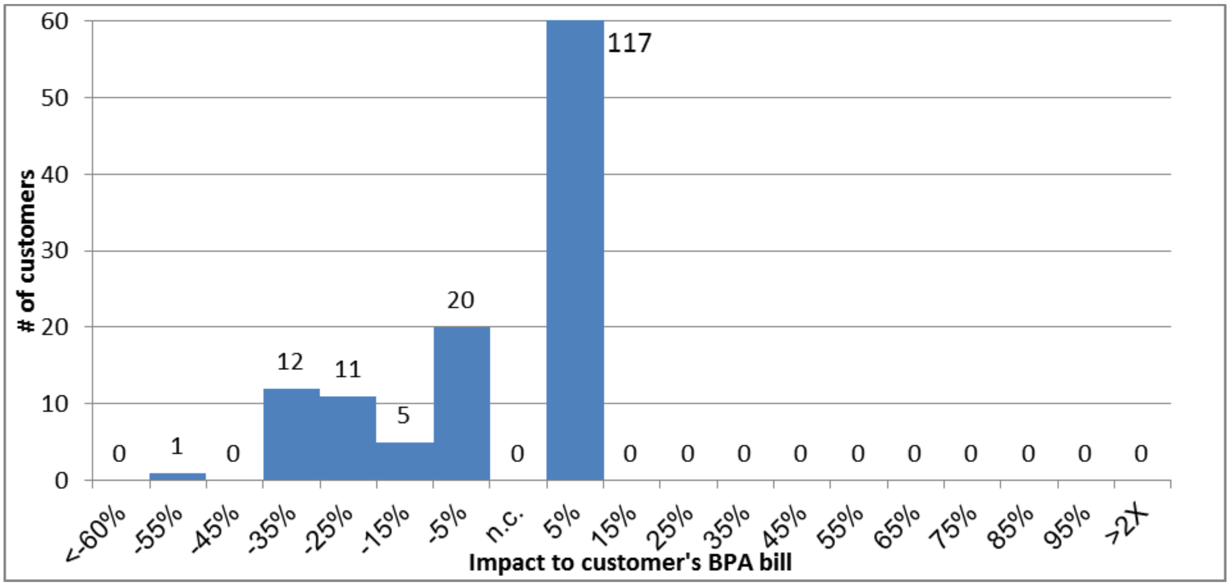
Alternative #1	BP-14 Rates	UD Full Recovery	Alternative #1	% Chage from BP-14*	% Change from Full Recovery*
FPT Rate	1.666	1.661	1.675	1%	0.8%
IR Rate	1.736	1.731	1.745	1%	0.8%
PTP Rate	1.479	1.474	1.488	1%	0.9%
NT Rate	1.741	1.734	1.751	1%	1%
Utility Delivery Rate	1.399	2.577	0.000	-100%	-100%
NT + Utility Delivery	3.140	4.311	1.751	-44%	-59%
PTP + Utility Delivery	2.878	4.051	1.488	-48%	-63%

* Note that this table shows effects on specific rates and rate combinations, and will not directly translate to the changes in overall costs that customers will experience under the proposal.

BPA has committed to treat its customers served by transfer over a third-party transmission system in a manner similar to those that are directly connected to BPA's transmission system. The costs of transfer service are included in BPA's power rates and the transfer customers pay BPA's transmission rates. Transfer customers taking delivery at a voltage below 34kV pay a separate delivery rate, the GTA Delivery rate. If the Utility Delivery rate is eliminated under Alternative #1, it is assumed that the GTA Delivery rate is also eliminated. Thus, the $2.1 million currently collected by the GTA Delivery charge would no longer exist and, because the total costs of transfer service are unchanged by BPA's rate design, power rates would increase by $2.1 million. The customer impact analysis presented below incorporates the effects of this change to transfer costs and rates.

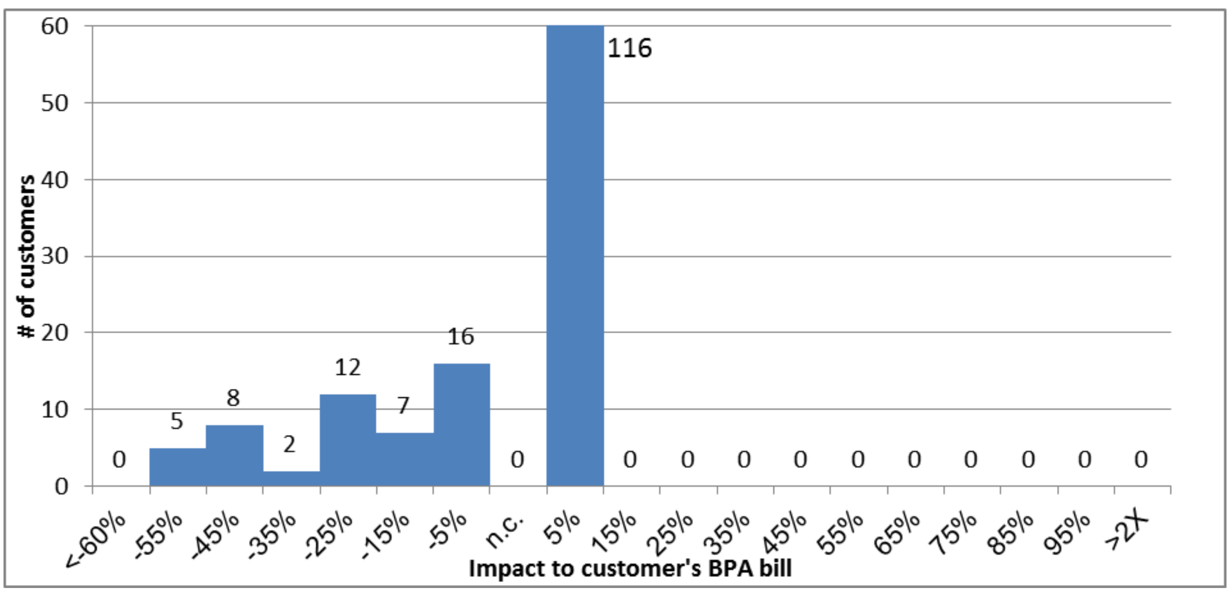
Rather than rely on a simple statement of the impact to a customer that pays both a network rate and the utility delivery rate (for example, NT+UD = -59%), the analyses present the impact on each customer's transmission payments. Only a few customers pay the Utility Delivery rate on its full load; thus the elimination of the Utility Delivery segment and rate impact customers differently depending on the proportion of load subject to different rates. The following charts show how customers are differentially affected by Alternative #1. The x-axis refers to the percentage change in costs each customer could expect to its transmission payments, using BP-14 data and based solely on the proposed Segmentation methodology change. This analysis includes all transmission products the customers' purchases and includes how changes in transfer service would affect their cost for power purchases if they are a power customer. The analysis does not include costs for Generation Inputs, nor does it include the effects of changes on transmission costs incurred by BPA Power Services that are included in power rates.

The impacts to customers under Alternative #1 compared to BP-14 rates:



This analysis shows that the majority of customers (117 of 166) would experience a slight rate increase (the column labeled "5%" includes bill impacts between 0 and 10 percent), but that for a small number of customers, there is a significant reduction in costs between 20 and 40 percent. One customer's bill is cut almost in half.

The impacts to customers under Alternative #1 compared to rate assuming UD Full Recovery:



Again this analysis reflects a relatively small impact for the majority of customers (around 5 percent). This comparison shows additional benefit to the 50 or so customers who pay Utility Delivery. The majority of the Utility Delivery customers see at least a 20 percent decrease in costs compared to what they would pay once the Utility Delivery rate reaches full recovery. Thirteen customers see savings of over 40 percent.

Network Alternative #2 - Maintain Adjusted Utility Delivery Charge

As with Alternative #1, to give proper context to this alternative, BPA assessed the two views of the Status Quo case discussed above. Alternative #2 is modelled assuming the UD rate is locked in at its current level and the current under-recovery is rolled into the Network segment. While NRU proposes to allow the Utility Delivery rate to escalate with Network rates, this analysis is only for the current rate period, thus it does not consider future Network rate changes.

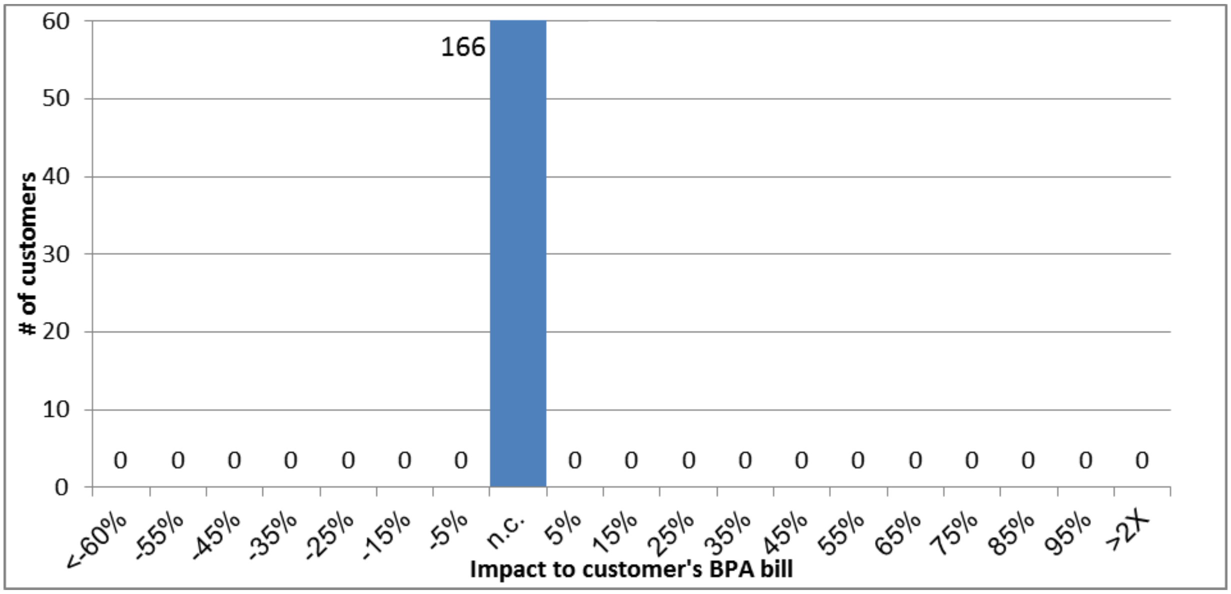
The table below shows rates under Alternative #2 compared to BP-14 and the UD Full Recovery scenarios.

Alternative #2	BP-14 Rates	UD Full Recovery	Alternative #2	% Chage from BP-14*	% Change from Full Recovery*
FPT Rate	1.666	1.661	1.666	0%	0.3%
IR Rate	1.736	1.731	1.736	0%	0.3%
PTP Rate	1.479	1.474	1.479	0%	0.3%
NT Rate	1.741	1.734	1.741	0%	0.4%
Utility Delivery Rate	1.399	2.577	1.399	0%	-46%
NT + Utility Delivery	3.140	4.311	3.140	0%	-27%
PTP + Utility Delivery	2.878	4.051	2.878	0%	-29%

* Note that this table shows effects on specific rates and rate combinations, and will not directly translate to the changes in overall costs that customers will experience under the proposal.

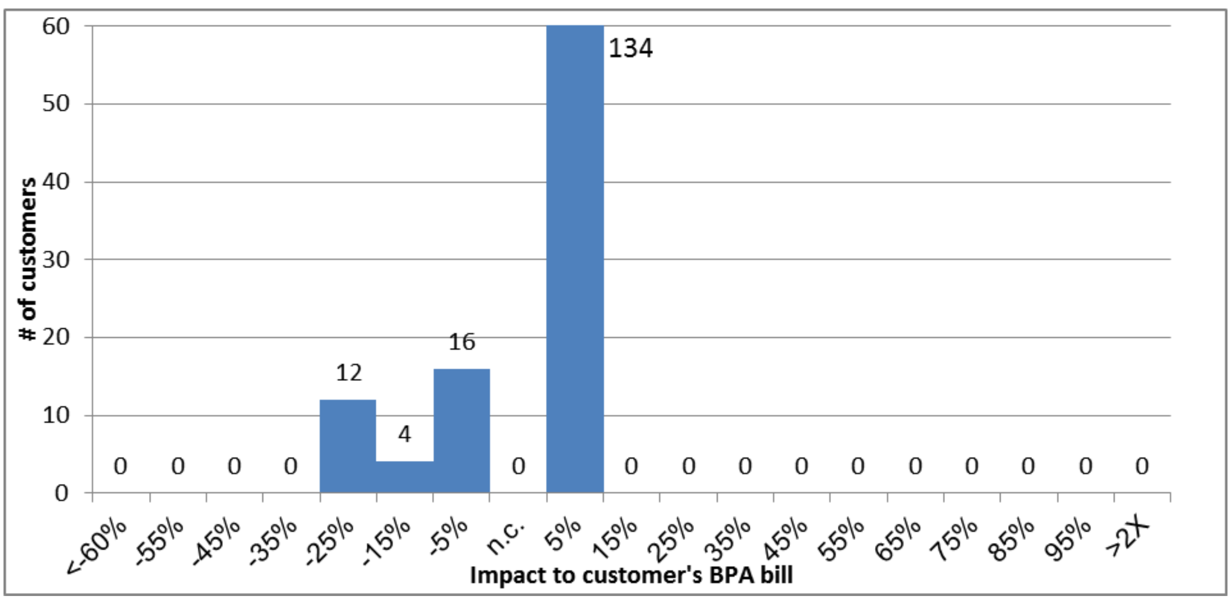
No change to transfer costs or the GTA Delivery rate would occur under this alternative.

The impacts to customers under Alternative #2 compared to BP-14 rates:



No customers would see changes in costs in relation to BP-14 rates because Alternative #2 would maintain the current rate level (BP-14) for Utility Delivery.

The impacts to customers under NRU proposal compared to UD Full Recovery:



As compared to full recovery for Utility Delivery, Alternative #2 would result in a significant cost savings between 5 and 25 percent for 32 Utility Delivery customers. Those costs are instead recovered through Network rates resulting in about a 5 percent increase in costs to all customers not taking Utility Delivery service.

Network Alternative #3 - Develop a "Radial" Segment

Network Alternative #3 proposes the exclusion of "radial" facilities in the Pacific Northwest from the Network segment. The costs of the "radial" facilities would be assigned to a separate segment and charged to the load-serving customers using those radial facilities. Costs for the radial segment would be assigned to these customers based on their pro-rata demand share of use of radial facilities in aggregate. BPA analyzed its system and segmented its transmission facilities based on criteria developed in consultation with Snohomish. (See the discussion of this alternative above.)

Analysis of Network Alternative #3 required the following:

1. Identification of radial facilities
2. Development of the revenue requirement associated with facilities
3. Identification of billing determinants for users of radial facilities

Dividing the Radial segment revenue requirement by the total loads (on a delivery point basis) utilizing the Radial segment yields a rate of $1.630 per kW per month.

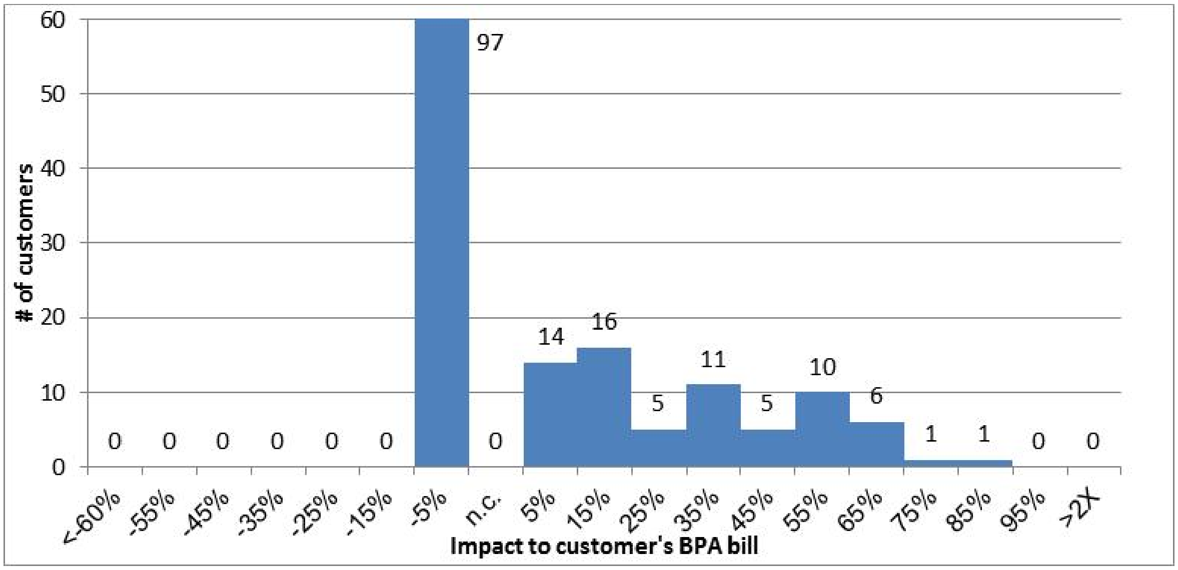
Alternative #3	BP-14 Rates	Alternative #3	% Chage from BP-14*
FPT Rate	1.666	1.595	-4%
IR Rate	1.736	1.662	-4%
PTP Rate	1.479	1.405	-5%
NT Rate	1.741	1.653	-5%
Radial Service Rate		1.630	
NT + Radial Service	1.741	3.283	+89%
PTP + Radial Service	1.479	3.035	+105%

* Note that this table shows effects on specific rates and rate combinations, and will not directly translate to the changes in overall costs that customers will experience under the proposal.

