BPA Informal Customer Meeting: Segmentation Analysis

Sponsored by
Transmission Services

September 9, 2009

Key Messages

- These meetings are preliminary informal discussions related to transmission rates.
- Please feel free to ask questions and provide input as we move through these draft materials.
- All information shared is pre-decisional and not indicative of any particular rate case outcome.

Meeting Objectives

1. Discuss high level approach to the rate case to establish common baseline.
2. Discuss protocols for how BPA will respond to customer inquiries during these discussions.
3. Discuss the building blocks of rate making with focus on the transmission segmentation analysis.
4. Discuss parking lot for customer issues raised related to transmission rates.

What did the partial transmission settlement agreement say?

- "3. During 2009, BPA will hold discussions with all interested parties regarding segmentation, cost of service methodology, and rate design for future transmission rates. Such discussions will include, but not be limited to, ratemaking to recover the costs of the Utility Delivery segment, and the costs of transmission facilities that comprised the former Northern Intertie transmission segment. Parties may raise other topics for BPA's consideration that are relevant to the design of transmission rates. In the discussions, BPA will establish protocols for how it will respond to issues raised."

What Transmission Rate Case Meetings are Scheduled?

- Sept 9th Transmission Rates Customer Meeting from 9:00 to Noon (today's meeting).
- Oct 7th Transmission Rates Customer Meeting from 9:00am to 3:00pm.
- Nov 4th Transmission Rates Customer Meeting from 9:00am to 3:00pm.

What is rate case process?

- The rate case is the administrative process for establishing rates for wholesale electric power and transmission services for specific products over a set time period, usually 2 to 5 years.
- It is a quasi-judicial proceeding presided over by a hearing officer required by Section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Northwest Power Act).
- The Northwest Power Act describes the general process that BPA and others who participate in the rate case must follow.
- The scope of today's discussion is outside of the rate case process.

What are the rate making principles?

- Full and timely cost recovery.
- Lowest possible rates consistent with sound business principles.
- Cost causation—fairly allocate costs to customers that cause the costs in the apportionment of total costs of service among the different consumers.
- Statutory requirement of equitable allocation.
- Simplicity, understandability, public acceptance, and feasibility of application.
- Avoidance of rate shock and rate stability from rate period to rate period.

Note: Principles are adapted from James Bonbright Principles of Public Utility Rates, 1968.

What protocols will be used for issues raised during informal rate discussion?

- BPA is open to customer input.
- With written consent from the customer, BPA will post customer comments related to transmission rates on the corporate rates website.
- BPA will identify whether the issue raised is within or out of scope of the rate case. If outside of the scope of the rate case, BPA will point customers to the appropriate forum, if known.
- Transmission Account Executives will remain the first line of communication for customers.

