NRU Proposal for Utility Delivery Charge

Overview of the Proposal

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 charge that is generally comparable to the current level in the FY 2014/2015 rates after the 25% increase for delivery service. In this proposal the Utility Delivery Segment is eliminated in FY 2016 and beyond, the adjusted costs are 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 34.5 kV.

Adherence to BPA Segmentation Principles

The NRU proposal adheres to the Segmentation Principles that the Agency has adopted to guide the Transmission Segmentation discussion. Our proposal would encourage the widest possible diversified use of electric power at the lowest possible rates to consumers by applying a uniform rate for delivery services. Equally important for NRU, the proposal is consistent with sound business principles because it recognizes BPA's efforts to scale back and possibly phase out the Utility Delivery Segment in a manner that is fair to both the Agency and the utilities taking service below 34.5 kV. The proposal does not implicate questions of allocation between federal and non-federal uses of the Transmission system because it makes no distinction between federal and non-federal power.

Our proposal also adheres to the principles of cost causation and cost recovery by generally recovering the costs of the facilities currently in the Delivery Segment from those utilities who use those facilities. At the same time, our proposal avoids rate shock and creates rate stability by avoiding an excessive and punitive charge to those utilities who may not be able to realistically purchase the delivery facilities that they use. The following description will demonstrate that our proposal is relatively straight forward, which makes it simple and easy to understand and implement.

Reduction in Scale of the Utility Delivery Segment

Since 1996 BPA has intended the Delivery Segment to shrink by incentivizing customers to purchase Delivery Facilities. To a large extent this has been accomplished with only the most challenging facilities remaining. In 1996 there were 206 facilities in the Utility Delivery Segment. The number has declined to 47 during the FY 2014 rate case, only 23% of the original amount. Some NRU members may be interested in purchasing some of the remaining facilities and are in active negotiations with BPA. We encourage the process to continue. However, for other utilities there are significant obstacles surrounding purchase, particularly those where BPA is not the land owner and where there are serious age and condition issues with the facilities. As a result, the number of remaining facilities in the Utility Delivery Segment will continue to decline but will not be eliminated, at least in the foreseeable future.

BPA's success in divesting low voltage delivery facilities is evident in the projected investment percentages in the various transmission segments. BPA is only forecasting additions of about 1% in the base plant investment for Utility Delivery compared to about 6% for the aggregate of all segments. The other segments are being sustained or expanded while the Utility Delivery Segment seems to reflect only investments that are necessary to keep the facilities in operation. In this context, it is appropriate during this BPA segmentation review to question whether Utility Delivery should be continued as a separate segment, or alternatively, as we propose, whether the remaining balance should be rolled into the Network Segment.

Summary of the Methodology for BPA Utility Delivery Cost Recovery

In the BP-14 rate case, BPA raised the UDC by 25%, from $1.119 kW/Mo to $1.399 kW/Mo. Using current cost recovery methodologies, BPA identified a revenue deficit in the UDC on a percentage basis, 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 UDC by another 25%, the charge for delivery would be basically equal to the current $1.741 kW/Mo charge for Network Transmission. The customer using low voltage delivery facilities effectively would be paying double the NT rate compared to other customers.

In contrast to the BPA UDC of $1.399 kW/Mo., we observe that the GTA Delivery Charge, which applies to Customers that purchase Federal power that is delivered over non-federal low voltage facilities operated below 34.5 kV is at a rate of $0.820 kW/Mo. Our understanding is that the GTA Delivery Charge recovers the average cost for delivery service where such costs are imposed by the GTA provider. The GTA UDC of $.0820 kW/Mo is less than 59% of the BPA UDC. While we have not analyzed the financial components of the UDC charged by the GTA providers, this raises questions regarding BPA's UDC, and if a revised methodology for BPA cost recovery would result in a more equitable charge for BPA Transmission's UDC Customers.

Cost Basis for a New Utility Delivery Charge

The proposed NRU staff methodology for deriving a new UDC is illustrated on the attached sheet. We display the existing BPA methodology and show 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% of the current level.