The radial service rate would also be applied to transfer service loads served over third-party radial lines (as determined utilizing the same criteria as for BPA's lines), producing $2.8 million to reduce the GTA cost embedded in power rates.

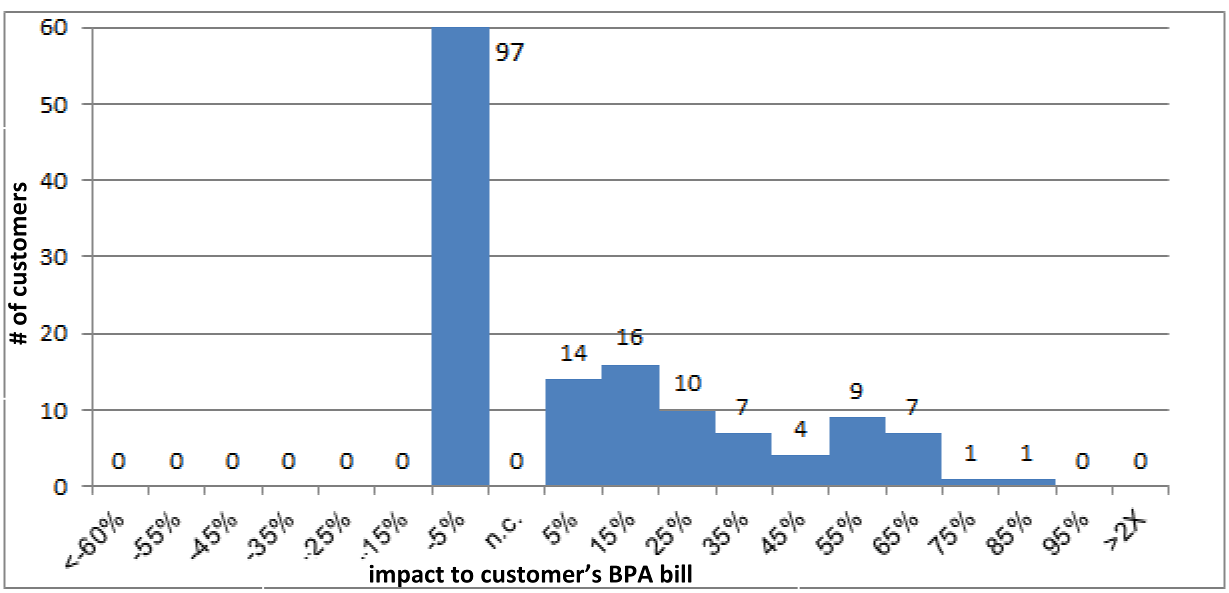
The charts below show how customers are affected by Alternative #3. The change in customer payments to BPA assesses each customer delivery point to determine if that delivery point would be subject to the radial service charge. Because only a few customers would be served entirely over the Radial segment, only those few customers would see rate impacts at the higher end of rate impacts.

Impacts to customers under Alternative #3 compared to BP-14 rates:



The majority of BPA's customers see some reduction in costs. This reduction is modest, around 5 percent, based on the removal of radial facilities from the Network segment. Those customers that are using radial facilities see a wide range of effects depending on the amount of their load is served from the radial facilities. These effects generally range from 5 to 65 percent, with two customers experiencing close to 80 percent increases in transmission payments to BPA. BPA did not test how many years it would take to reach full recovery of the radial segment using Snohomish's mitigation proposal. The analysis examines the end state based on the full recovery of radial facility costs by a radial service rate.

The impacts to customers under Alternative #3 compared to rate assuming UD Full Recovery:



Network Alternative 4 – Develop Transformation Charge

Delivery voltages (below 34.5kV) continue to be in the Delivery Segment and are not considered in determining transformation voltage.

All PODs are deemed to use 230kV and 500kV service (defined as Network service for this scenario); for example, if a 115kV POD is located near a generator integrated at 115kV, the POD is charged the Network rate plus 115kV transformation rate.

Generation integrated below 161kV is charged for transformation. If the generator owns the transformer that steps up to 230kV, or the step-up is in the Generation-Integration segment, it is not charged.

Cost Determination Methodology

For each BPA Network transformer, the actual investment cost was pulled from the same database used to determine segmentation study investment. 15 transformers had no or incomplete investment data. Proxy costs were used to estimate the investment for these transformers.

Transformers were divided into three groups, which were determined using the low-side of the transformer:

1. 230kV (146+)
2. 115kV (100-145)
3. 69kV (30-99)

The total investment of each transformer group within each substation was divided by the total investment for the substation; this ratio was used to determine the share of substation O&M to be assigned to that transformer group. The total transformer investment and O&M was used to develop a segmented revenue requirement including a new transformation segment. For simplicity NT Cost Allocation is based on Coincident Peak for Transformation Charge Calculation.

One-Step Transformation Alternative

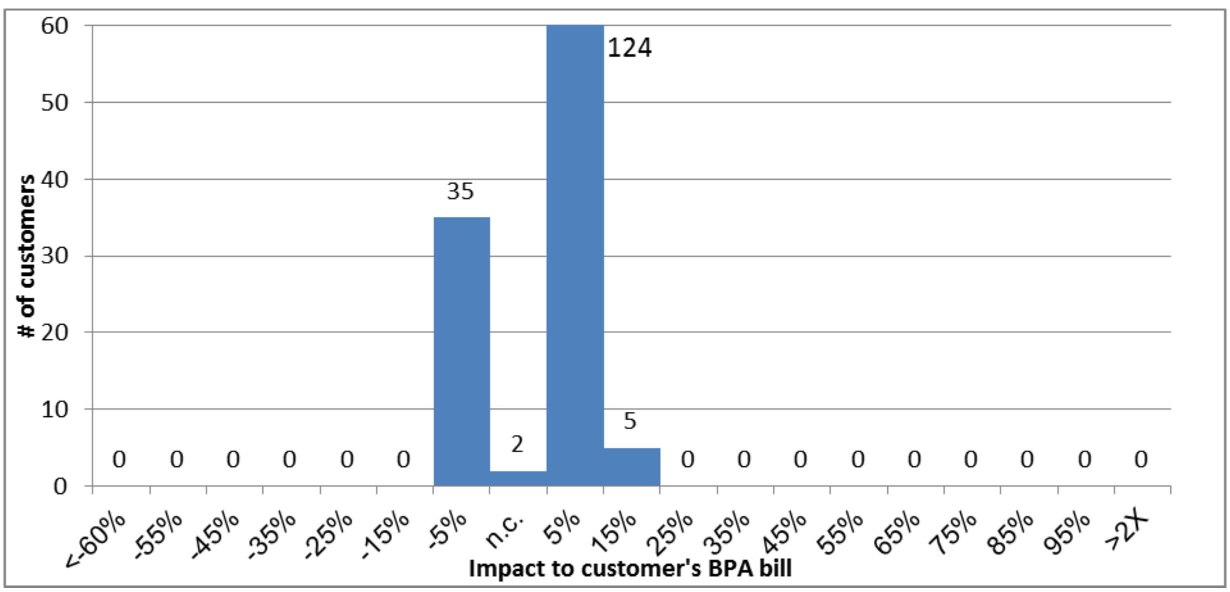
Dividing the revenue requirement by the total load yields a rate of $0.296 per kW per month.

Alt #4—One Step	BP-14 Rates	Alternative #4	% Chage from BP-14*
FPT Rate	1.666	1.666	-0%
IR Rate	1.736	1.661	-4%
PTP Rate	1.479	1.404	-5%
NT Rate	1.741	1.652	-5%
Transformation Rate		0.296	
NT + Transformation	1.741	1.948	+15%
PTP + Transformation	1.479	1.700	+12%

* Note that this table shows effects on specific rates and rate combinations, and will not directly translate to the changes in overall costs that customers will experience under the proposal.

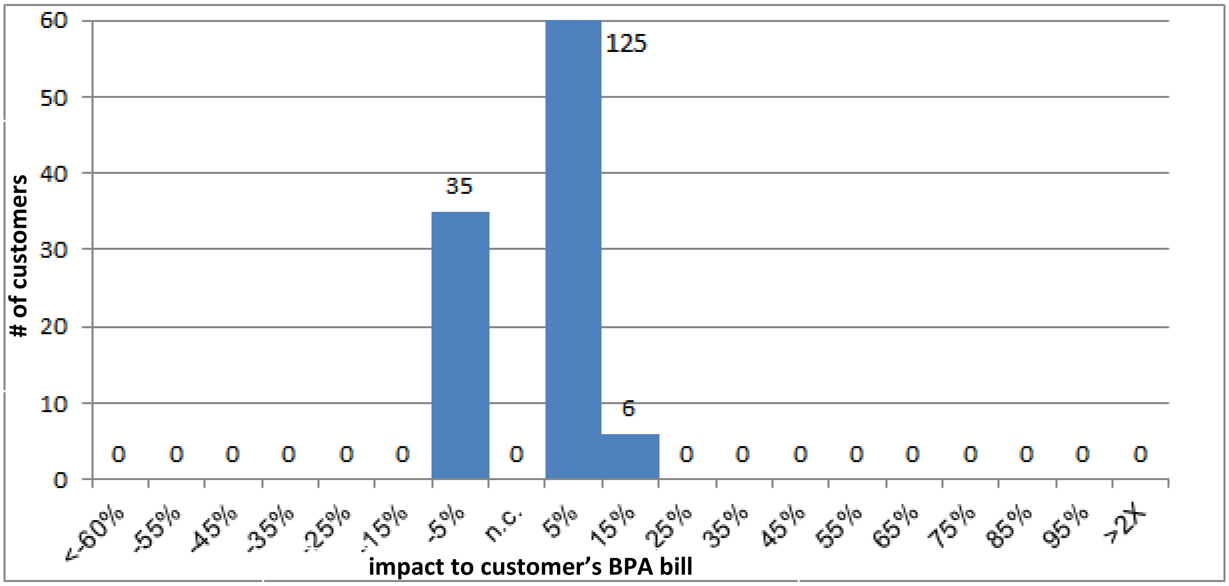
The transformation rate would also be applied to transfer service loads below 145kV, producing $3.2 million to reduce the GTA cost embedded in power rates.

The charts below show how customers are affected by Alternative #4. The change in customer payments to BPA assesses each customer delivery point to determine if that delivery point would be subject to the transformation charge. Because most of BPA's power customers would be served entirely using the Transformation segment, the amount of load over which Transformation costs are spread are substantial, amounting to about one-third of total Network segment load. The impacts to customers under Alternative #4 compared to BP-14 rates:



In the transformation charge proposal, the majority of customers experience a relatively modest increase of about 5 percent of total costs. About a third as many customers receive a similar sized decrease in costs. A handful of customers experience a slightly higher cost increase than the others—around 15 percent.

The impacts to customers under Alternative #4 compared to rate assuming UD Full Recovery:



Two-Step Transformation Alternative

A rate analysis was performed to examine the effect on rates if the transformation charge was divided between higher voltage (100-145kV) customers and lower voltage (34-99kV) customers. This would produce a two-step transformation rate. Dividing the revenue requirement by the total load yields an additional cost of $1.07 per KW per month for service at or below 69kV. The other network rates are the same as in the one-step variant.

Alt #4—Two Step	BP-14 Rates	Alternative #4	% Chage from BP-14
115kV Xfmr Rate		0.204	
35-69kV Xfmr Rate		0.863	
115+69kV Xfmr Rate*		1.067	

* Under this alternative, delivery to a POD below 80kV would pay the 115+69kV Xfmr rate.

BPA did not analyze this scenario for a customer level impact. Rather, based on time and customer feedback, BPA focused on the One-Step Transformation alternative to calculate customer specific impacts for related to the transformation alternative.

Variant on Two-Step Transformation Alternative

After presenting the results of the Two-Step Transformation Alternative, an observation was offered that there were a number of 35/69kV delivery points that had transformation directly from BPA's 230kV system. The assumption that these delivery points would be assessed the 115kV plus 69kV transformation rates might not reflect the cost of serving these delivery points. Thus, BPA added a variant to the Two-Step Alternative that includes a hybrid approach that isolates the costs of 230-to-35/69kV transformation from the costs of 115-to-35/69kV transformation. Separate rates and loads have been developed to assess this hybrid approach.

Alt #4—Two Step Hybrid	BP-14 Rates	Alternative #4	% Chage from BP-14
115kV Xfmr Rate		0.237	
35-69kV Xfmr Rate		1.152	
115+69kV Xfmr Rate*		1.389	
69kV / 230kV Rate		0.681	

* Under this alternative, delivery to a POD below 80kV that utilizes 115kV transformation would pay the 115+69kV Xfmr rate; delivery to a POD below 80kV that does not utilize 115kV transformation would pay only the 69kV / 230kV Xfmr rate.

BPA did not analyze this scenario for a customer level impact. Rather, based on time and customer feedback, BPA focused on the One-Step Transformation alternative to calculate customer specific impacts for related to the transformation alternative.

Network Alternative 4a - Apply Seven Factor Test to Create Segment Based on Function

Rate analysis was not developed for this alternative. The initial analysis of this alternative was delayed because the proposal was somewhat similar to Snohomish's proposal. Later in the process, no specific criteria to apply the seven factors to BPA facilities were developed. Without specific criteria and due to time constraints, BPA was not able to conduct this analysis. BPA notes that the Commission-stated purpose of the Seven Factor Test—to determine whether facilities are used for a wholesale transaction—holds for all but two short transmission lines included in BPA's Network segment.

Network Alternative 5 - Establish a Subtransmission Segment and Rate

For each transmission facility below 145kV, the investment and historical O&M were moved from the Network segment to a new Subtransmission segment. Revenue requirements were developed for the Network and Subtransmission segments; by happenstance, both segments average $208 million per year before ratemaking adjustments. The loads used for this alternative are the same as used for the transformation alternative.

Dividing the revenue requirement by the total load yields a Subtransmission rate of $1.950 per kW per month.

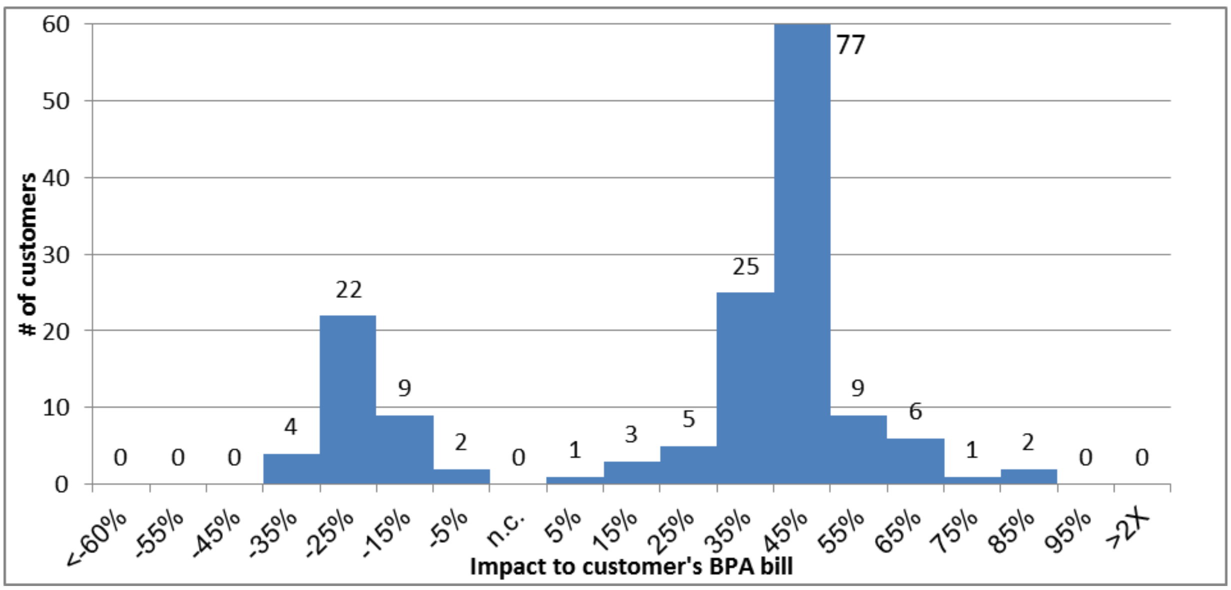
Alt #4—One Step	BP-14 Rates	Alternative #4	% Chage from BP-14*
FPT Rate	1.666	1.210	-20%
IR Rate	1.736	1.261	-27%
PTP Rate	1.479	0.999	-32%
NT Rate	1.741	1.177	-32%
Subtransmission Rate		1.950	
NT + Subtransmission	1.741	3.127	+80%
PTP+Subtransmission	1.479	2.949	+99%

* Note that this table shows effects on specific rates and rate combinations, and will not directly translate to the changes in overall costs that customers will experience under the proposal.