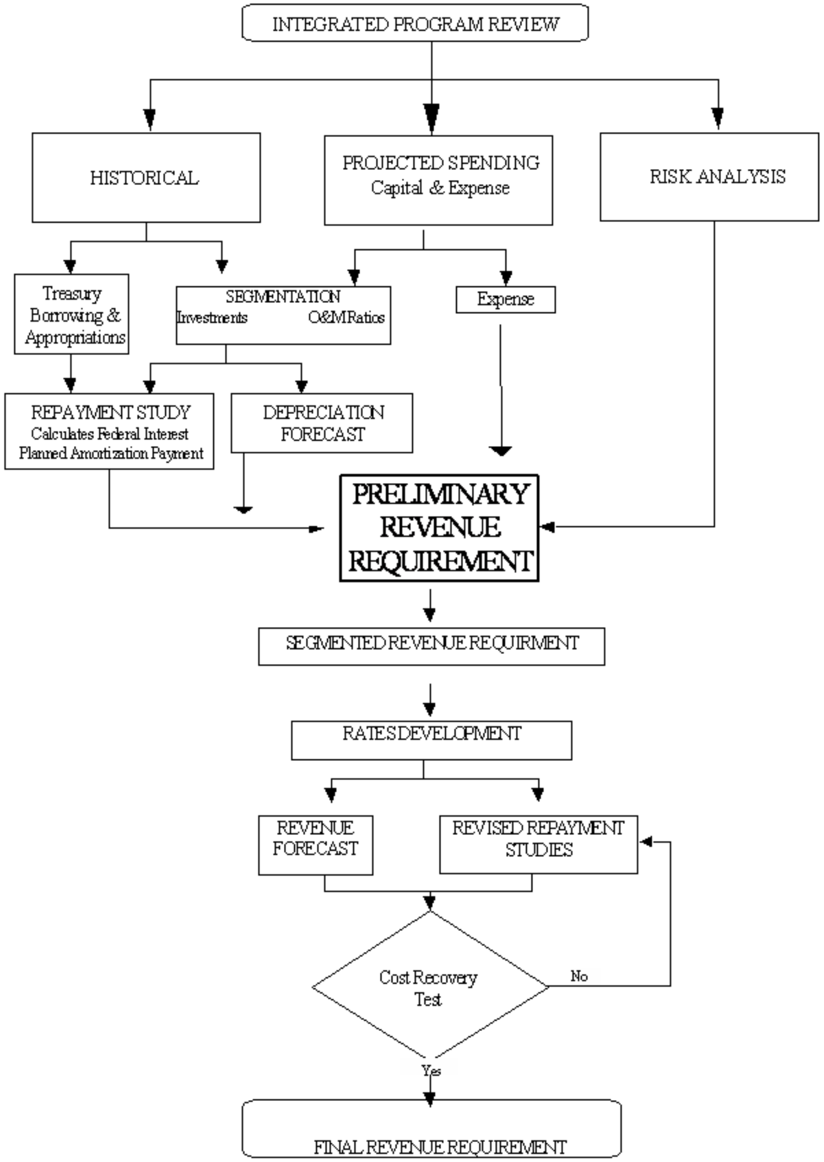
Informal Process
Outside of Scope of Rate Case

What happens before release of the Initial Proposal?

- Spending levels are determined.
- **Conduct a preliminary revenue requirement assessment, develop a segmentation and cost of service analysis**.
- Nail down issues and crunch preliminary numbers.
- Explore rate sensitivities and rate design options.
- Pre-Rate Case workshops with interested parties are held to discuss all of the above, except spending levels.
- Finalize decisions and numbers for Initial Proposal.

What is Segmentation Analysis?

