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.

<u>Summary of Key Features of the Settlement</u>

- ✓ <u>No rate increase for Balancing Services</u>. BP-16 Rates for Balancing Services that are set equal to the BP-14 settled rates. (*See Appendix Table 5*)
- ✓ <u>Replacement of controversial Persistent Deviation</u> with Intentional Deviation Charge for wind and solar resources.
- ✓ <u>Cost and rate certainty</u> for Balancing Service customers through fixed rates that are not subject to the variability of third-party balancing reserves purchases.
- ✓ <u>A substantial acquisition budget</u>, more than $22 million, that provides BPA the flexibility to carry and purchase balancing reserves efficiently while still maintaining a high-quality balancing service to all customers.
- ✓ <u>A mid-rate period election</u> provides customers the choice to self-supply or take advantage of more efficient scheduling behaviors while limiting BPA's revenue risk exposure.
- ✓ <u>Reliability Tool automation expanded</u> to include dispatchable energy resources.

Two Proposals: **Proposal A** 1,100 MW of Decs from FCRPS // **Proposal B** 900 MW of Decs from FCRPS

	Summary of Features	
1	Inc Need for BP-16 Rate Period*	950 MW
2	Dec Need for BP-16 Rate Period*	1,100 MW // 900 MW
3	Planned Dec Sourced from FCRPS in All Months	1,100 MW // 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 - $23,100,000 // 24,500,000 for 3PS and Additional Spring Capacity + Energy Cost above Powerdex Index. Decreased for Mid-Rate Period Election by [$4,500,000 * 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.
13	3rd Party Supply	50 MW year round subject to availability and mid-rate period election adjustment
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	$0.28/kW/day
19	Features	
20	EI/GI energy band thresholds and applicability	No change but for 100/60 Forecast Intentional Deviation
21	EI/GI Index Base (Band 1)	Net Imbalance by HLH/LLH * Month Average HLH/LLH Powerdex * 110% (inc) /100% (dec)
22	EI/GI Index Base (Band 2)	Hourly Powerdex * 120% (inc) /90% (dec)
23	EI/GI Index Base (Band 3)	Hourly Powerdex * 140% (inc) /75% (dec)
24	Intentional Deviation (ID) Applicability	Wind (including CSGI) and Solar
25	Intentional Deviation Base Forecast	BPA Super Forecast methodology Wind / Solar Election / Committed
26	Intentional Deviation Penalty	$100/MWh
27	Intentional Deviation Performance Waiver	Abs(Actual Error) <= Abs(BPA Official Forecast Error) + 1 MWh
28	BPA Official Hourly Forecast Made Available	xx:20
29	BPA Official Forecast	40/60 Forecast and 100/60 Forecast
30	Premium if Intentional Deviation set on 100/60 Forecast	Band 3 GI Applies **or** $0.20/kW-nameplate/mo (fixed premium - if applicable, used to mitigate Transmission Service Risk and Level of Service Risk)
31	Persistent Deviation (PD) Applicability	Load and DERs
32	EI/GI PD and ID Penalty Revenue Treatment	Transmission Services
33	3PS Deployment Cost Risk	Transmission Services
34	Mid-rate Period Election Change	Yes - subject to caps
35	Total Election Allowable Nameplate Movement	800 MW Nameplate Cap
36	Self-Supply, CSGI Nameplate Movement	300 MW Nameplate Cap
37	Max Rate Period Revenue Risk of Mid-Rate Change to TS (info only)	$5,328,000
38	DER Reliability Tool Inc	Automatically Impacted when SCE > Max(1 MW or 4.75% of Nameplate)
39	DER & Federal non-controlling Reliability Tool Dec	No Automatic Impact
40	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
41	Capacity-based ACS Risk Share	8.2%
42	Type 4 Acquisition Formula	Yes - Round down to whole MW - Delta between $.28/kW/day and actual cost
43	Type 4 Cost if Provided by FCRPS	$0.28/kW/day
44	DERBS Dead Band	3 MW
45	DERBS Billing Determinant	5-minute
46	Minimum TS Payment to PS for Balancing Capacity	$50,433,600 // $49,033,600
47	PS Expected Revenue in BP14 (info only)	$65,112,406
48	Potential TS Cost of Additional Spring + 3PS Annual Capacity	$22,100,000 // $23,500,000
49	Total Capacity Cost of Service to Transmission Services	$72,533,600
50	Expected TS Revenue	$72,537,518
51	Net Revenue TS	$3,918
		*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 $1 million annual cap above budget for actual 3PS and additional spring Transmission Service expenses.

	3PS and Additional Spring Cost Assumptions		
	Proposal A	Proposal B	1
Annual 3PS and Additional Spring Budget in Rates	$22,100,000	$23,500,000	2
Budget per kW in Rate ($/kW/mo)	$ 8.50	$ 9.04	3
TS Annual 3PS and Additional Spring Cost Cap	$22,200,000	$23,600,000	4
Cost Cap per kW ($/kW/mo)	$ 8.88	$ 9.42	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. Additional risk not yet captured is uncertainty around the forecast of new resource integration during the BP-16 Rate Period. Values in this proposed settlement assume ~350 MW of additional resource integration on average over the rate period.