Applying the Subtransmission rate to transfer service radial loads produces $21.1 million to reduce the GTA cost embedded in power rates.

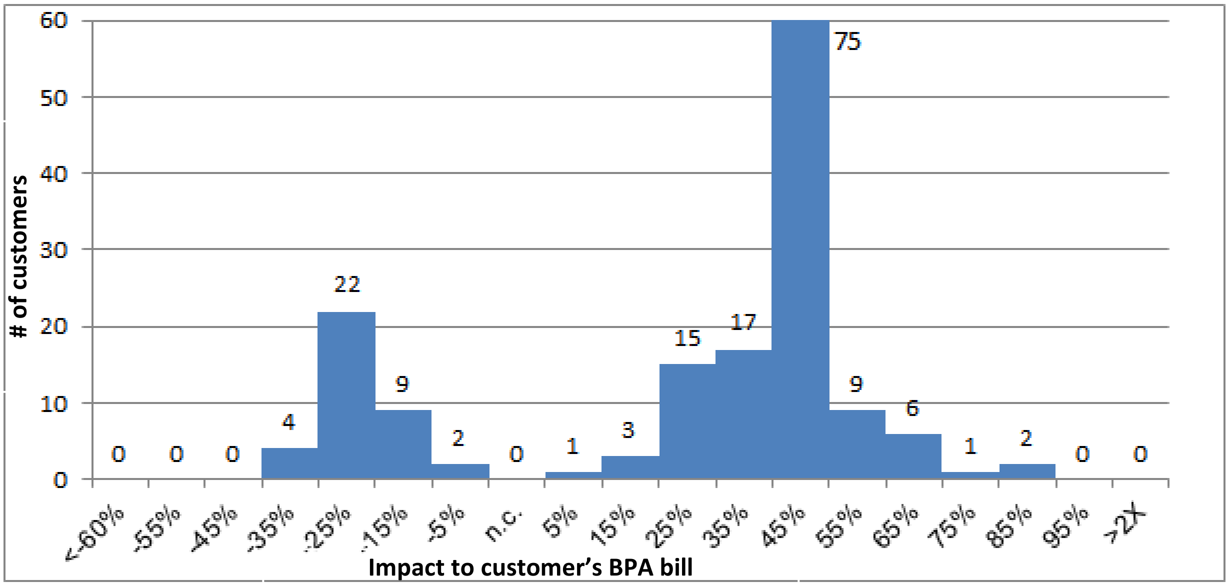
The charts below show how customers are affected by Alternative #5.

The impacts to customers under Alternative #5 compared to BP-14 rates:



Under Alternative #5, a majority of customers experience significant increases to their transmission payments. More than half of BPA customers experience rate increases of at least 45 percent. About a sixth of customers would experience costs reductions ranging from 5-35 percent of their total transmission payments.

The impacts to customers under Alternative #5 compared to rate assuming UD Full Recovery:



Montana Intertie Status Quo

The Status Quo for the IM Alternative is identical to the Network Status Quo.

Montana Intertie Alternative 6 - Roll IM Rate into the Network

In the Segmentation analysis, BPA identifies assets related to the Eastern Intertie (IE) segment. These facilities support multiple BPA transmission services including:

- Montana Intertie Service (IM)
- Townsend-Garrison Transmission (TGT)
- Eastern Intertie Hourly Product

Any over/under-recovery on costs allocated to this segment is allocated to all other segments.

<u>Assignments of costs on the Eastern Intertie</u>

Per the Montana Intertie Agreement, costs associated with the Eastern Intertie are $12.5 million. This cost is recovered on a pro rata share between sales of TGT and IM.

For BP-14:

- TGT = 1,730 MW (99%)

- IM = 16 MW (1%)

BPA has a right to sell up to 200 MW of IM which would shift the allocation of costs between these two products

The Eastern Intertie Hourly costs were developed based on Eastern Intertie segmented costs ($9.9 million in BP-14) over possible sales (1,930 MW).

Treatment of Revenues

BPA recognizes revenue received as IM and TGT as credits against the segmented Revenue Requirement for the Eastern Intertie. Any under/over recovery is allocated among other segments based on Net Plant Investment.

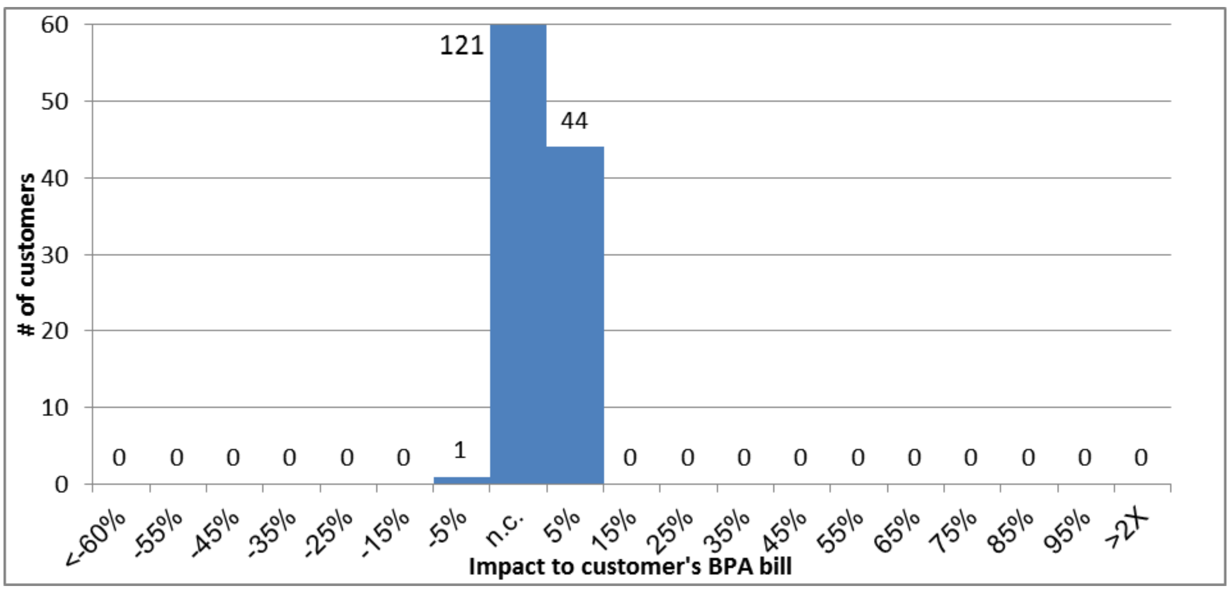
Eastern/Montana Intertie Scenarios					
	Scenario 1	Scenario 1a	Scenario 2	Scenario 2a	Scenario 3
	Status Quo	Current Seg w/ 184 MW Additional IM and PTP Sales	IM Roll In Current Subscription (16 MW)	IM Roll In 184 MW additional PTP Sales	Eastern Intertie Roll In with TGT Revenues as Network Credits
Eastern Intertie Investment	Separate segment	Separate segment	Separate segment	Separate segment	Investment rolled into Network
IM Rate	Collected based on share of IE costs	Collected based on share of IE costs. Assumes additional sale of 184 MW on the Network and IM	Eliminated. Customer pay only Network rate.	Eliminated. Customers pay only Network rate. Assumes additional sale of 184 MW on the Network.	Eliminated. Customers pay only Network rate.
TGT Rate	Collected based on share of IE costs per IM Agreement. Credited to IE segment.	Collected based on share of IE costs per the IM Agreement. Credited to IE segment.	Collected based on share of IE costs per IM Agreement. Credited to IE segment.	Collected based on share of IE costs per IM Agreement. Credited to IE segment.	Collected based on share of IE costs per IM Agreement. Credited to Network segment.

	Scenario #1 Rates	Scenario #1a Rates	Scenario #2 Rates	Change / Scn #1	Scenario #2a Rates	Change / Scn #1	Scenario #3 Rates	Change / Scn #1
IM	$0.855	$0.796	$ -	-100.0%	$ -	-100.0%	$ -	-100.0
TGT	$0.598	$0.541	$0.598	0.0%	$0.541	0.0%	$0.598	0.0%
PTP	$1.736	$1.725	$1.737	0.1%	$1.734	0.5%	$1.735	-0.1%
NT	$2.027	$2.027	$2.041	0.0%	$2.037	0.5%	$2.040	0.0%
IS	$1.381	$1.381	$1.385	0.0%	$1.386	0.4%	$1.390	0.4%
UD	$1.399	$1.399	$1.399	0.0%	$1.399	0.0%	$1.399	0.0%
IM+PTP	$2.591	$2.521	$1.737	-33.0%	$1.734	-31.2%	$1.735	-33.0%
TGT+PTP	$2.334	$2.266	$2.335	0.0%	$2.275	0.4%	$2.333	0.0%

For purposes of further assessing this alternative, BPA focused on Scenario 2 described above.

The chart below shows how customers are affected by Alternative #6. The x-axis refers to the change in costs the customer could expect using BP-14 data, based solely on the proposed Segmentation methodology change. This analysis includes all transmission products the customers purchase and how changes in transfer service would affect their cost for power purchases if they are a power customer. The analysis does not include costs for Generation Inputs.

Impacts to customers under Alternative #6 compared to BP-14 rates (UD Full Recovery impacts are very similar to BP-14 and are not presented):



This scenario has very little rate impact on customers. One customer receives a small amount of rate relief on their bill. Most other customers see not impact. About a fourth of customers experience a very small increase to their costs.

Appendix

Appendix A - Commission’s Seven Factor Test

The Seven Factor Test is a jurisdictional test that applies to public utilities under the Federal Power Act and determines whether facilities serve a transmission function (subject to the Commission’s jurisdiction) or distribution function (subject to state jurisdiction). The Seven Factor Test allows for the weighing of the factors in determining whether a facility serves a transmission or distribution function.

The indicators of local distribution in the Commission’s seven-factor test are:

(1) Local distribution facilities are normally in close proximity to retail customers;
(2) Local distribution facilities are primarily radial in character;
(3) Power flows into local distribution systems, and rarely, if ever flows out;
(4) When power enters a local distribution system, it is not reconsigned or transported on to some other market;
(5) Power entering a local distribution system is consumed in a comparatively restricted geographic area;
(6) Meters are based at the transmission/local distribution interface to measure flow into the local distribution system; and
(7) Local distribution systems will be of reduced voltage.

Appendix B - Commission's *Mansfield* Test

For jurisdictional utilities, the test for whether a facility is transmission or distribution is different from the test for integration. The Commission's integration test—known as the *Mansfield* test—contains five factors to determine whether transmission facilities are integrated (the costs should be rolled into network transmission rates) or not integrated (the costs should be directly assigned to the user). Because integration addresses whether the costs of transmission facilities should be rolled into network rates or directly assigned, the Commission's *Mansfield* test applies only to transmission facilities, not to distribution facilities. Unlike the Seven Factor Test, under which a balancing of the seven factors guides the outcome, the *Mansfield* test requires that all five factors be met before a facility can be considered non-integrated and its costs directly assigned.

The indicators for distinguishing integrated and non-integrated transmission facilities are:

(1) whether the facilities are radial, or whether they loop back into the transmission system;
(2) whether energy flows only in one direction, from the transmission system to the customer over the facilities, or in both directions;
(3) whether the transmission provider is able to provide transmission service to itself or other transmission customers over the facilities;
(4) whether the facilities provide benefits to the transmission grid in terms of capability or reliability, and whether the facilities can be relied on for coordinated operation of the grid; and
(5) whether an outage on the facilities would affect the transmission system.

Appendix C – Tables Supporting Industry Scan

Table 1: List of Utilities Surveyed; Designation of Utilities Included in Industry Scan

Operating Utility	Holding Company	ISO/RTO (included utilities only)	Line Miles	Included (noted by mileage rank)
AEP Appalachian Trans	AEP		0	
AEP Indiana Michigan Trans	AEP		17	
AEP Kentucky Trans	AEP		0	
AEP Ohio Trans	AEP		145	
AEP Oklahoma Trans	AEP		91	
AEP Southwestern Trans	AEP		0	
AEP Texas Central	AEP		4,250	31
AEP Texas North	AEP		4,147	with #31
AEP West Virginia Trans	AEP		0	
Alabama	Southern		10,544	7
Alaska			61	
Alcoa			147	
Allegheny	FirstEnergy		87	
Allete (Minnesota Power)	Allete	MISO	2,623	49
Ameren Illinois	Ameren		0	
Ameren Transmission	Ameren		29	
American Transmission Co	Integrys	MISO	10,921	6
American Transmission Systems	FirstEnergy	PJM	6,740	13
Appalachian	AEP	PJM	5,595	21
Arizona	Pinnacle		5,913	18
Atlantic City	Pepco	PJM	1,402	77
Attala	Cleco		0	
Avista			2,198	56
Baltimore	Exelon	PJM	923	90
Bangor	Emera	ISO-NE	868	91
Black Hills	Black Hills		626	92
Black Hills Colorado	Black Hills		231	with #92
Buckeye			0	
CAISO			0	
Carolina	Duke		6,198	17
CenterPoint			3,739	37
Central Hudson		NYISO	629	100
Central Maine	Iberdrola	ISO-NE	2,654	47
Central Vermont	Gaz Metro	ISO-NE	693	97
Cheyenne	Black Hills		26	
Chugach			536	101
Cleco	Cleco		1,322	81

Cleveland	FirstEnergy	PJM	2,114	59
Colorado	Xcel		5,701	19
Commonwealth Edison	Exelon	PJM	4,879	27
Commonwealth Indiana			6	
Connecticut	Northeast	ISO-NE	1,761	67
Consolidated Edison	ConEd	NYISO	505	102
Consolidated Water			61	
Consumers	CMS		0	
Dayton	AES	PJM	2,417	53
Delmarva	Pepco	PJM	1,835	64
Deseret			274	
DTE (Detroit)			0	
Duke Carolinas	Duke		8,351	9
Duke Indiana	Duke	MISO	5,280	23
Duke Kentucky	Duke		105	
Duke Ohio	Duke	PJM	1,937	62
Duquesne		PJM	677	98
El Paso			1,784	66
Electric Energy			55	
Empire		SPP	1,354	79
Entergy Arkansas	Entergy	MISO	4,825	28
Entergy Gulf	Entergy	MISO	2,361	55
Entergy Louisiana	Entergy	MISO	2,777	45
Entergy Mississippi	Entergy	MISO	2,869	43
Entergy New Orleans	Entergy		142	
Entergy Texas	Entergy	MISO	2,466	52
Fitchburg	Unitil		38	
Florida Light	NextEra		6,725	14
Florida Power	Duke		5,115	24
Georgia	Southern		12,809	4
Golden Spread			299	
Golden State			0	
Granite State	National Grid		0	
Green Mountain	Gaz Metro	ISO-NE	1,009	88
Gulf	Southern		1,616	72
Idaho			4,790	29
Indiana-Kentucky			45	
Indiana-Michigan	AEP	PJM	4,046	35
Indianapolis	AES	MISO	839	93
International	ITC	MISO	2,818	44
Interstate	Alliant		0	
ISO New England			0	
ITC Midwest	ITC	MISO	6,526	15
Jersey Central	FirstEnergy	PJM	2,159	58