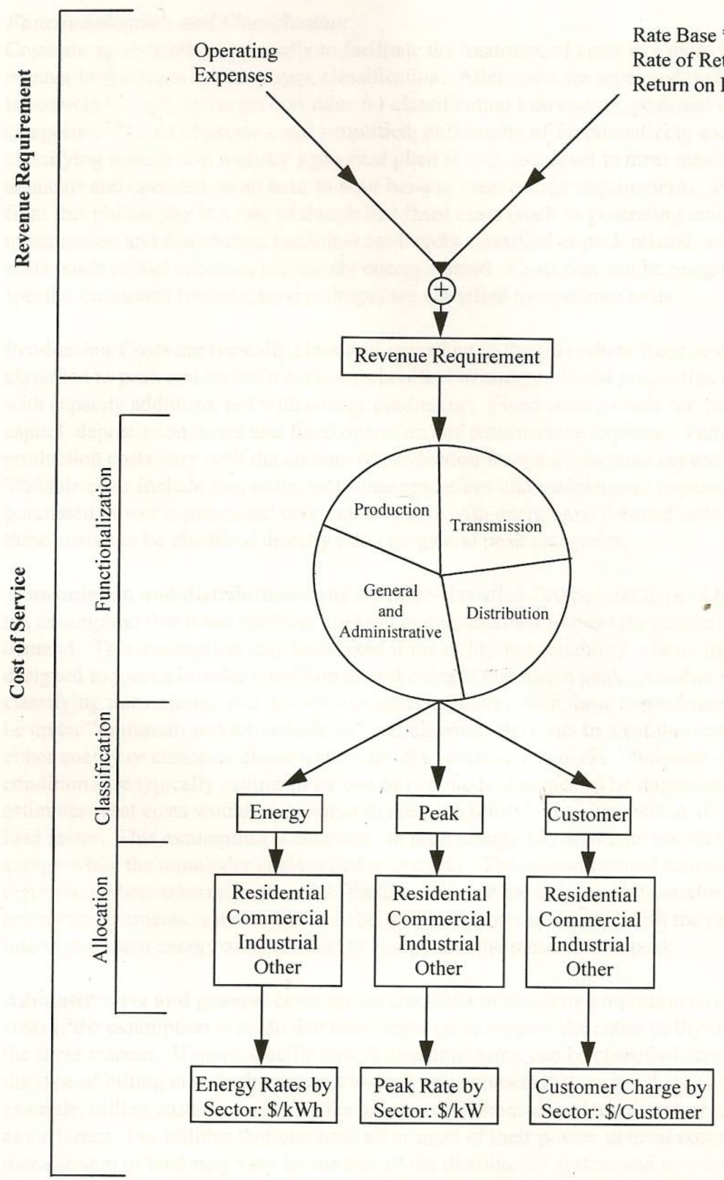
- An integral part of the Transmission Rate Case.
- Purpose: A preliminary step in determining the cost of serving our customers and used to develop an equitable distribution of costs among diverse users of our transmission system
- Output: Segmented capital investment and historical O&M costs.
- Used in allocating the BPA Transmission Revenue Requirement, and ultimately developing transmission rates.



Predecisional/For Discussion Purposes Only

What is Cost of Service Analysis?

- Traditional COSA is a type of research and reporting used to determine the actual costs of providing service to individual customers, groups of customers, or an entire customer base.
- In the energy industry, cost-of-service analyses are performed at all stages of the supply chain from generation right through to billing. Traditionally, utilities use these studies to determine what they require in the way of operating capital and what rates they can afford to set for some or all services.
- The three components of COSA include: Functionalization, Classification, and Allocation. The end product produces utility rates by customer class.



Predecisional/For Discussion Purposes Only

What are the steps of the Segmentation Study?

- Starts with listing the facilities (substations and lines) of the FCRTS; then
- Assigns them to different categories of service (segments) according to the types of services they provide; then
- Develops **historical** investment and O&M cost ratios for these segments and for **projected** future investments.
- The final Segmentation Study is an input to the Revenue Requirements Study, in which the segment **ratios** are applied to **total** revenue requirements to develop the segmented costs.
- This results in the rates paid by users of the FCRTS being based on what segments they use.

What are the steps of the Segmentation Study?

- It might be helpful to see the Segmentation Study's output primarily as **ratios**, not **costs**.
- The **costs** BPA must recover via rates are contained in our Revenue Requirements documents.
- The **ratios** arrived at in the Segmentation Study are applied to **total** revenue requirements to develop the rates for products associated with the segments.

What segments has BPA divided its system into?

- Generation Integration (GI) – Connects federal generation to the Network.
- Integrated Network (Network) – Bulk power transmission.
- Southern Intertie (IS) – AC and DC connections to California.
- Eastern Intertie (IE) – Garrison-Townsend 500-kV line and associated equipment.
- Utility Delivery (UD) – Facilities to deliver power to public utilities at less than 34.5-kV.
- Industrial Delivery (DSI) – Facilities to deliver power to DSIs at less than 34.5-kV.
- Ancillary Services – Facilities and operations necessary for reliable transmission service.

What is the Generation Integration Segment?

- Consists of all facilities that connect the Federal generating plants to the integrated BPA transmission network.
- Includes transmission lines and equipment between the generator bus and the first BPA transmission system substation encountered by the generated power.
- All GI costs are assigned to Power

What is the Integrated Network Segment?

