BP-16 Settlement Proposal for Generation Inputs and Ancillary and Control Area Services

BPA Staff would like to build on the success of the BP-14 Gen. Inputs Settlement and reach another settlement of issues for the BP-16 rate period. We are seeking to settle all Generation Inputs and Ancillary and Control Area Services rates but Scheduling, System Control, and Dispatch Service (SCD) and Reactive Supply and Voltage Control from Generation Sources (GSR) Service.

In addition to building on the successes achieved in the last 12 months, a BP-16 settlement would provide the region with another two years of relief from the threat of costly and time consuming Ancillary and Control Area Service-related litigation. Reaching a settlement (by early September) before the BP-16 Initial Proposal would also decrease rate case contention and workload considerably, which saves all parties time and money. It would free up regional staff time to work on other rate case issues and regional efforts (such as the two Energy Imbalance Market (EIM) initiatives). Further, the result of the EIM initiatives has the potential to change the landscape or perspective of BPA's balancing services, making settlement more attractive if for nothing else than to wait and see what transpires before spending time and money on the potentially moot disagreements of today.

In the last 12 months implementing the BP-14 Settlement, BPA and customers have:

1. Actively participated in 7 all-customer workshops and approximately a dozen sub-team efforts to collaboratively explore the design of BPA's Ancillary and Control Area balancing services;
2. Implemented day-ahead third-party balancing reserve purchasing capability;
3. Gained valuable market information and experience with the purchase of third-party balancing reserves;
4. Developed and tested the ability to forecast reserve need at the preschedule timeframe;
5. Explored new methods to calculate the embedded cost of balancing reserves provided by the Federal Columbia River Power System;
6. Observed a significant decrease in the number of DSO 216 events;
7. Had encouraging discussions on a potential new reliability tool;
8. Found support for a design that provides a single high-quality balancing service to all customers; and
9. Created a conditional momentum of support for the replacement of Persistent Deviation for some customers with a new Intentional Deviation measurement.

Summary of Key Features of the Settlement

- ✓ No rate increase for Balancing Services. BP-16 Rates for Balancing Services that are set equal to the BP-14 settled rates.
- ✓ Replacement of controversial Persistent Deviation with Intentional Deviation Charge for wind and solar resources.
- ✓ Cost and rate certainty for Balancing Service customers through fixed rates that are not subject to the variability of third-party balancing reserves purchases.
- ✓ A substantial acquisition budget, more than $20 million, that provides BPA the flexibility to carry and purchase balancing reserves efficiently while still maintaining a high-quality balancing service to all customers.
- ✓ A mid-rate period election provides customers the choice to self-supply or take advantage of more efficient scheduling behaviors while limiting BPA's revenue risk exposure.
- ✓ Reliability Tool automation expanded to include dispatchable energy resources.

The proposed settlement rates compared to the BP-14 rates. Assumes scheduling elections similar to those elected in BP-14. Settlement rates subject to revision with substantial changes in scheduling election for FY 2016. A condition of the settlement would be that scheduling elections for FY 2016 are made by 5pm on September 18th 2014.

	BP-14 Rates	Proposed Settlement	% Change
30/15	$0.73	$0.73	0.0%
40/15	$0.94	$0.94	0.0%
30/60	$1.20	$1.20	0.0%
Uncommitted	$1.48	$1.48	0.0%
CSGI	$0.40	$0.40	0.0%
Solar	$0.21	$0.21	0.0%
DERBS Inc	$18.15	$18.15	0.0%
DERBS Dec	$3.94	$3.94	0.0%
Regulating	$0.12	$0.12	0.0%
Operating Reserves Spinning	$10.86	$11.40	5.0%
Operating Reserve Supplemental	$9.95	$10.45	5.0%