Kansas City Missouri		SPP	1,650	70
Kansas City Power	Great Plains	SPP	1,807	65
Kansas Gas	Westar	SPP	2,514	51
Kentucky Power	AEP	PJM	1,282	84
Kentucky Utilities	PPL		4,079	34
Kingsport			72	
Lockhart			90	
Louisville	PPL		0	
Madison	MGE		0	
Maine Electric			185	
Maine Public	Emera		381	
MassElec	National Grid		144	
Metropolitan	FirstEnergy	PJM	1,422	76
Michigan	ITC	MISO	5,600	20
MidAmerican	MidAmerican	MISO	3,875	36
Midwest Electric			0	
Midwest Energy		SPP	1,670	69
MISO		MISO	0	
Mississippi	Southern		2,178	57
Monongahela	FirstEnergy	PJM	1,600	73
Montana-Dakota	MDU	MISO	3,105	42
Mt Carmel			19	
Narragansett	National Grid		320	
National Grid	National Grid		0	
Nevada	NV Energy		1,725	68
New England H-T			121	
New England Power	National Grid		0	
New England Trans			6	
New Hampshire	Northeast	ISO-NE	1,013	87
New Mexico	PNM		3,189	41
New York	Iberdrola	NYISO	4,426	30
Niagara Mohawk	National Grid	NYISO	10,380	8
North Central			0	
Northern Indiana	NiSource		0	
Northern States Minnesota	Xcel	MISO	4,956	26
Northern States Wisconsin	Xcel	MISO	2,375	54
NorthWestern	Northwestern	MISO in SD	8,135	10
Northwestern Wisconsin			147	
NSTAR	NSTAR	ISO-NE	951	89
NYISO		NYISO	0	
Ohio Edison	FirstEnergy	PJM	707	96
Ohio Power	AEP	PJM	7,772	11
Ohio Valley			427	
Oklahoma Gas	OGE	SPP	5,046	25

Oklahoma Public	AEP	SPP	3,537	39
Old Dominion			95	
Oncor	Energy Future	ERCOT	15,473	3
Orange	ConEd		302	
Otter Tail		MISO	5,390	22
Pacific Gas	PG&E	CAISO	18,618	1
PacifiCorp	MidAmerican		16,784	2
PECO	Exelon	PJM	1,381	78
Penn Elec	FirstEnergy	PJM	2,701	46
Penn Power	FirstEnergy	PJM	48	
Pike County			48	
Pioneer			0	
PJM			0	
Portland			1,129	85
Potomac Edison	FirstEnergy	PJM	1,284	83
Potomac Electric	Pepco	PJM	784	94
PPL	PPL	PJM	4,123	32
PSEG		PJM	1,461	75
Puget Sound			2,618	50
Rochester	Iberdrola	NYISO	1,287	82
Rockland	ConEd		91	
Safe Harbor			1	
San Diego	Sempra	CAISO	1,935	63
Sharyland			15	
Sierra Pacific	NV Energy		2,050	61
South Carolina	SCANA		3,463	40
Southern California		CAISO	12,302	5
Southern Indiana	Vectren	MISO	1,017	86
Southwestern Electric	AEP	SPP	4,086	33
Southwestern Public	Xcel		6,904	12
Southwest Power Pool			0	
Superior	Allete		89	
System			0	
Tampa	TECO		1,333	80
Toledo	FirstEnergy		223	
Tuscon	Unisource		2,074	60
UGI			0	
Union	Ameren	MISO	2,627	48
United Illuminating	UIL		105	
Unitil	Unitil		0	
UNS	Unisource		330	
Upper Peninsula	Integrys		0	
Vermont Electric			0	
Vermont Transco		ISO-NE	713	95

Vermont Transmission			52	
Virginia	Dominion	PJM	6,406	16
Wabash Valley			203	
West Penn	FirstEnergy	PJM	1,620	71
Westar	Westar	SPP	3,659	38
Western Mass	Northeast	ISO-NE	636	99
Wheeling			216	
Wisconsin Electric	We Energies		0	
Wisconsin Power	Alliant		0	
Wisconsin Public	Integrys		0	
Wisconsin River			0	
Wolverine		MISO	1,553	74
Select Holding Companies	Southern		27,147	
	FirstEnergy		9,870	
	Entergy		15,440	
	Duke		26,986	
	AEP		34,966	
	Xcel		19,937	
Tennessee Valley Auth			16,080	
WAPA			17,060	
SWPA			1,380	
BPA			15,173	

Table 2: Network Transmission Rate Designs—Voltage Differentiation

Operating Utility	Network Transmission Rate Design
66 utilities	No voltage differentiated Network rates
Southern Company utilities:	
Alabama	Southern-wide Bulk System (69kV+) plus Sub-transmission (44/46kV)
Georgia	Southern-wide Bulk System (69kV+) plus Sub-transmission (44/46kV)
Gulf	Southern-wide Bulk System (69kV+) plus Sub-transmission (44/46kV)
Mississippi	Southern-wide Bulk System (69kV+) plus Sub-transmission (44/46kV)
FirstEnergy utilities:	
American Transmission Systems	Bulk System (138kV+) plus Sub-transmission (69kV-)
Atlantic City	Bulk System (69kV+) plus case-by-case below
Cleveland	Bulk System (138kV+) plus Sub-transmission (69kV-)
Jersey Central	Bulk System (34kV+) plus case-by-case below
Monongahela	Bulk System (138kV+) plus Sub-transmission (69kV-)
Penn Elec	Bulk System (46kV+) plus case-by-case below
Potomac Edison	Bulk System (138kV+) plus Sub-transmission (69kV-)
Potomac Electric	Bulk System (115kV+) plus case-by-case below
West Penn	Bulk System (138kV+) plus Sub-transmission (69kV-)
ISO New England utilities:	
Bangor	ISO BHE network rate for 69kV+ plus a BHE retail service rate for lower voltage
Central Maine	ISO CMP network rate for 69kV+ plus a CMP retail service rate for lower voltage
Green Mountain	ISO GMP network rate for 69kV+ plus a GMP retail service rate for lower voltage
NSTAR	ISO NSTAR network rate for 69kV+
Western Mass	ISO NSTAR network rate for 69kV+
Connecticut	ISO NU network rate for 69kV+ plus a NU retail service rate for lower voltage
New Hampshire	ISO NU network rate for 69kV+ plus a NU retail service rate for lower voltage
Vermont Transco	ISO VT network rate for 69kV+
Southwest Power Pool RTO utilities:	
Empire	SPP Bulk System (60kV+) plus utility-specific basis for lower voltage and one-customer radials
Kansas City Missouri	SPP Bulk System (60kV+) plus utility-specific basis for lower voltage and one-customer radials
Kansas City Power	SPP Bulk System (60kV+) plus utility-specific basis for lower voltage and one-customer radials
Kansas Gas	SPP Bulk System (60kV+) plus utility-specific basis for lower voltage and one-customer radials

Midwest Energy	SPP Bulk System (60kV+) plus utility-specific basis for lower voltage and one-customer radials
Oklahoma Public	SPP Bulk System (60kV+) plus utility-specific basis for lower voltage and one-customer radials
Southwestern Electric	SPP Bulk System (60kV+) plus utility-specific basis for lower voltage and one-customer radials
Westar	SPP Bulk System (60kV+) plus utility-specific basis for lower voltage and one-customer radials
California ISO utilities:	
Pacific Gas	Regional Access Charge (200kV+) plus Local Access Charge (<200kV)
San Diego	Regional Access Charge (200kV+)
Southern California	Regional Access Charge (200kV+) plus Local Access Charge (<200kV)
Virginia	Bulk System (69kV+) plus case-by-case below
Tucson	EHV (345kV+) plus Non-EHV (69-138kV), with separate loss factors
Chugach	Transmission rate applies to 115kV+ (Chugach settled its rate case by including its 34.5kV sub-transmission facilities in retail rates)

Table 3: Network Transmission Rate Designs—Facility Differentiation

Operating Utility	Facility Transmission Rate Design
Allete	separate rate for HVDC facilities
Avista	separate rate for Colstrip facilities
Black Hills	separate rate for DC intertie facilities
El Paso	separate rate for Palo Verde-Westwing facilities
Oncor	separate rate for intertie facilities
Puget Sound	separate rate for Colstrip and Southern Intertie facilities

Table 4: Count of 13kV Transmission (TX) and Distribution (DX) Stations

Operating Utility	13kV TX Stations	13kV DX Stations
AEP Texas	129	134
Alabama	230	662
Allete	4	15
American Transmission Co	71	290
Atlantic City	21	36
CenterPoint	21	152
Central Maine	33	137
Chugach	23	33
Cleco	25	179
Colorado	67	222
Connecticut	59	21
Duke Carolinas	60	146
Duke Indiana	96	401
Duke Ohio	11	122
Empire	16	73
Florida Light	70	334
Georgia	126	924
Idaho	60	118
Indiana-Michigan	81	140
ITC Midwest	18	205
Jersey Central	15	197
Kansas City Missouri	28	93
Kansas City Power	14	74
Kansas Gas	29	200
Kentucky Power	20	40
Kentucky Utilities	83	209
MDU	20	39
Metropolitan	15	123
Michigan	17	278
MidAmerican	175	183
Mississippi	16	39
Monongahela	15	94
New York	82	111
Niagara Mohawk	238	132
Northern States Minnesota	82	335
Northern States Wisconsin	37	111
NorthWestern	12	91
Ohio Power	188	263
Oklahoma Gas	52	201
Oklahoma Public	78	112
Oncor	47	1050
Potomac Edison	11	99

PPL	42	320
PSEG	32	128
Sierra Pacific	38	72
South Carolina	22	52
Southern California	89	501
Southwestern Electric	67	171
Southwestern Public	114	187
Tucson	17	29
Vermont Transco	25	128
Virginia	64	262
West Penn	20	155
Westar	27	199
Western Mass	18	43

Appendix D – Snohomish Comments on Background Section of White Paper

(See Page 8)

The other functional test that customers referenced in their argument after the evidentiary phase of the BP-14 proceeding closed is the *Mansfield* Test (see appendix for detail). This test was developed in a Commission case, *Mansfield v. New England ISO*. The *Mansfield* test presumes integration and, therefore, facility costs should be rolled into network rates unless all five factors of the test are met which results in direct assignment of those costs to the customer necessitating those costs. BPA's current methodology for deciding between rolling costs into its Integrated Network or directly assigning them uses a comparable test but is not exactly the same as the *Mansfield* test, but relies on some of the same principles (the *Mansfield* and subsequent Commission decisions are considered in directly assigning costs). This issue was not explored in testimony, so the arguments made in BP-14 concerning potential application of the *Mansfield* test to BPA facilities were not based on any evidence in the record.

In BP-14, some customers cited the North American Electric Reliability Corporation's (NERC) Bulk Electric System (BES) definition of transmission and local distribution and argued that BPA should make its definition of the Integrated Network segment consistent with the BES definition. NERC currently defines the BES as any facilities operated at or above 100kV with exclusions for facilities used in local distribution, radial systems, local networks, generating units on the customer's side of a retail meter, and reactive power devices owned and operated by a retail customer for their own use. (FERC's approval of ~~T~~this definition ~~continues to undergo Commission and NERC review.~~ was appealed and is pending before the Second Circuit Court of Appeals) NERC's purpose for defining the BES is to determine which facilities are critical to the reliability of the grid. NERC developed extensive reliability standards and reporting requirements for BES facilities, and they monitor compliance. Customers arguing for the use of the BES definition also argued that the BPA application of the threshold should be raised to 116kV. No Commission cases have been found to indicate the use of the 100kV BES definition as a method for setting rates. Instead, excluding a high number of facilities using this method seems at odds with the Commission's demonstrated "roll in" preference. ~~Furthermore, the BES definition has no mention of state versus Federal jurisdiction, nor does it mention wholesale activity; the BES definition was developed to determine operational jurisdiction, not ratemaking or contractual jurisdiction.~~

There were four main reasons staff gave for not performing a detailed functional analysis of BPA's transmission facilities for BP-14 rates. First, there were unanswered questions regarding cost recovery (*e.g.*, direct assignment, a new segment and rate, etc.) had BPA adopted a functional test that were not addressed in parties' testimony and staff did not have sufficient time within the timeframes of

Comment [FJ1]: We are unaware of any ongoing NERC or FERC processes or proceedings further reviewing the BES definition that will become effective on July 1st. The definition was appealed and is pending court review in Case No. 13-2316 at the Second Circuit Court of Appeals. The New York Public Service Commission is arguing that the definition sweeps in local distribution facilities even though the definition and Sections 201 and 215 of the Federal Power Act exclude them.

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Comment [FJ2]: The point that the BES definition should not be used seems already made without this sentence.

The definition does distinguish between facilities that are and are not FERC-jurisdictional. The definition specifically states that "This does not include facilities used in the local distribution of electric energy." Jurisdiction over local distribution facilities is reserved for the states under Sections 201(b) and 215 of the Federal Power Act. FERC stated in Order No. 773 (P 71), that it will use the 7-factor test to determine whether a facility is local distribution within the context of the BES definition.

Also, neither FERC nor the Federal Power Act distinguish between operational and ratemaking jurisdiction. FERC will apply the 7-factor test uniformly to "local distribution" per Order No. 773.

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Appendix E – Supporting Information for NRU Proposal

Table 1: Delivery Segment Facilities from BP-14 Segmentation Study

			BP-14 Transmission Segmentation Study			Transformer Age	
	Substation	Utility	Initial Investment	O&M	% Delivery	Since Instillation	Since Manufacture
1	Acton	City of Cascade Locks	$ 163,592	$ 27,271	100%	29	66
2	Albany	US DOE Albany Research Center / Pacificorp & CPI	$ 1,587,757	$ 45,746	12%	22	25
3	Alderwood	Blachly-Lane	$ 668,497	$ 20,094	100%	33	36
4	Bonners Ferry	Northern Lights / Bonners Ferry	$ 837,266	$ 39,854	36%	54	66
5	Burbank	Columbia REA	$ 619,504	$ 45,672	100%	50	66
6	Burnt Woods	Consumers Power Inc	$ 319,577	$ 54,410	100%	48	65
7	Cascade Locks	City of Cascade Locks	$ 386,614	$ 57,648	100%	57	66
8	Davis Creek	Surprise Valley	$ 545,221	$ 25,430	100%	35	69
9	Dixie	Idaho Power Company	$ 519,936	$ 41,615	100%	63	65
10	Drain	Douglas Electric Coop / City of Drain	$ 277,801	$ 12,484	9%	38	41
11	Eagle Lake	Big Bend Electric Coop, Inc.	$ 380,534	$ 39,746	100%	57	58
12	East Grangeville	Idaho Co Light & Power	$ 683,793	$ 67,349	100%	31	66
13	Gardiner	Central Lincoln / Douglas Elec	$ 744,369	$ 89,051	100%	45	54
14	Glade	Big Bend Electric Coop, Inc.	$ 497,771	$ 32,210	100%	33	36
15	Harrisburg	Consumers Power Inc	$ 186,326	$ 55,066	100%	45	69
16	Hood River	Hood River Elec Coop	$ 627,932	$ 56,122	51%	24	54
17	Ione	Columbia Basin Electric	$ 285,241	$ 37,277	36%	45	64
18	Laclede	Northern Lights	$ 31,715	$ 20,768	100%	40	70
19	Langlois	City of Bandon/Coos Curry	$ 1,101,133	$ 32,499	100%	59	70
20	Lynch Creek	Eatonville / OHOP Mutual	$ 1,271,810	$ 62,626	100%	31	37
21	Mapleton	Central Lincoln (12.5kV) / Blachley (34.5kV)	$ 183,012	$ 26,037	32%	46	48
22	Minidoka	City of Minidoka	$ 385,789	$ 19,240	100%	53	37
23	Mountain Avenue	City of Ashland	$ 2,098,603	$ 45,487	100%	22	39
24	Moyie	Northern Lights / Bonners Ferry	$ 65,707	$ 24,082	100%	44	66
25	Necanicum	West Oregon Electric Cooperative	$ 127,264	$ 15,403	100%	33	76
26	North Bench	Northern Lights / Bonners Ferry	$ 527,396	$ 12,577	100%	28	36
27	North Butte	Consumers Power Inc	$ 168,857	$ 13,863	100%	35	68
28	Parkdale	Hood River Elec Coop	$ 604,963	$ 24,831	49%	42	52
29	Port Orford	Coos-Curry Elec Coop, Inc.	$ 407,963	$ 44,779	91%	54	68
30	Potlatch	Mason PUD #3 & Mason PUD #1	$ 188,784	$ 10,434	17%	18	65
31	Reedsport	Douglas Elec Coop (12.5kV) / Central Lincoln (115kV)	$ 518,873	$ 21,854	20%	44	46
32	Ringold	Big Bend / Franklin PUD	$ 522,279	$ 48,296	100%	59	61
33	Sandpoint	Northern Lights	$ 260,551	$ 34,086	23%	66	66
34	Scooteney	Big Bend Electric Coop, Inc.	$ 280,744	$ 18,597	23%	63	65
35	Selle	Northern Lights	$ 565,619	$ 31,095	100%	36	37
36	Stateline	Columbia REA	$ 141,727	$ 97,312	100%	42	43
37	Steilacoom	Town of Steilacoom	$ 1,101,095	$ 26,406	100%	35	36
38	Surprise Lake	City of Milton	$ 760,077	$ 58,734	100%	36	45
39	Swan Valley	Lower Valley	$ 447,947	$ 11,640	8%	32	66
40	Troy	Northern Lights / City of Troy	$ 815,848	$ 62,677	88%	28	37
41	Tumble Creek	Consumers Power Inc	$ 959,049	$ 26,488	100%	41	44
42	Two Mile	City of Bandon	$ 1,517,678	$ 69,347	100%	22	22
43	Walton	Blachly-Lane	$ 321,529	$ 39,541	94%	67	67
44	Winthrop	Okanogan Electric Coop	$ 361,348	$ 12,253	24%	42	45
45	Yaak	Northern Lights	$ 375,561	$ 30,660	100%	53	76
46	Bandon Substation		$ 1,143,260	$ 54,244	25%	Not avaiable	Not avaiable
47	Monmouth Substation		$ 1,244,686	$ 77,057	100%	Not avaiable	Not avaiable
48	Sun Harbor Substation		$ 1,420,980	$ 33,945	100%	Not avaiable	Not avaiable
		Total:	$ 29,253,578	$ 1,853,903			
		Average Age of Transformer				42	55
		# of Fully Depreciated Transformers: 37 Years*				26	39
		# of Fully Depreciated Transformers: 43 Years*				20	39