- Consists of the facilities that transfer bulk power to and from the Southern and Eastern Intertie and Delivery segments, and from/to points on the Network itself.
- Consists almost entirely of lines and substation equipment at voltages from 34.5-kV to 500-kV owned and operated by BPA.
- Provides bulk power transfers between service areas, voltage regulation, and overall reliability resulting from alternative transmission pathways.
- By far the biggest segment.

What is the Southern Intertie Segment?

- This segment is a system of transmission lines that interconnect the PNW to California power systems at the Oregon border.
- The Southern Intertie consists of:
  - One 1,000-kV direct-current line from the Celilo Converter Station at The Dalles (the DC Intertie) and converter and connecting lines.
  - A set of 500-kV alternating-current lines originating in North Central Oregon (the AC Intertie). BPA owns most of the Intertie facilities north of the California-Oregon and Nevada-Oregon borders.

What is the Eastern Intertie Segment?

- Consists of the Garrison-Townsend 500-kV line and the associated substation facilities at Garrison.
- These facilities are used to connect power generated at Colstrip to the BPA network and to transfer power between the Northwest and Montana.
- Most of the costs of this segment are recovered from NorthWestern Energy and the Colstrip owners that contracted for service on this line.

What is the Delivery Segment?

- This two-component delivery segment consists primarily of substation facilities required to "step down" (reduce) transmission voltages for delivery to customers at voltages below 34.5-kV.
- The primary facilities included in these segments are step-down transformers and associated switching and protection equipment.
- Utility Delivery Segment: Consists of facilities required to supply power at delivery voltages to BPA's public utility customers.
- Industrial Delivery (DSI) Segment: Consists of facilities required to supply BPA's industrial customers.

What is the Ancillary Services Segment?

- Services that public utility transmission providers are required by FERC order to supply.
- Required for reliable transmission service.
- FCRTS assets are assigned to the “Scheduling, System Control, and Dispatch Service” component of Ancillary Services.
- The costs of all other Ancillary Services are generation inputs.
- The facilities that supply these services are the control equipment and computer hardware and software located at the control centers and communications system and SCADA equipment connected to the equipment being controlled.

Segmentation Methodology

What is the Segmentation Methodology?

- TBL transmission facilities (primarily lines and substations) are assigned to segments on the basis of voltage and function.
- A number of technical sources are relied upon to identify facilities for specific services.

More on BPA's Transmission Services Segmentation Methodology

- All the facilities in the FCRTS are identified and the investment in each facility is determined from accounting records. Investment in transmission assets is included at gross (i.e., **not** net of depreciation) **installed** cost.

- Each facility (and its associated cost) is assigned to a specific segment.

- Some facilities serve more than one segment. In that case, the facility costs are divided among the major segments based on the use of the major components of the facility.

More on BPA's Transmission Services Segmentation Methodology

What types of transmission assets does Bonneville have?

1. BPA owned, operated, and financed through Treasury Borrowing.
2. BPA operated. Financed via Capital Leases/Third Party Financed Assets.
3. BPA owned and operated. Financed via Projects Funded in Advance.
4. BPA owned and operated. Financed via Customer Financed Projects.

More on BPA's Transmission Services Segmentation Methodology

- Which investments are included in the segmentation analysis?

Asset Class	Included In Segmentation?
1. BPA owned, operated, and financed through Treasury Borrowing	Yes
2. BPA operated. Financed via Capital Leases/Third Party Financed Assets	Yes
3. BPA owned and operated. Financed via Projects Funded in Advance	No
4. BPA owned and operated. Financed via Customer Financed Projects	No

More on BPA's Transmission Services Segmentation Methodology

- What about Operation and Maintenance Costs?
  - O&M expenses (including some but not all overhead) for each transmission line and substation are obtained for the latest 3 years.
  - The amount of maintenance work performed on an asset, particularly with respect to lines, varies from year to year. To smooth out fluctuations in the amount of O&M work done at any specific site, we use the average of 3 years data.
  - For each site we apply the cost of O&M work at that site **relative to all O&M work for the period** to BPA's **budgeted amount** of O&M expense for the years in the rate period.