- The financial value of the FCRPS Investment Base (Net Plant) of about $21 M for Utility Delivery is reduced to 20% of its current level based on our membersô 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 (see attachment footnote to the list of delivery facilities). The situation will vary from facility to facility, but generally our members believe they are ñoldò and over-valued.
- Based on the revised 20% value of Utility Delivery Net Plant, the direct depreciation calculation is reduced proportionately. However, we depreciate BPAôs General Plant, which supports the delivery of O&M, at 100%. This results in a <u>total</u> depreciation cost of about 49% of the current level.
- This 49% 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 Delivery Charge cost basis becomes 56% of the current amount, reduced from about $6.4 M to $3.6 M.
- We did not adjust the reported Revenue Credits of about $240,000 accruing to the Utility Delivery Segment but recognize they could change.
- Finally, we reduce the level of Transmission financial reserves applied in the FY 2014 ï FY 2015 rate case to offset the UDC, based on a lower overall recommended cost for delivery service
- When these elements are combined it appears as if the UDC recovers the cost of the utility delivery facilities.

<u>Rationale for Revisions in O&M Costs</u>

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 M. O&M activities represent about 3.9% of the investment value for Network Substations. The Utility Delivery Facilities have a reported investment of $29.575 M and O&M at $1.85 M. O&M activities represent about 6.3% of the reported investment value for Delivery Substations. The O&M for Delivery Substations is 62% higher based on investment than for Network Substations. This leads to a conclusion that BPAôs 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 O&M would be lower as well as all of the overhead items that are added to it. In the NRU proposal Utility Delivery customers continue to pay all direct O&M costs, but we recommend other revisions in the calculation of the charge.

In examining the Overhead categories applied to O&M (see attachment) they represent about 43% of the total O&M cost. The categories of Marketing, Business Support, Systems

Engineering, and Corporate together account for about $1.5 M or close to 25% of the overall cost for the current UDC. While overhead charges to O&M are often used to recover full costs of service, for the UDC they are duplicative and should be eliminated.

Network Transmission customers are already paying the full cost of each kW 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 UDC 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 UDC should be limited to the direct cost of the program rather than adding on administrative overheads, which result in a double collection of costs.

Impact on Other Customers

There is no impact on other customers by adopting this proposed UDC because the UDC would recover the same general amount as the current rates. The revenue from the new UDC would become a component of the overall $650 M revenue requirement for the Network Segment. To the extent that any of the proposed calculations of the UDC are not 100% 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% of the Network Revenue Requirement. While the bandwidth of exposure resulting in changes in UDC revenue for the Network is nominal, the impact of not making a change for the remaining UDC customers is significant.

Changes to the UDC Over Time

Once the UDC is set, we recommend 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 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. 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, there is a remaining incentive for utilities to purchase 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.

Conclusion

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. We note the significant discrepancy between the BPA charge and the charge from the GTA providers. Other methodologies have the potential for a lower UDC than $1.399 kW/Mo and should be explored by BPA staff and the customers in advance of the FY 2016 ï FY 2017 Transmission rate case. We look forward to participating in that process.

Appendix A: Delivery Segment Facilities

	Substation	Utility	BP-14 Transmission Segmentation Study: Initial Investment	O&M	% Delivery	Transformer Age: 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

Appendix B: Delivery Charge Determination

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**

Notes:

All Direct O&M recovered at 100%

O&M Overheads not applicable, customer pays through NT rate for Transmission Support services

Net plant for substations reduced by 80%, and depreciation recovery for general plant at 100%

Combined depreciation for smaller Substation net investment and for General Plant at 48.62%

Net Interest and Planned Net Revenues based on revised net plant of 48.62%

Revenue and Revised Cost Comparision using FY 2014 - FY 2015 Rates and Loads		
Revenue Credits (assumed to stay the same but could be smaller)	241	237
Rate Case Use of Reserves	139	137
Revised Use of Reserves based on lower costs	78	77
Current Delivery Charge Revenues	**3,265**	**3,295**
All Revenues (with revised use of reserves)	**3,584**	**3,609**
Proposed Cost Basis	**3,528**	**3,648**
Amount of Underrecovery	**-56**	**39**
Percent Underrecovery	**-1.56%**	**1.08%**