*BPA's Depreciation Study in 1984, 1989, and 2004 identified a 37 year life for substation equipment; in the 2011 Study, this increased to 43 years

Table 2: Delivery Charge Determination – Demonstration of NRU proposal

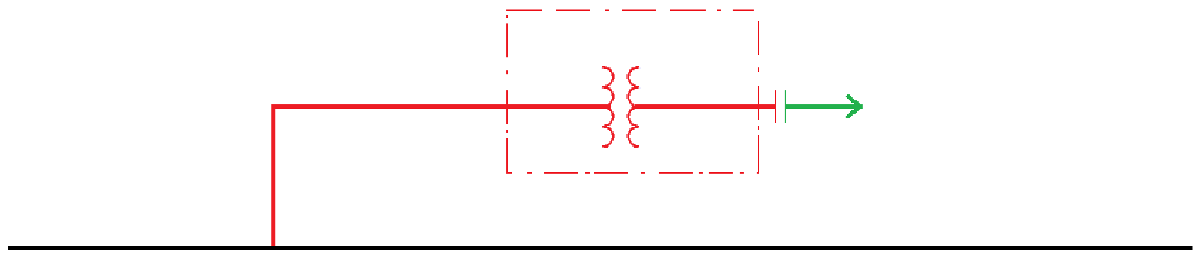
Current Cost Recovery Basis			**Proposed Cost Recovery**		
(BPA-08A P 11-13)	**Current Rev Req.**		Factor	Included	Included
O&M Direct	FY 2014	FY 2015	Used	FY 2014	FY 2015
Direct Lines and Substations	2,057	2,105	100%	2,057	2,105
O&M Overheads					
Marketing	158	161	0%	0	0
Business Support	362	368	0%	0	0
System Engineering	364	364	0%	0	0
Corporate	685	705	0%	0	0
Subtotal O&M	**3,626**	**3,703**	**56.73%**	**2,057**	**2,105**
Other					
Acq and Ancillary Services	319	313	100%	319	313
Direct Depreciation	668	675	20%	134	135
General Plant Depreciation	372	395	100%	372	395
Subtotal Depreciation	**1,040**	**1,070**	**48.62%**	**506**	**530**
Net Interest	794	883	48.62%	386	429
Planned Net Revenues	535	556	48.62%	260	270
Subtotal Other	**2,688**	**2,822**	**54.71%**	**1,471**	**1,543**
Total Charge Cost Basis	**6,314**	**6,525**	**55.87%**	**3,528**	**3,648**

Appendix F – Clarification on Radial Determinations for Snohomish Proposal

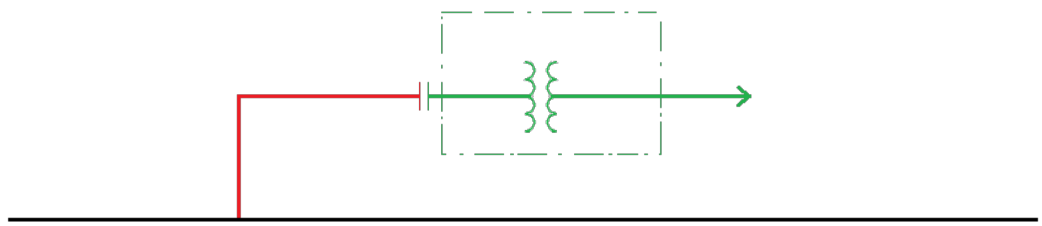
Below are some examples of what is and is not classified as "radial" in the analysis accompanying the Snohomish proposal. These determinations were developed working with Snohomish on the intent of their proposal. These examples were shared with customers at the April 16, 2014 workshop.

Black = BPA Network Red = BPA Radial Green = Non-BPA

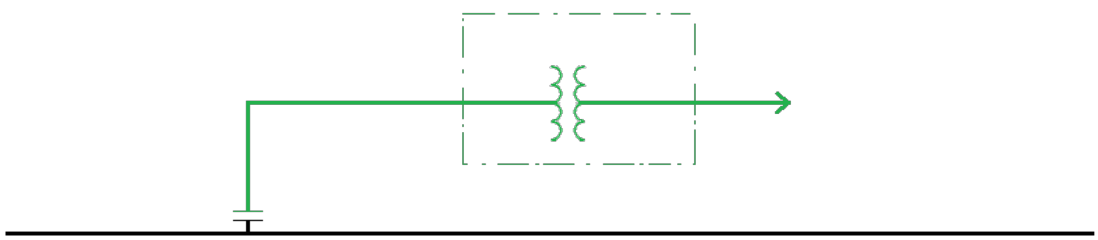
Example 1: Radial line – BPA owns station = RADIAL



Example 2: Radial line – customer owns station = RADIAL

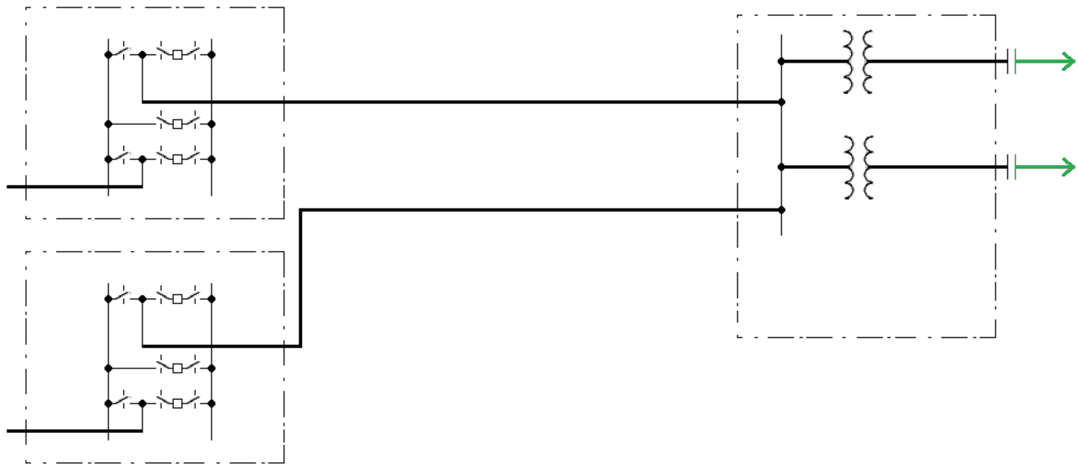


Example 3: Short BPA line – customer tap of network line = NETWORK

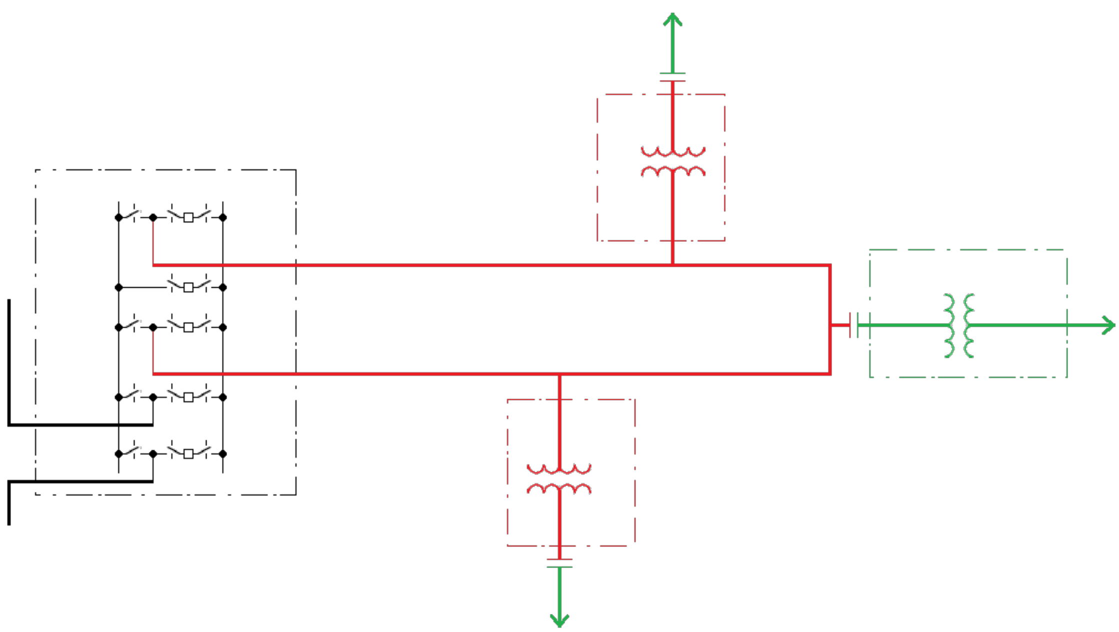


Example 4: Bus to bus service over parallel lines = RADIAL

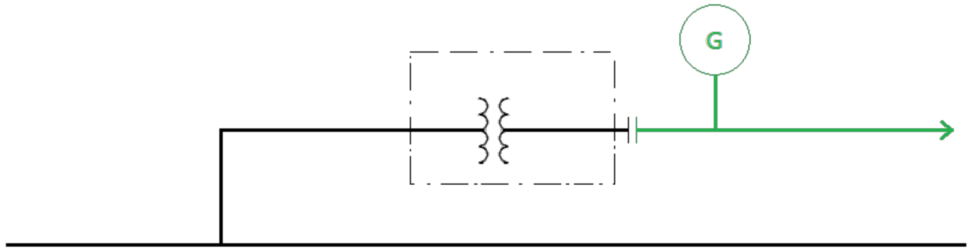
Example 5: Separate bus service over parallel lines = NETWORK



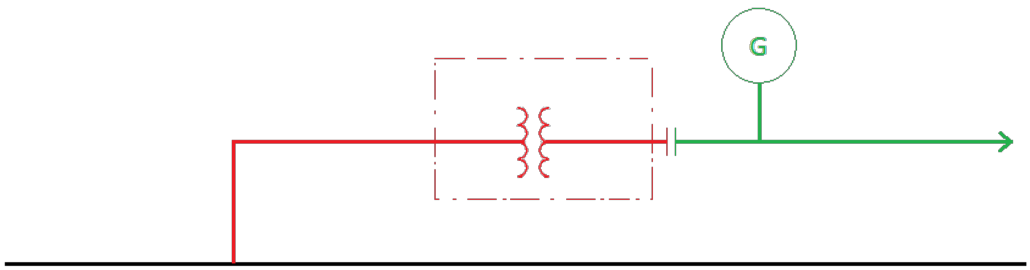
Example 6: Same bus service over looped lines = NETWORK



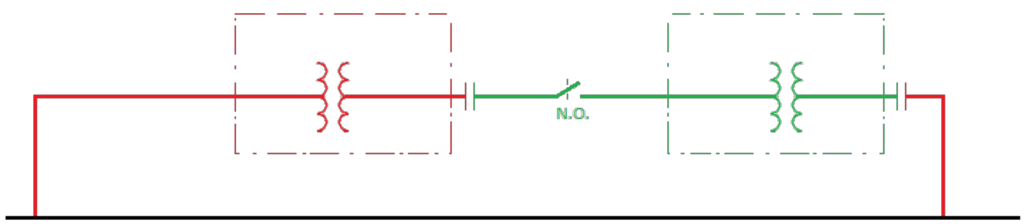
Example 7: Non-federal generation – wheeled + scheduled = NETWORK



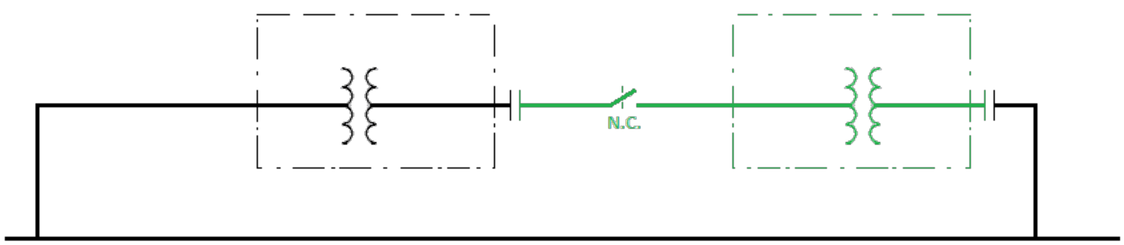
Example 8: Non-federal generation – consumed locally = RADIAL



Example 9: Looped service – normally open circuit = RADIAL



Example 10: Looped service normally closed circuit = NETWORK



Appendix G – Customer Impacts of Segmentation Alternatives

See Customer Impacts of Segmentation Alternatives posted on the BP-16 Meetings and Workshops page under the July 2, 2014 subheading.

Segmentation Alternative Analysis
Customer Impacts

Comparison of Customers' Transmission Payments

BP-14 Rates and Billing Determinants
Transmission Rates and GTA Costs in Power Rates

Comparison of BP-14 Rates with Each Alternative (BP-14)
and
Comparison of BP-14 Rates assuming Utility Delivery Rate Recovers Full Allocated Costs with Each Alternative (UDC-FR)