More on BPA's Transmission Services Segmentation Methodology

- These **historical** segmented O&M **costs** are then used in the Revenue Requirements Study to develop the **ratios** used to allocate **future budgeted total** O&M costs (including overhead) to the rate period.

- Later we'll walk though a hypothetical example of how we do this.

More on BPA's Transmission Services Segmentation Methodology

- Investment and O&M associated with providing the FERC-defined Ancillary Services are identified.
- These costs are assigned to Ancillary Services.
- We'll talk more later about changes we've made in the allocation of Ancillary Services costs.

What Other Considerations are Factored into the Segmentation Study?

- Projected plant investment throughout the rate period is segmented and included in the study. This is done by working with the Plant In Service projections resulting from the Integrated Program Review (IPR).

- Conversely, sales of certain FCRTS assets (primarily delivery substations) are forecasted and the assets excluded from rates. We work with BPA Account Executives and Customer Service Engineers to develop a forecast of facilities to be sold. These are removed from the segment to which they would otherwise be assigned.

What are the Results?

- At the conclusion of our work, we'll have taken the entire transmission investment and allocated its costs among the segments.
- The revenue requirement of the entire transmission system is then apportioned to the various segments, with each segment "responsible" for recovering its own costs.
- The segmented revenue requirements then go into the Rate Design Study to determine the rates necessary to recover each segment's required revenues.
- The Rate Design Study adjusts the revenue requirements for various credits to determine the final revenue requirement.

What are the Data Sources?

- Investment data for existing assets come from BPA's Asset Accounting group.
- Investment costs for assets not yet constructed are taken from capital budgets, notably the IPR.
- Historical O&M costs come from BPA's Reliability Centered Maintenance group.
- Future O&M costs come from expense budgets, notably the IPR.
- Data regarding facilities to be sold come from the customer service engineers and account executives who work closely with customers.

Who pays for the Utility Delivery work?

- Only utilities served by the segment specifically identified as being used solely to deliver energy to utilities (e.g., the step-down facilities referred to earlier) pay for this segment.
- Therefore, a Utility Delivery charge is included in these customers' bills, based on the estimated costs of this segment and spread out over the expected activity of this segment.

What is the approach for Multipurpose Substations?

- Task: BPA will divide the entire transmission system up into segments, each of which is to recover its own costs.
- The issue:
  - Some substations serve more than one segment.
  - Much of the cost of a substation is “common” to all uses, e.g., fencing, gravel, parking lot, buildings, etc.
  - Solution: Develop a ‘systematic and rational’ method of allocating the common costs over multiple segments.

What's the Solution to Multipurpose Substations?

- **Step 1**: Identify the substation components that are "Major Equipment" (defined as breakers, transformers, and reactive equipment).
- **Step 2**: Cost out each component of the "Major Equipment."
- **Step 3**: In consultation with an engineer, determine what segment each component of the Major Equipment serves. **Assign** all these costs to that segment.
- **Step 4**: Determine what percentage of all the Major Equipment serves each segment.
- **Step 5**: Apply each segment's Major Equipment percentage to the substation's common costs and **allocate** it accordingly
- **Step 6**: Total cost = **assigned** direct costs + **allocated** common costs.

Can you provide an example from the TR-10 Rate Case?

- Chief Joseph Substation – Investment base is $20,973,286.
- It serves 3 segments: Generation Integration (GI), Integrated Network (N), and Southern Intertie (IS).
- Major Equipment investments are as shown on the next slide.

