Segmentation Workshop

May 29, 2014

Agenda

- Transformation Charge Alternative
- Modifications to the Radial Alternative
- Segmentation White Paper Review
- Next Steps

Transformation Charge—1

- The Large Customer Coalition suggested an alternative that would establish a new charge for customers utilizing transformation to lower voltages.
- Any customer taking power off BPA's grid at 161kV or higher would pay the Network rate. Any customer taking power off BPA's grid below 161kV would pay an additional transformation charge (or two).
- All other transmission charges would remain as they are currently implemented, i.e., Delivery, Intertie, and ACS rates remain unchanged.

Transformation Charge—2

- Delivery voltages (below 34.5kV) are not considered in determining transformation voltage. For example, BPA has 33 transformers with a high-side of 230kV and a low-side below 34.5kV—these are considered 230kV transmission off-take for purposes of the transformation charge(s).
- All PODs are deemed to use Network transmission; 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.

Transformation Charge—3

- 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.
- Due to time considerations, not all generators have been identified in this analysis. The rates shown in this package have not yet fully implemented this feature: this would somewhat lower the transformation rates shown.

Transformation Charge—4

- **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 by low-side class: 230kV (146+), 115kV (100-145), 69kV (30-99).

Transformation Charge—5

- 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.
- The 115kV group revenue requirement is $22 million.
- The 35-69kV group revenue requirement is $10 million.
- The total transformation revenue requirement is about $32 million, or about 5 percent of the Network.

Transformation Charge—6

- Total……………………….860 PODs or interconnections
  - 648 BPA, 212 transfer
- 69kV (34.5-69kV)………..146 PODs or interconnections
  - 106 BPA, 40 transfer
- 115kV (110-138kV)……...594 PODs or interconnections
  - 428 BPA, 166 transfer
- 230 kV (161-500kV)……..120 PODs or interconnections
  - 114 BPA, 6 transfer
- The loads for each POD were aggregated by transformer grouping.

- For simplicity NT Cost Allocation is based on Coincident Peak for Transformation Charge Calculation

Transformation Charge—7

- Two options were analyzed:
- 1) One-Step Rate:
  - The total revenue requirement of $32 million is divided by the total load to derive a rate of $0.285 per kW per month.
- 2) Two-Step Rate:
  - The 115kV revenue requirement of $22 million is divided by the total loads for 115kV + 69kV to derive a 115kV rate of $0.194 per kW per month.
  - The 69kV revenue requirement of $10 million is divided by the 69kV load to derive a 69kV rate of $0.863 per kW per month.
  - Loads in the 69kV group would pay both charges.
- The rates are also applied to transfer loads to produce $6 million (one-step) or $9.5 million (two-step) to reduce the GTA cost embedded in power rates.

Transformation Charge–8

	BP-14	Transformer Charge (1 Step)		Transformer Charge (2 Step)	
	Rate	Rate	% Change	Rate	% Change
FPT	1.666	1.666	0%	1.666	0%
IR	1.736	1.661	-4%	1.661	-4%
PTP	1.479	1.404	-5%	1.404	-5%
NT	1.741	1.652	-5%	1.652	-5%
Transformer Charge 1 (115 and below)		0.285		0.194	
Transformer Charge 2 (69 kV and below)				0.863	
IR + Transformer Charge(s)	1.736	1.946	12%	1.855	7%
PTP + Transformer Charge(s)	1.479	1.689	14%	2.461	66%
NT + Transformer Charge(s)	1.741	1.937	11%	2.709	56%

- Under 2 step charge PTP/NT + Transformer charges includes both Charge 1 and Charge 2.

Radial Service Alternative Update

- Based on a comment offered at the May 7 workshop, 4 substations were removed from the Raft River radial due to the USGen geothermal plant, which is wheeled to Idaho Power. This reduced the radial revenue requirement for this area from $1.15 million to $220 thousand.
- The Tincup substation was removed because the Afton cogenerator is wheeled to Idaho Power. This removed $160 thousand from the radial revenue requirement.
- The total radial revenue requirement is now a little over $33 million, or 5.1 percent of the Network.

Radial Service Alternative Update

- The loads for the radial PODs were accumulated.
- Dividing the revenue requirement by the total load yields a rate of $2.266 per kW per month.
  - PTP + Radial Rate = $3.671 (148% increase over PTP BP-14)
  - NT + Radial Rate = $3.919 (125% increase over NT BP-14)
- This rate is applied to transfer service radial loads, producing $24 million to reduce the GTA cost embedded in power rates.

	BP-14	Radial Charge	
	Rate	Rate	% Change
FPT	1.666	1.595	-4%
IR	1.736	1.662	-4%
PTP	1.479	1.405	-5%
NT	1.741	1.653	-5%
Radial Charge		2.266	
PTP + Radial Charge	1.479	3.671	148%
NT + Radial Charge	1.741	3.919	125%

Note: For simplicity NT Cost Allocation is based off of coincident peak for Radial Segment

Segmentation White Paper

- A draft of the regional white paper has been posted as part of today's meeting materials.
- Customers participated in drafting descriptions and justifications for their own proposals.
- Customers are asked to review and comment on the regional white paper and specifically comment on the various proposals, adding either considerations in favor or in opposition to the various alternatives.
- All comments on proposals will be shared with executives in customer's own words. Staff reserves the right to edit comments for length, so please be concise.
- **Please comment by June 13**

Next Steps

- BPA staff will continue work on any outstanding analysis and update customers as that becomes available.
- Customers are asked to review and comment on the regional white paper and specifically comment on the various proposals, adding either considerations in favor or in opposition to the various alternatives.
- At the June 11th workshop BPA and staff will discuss the status of the white paper and update any outstanding analysis.
- At the June 11th workshop, we will decide if a workshop on June 25th is needed.

BP-16 Segmentation Timeline

JAN	FEB	MAR	APR	MAY	JUN
Jan 28 Workshop: Kick-Off	**Feb 19** Workshop: Principles development and benchmarking	**Mar 20** Workshop: Customer Proposals	**Apr 16** Workshop—Share work-in-progress	**May 7** Workshop—Share work-in-progress **Mid-May** Transmit draft white paper to customers **Mid-May** Provide customers expectations on what feedback is needed for the white paper **End of May** Customer's white paper comments due **May 29** Workshop—Share final analytical results	**June 11** Workshop—review white paper **June 25** Workshop, if needed