Alternative #1 Eliminate Delivery Segment	BP-14 % change	UDC-FR % change		BP-14 % change	UDC-FR % change
Albion, City of	1.1%	1.7%	Farmers Electric Co	1.1%	1.7%
Alcoa	1.2%	1.6%	Ferry County PUD No 1	1.1%	1.7%
Alder Mutual Light Co	1.1%	1.7%	Finley Bioenergy	0.5%	1.1%
Arlington Wind	0.5%	1.1%	Flathead Electric Coop	1.2%	1.7%
Ashland, City of	-21.0%	-27.1%	Forest Grove, City of	1.0%	1.6%
Asotin County PUD No 1	-53.0%	-52.9%	Franklin County PUD No 1	0.0%	-0.4%
Avista	0.5%	1.1%	Gaelectric	0.6%	1.3%
Bandon, City of	-34.6%	-49.3%	Glacier Electric Coop	1.2%	1.7%
Benton County PUD No 1	1.0%	1.5%	Grant County PUD No 2	-1.3%	-2.4%
Benton Rural Electric Assn	1.2%	1.7%	Grays Harbor County PUD No 1	1.0%	1.5%
Big Bend Electric Coop	-15.5%	-22.4%	Harney Electric Coop	1.1%	1.7%
Blachly-Lane Electric Coop	-12.3%	-20.7%	Hermiston Energy Services	-26.4%	-26.1%
Blaine, City of	-24.7%	-24.3%	Hermiston Power	0.6%	1.3%
Bonners Ferry, City of	-38.6%	-53.6%	Heyburn, City of	1.0%	1.6%
BPA Power	0.4%	0.8%	Hood River Electric Coop	-16.2%	-26.4%
Burley, City of	1.1%	1.7%	Iberdrola	0.3%	0.5%
Canby Utility Board	-8.2%	-7.7%	Idaho Co Light & Power Coop Assn	-25.4%	-33.8%
Cascade Locks, City of	-35.0%	-49.8%	Idaho Falls Power	1.1%	1.7%
Central Electric Coop	1.3%	1.9%	Idaho Power	0.4%	0.9%
Central Lincoln PUD	0.6%	0.6%	Inland Power & Light	-4.2%	-3.7%
Centralia City Light	1.1%	1.6%	Jefferson County PUD	1.3%	1.8%
CEP Funding	0.6%	1.3%	Kittitas County PUD No 1	-2.0%	-1.5%
Chelan County PUD No 1	0.5%	1.1%	Klickitat County PUD No 1	1.1%	1.5%
Cheney, City of	1.1%	1.7%	Kootenai Electric Coop	-6.0%	-5.5%
Chewelah, City of	-25.9%	-25.5%	L & M Angus Ranch	0.5%	1.1%
Clallam County PUD No 1	1.2%	1.7%	LADWP	0.5%	1.1%
Clark Public Utilities	0.9%	1.4%	Lakeview Light & Power	1.1%	1.7%
Clatskanie PUD	1.1%	1.6%	Lane Electric Coop	1.2%	1.8%
Clearwater Power Co	-20.1%	-19.6%	Lewis County PUD No 1	1.1%	1.7%
Columbia Basin Electric Coop	1.1%	1.7%	Lincoln Electric Coop	1.3%	1.9%
Columbia Power Coop Assn	1.1%	1.7%	Lost River Electric Coop	1.2%	1.7%
Columbia River PUD	0.9%	1.5%	Lower Valley Energy	0.1%	-0.3%
Columbia Rural Electric Assn	-15.1%	-24.8%	Mason County PUD No 1	1.1%	1.7%
Consolidated Irrigation District No 19	1.3%	1.8%	Mason County PUD No 3	-0.5%	-1.4%
Consumers Power Inc	-9.5%	-16.7%	McCleary, City of	1.1%	1.7%
Coos Curry Electric Coop Inc	-7.3%	-13.1%	McMinnville, City of	1.1%	1.7%
Coulee Dam, Town of	-35.1%	-49.9%	Middle Fork Irrigation	0.5%	1.1%
Cowlitz County PUD No 1	1.2%	1.8%	Midstate Electric Coop	1.2%	1.7%
Delco, City of	1.1%	1.7%	Milton, City of	-34.7%	-49.5%
Douglas County PUD No 1	0.5%	1.2%	Milton-Freewater, City of	1.0%	1.6%
Douglas Electric Coop	-7.9%	-13.9%	Minidoka, City of	-34.3%	-49.1%
Drain, City of	-34.5%	-49.3%	Mission Vallley Power	1.1%	1.6%
East End Mutual Electric Co	1.1%	1.6%	Missoula Electric Coop	-6.7%	-6.2%
Eatonville, Town of	-35.2%	-50.0%	Modern Electric Water Co	1.1%	1.7%
EDP Renewables	0.6%	1.2%	Monmouth, City of	-0.9%	-1.9%
Ellensburg, City of	1.1%	1.7%	Nespelem Valley Electric Coop	-8.5%	-13.0%
Elmhurst Mutual Power & Light Co	1.1%	1.7%	Northern Lights	-20.5%	-30.6%
Emerald PUD	1.0%	1.6%	Northern Wasco County PUD	1.2%	1.7%
Energy Northwest Inc	1.8%	2.2%	Ohop Mutual Light Co	-10.9%	-18.7%
Eugene Water and Electric Board	1.1%	1.7%	Okanogan County Electric Coop	-37.4%	-51.1%
Eurus	0.5%	1.1%	Okanogan County PUD No 1	0.9%	1.4%
Fall River Rural Electric Coop	-0.1%	0.5%	Orcas Power & Light Coop	1.1%	1.6%

Alternative #1 **Eliminate Delivery Segment**	**BP-14** **% change**	**UDC-FR** **% change**
Oregon Trail Electric Coop	1.1%	1.7%
Pacific County PUD No 2	1.1%	1.6%
PacifiCorp	0.3%	0.8%
Parkland Light & Water Co	1.1%	1.7%
PaTu Wind	0.5%	1.1%
Pend Oreille County PUD No 1	1.2%	1.6%
Peninsula Light Co	1.1%	1.7%
Plummer, City of	-29.6%	-29.3%
Port Angeles City Light	1.4%	1.9%
Port of Seattle (Sea Tac)	1.2%	1.8%
Port Townsend Paper Corp	1.2%	1.8%
Portland General Electric	0.5%	1.1%
Power Resources Coop	0.5%	1.1%
Powerex	0.2%	0.4%
PPL EnergyPlus	0.5%	1.1%
Puget Sound Energy	0.5%	1.1%
Raft River Energy	0.5%	1.1%
Raft River Rural Electric Coop	-5.1%	-5.4%
Ravalli County Electric Coop	-4.8%	-4.3%
Richland, City of	1.1%	1.7%
Riverside Electric Co	1.1%	1.7%
Rupert, City of	1.1%	1.7%
Salem Electric Coop	1.1%	1.7%
Salmon River Electric Coop	1.3%	1.8%
Seattle City Light	0.8%	1.3%
Shell Energy	0.3%	0.6%
Sherman County Wind	0.5%	1.1%
Skamania County PUD No 1	1.1%	1.7%
SMUD	0.5%	1.0%
Snohomish County PUD No 1	0.9%	1.4%
Soda Springs, City of	1.1%	1.7%
South Side Electric Lines	1.1%	1.7%
Southern California Edison	0.5%	1.1%
Springfield Utility Board	1.1%	1.7%
Steilacoom, Town of	-34.9%	-49.7%
Sumas, City of	-28.3%	-27.9%
Surprise Valley Electrification Corp	-3.1%	-4.1%
Tacoma Power	1.0%	1.5%
Tanner Electric Coop	-3.5%	-3.0%
Tillamook PUD	1.1%	1.7%
TransAlta	0.4%	0.8%
Troy, City of	-35.2%	-50.0%
Turlock Irrigation	0.5%	1.1%
Umatilla Electric Coop	1.2%	1.8%
Umpqua Indian Utility Coop	-25.8%	-25.5%
United Electric Coop	1.3%	1.8%
US DOE Natl Energy Technology Lab	-34.8%	-49.6%
US DOE Richland Operations Office	1.2%	1.7%
USAF Fairchild	1.2%	1.7%
USN Bangor	1.2%	1.7%
USN Bremerton	1.2%	1.8%
USN Everett	1.3%	1.8%

	BP-14 **% change**	**UDC-FR** **% change**
Vera Water & Power	1.1%	1.6%
Vigilante Electric Coop	-6.2%	-5.7%
Wahkiakum County PUD No 1	1.0%	1.6%
Wasco Electric Coop	1.2%	1.8%
Weiser, City of	-26.1%	-25.7%
Wells Rural Electric Co	1.2%	1.8%
West Oregon Electric Coop	-9.0%	-10.1%
Whatcom County PUD No 1	1.3%	1.8%
Wheat Field Wind	0.5%	1.1%
Yakama Power	-8.2%	-7.8%

Alternative #2 Capped Delivery Rate	BP-14 % change	UDC-FR % change
Albion, City of	0.0%	0.6%
Alcoa	0.0%	0.5%
Alder Mutual Light Co	0.0%	0.5%
Arlington Wind	0.0%	0.6%
Ashland, City of	0.0%	-7.8%
Asotin County PUD No 1	0.0%	0.2%
Avista	0.0%	0.6%
Bandon, City of	0.0%	-22.7%
Benton County PUD No 1	0.0%	0.5%
Benton Rural Electric Assn	0.0%	0.5%
Big Bend Electric Coop	0.0%	-8.3%
Blachly-Lane Electric Coop	0.0%	-9.6%
Blaine, City of	0.0%	0.4%
Bonners Ferry, City of	0.0%	-24.6%
BPA Power	0.0%	0.4%
Burley, City of	0.0%	0.5%
Canby Utility Board	0.0%	0.5%
Cascade Locks, City of	0.0%	-22.9%
Central Electric Coop	0.0%	0.6%
Central Lincoln PUD	0.0%	0.0%
Centralia City Light	0.0%	0.5%
CEP Funding	0.0%	0.7%
Chelan County PUD No 1	0.0%	0.6%
Cheney, City of	0.0%	0.6%
Chewelah, City of	0.0%	0.4%
Clallam County PUD No 1	0.0%	0.5%
Clark Public Utilities	0.0%	0.6%
Clatskanie PUD	0.0%	0.5%
Clearwater Power Co	0.0%	0.5%
Columbia Basin Electric Coop	0.0%	0.5%
Columbia Power Coop Assn	0.0%	0.6%
Columbia River PUD	0.0%	0.6%
Columbia Rural Electric Assn	0.0%	-11.5%
Consolidated Irrigation District No 19	0.0%	0.5%
Consumers Power Inc	0.0%	-7.9%
Coos Curry Electric Coop Inc	0.0%	-6.2%
Coulee Dam, Town of	0.0%	-22.9%
Cowlitz County PUD No 1	0.0%	0.5%
Delco, City of	0.0%	0.6%
Douglas County PUD No 1	0.0%	0.6%
Douglas Electric Coop	0.0%	-6.5%
Drain, City of	0.0%	-22.6%
East End Mutual Electric Co	0.0%	0.6%
Eatonville, Town of	0.0%	-23.0%
EDP Renewables	0.0%	0.6%
Ellensburg, City of	0.0%	0.6%
Elmhurst Mutual Power & Light Co	0.0%	0.6%
Emerald PUD	0.0%	0.6%
Energy Northwest Inc	0.0%	0.4%
Eugene Water and Electric Board	0.0%	0.5%
Eurus	0.0%	0.6%
Fall River Rural Electric Coop	0.0%	0.6%

	BP-14 % change	UDC-FR % change
Farmers Electric Co	0.0%	0.6%
Ferry County PUD No 1	0.0%	0.6%
Finley Bioenergy	0.0%	0.6%
Flathead Electric Coop	0.0%	0.5%
Forest Grove, City of	0.0%	0.6%
Franklin County PUD No 1	0.0%	-0.4%
Gaelectric	0.0%	0.7%
Glacier Electric Coop	0.0%	0.5%
Grant County PUD No 2	0.0%	-1.0%
Grays Harbor County PUD No 1	0.0%	0.5%
Harney Electric Coop	0.0%	0.5%
Hermiston Energy Services	0.0%	0.4%
Hermiston Power	0.0%	0.7%
Heyburn, City of	0.0%	0.6%
Hood River Electric Coop	0.0%	-12.2%
Iberdrola	0.0%	0.3%
Idaho Co Light & Power Coop Assn	0.0%	-11.4%
Idaho Falls Power	0.0%	0.6%
Idaho Power	0.0%	0.5%
Inland Power & Light	0.0%	0.5%
Jefferson County PUD	0.0%	0.5%
Kittitas County PUD No 1	0.0%	0.5%
Klickitat County PUD No 1	0.0%	0.5%
Kootenai Electric Coop	0.0%	0.5%
L & M Angus Ranch	0.0%	0.6%
LADWP	0.0%	0.6%
Lakeview Light & Power	0.0%	0.6%
Lane Electric Coop	0.0%	0.7%
Lewis County PUD No 1	0.0%	0.6%
Lincoln Electric Coop	0.0%	0.6%
Lost River Electric Coop	0.0%	0.5%
Lower Valley Energy	0.0%	-0.4%
Mason County PUD No 1	0.0%	0.6%
Mason County PUD No 3	0.0%	-0.8%
McCleary, City of	0.0%	0.5%
McMinnville, City of	0.0%	0.6%
Middle Fork Irrigation	0.0%	0.6%
Midstate Electric Coop	0.0%	0.5%
Milton, City of	0.0%	-22.7%
Milton-Freewater, City of	0.0%	0.6%
Minidoka, City of	0.0%	-22.6%
Mission Vallley Power	0.0%	0.6%
Missoula Electric Coop	0.0%	0.5%
Modern Electric Water Co	0.0%	0.5%
Monmouth, City of	0.0%	-1.1%
Nespelem Valley Electric Coop	0.0%	-4.9%
Northern Lights	0.0%	-12.7%
Northern Wasco County PUD	0.0%	0.5%
Ohop Mutual Light Co	0.0%	-8.7%
Okanogan County Electric Coop	0.0%	-21.9%
Okanogan County PUD No 1	0.0%	0.5%
Orcas Power & Light Coop	0.0%	0.6%

Alternative #2 Capped Delivery Rate	BP-14 % change	UDC-FR % change
Oregon Trail Electric Coop	0.0%	0.5%
Pacific County PUD No 2	0.0%	0.6%
PacifiCorp	0.0%	0.4%
Parkland Light & Water Co	0.0%	0.6%
PaTu Wind	0.0%	0.6%
Pend Oreille County PUD No 1	0.0%	0.5%
Peninsula Light Co	0.0%	0.6%
Plummer, City of	0.0%	0.4%
Port Angeles City Light	0.0%	0.5%
Port of Seattle (Sea Tac)	0.0%	0.5%
Port Townsend Paper Corp	0.0%	0.5%
Portland General Electric	0.0%	0.6%
Power Resources Coop	0.0%	0.6%
Powerex	0.0%	0.2%
PPL EnergyPlus	0.0%	0.6%
Puget Sound Energy	0.0%	0.6%
Raft River Energy	0.0%	0.6%
Raft River Rural Electric Coop	0.0%	-0.3%
Ravalli County Electric Coop	0.0%	0.5%
Richland, City of	0.0%	0.6%
Riverside Electric Co	0.0%	0.6%
Rupert, City of	0.0%	0.5%
Salem Electric Coop	0.0%	0.6%
Salmon River Electric Coop	0.0%	0.5%
Seattle City Light	0.0%	0.5%
Shell Energy	0.0%	0.3%
Sherman County Wind	0.0%	0.6%
Skamania County PUD No 1	0.0%	0.6%
SMUD	0.0%	0.5%
Snohomish County PUD No 1	0.0%	0.5%
Soda Springs, City of	0.0%	0.6%
South Side Electric Lines	0.0%	0.6%
Southern California Edison	0.0%	0.6%
Springfield Utility Board	0.0%	0.6%
Steilacoom, Town of	0.0%	-22.8%
Sumas, City of	0.0%	0.4%
Surprise Valley Electrification Corp	0.0%	-1.0%
Tacoma Power	0.0%	0.5%
Tanner Electric Coop	0.0%	0.5%
Tillamook PUD	0.0%	0.5%
TransAlta	0.0%	0.4%
Troy, City of	0.0%	-23.0%
Turlock Irrigation	0.0%	0.6%
Umatilla Electric Coop	0.0%	0.6%
Umpqua Indian Utility Coop	0.0%	0.3%
United Electric Coop	0.0%	0.5%
US DOE Natl Energy Technology Lab	0.0%	-22.8%
US DOE Richland Operations Office	0.0%	0.5%
USAF Fairchild	0.0%	0.5%
USN Bangor	0.0%	0.5%
USN Bremerton	0.0%	0.5%
USN Everett	0.0%	0.5%

	BP-14 % change	UDC-FR % change
Vera Water & Power	0.0%	0.6%
Vigilante Electric Coop	0.0%	0.5%
Wahkiakum County PUD No 1	0.0%	0.6%
Wasco Electric Coop	0.0%	0.5%
Weiser, City of	0.0%	0.4%
Wells Rural Electric Co	0.0%	0.5%
West Oregon Electric Coop	0.0%	-1.2%
Whatcom County PUD No 1	0.0%	0.5%
Wheat Field Wind	0.0%	0.6%
Yakama Power	0.0%	0.4%

Alternative #3 Radial Service Segment	BP-14 % change	UDC-FR % change
Albion, City of	-4.4%	-4.4%
Alcoa	71.2%	71.4%
Alder Mutual Light Co	59.4%	59.6%
Arlington Wind	-4.3%	-4.3%
Ashland, City of	16.8%	15.5%
Asotin County PUD No 1	-2.1%	-2.1%
Avista	-4.1%	-4.1%
Bandon, City of	38.3%	29.5%
Benton County PUD No 1	31.1%	31.2%
Benton Rural Electric Assn	8.0%	8.0%
Big Bend Electric Coop	17.0%	15.6%
Blachly-Lane Electric Coop	46.7%	42.1%
Blaine, City of	41.6%	41.7%
Bonners Ferry, City of	-2.6%	-2.0%
BPA Power	-3.2%	-3.2%
Burley, City of	59.0%	59.2%
Canby Utility Board	-4.0%	-4.0%
Cascade Locks, City of	-2.9%	-2.2%
Central Electric Coop	-5.0%	-5.0%
Central Lincoln PUD	-4.4%	-4.4%
Centralia City Light	59.2%	59.4%
CEP Funding	-5.0%	-5.0%
Chelan County PUD No 1	-4.3%	-4.3%
Cheney, City of	60.1%	60.3%
Chewelah, City of	-3.3%	-3.2%
Clallam County PUD No 1	4.6%	4.7%
Clark Public Utilities	-3.7%	-3.7%
Clatskanie PUD	-4.4%	-4.4%
Clearwater Power Co	17.1%	17.2%
Columbia Basin Electric Coop	32.6%	32.7%
Columbia Power Coop Assn	3.5%	3.6%
Columbia River PUD	-4.4%	-4.4%
Columbia Rural Electric Assn	0.1%	0.2%
Consolidated Irrigation District No 19	-4.5%	-4.4%
Consumers Power Inc	-3.4%	-3.0%
Coos Curry Electric Coop Inc	58.6%	54.9%
Coulee Dam, Town of	-2.8%	-2.2%
Cowlitz County PUD No 1	-4.5%	-4.4%
Delco, City of	-4.4%	-4.4%
Douglas County PUD No 1	-4.3%	-4.3%
Douglas Electric Coop	37.8%	35.3%
Drain, City of	38.2%	29.5%
East End Mutual Electric Co	-4.4%	-4.4%
Eatonville, Town of	39.0%	30.0%
EDP Renewables	-4.7%	-4.7%
Ellensburg, City of	18.7%	18.8%
Elmhurst Mutual Power & Light Co	52.1%	52.3%
Emerald PUD	14.4%	14.5%
Energy Northwest Inc	-4.6%	-4.6%
Eugene Water and Electric Board	-4.4%	-4.4%
Eurus	-4.3%	-4.3%
Fall River Rural Electric Coop	15.8%	15.8%