	Transmission Services Max Downside Risk		9
	Rate Period	Annual	10
Mid Rate Period Election Max Potential*	($5,328,000)	($2,664,000)	11
3PS and Additional Spring (Capacity and Deployments)	($2,000,000)	($1,000,000)	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 and Persistent Deviation penalty revenue (for Intentional Deviation it would be the entire charge and for Persistent Deviation (PD) cost it would be the difference between PD and the price index) to be retained by Transmission Services. Expectation is that Intentional Deviation revenue collection will be small. A fixed premium for wind projects scheduling with a 100/60 forecast is a potential option of the settlement proposal. To the extent there is a fixed premium, the increased revenues will be used to manage Transmission Services risk as well as level of service risk by making additional 3PS purchases above the amount in the Annual 3PS and Additional Spring Budget. Line 19 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		15
	Rate Period	Annual	16
ID & PD Penalty Revenue	< $100,000	< $50,000	17
100/60 Forecast Fixed Premium (if applicable)	Depends	Depends	18
3PS and Additional Spring (Capacity and Deployments)	$2,560,000	$1,280,000	19

Appendix

Table 4: Percentages used to calculate the additional amount of balancing reserves needed by the BPA Balancing Authority Area when a customer 1) elects to self-supply but does not self-supply; 2) has a projected generator interconnection date after FY 2017 but interconnects during the FY 2016-2017 rate period; 3) elects to take a service but fails to conform to the criteria specified in BPA business practices; 4) elected one scheduling practice but later chooses to change its election to a longer scheduling period. Exact language to be included in the Transmission rate schedules.

	Type 4 Additional Amount of Inc Capacity on Nameplate			
From (Row) to (Column)	30/15	40/15	30/60	Uncommitted
30/15		2.0%	5.0%	7.5%
40/15			3.5%	5.5%
30/60				2.5%
CSGI	2.0%	3.5%	6.5%	9.0%

Table 5: 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 in August or September of FY 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%

Appendix

Tables 6 and 7: Analysis to help customers identify the financial consequences of holding various levels of dec balancing reserve amounts at two price points - specifically, the projected operational impact and cost associated with different dec balancing reserve amounts. Both tables assume the generation is lost and that a within-hour schedule change is not made to sell the excess generation above schedule.

Table 6: Opportunity cost of lost generation assumed to be $50/MWh. Under these assumptions, most economical amount of dec balancing reserves would be 750 MW.

				Assumed Value $/MWh		$50		
Reserve Level	Limits Per Year (#)	Limits Per Month (#)	Average Limit Capacity (MW)	Average Limit Energy (MWh)***	Total Lost Gen(MWh)	Cost of Lost Gen Decs	Cost of FCRPS Decs	Total Cost of Decs
-700	198	17	395	198	39,204	$ 1,960,200	$ 1,772,454	$ 3,732,654
-750	154	13	401	201	30,954	$ 1,547,700	$ 2,132,709	$ 3,680,409
-800	120	10	396	198	23,760	$ 1,188,000	$ 2,492,964	$ 3,680,964
-850	94	8	393	196	18,424	$ 921,200	$ 2,853,219	$ 3,774,419
-900	79	7	385	193	15,247	$ 762,350	$ 3,213,473	$ 3,975,823
-950	68	6	372	186	12,648	$ 632,400	$ 3,573,728	$ 4,206,128
-1000	58	5	358	179	10,382	$ 519,100	$ 3,933,983	$ 4,453,083
-1050	43	4	348	174	7,482	$ 374,100	$ 4,294,238	$ 4,668,338
-1100	35	3	338	169	5,915	$ 295,750	$ 4,654,493	$ 4,950,243
*** Assumes Limit events last 45 minutes of the hour and the average generation lost is 2/3 of max.								

Table 7: Opportunity cost of lost generation assumed to be $100/MWh. Under these assumptions, most economical amount of dec balancing reserves would be 850 MW.

				Assumed Value $/MWh		$100		
Reserve Level	Limits Per Year (#)	Limits Per Month (#)	Average Limit Capacity (MW)	Average Limit Energy (MWh)***	Total Lost Gen(MWh)	Cost of Lost Gen Decs	Cost of FCRPS Decs	Total Cost of Decs
-700	198	17	395	198	39,204	$ 3,920,400	$ 1,772,454	$ 5,692,854
-750	154	13	401	201	30,954	$ 3,095,400	$ 2,132,709	$ 5,228,109
-800	120	10	396	198	23,760	$ 2,376,000	$ 2,492,964	$ 4,868,964
-850	94	8	393	196	18,424	$ 1,842,400	$ 2,853,219	$ 4,695,619
-900	79	7	385	193	15,247	$ 1,524,700	$ 3,213,473	$ 4,738,173
-950	68	6	372	186	12,648	$ 1,264,800	$ 3,573,728	$ 4,838,528
-1000	58	5	358	179	10,382	$ 1,038,200	$ 3,933,983	$ 4,972,183
-1050	43	4	348	174	7,482	$ 748,200	$ 4,294,238	$ 5,042,438
-1100	35	3	338	169	5,915	$ 591,500	$ 4,654,493	$ 5,245,993
*** Assumes Limit events last 45 minutes of the hour and the average generation lost is 2/3 of max.								