	Summary of Features	
1	Inc Need for BP-16 Rate Period*	950 MW
2	Dec Need for BP-16 Rate Period*	900 MW
3	Planned Dec Sourced from FCRPS in All Months	900 MW
4	Acquisition Strategy for Inc Non-Spring*	Attempt to hold 950 MW all the time
5	Acquisition Strategy Inc Spring	Hold at least 400 MW - BPA managed
6	Acquisition Cost Risk of 3rd Party Supply and Additional Spring	Transmission Services
7	TS Not Required to Spend Entire 3PS and Additional Spring Budget. TS not Required to Spend More Than (excluding Type 4)	Annually - $21.7m for 3PS and Additional Spring Capacity + Energy Cost above Powerdex Index. Decreased for Mid-Rate Period Election by [$4.5m * Nameplate Moved / 800 MW]
8	All Months but Spring	
9	Planned Inc Sourced from FCRPS in All Months but Spring	900 MW + Type 4 at BPA Discretion
10	Planned FCRPS Subject to Operational Reduction	Yes
11	Attempt to Replace Planned FCRPS when Reduced	Incs: Yes if identified by 15:00 PPT day prior to preschedule / Decs: No
12	Inc Planned FCRPS Replacement Risk	Power Services with exceptions for transmission-related reasons and significant energy accumulations. No replacement made when these exceptions occur or if cost exceeds $0.58/kW/day.
13	3rd Party Supply	50 MW year round subject to availability and mid-rate period election
14	Mid-Rate Period 3PS Election Adjustment (Rounded to Whole MW)	(50 MW * Nameplate Moved / 800 MW)
15	Spring (April, May, June, July)	
16	Spring	BPA Managed FCRPS & 3PS
17	FCRPS-Sourced Supply	At least 400 MW
18	FCRPS-Source Supply Cost	$0.29/kW/day
19	Features	
20	EI/GI energy band, Index, thresholds and applicability	No Change
21	Intentional Deviation (ID) Applicability	Wind and Solar
22	Intentional Deviation Base Forecast	BPA Super Forecast methodology Wind / Solar Election / Committed
23	Intentional Deviation Penalty	$100/MWh
24	Intentional Deviation Performance Waiver	Abs(Actual Error) <= Abs(BPA Official Forecast Error) + 1 MWh
25	BPA Official Hourly Forecast Made Available	xx:20
26	BPA Official Forecast	1-Hour Forecast
27	Premium for no Intentional Deviation (ID)	$0.20/kW-nameplate/mo + Persistent Deviation Penalty
28	Persistent Deviation (PD) Applicability	CSGI, No ID VERs, Load and DERs
29	EI/GI PD and ID Revenue Treatment	EI/GI and PD to Power Services / ID to Transmission Services
30	3PS Deployment Cost Risk	Transmission Services
31	Mid-rate Period Election Change	Yes - subject to caps
32	Total Election Allowable Nameplate Movement	800 MW Nameplate Cap
33	Self-Supply, CSGI Nameplate Movement	300 MW Nameplate Cap
34	DER Reliability Tool Inc	Automatically Impacted when SCE > Max(1 MW or 4.75% of Nameplate)
35	DER & Federal non-controlling Reliability Tool Dec	No Automatic Impact
36	Federal non-controlling Reliability Tool Inc	BPA to research potential impact that Federal non-controlling resources have on BPA BAA net SCE during reliability events and provide results to customers in spring 2015
37	Capacity-based ACS Risk Share	8.2%
38	Type 4 Acquisition Formula	Yes - Round down to whole MW - Delta between $.29/kW/day and actual cost
39	Type 4 Cost if Provided by FCRPS	$0.29/kW/day
40	DERBS Dead Band	3 MW
41	DERBS Billing Determinant	5-minute
42	Minimum TS Payment to PS for Balancing Capacity	$50,834,800
43	Potential TS Cost of Additional Spring + 3PS Annual Capacity	$20,800,000
44	Total Capacity Cost of Service to Transmission Services	$71,634,800
45	Expected TS Revenue	$71,632,737
46	Net Revenue TS	($2,063)

*Assuming elections similar to BP14 balancing service and scheduling elections.

Appendix

Table 1: Third-party supply (3PS) and additional spring budget broken down into the budget per kW of forecast balancing reserve need (950 MW year round) less the planned FCRPS capability. Line 3 = Line 2 divided by 2,600 MW months. 2,600 MW months calculated by multiplying 50 MW for 12 months (50 x 12) plus 500 MW for 4 months (500 x 4). Lines 4 and 5 take into account the $0.9 million annual cap above budget for actual 3PS and additional spring Transmission Service expenses.

	3PS and Additional Spring Cost Assumptions	
Annual 3PS and Additional Spring Budget in Rates	$20,800,000	2
Budget per kW in Rate ($/kW/mo)	$8.00	3
TS Annual 3PS and Additional Spring Cost Cap	$21,700,000	4
Cost Cap per kW ($/kW/mo)	$8.35	5
	* BPA not required to purchase 500 MW in spring every hour.	6
	** These values assume Mid-C Index Deployment Costs	7

Table 2: Downside risk to Transmission Services embedded in the settlement proposal. Mid-rate period election max (line 11) calculated as the worst case scenario with respect to reduced revenue collection for Transmission Services. Assumes the full mid-rate period election cap is used with 300 MW of nameplate movement from uncommitted to self-supply and 500 MW of nameplate movement from uncommitted to 30/15 committed scheduling.

	Transmission Services Max Downside Risk		
	Rate Period	Annual	10
Mid Rate Period Election Max Potential*	($5,328,000)	($2,664,000)	11
3PS and Additional Spring (Capacity and Deployments)	($1,800,000)	($900,000)	12
	*This is max exposure - Very unlikely to see this much movement		13

Table 3: Upside risk to Transmission Services embedded in the settlement proposal. Any Intentional Deviation (ID) penalty revenue to be retained by Transmission Services. Expectation is that Intentional Deviation revenue collection will be small. Line 18 presumes a hypothetical acquisition strategy where Transmission Services could spend less than the full Annual 3PS and Additional Spring Budget. The hypothetical acquisition cost was calculated assuming 600 MW months at $5/kW/mo, 1000 MW months from FCRPS during the spring, and 500 MW months at $16/kW/mo during the spring. While conceivable, likelihood of this hypothetical outcome was not evaluated.

	Transmission Services Upside Risk		
	Rate Period	Annual	16
ID Penalty Revenue	< $50,000	$25,000	17
3PS and Additional Spring (Capacity and Deployments)	$1,910,000	$955,000	18
	* Assumes 600 MW months at $5/kW/mo, 1000 MW months from FCRPS during the spring, and 500 MW months at $16/kW/mo during the spring.		