	BP-14 % change	UDC-FR % change
Farmers Electric Co	60.4%	60.6%
Ferry County PUD No 1	59.9%	60.1%
Finley Bioenergy	-4.3%	-4.3%
Flathead Electric Coop	-4.4%	-4.4%
Forest Grove, City of	14.8%	14.8%
Franklin County PUD No 1	11.7%	11.7%
Gaelectric	-5.0%	-5.0%
Glacier Electric Coop	-4.4%	-4.4%
Grant County PUD No 2	-4.1%	-4.1%
Grays Harbor County PUD No 1	-4.4%	-4.4%
Harney Electric Coop	-4.4%	-4.4%
Hermiston Energy Services	15.1%	15.2%
Hermiston Power	-5.0%	-5.0%
Heyburn, City of	61.9%	62.1%
Hood River Electric Coop	31.3%	27.5%
Iberdrola	-2.1%	-2.1%
Idaho Co Light & Power Coop Assn	24.7%	21.9%
Idaho Falls Power	-4.4%	-4.4%
Idaho Power	-0.4%	-0.4%
Inland Power & Light	8.9%	9.0%
Jefferson County PUD	-4.5%	-4.4%
Kittitas County PUD No 1	9.1%	9.2%
Klickitat County PUD No 1	10.8%	10.8%
Kootenai Electric Coop	1.4%	1.4%
L & M Angus Ranch	89.6%	89.9%
LADWP	-4.3%	-4.3%
Lakeview Light & Power	-4.4%	-4.4%
Lane Electric Coop	16.4%	16.5%
Lewis County PUD No 1	0.2%	0.3%
Lincoln Electric Coop	67.8%	68.1%
Lost River Electric Coop	-4.5%	-4.4%
Lower Valley Energy	-4.4%	-4.3%
Mason County PUD No 1	-4.4%	-4.4%
Mason County PUD No 3	-4.4%	-4.3%
McCleary, City of	59.0%	59.2%
McMinnville, City of	23.5%	23.6%
Middle Fork Irrigation	-4.3%	-4.3%
Midstate Electric Coop	-4.5%	-4.4%
Milton, City of	38.9%	30.0%
Milton-Freewater, City of	62.4%	62.7%
Minidoka, City of	38.1%	29.5%
Mission Vallley Power	-4.4%	-4.4%
Missoula Electric Coop	-0.8%	-0.8%
Modern Electric Water Co	-4.4%	-4.4%
Monmouth, City of	-4.4%	-4.3%
Nespelem Valley Electric Coop	23.6%	22.5%
Northern Lights	4.1%	3.6%
Northern Wasco County PUD	-4.4%	-4.4%
Ohop Mutual Light Co	1.5%	1.4%
Okanogan County Electric Coop	42.7%	33.3%
Okanogan County PUD No 1	-4.4%	-4.4%
Orcas Power & Light Coop	60.4%	60.7%

Alternative #3 **Radial Service Segment**	**BP-14** **% change**	**UDC-FR** **% change**
Oregon Trail Electric Coop	-4.4%	-4.4%
Pacific County PUD No 2	53.4%	53.6%
PacifiCorp	-3.2%	-3.2%
Parkland Light & Water Co	6.7%	6.8%
PaTu Wind	-4.3%	-4.3%
Pend Oreille County PUD No 1	-4.4%	-4.4%
Peninsula Light Co	17.9%	18.0%
Plummer, City of	-3.1%	-3.1%
Port Angeles City Light	-4.5%	-4.5%
Port of Seattle (Sea Tac)	-4.5%	-4.4%
Port Townsend Paper Corp	-4.5%	-4.4%
Portland General Electric	-4.3%	-4.3%
Power Resources Coop	-4.1%	-4.1%
Powerex	-1.7%	-1.7%
PPL EnergyPlus	-4.3%	-4.3%
Puget Sound Energy	-4.2%	-4.2%
Raft River Energy	-4.1%	-4.2%
Raft River Rural Electric Coop	5.5%	5.5%
Ravalli County Electric Coop	-4.2%	-4.2%
Richland, City of	-4.4%	-4.4%
Riverside Electric Co	20.2%	20.3%
Rupert, City of	-4.4%	-4.4%
Salem Electric Coop	43.1%	43.2%
Salmon River Electric Coop	54.6%	54.8%
Seattle City Light	-4.3%	-4.3%
Shell Energy	-2.2%	-2.2%
Sherman County Wind	-4.3%	-4.3%
Skamania County PUD No 1	47.1%	47.2%
SMUD	-3.9%	-3.9%
Snohomish County PUD No 1	-4.4%	-4.4%
Soda Springs, City of	-4.4%	-4.4%
South Side Electric Lines	-4.4%	-4.4%
Southern California Edison	-4.1%	-4.1%
Springfield Utility Board	11.3%	11.4%
Steilacoom, Town of	-2.9%	-2.2%
Sumas, City of	-3.2%	-3.1%
Surprise Valley Electrification Corp	36.6%	36.2%
Tacoma Power	-4.4%	-4.4%
Tanner Electric Coop	34.5%	34.6%
Tillamook PUD	-4.4%	-4.4%
TransAlta	-3.2%	-3.2%
Troy, City of	-2.8%	-2.2%
Turlock Irrigation	-4.3%	-4.3%
Umatilla Electric Coop	8.6%	8.7%
Umpqua Indian Utility Coop	-3.3%	-3.3%
United Electric Coop	18.7%	18.7%
US DOE Natl Energy Technology Lab	-2.9%	-2.2%
US DOE Richland Operations Office	-4.4%	-4.4%
USAF Fairchild	58.6%	58.8%
USN Bangor	-4.5%	-4.4%
USN Bremerton	-4.5%	-4.4%
USN Everett	-4.5%	-4.4%

	BP-14 **% change**	**UDC-FR** **% change**
Vera Water & Power	-4.4%	-4.4%
Vigilante Electric Coop	12.4%	12.5%
Wahkiakum County PUD No 1	-4.4%	-4.4%
Wasco Electric Coop	17.4%	17.5%
Weiser, City of	-3.2%	-3.2%
Wells Rural Electric Co	6.0%	6.0%
West Oregon Electric Coop	21.2%	20.9%
Whatcom County PUD No 1	-2.8%	-2.8%
Wheat Field Wind	-4.3%	-4.3%
Yakama Power	-4.1%	-4.1%

Alternative #4 Transformation Segment	BP-14 % change	UDC-FR % change		BP-14 % change	UDC-FR % change
Albion, City of	7.0%	7.1%	Farmers Electric Co	7.2%	7.2%
Alcoa	-4.6%	-4.7%	Ferry County PUD No 1	7.1%	7.1%
Alder Mutual Light Co	7.0%	7.0%	Finley Bioenergy	-4.3%	-4.3%
Arlington Wind	-4.3%	-4.3%	Flathead Electric Coop	-1.8%	-1.8%
Ashland, City of	5.6%	5.2%	Forest Grove, City of	7.4%	7.4%
Asotin County PUD No 1	2.3%	2.3%	Franklin County PUD No 1	9.1%	9.0%
Avista	-2.8%	-2.8%	Gaelectric	-5.1%	-5.1%
Bandon, City of	4.5%	3.5%	Glacier Electric Coop	6.8%	6.9%
Benton County PUD No 1	10.0%	10.0%	Grant County PUD No 2	11.1%	11.0%
Benton Rural Electric Assn	6.1%	6.2%	Grays Harbor County PUD No 1	10.0%	10.0%
Big Bend Electric Coop	5.7%	5.3%	Harney Electric Coop	6.9%	7.0%
Blachly-Lane Electric Coop	7.1%	6.5%	Hermiston Energy Services	5.2%	5.2%
Blaine, City of	4.7%	4.7%	Hermiston Power	-5.1%	-5.1%
Bonners Ferry, City of	4.6%	3.5%	Heyburn, City of	7.5%	7.5%
BPA Power	-3.2%	-3.2%	Hood River Electric Coop	5.9%	5.2%
Burley, City of	6.9%	6.9%	Iberdrola	-2.1%	-2.1%
Canby Utility Board	6.6%	6.6%	Idaho Co Light & Power Coop Assn	5.4%	4.8%
Cascade Locks, City of	4.6%	3.5%	Idaho Falls Power	-0.2%	-0.1%
Central Electric Coop	7.7%	7.8%	Idaho Power	-3.1%	-3.1%
Central Lincoln PUD	6.5%	6.5%	Inland Power & Light	6.5%	6.6%
Centralia City Light	7.0%	7.0%	Jefferson County PUD	6.3%	6.4%
CEP Funding	-5.1%	-5.1%	Kittitas County PUD No 1	6.8%	6.8%
Chelan County PUD No 1	-4.3%	-4.3%	Klickitat County PUD No 1	9.6%	9.6%
Cheney, City of	7.1%	7.2%	Kootenai Electric Coop	6.5%	6.6%
Chewelah, City of	5.1%	5.1%	L & M Angus Ranch	-4.3%	-4.3%
Clallam County PUD No 1	6.8%	6.9%	LADWP	-4.3%	-4.3%
Clark Public Utilities	6.8%	6.9%	Lakeview Light & Power	7.0%	7.1%
Clatskanie PUD	1.3%	1.3%	Lane Electric Coop	8.6%	8.7%
Clearwater Power Co	6.2%	6.3%	Lewis County PUD No 1	6.8%	6.9%
Columbia Basin Electric Coop	6.9%	7.0%	Lincoln Electric Coop	8.0%	8.1%
Columbia Power Coop Assn	7.1%	7.1%	Lost River Electric Coop	6.7%	6.7%
Columbia River PUD	7.9%	8.0%	Lower Valley Energy	6.8%	6.8%
Columbia Rural Electric Assn	5.7%	5.1%	Mason County PUD No 1	7.0%	7.0%
Consolidated Irrigation District No 19	6.2%	6.3%	Mason County PUD No 3	6.8%	6.8%
Consumers Power Inc	6.3%	5.8%	McCleary, City of	6.9%	6.9%
Coos Curry Electric Coop Inc	7.1%	6.7%	McMinnville, City of	4.1%	4.1%
Coulee Dam, Town of	4.6%	3.6%	Middle Fork Irrigation	-4.3%	-4.3%
Cowlitz County PUD No 1	1.5%	1.5%	Midstate Electric Coop	6.6%	6.6%
Delco, City of	7.1%	7.2%	Milton, City of	4.6%	3.6%
Douglas County PUD No 1	0.0%	0.0%	Milton-Freewater, City of	7.6%	7.6%
Douglas Electric Coop	7.4%	6.9%	Minidoka, City of	4.4%	3.4%
Drain, City of	4.5%	3.5%	Mission Vallley Power	7.2%	7.3%
East End Mutual Electric Co	7.3%	7.4%	Missoula Electric Coop	3.5%	3.5%
Eatonville, Town of	4.6%	3.6%	Modern Electric Water Co	6.9%	7.0%
EDP Renewables	-4.8%	-4.8%	Monmouth, City of	6.9%	6.8%
Ellensburg, City of	7.0%	7.0%	Nespelem Valley Electric Coop	6.6%	6.3%
Elmhurst Mutual Power & Light Co	7.1%	7.2%	Northern Lights	5.6%	4.9%
Emerald PUD	6.8%	6.9%	Northern Wasco County PUD	6.1%	6.1%
Energy Northwest Inc	2.0%	2.0%	Ohop Mutual Light Co	6.0%	5.5%
Eugene Water and Electric Board	6.0%	6.1%	Okanogan County Electric Coop	5.1%	4.0%
Eurus	-4.3%	-4.3%	Okanogan County PUD No 1	10.2%	10.3%
Fall River Rural Electric Coop	7.7%	7.8%	Orcas Power & Light Coop	7.2%	7.2%

Alternative #4 Transformation Segment	BP-14 % change	UDC-FR % change
Oregon Trail Electric Coop	6.9%	6.9%
Pacific County PUD No 2	7.2%	7.3%
PacifiCorp	-1.9%	-1.9%
Parkland Light & Water Co	7.1%	7.1%
PaTu Wind	12.7%	12.8%
Pend Oreille County PUD No 1	-2.5%	-2.5%
Peninsula Light Co	7.1%	7.2%
Plummer, City of	4.7%	4.7%
Port Angeles City Light	5.6%	5.7%
Port of Seattle (Sea Tac)	6.5%	6.5%
Port Townsend Paper Corp	6.5%	6.6%
Portland General Electric	-4.3%	-4.3%
Power Resources Coop	0.0%	0.0%
Powerex	-1.7%	-1.7%
PPL EnergyPlus	-4.3%	-4.3%
Puget Sound Energy	-2.0%	-2.0%
Raft River Energy	-4.2%	-4.2%
Raft River Rural Electric Coop	6.2%	6.2%
Ravalli County Electric Coop	6.2%	6.2%
Richland, City of	7.0%	7.1%
Riverside Electric Co	7.1%	7.1%
Rupert, City of	7.0%	7.0%
Salem Electric Coop	7.1%	7.2%
Salmon River Electric Coop	-0.5%	-0.5%
Seattle City Light	-4.4%	-4.5%
Shell Energy	-2.2%	-2.2%
Sherman County Wind	12.7%	12.8%
Skamania County PUD No 1	7.0%	7.1%
SMUD	-3.9%	-3.9%
Snohomish County PUD No 1	9.9%	10.0%
Soda Springs, City of	7.1%	7.1%
South Side Electric Lines	7.1%	7.2%
Southern California Edison	-4.2%	-4.2%
Springfield Utility Board	7.0%	7.1%
Steilacoom, Town of	4.6%	3.5%
Sumas, City of	4.8%	4.8%
Surprise Valley Electrification Corp	6.6%	6.6%
Tacoma Power	-4.5%	-4.5%
Tanner Electric Coop	6.7%	6.8%
Tillamook PUD	6.9%	7.0%
TransAlta	-3.3%	-3.3%
Troy, City of	4.6%	3.6%
Turlock Irrigation	-4.3%	-4.3%
Umatilla Electric Coop	8.2%	8.3%
Umpqua Indian Utility Coop	3.4%	3.4%
United Electric Coop	6.3%	6.4%
US DOE Natl Energy Technology Lab	4.5%	3.5%
US DOE Richland Operations Office	-3.8%	-3.8%
USAF Fairchild	6.8%	6.9%
USN Bangor	6.6%	6.6%
USN Bremerton	6.5%	6.6%
USN Everett	6.3%	6.4%

	BP-14 % change	UDC-FR % change
Vera Water & Power	7.2%	7.3%
Vigilante Electric Coop	5.6%	5.7%
Wahkiakum County PUD No 1	7.5%	7.6%
Wasco Electric Coop	6.5%	6.5%
Weiser, City of	5.2%	5.2%
Wells Rural Electric Co	6.5%	6.5%
West Oregon Electric Coop	6.9%	6.9%
Whatcom County PUD No 1	6.4%	6.4%
Wheat Field Wind	-4.3%	-4.3%
Yakama Power	4.8%	4.8%