Major Equipment Costs – Chief Joseph Substation

Segment	Breakers	Transformers	Reactive	Totals
GI	$3,419,654	$ 0	$ 0	$ 3,419,654
Network	$8,943,631	$1,143,358	$1,955,527	$12,042,515
IS	$ 438,444	$ 0	$ 304,251	$ 742,695
Totals	**N/A**	**N/A**	**N/A**	**$16,204,864**

Major Component Percentages – Chief Joseph Substation

Segment	Costs	Percentage
GI	$ 3,419,654	21.1%
Network	$ 12,042,515	74.3%
IS	$ 742,695	4.6%
Total	**$ 16,204,864**	**100.0%**

Calculation of Common Costs – Chief Joseph Substation

Total Costs	$ 20,973,286
Less: Direct Costs **Assigned**	$ 16,204,864
Equals: Common Costs to be **Allocated**	$ 4,768,422

Final Allocation – Chief Joseph Substation

Cost Type	Cost Amount ($)	GI (@ 21.1%) ($)	Network (@ 74.3%) ($)	IS (@ 4.6%) ($)
Direct	16,204,864	3,419,654	12,042,515	742,695
Common	4,768,422	1,006,137	3,542,938	219,347
Total	20,973,286	4,425,791	15,585,453	962,042

What's the Magnitude of Investment?

As of 09/30/2002

Segment	Investment ($)	% of Total
Generation Integration	59,386,207	1.5%
Network	2,943,631,077	74.2%
Southern Intertie	667,931,943	16.8%
Eastern Intertie	121,756,685	3.1%
Utility Delivery	88,314,128	2.2%
DSI Delivery	88,154,482	2.2%
Totals	**3,969,174,522**	**100.0%**

What's the Magnitude of Investment?

As of 09/30/2007

Segment	Investment ($)	% of Total
Generation Integration	61,366,601	1.3%
Network	3,703,930,733	79.8%
Southern Intertie	712,121,650	15.3%
Eastern Intertie	118,137,417	2.5%
Utility Delivery	25,802,268	0.6%
DSI Delivery	19,803,072	0.4%
Totals	**4,641,161,743**	**100.0%**

What are some of the Significant Changes between 2002-2007?

Changes in **data**:

Segment	2002 $ / %	2007 $ / %
Network	$2,943,631,077 / 74.2%	$3,703,930,733 / 79.8%
DSI Delivery	$ 88,154,482 / 2.2%	$ 19,803,072 / 0.4%
Utility Delivery	$ 88,314,128 / 2.2%	$ 25,802,268 / 0.6%

- The size of the Network segment, both absolutely and relative to the other segments, has grown.
- The size of the Delivery segments, both absolutely and relative to the other segments, has contracted.

What Other Changes in Assumptions to Segmentation Analysis have occurred?

- Changes in assumptions:
- In prior years, investment and O&M costs associated with providing the FERC-defined Ancillary Services were identified and allocated between the 6 Ancillary Services.
  - 90+% were allocated to the Scheduling, System Control and Dispatch service.
  - Dividing these costs up was methodologically difficult and quite burdensome
  - As a result, these costs are now all assigned to the Scheduling, System Control and Dispatch service.

What are the O&M Costs?

- Now let’s look at Operations and Maintenance costs.
- We’ll walk though an example of how we:
  - Estimate future O&M expenditures.
  - Allocate these costs over the various segments.

Example O&M Cost Allocation – Chief Joseph Substation

(1) 3-year average **direct** O&M costs	$994,811
(2) 3-year average **direct** FCRTS O&M costs	$43,866,406
(3) Percentage of total O&M costs borne by Chief Joseph substation [5= (1)/(3)]	2.27%
(4) Total budgeted FCRTS O&M costs, **including all overhead**, for the first year of the rate period	$235,686,000
(5) Total budgeted FCRTS O&M costs, **including all overhead**, for the first year of the rate period, allocated to the Chief Joseph Substation [5=(3)*(4)]	$5,344,934
(6) Continuing the example of the Chief Joseph substation, this would be allocated 21.1%/74.3%/4.6% to GI/Network/IS	

Northern Intertie

What's the History of Northern Intertie Segment?