Alternative #5 Subtransmission Segment	BP-14 % change	UDC-FR % change		BP-14 % change	UDC-FR % change
Albion, City of	47.2%	47.5%	Farmers Electric Co	48.0%	48.3%
Alcoa	-29.9%	-30.0%	Ferry County PUD No 1	47.4%	47.6%
Alder Mutual Light Co	46.7%	47.0%	Finley Bioenergy	-27.6%	-27.7%
Arlington Wind	-27.6%	-27.7%	Flathead Electric Coop	-11.1%	-11.0%
Ashland, City of	37.7%	34.8%	Forest Grove, City of	49.5%	49.7%
Asotin County PUD No 1	15.4%	15.4%	Franklin County PUD No 1	60.5%	60.2%
Avista	-19.0%	-19.0%	Gaelectric	-32.5%	-32.5%
Bandon, City of	30.0%	23.2%	Glacier Electric Coop	45.7%	46.0%
Benton County PUD No 1	66.5%	66.7%	Grant County PUD No 2	74.2%	73.3%
Benton Rural Electric Assn	41.3%	41.5%	Grays Harbor County PUD No 1	66.6%	66.8%
Big Bend Electric Coop	38.4%	35.2%	Harney Electric Coop	46.5%	46.7%
Blachly-Lane Electric Coop	47.9%	43.3%	Hermiston Energy Services	34.8%	34.9%
Blaine, City of	31.4%	31.5%	Hermiston Power	-32.5%	-32.5%
Bonners Ferry, City of	30.7%	23.2%	Heyburn, City of	50.0%	50.3%
BPA Power	-20.6%	-20.6%	Hood River Electric Coop	39.5%	34.7%
Burley, City of	46.2%	46.4%	Iberdrola	-13.5%	-13.5%
Canby Utility Board	44.0%	44.2%	Idaho Co Light & Power Coop Assn	36.0%	31.9%
Cascade Locks, City of	30.7%	23.7%	Idaho Falls Power	-0.3%	-0.2%
Central Electric Coop	51.7%	52.0%	Idaho Power	-19.6%	-19.6%
Central Lincoln PUD	43.6%	43.6%	Inland Power & Light	43.7%	43.9%
Centralia City Light	46.9%	47.1%	Jefferson County PUD	42.5%	42.8%
CEP Funding	-32.5%	-32.5%	Kittitas County PUD No 1	45.6%	45.8%
Chelan County PUD No 1	-27.6%	-27.7%	Klickitat County PUD No 1	64.1%	64.3%
Cheney, City of	47.7%	48.0%	Kootenai Electric Coop	43.8%	44.0%
Chewelah, City of	34.1%	34.2%	L & M Angus Ranch	-27.6%	-27.7%
Clallam County PUD No 1	45.7%	46.0%	LADWP	-27.7%	-27.7%
Clark Public Utilities	45.9%	46.1%	Lakeview Light & Power	47.1%	47.3%
Clatskanie PUD	9.2%	9.3%	Lane Electric Coop	57.8%	58.1%
Clearwater Power Co	41.8%	42.0%	Lewis County PUD No 1	46.0%	46.2%
Columbia Basin Electric Coop	46.3%	46.5%	Lincoln Electric Coop	53.6%	53.9%
Columbia Power Coop Assn	47.4%	47.6%	Lost River Electric Coop	44.8%	45.0%
Columbia River PUD	53.0%	53.3%	Lower Valley Energy	45.5%	45.3%
Columbia Rural Electric Assn	38.4%	34.0%	Mason County PUD No 1	46.9%	47.2%
Consolidated Irrigation District No 19	41.8%	42.0%	Mason County PUD No 3	45.8%	45.5%
Consumers Power Inc	42.1%	38.8%	McCleary, City of	46.3%	46.5%
Coos Curry Electric Coop Inc	47.5%	44.5%	McMinnville, City of	27.7%	27.9%
Coulee Dam, Town of	31.0%	23.9%	Middle Fork Irrigation	-27.6%	-27.7%
Cowlitz County PUD No 1	10.6%	10.7%	Midstate Electric Coop	44.3%	44.5%
Delco, City of	47.8%	48.1%	Milton, City of	30.9%	23.9%
Douglas County PUD No 1	-27.4%	-27.4%	Milton-Freewater, City of	50.7%	51.0%
Douglas Electric Coop	49.6%	46.3%	Minidoka, City of	29.7%	23.0%
Drain, City of	29.9%	23.2%	Mission Vallley Power	48.3%	48.6%
East End Mutual Electric Co	49.1%	49.4%	Missoula Electric Coop	23.6%	23.7%
Eatonville, Town of	31.1%	24.0%	Modern Electric Water Co	46.6%	46.9%
EDP Renewables	-30.6%	-30.6%	Monmouth, City of	46.2%	45.7%
Ellensburg, City of	46.8%	47.0%	Nespelem Valley Electric Coop	44.1%	41.9%
Elmhurst Mutual Power & Light Co	47.9%	48.2%	Northern Lights	37.9%	33.1%
Emerald PUD	45.7%	45.9%	Northern Wasco County PUD	40.8%	41.0%
Energy Northwest Inc	13.7%	13.8%	Ohop Mutual Light Co	40.0%	36.5%
Eugene Water and Electric Board	40.6%	40.9%	Okanogan County Electric Coop	34.1%	26.6%
Eurus	-27.6%	-27.7%	Okanogan County PUD No 1	68.1%	68.4%
Fall River Rural Electric Coop	51.6%	51.9%	Orcas Power & Light Coop	48.1%	48.4%

Alternative #5 Subtransmission Segment	BP-14 % change	UDC-FR % change
Oregon Trail Electric Coop	46.3%	46.5%
Pacific County PUD No 2	48.5%	48.8%
PacifiCorp	-17.4%	-17.4%
Parkland Light & Water Co	47.4%	47.7%
PaTu Wind	84.7%	85.0%
Pend Oreille County PUD No 1	-15.5%	-15.5%
Peninsula Light Co	47.7%	48.0%
Plummer, City of	31.5%	31.7%
Port Angeles City Light	37.7%	37.9%
Port of Seattle (Sea Tac)	43.4%	43.6%
Port Townsend Paper Corp	43.7%	43.9%
Portland General Electric	-27.7%	-27.7%
Power Resources Coop	-26.1%	-26.1%
Powerex	-10.9%	-10.9%
PPL EnergyPlus	-27.6%	-27.7%
Puget Sound Energy	-12.5%	-12.5%
Raft River Energy	-26.9%	-26.9%
Raft River Rural Electric Coop	41.7%	41.6%
Ravalli County Electric Coop	41.5%	41.7%
Richland, City of	47.2%	47.4%
Riverside Electric Co	47.6%	47.8%
Rupert, City of	46.7%	46.9%
Salem Electric Coop	48.0%	48.2%
Salmon River Electric Coop	-2.7%	-2.6%
Seattle City Light	-28.5%	-28.6%
Shell Energy	-14.1%	-14.1%
Sherman County Wind	84.7%	85.0%
Skamania County PUD No 1	47.2%	47.5%
SMUD	-25.2%	-25.2%
Snohomish County PUD No 1	66.1%	66.3%
Soda Springs, City of	47.4%	47.6%
South Side Electric Lines	47.6%	47.9%
Southern California Edison	-26.8%	-26.8%
Springfield Utility Board	47.2%	47.4%
Steilacoom, Town of	30.6%	23.7%
Sumas, City of	32.2%	32.3%
Surprise Valley Electrification Corp	44.6%	44.1%
Tacoma Power	-29.1%	-29.1%
Tanner Electric Coop	45.0%	45.2%
Tillamook PUD	46.5%	46.7%
TransAlta	-20.9%	-20.9%
Troy, City of	31.2%	24.0%
Turlock Irrigation	-27.6%	-27.7%
Umatilla Electric Coop	55.1%	55.4%
Umpqua Indian Utility Coop	22.8%	22.9%
United Electric Coop	42.7%	42.9%
US DOE Natl Energy Technology Lab	30.1%	23.3%
US DOE Richland Operations Office	-24.1%	-24.1%
USAF Fairchild	45.7%	45.9%
USN Bangor	44.2%	44.5%
USN Bremerton	43.8%	44.0%
USN Everett	42.5%	42.7%

	BP-14 % change	UDC-FR % change
Vera Water & Power	48.6%	48.8%
Vigilante Electric Coop	38.0%	38.2%
Wahkiakum County PUD No 1	50.3%	50.6%
Wasco Electric Coop	43.3%	43.6%
Weiser, City of	34.9%	35.1%
Wells Rural Electric Co	43.6%	43.8%
West Oregon Electric Coop	46.7%	46.1%
Whatcom County PUD No 1	42.7%	42.9%
Wheat Field Wind	-27.6%	-27.7%
Yakama Power	32.0%	32.2%

Alternative #6 **Eliminate Montana Intertie**	**BP-14** **% change**	**UDC-FR** **% change**
Albion, City of	0.0%	0.0%
Alcoa	0.0%	0.0%
Alder Mutual Light Co	0.0%	0.0%
Arlington Wind	0.1%	0.1%
Ashland, City of	0.0%	0.0%
Asotin County PUD No 1	0.0%	0.0%
Avista	0.1%	0.1%
Bandon, City of	0.0%	0.0%
Benton County PUD No 1	0.0%	0.0%
Benton Rural Electric Assn	0.0%	0.0%
Big Bend Electric Coop	0.0%	0.0%
Blachly-Lane Electric Coop	0.0%	0.0%
Blaine, City of	0.0%	0.0%
Bonners Ferry, City of	0.0%	0.0%
BPA Power	0.0%	0.0%
Burley, City of	0.0%	0.0%
Canby Utility Board	0.0%	0.0%
Cascade Locks, City of	0.0%	0.0%
Central Electric Coop	0.0%	0.0%
Central Lincoln PUD	0.0%	0.0%
Centralia City Light	0.0%	0.0%
CEP Funding	0.1%	0.1%
Chelan County PUD No 1	0.1%	0.1%
Cheney, City of	0.0%	0.0%
Chewelah, City of	0.0%	0.0%
Clallam County PUD No 1	0.0%	0.0%
Clark Public Utilities	0.0%	0.0%
Clatskanie PUD	0.0%	0.0%
Clearwater Power Co	0.0%	0.0%
Columbia Basin Electric Coop	0.0%	0.0%
Columbia Power Coop Assn	0.0%	0.0%
Columbia River PUD	0.0%	0.0%
Columbia Rural Electric Assn	0.0%	0.0%
Consolidated Irrigation District No 19	0.0%	0.0%
Consumers Power Inc	0.0%	0.0%
Coos Curry Electric Coop Inc	0.0%	0.0%
Coulee Dam, Town of	0.0%	0.0%
Cowlitz County PUD No 1	0.0%	0.0%
Delco, City of	0.0%	0.0%
Douglas County PUD No 1	0.1%	0.1%
Douglas Electric Coop	0.0%	0.0%
Drain, City of	0.0%	0.0%
East End Mutual Electric Co	0.0%	0.0%
Eatonville, Town of	0.0%	0.0%
EDP Renewables	0.1%	0.1%
Ellensburg, City of	0.0%	0.0%
Elmhurst Mutual Power & Light Co	0.0%	0.0%
Emerald PUD	0.0%	0.0%
Energy Northwest Inc	0.0%	0.0%
Eugene Water and Electric Board	0.0%	0.0%
Eurus	0.1%	0.1%
Fall River Rural Electric Coop	0.0%	0.0%

	BP-14 **% change**	**UDC-FR** **% change**
Farmers Electric Co	0.0%	0.0%
Ferry County PUD No 1	0.0%	0.0%
Finley Bioenergy	0.1%	0.1%
Flathead Electric Coop	0.0%	0.0%
Forest Grove, City of	0.0%	0.0%
Franklin County PUD No 1	0.0%	0.0%
Gaelectric	0.1%	0.1%
Glacier Electric Coop	0.0%	0.0%
Grant County PUD No 2	0.1%	0.1%
Grays Harbor County PUD No 1	0.0%	0.0%
Harney Electric Coop	0.0%	0.0%
Hermiston Energy Services	0.0%	0.0%
Hermiston Power	0.1%	0.1%
Heyburn, City of	0.0%	0.0%
Hood River Electric Coop	0.0%	0.0%
Iberdrola	0.0%	0.0%
Idaho Co Light & Power Coop Assn	0.0%	0.0%
Idaho Falls Power	0.0%	0.0%
Idaho Power	0.0%	0.0%
Inland Power & Light	0.0%	0.0%
Jefferson County PUD	0.0%	0.0%
Kittitas County PUD No 1	0.0%	0.0%
Klickitat County PUD No 1	0.0%	0.0%
Kootenai Electric Coop	0.0%	0.0%
L & M Angus Ranch	0.1%	0.1%
LADWP	0.1%	0.1%
Lakeview Light & Power	0.0%	0.0%
Lane Electric Coop	0.0%	0.0%
Lewis County PUD No 1	0.0%	0.0%
Lincoln Electric Coop	0.0%	0.0%
Lost River Electric Coop	0.0%	0.0%
Lower Valley Energy	0.0%	0.0%
Mason County PUD No 1	0.0%	0.0%
Mason County PUD No 3	0.0%	0.0%
McCleary, City of	0.0%	0.0%
McMinnville, City of	0.0%	0.0%
Middle Fork Irrigation	0.1%	0.1%
Midstate Electric Coop	0.0%	0.0%
Milton, City of	0.0%	0.0%
Milton-Freewater, City of	0.0%	0.0%
Minidoka, City of	0.0%	0.0%
Mission Vallley Power	0.0%	0.0%
Missoula Electric Coop	0.0%	0.0%
Modern Electric Water Co	0.0%	0.0%
Monmouth, City of	0.0%	0.0%
Nespelem Valley Electric Coop	0.0%	0.0%
Northern Lights	0.0%	0.0%
Northern Wasco County PUD	0.0%	0.0%
Ohop Mutual Light Co	0.0%	0.0%
Okanogan County Electric Coop	0.0%	0.0%
Okanogan County PUD No 1	0.0%	0.0%
Orcas Power & Light Coop	0.0%	0.0%

Alternative #6 **Eliminate Montana Intertie**	**BP-14** **% change**	**UDC-FR** **% change**
Oregon Trail Electric Coop	0.0%	0.0%
Pacific County PUD No 2	0.0%	0.0%
PacifiCorp	-0.1%	-0.1%
Parkland Light & Water Co	0.0%	0.0%
PaTu Wind	0.1%	0.1%
Pend Oreille County PUD No 1	0.0%	0.0%
Peninsula Light Co	0.0%	0.0%
Plummer, City of	0.0%	0.0%
Port Angeles City Light	0.0%	0.0%
Port of Seattle (Sea Tac)	0.0%	0.0%
Port Townsend Paper Corp	0.0%	0.0%
Portland General Electric	0.1%	0.1%
Power Resources Coop	0.1%	0.1%
Powerex	0.0%	0.0%
PPL EnergyPlus	0.1%	0.1%
Puget Sound Energy	0.1%	0.1%
Raft River Energy	0.1%	0.1%
Raft River Rural Electric Coop	0.0%	0.0%
Ravalli County Electric Coop	0.0%	0.0%
Richland, City of	0.0%	0.0%
Riverside Electric Co	0.0%	0.0%
Rupert, City of	0.0%	0.0%
Salem Electric Coop	0.0%	0.0%
Salmon River Electric Coop	0.0%	0.0%
Seattle City Light	0.1%	0.1%
Shell Energy	0.0%	0.0%
Sherman County Wind	0.1%	0.1%
Skamania County PUD No 1	0.0%	0.0%
SMUD	0.1%	0.1%
Snohomish County PUD No 1	0.1%	0.1%
Soda Springs, City of	0.0%	0.0%
South Side Electric Lines	0.0%	0.0%
Southern California Edison	0.1%	0.1%
Springfield Utility Board	0.0%	0.0%
Steilacoom, Town of	0.0%	0.0%
Sumas, City of	0.0%	0.0%
Surprise Valley Electrification Corp	0.0%	0.0%
Tacoma Power	0.0%	0.0%
Tanner Electric Coop	0.0%	0.0%
Tillamook PUD	0.0%	0.0%
TransAlta	0.0%	0.0%
Troy, City of	0.0%	0.0%
Turlock Irrigation	0.1%	0.1%
Umatilla Electric Coop	0.0%	0.0%
Umpqua Indian Utility Coop	0.0%	0.0%
United Electric Coop	0.0%	0.0%
US DOE Natl Energy Technology Lab	0.0%	0.0%
US DOE Richland Operations Office	0.0%	0.0%
USAF Fairchild	0.0%	0.0%
USN Bangor	0.0%	0.0%
USN Bremerton	0.0%	0.0%
USN Everett	0.0%	0.0%

	BP-14 **% change**	**UDC-FR** **% change**
Vera Water & Power	0.0%	0.0%
Vigilante Electric Coop	0.0%	0.0%
Wahkiakum County PUD No 1	0.0%	0.0%
Wasco Electric Coop	0.0%	0.0%
Weiser, City of	0.0%	0.0%
Wells Rural Electric Co	0.0%	0.0%
West Oregon Electric Coop	0.0%	0.0%
Whatcom County PUD No 1	0.0%	0.0%
Wheat Field Wind	0.1%	0.1%
Yakama Power	0.0%	0.0%