- Previously the issue of the Northern Intertie was raised with respect to the possibility of re-establishing it. The following background information was presented then:
  - The Northern Intertie was built in the 1940s.
  - Treated as a discrete segment beginning in 1983.
  - During discussions for the 1996 rate case, some parties proposed rolling this segment into the Network segment.
  - This new treatment was agreed to as part of the 1996 Rate Case settlement.

What's the History of Northern Intertie Segment?

- **Purpose:** Provided for better coordination between the systems of the PNW and Canada. Uses included sales and exchanges of power and power transfers during scheduled maintenance and emergency outages.
- **The Northern Intertie assets consisted of:**
  - Two 500-kV lines between the Custer substation (NW of Bellingham) and the United States-Canadian border.
  - Fifty per cent of the cost of two 500-kV lines between Custer and Monroe (East of Snohomish) substations.
  - Two 230-kV lines from the Boundary Substation (NE corner of Washington) to the United States-Canadian border.
  - Allocated portions of the associated substation facilities.

What's the FCRTS Investment?

As of 09/30/2007

	Without Northern Intertie		With Northern Intertie	
Segment	**Investment ($)**	**%**	**Investment ($)**	**%**
GI	61,366,601	1.3%	61,366,601	1.3%
N	**3,703,930,733**	**79.8%**	**3,670,111,654**	**79.1%**
IS	712,121,650	15.3%	712,121,650	15.3%
IE	118,137,417	2.5%	118,137,417	2.5%
IN	**----------**	**----------**	**33,819,079**	**0.7%**
UD	25,802,268	0.6%	25,802,268	0.6%
DSI	19,803,072	0.4%	19,803,072	0.4%
Totals	**4,641,161,743**	**100.0%**	**4,641,161,743**	**100.0%**

Utility Delivery Segment

What are Utility Delivery Substation Sales?

- As part of the 1996 rate case settlement, Bonneville agreed to adopt a policy that gives customers the right to buy or lease, and commits Bonneville to sell or lease, Bonneville's delivery facilities.
- In response to this agreement, and after consulting with interested customers/customer representatives and holding meetings throughout the region, Bonneville developed a Policy for Sale or Lease of Delivery Facilities.

What's the timeline of Utility Delivery Substation Sales?

- Between April 1997 and January 2008, Bonneville sold 154 Utility Delivery substations.
- A a result of these sales, the size of the Utility Delivery segment has shrunk considerably.
- The sale of Utility Delivery substations has slowed; 53 remain unsold.

What type of sensitivity analysis is performed on segmentation analysis?

1. What if the Northern Intertie was separated from the Network into a separate segment?
   - ➢ Network transmission rates could decrease approximately 0.5%.
2. What if existing segments like the Montana and/or Eastern Intertie were rolled into the Network?
   - ➢ Network transmission rates could increase 0.5% to 2.2%, depending on assumptions.
3. What if BPA rolled the utility delivery charge into the network?
   - ➢ Network transmission rates could increase approximately 0.5%.

Parking Lot

1. Whether or not to establish a formula for incremental cost rates for NOS plan-of-service that do not meet the criteria to move forward at embedded cost rates? If so, how and when should discussions take place to develop the structure and elements of the public process?
2. Whether or not to offer to replace customer served load to preserve some benefit previously received through CSL credits?
3. Whether or not to establish a short distance discount for the Southern Intertie?

Wrap Up

1. What suggestions do customers have for parking lot of topics to focus on for future transmission rates related discussions?

2. Did we reach agreement on the protocols for how to respond to questions or issues raised during such informal discussions?

Where to find more information?

- Check the agency calendar for future meetings at http://www.bpa.gov/corporate/public_affairs/calendar/
- Additional rates backgrounds is available at http://www.bpa.gov/corporate/ratecase/2008/2010_BPA_Rate_Case/meetings.cfm