WP-07 Supplemental Proposal and ASC Methodology Proposal

Overview of the Proposals

February 13, 2008

Agenda

- Background of Proposal
- Summary of WP-07 Supplemental Proposal
  - Revisions to FY 2009 Rates other than those related to the REP
  - Response to the Court's Opinions
  - Proposed changes to the 7(b)(2) Methodology
- Summary of ASC Methodology Proposal
- Timelines

Purpose of WP-07 Supplemental Proposal

- Respond to the May and October, 2007 Court rulings
    - Golden NW
    - PGE
    - Snohomish
- Revise rates for FY 2009
- Propose new 7(b)(2) Methodology and Legal interpretation

Background

- BPA developed WP-02 power rates that included the costs of the 2000 REP Settlement Agreements with six regional IOUs
  - The majority of these settlement costs were allocated to the Priority Firm (PF) Preference Rate

- A number of parties challenged the 2000 REP Settlement Agreements and BPA's WP-02 power rates in the Ninth Circuit
  - In *Portland General Elec. Co. v. Bonneville Power Admin*., the Court held BPA's 2000 REP Settlement Agreements with the IOUs were contrary to the Northwest Power Act
  - In *Golden NW Aluminum, Inc. v Bonneville Power Admin*., the Court held BPA had improperly allocated REP Settlement Agreement costs to BPA's FY 2002-2006 rates for preference customers
  - Because the Court held that BPA's allocation of REP settlement costs in its WP-02 rates was improper, BPA's similar allocation of such costs in its WP-07 rates is also flawed
  - In *PUD No. 1 of Snohomish County, Wash. v. Bonneville Power Admin*., the Court remanded 2004 Amendments to the REP Settlement Agreements and the Reduction of Risk discount
  - In three memorandum opinions, the Court dismissed challenges to the Load Reduction Agreements

Revisions to FY 2009 Rates other than those related to the REP

Summary of non-REP updates to assumptions for the FY 2009 rates

- Loads and Resources
  - Updated FY 2009 loads by 150 aMW to reflect forecast of higher load growth based on actuals
  - Added 46 aMW for Klondike III purchase, Idaho Falls bulb turbine purchase, and Slice ERE purchase
  - No updates to the hydro reg
    - Without a final FCRPS Biological Opinion, reasonable estimates of operation of the system were not available The hydro reg will be updated for the final Supplemental Proposal based on the final FCRPS BiOp, or our best estimates of the final BiOp if it is not released in time.
- Revenue Requirement – net $10M reduction in non-REP costs
  - Updated for revised CGS costs
  - Updated for revised estimates of interest expense, amortization, and depreciation
  - No revisions to repayment schedule
  - No revisions to estimates of fish and wildlife costs at this time. Again, BPA is waiting until the final FCRPS BiOp is available. If it is not available in time, BPA will use its best estimates.
  - These updates to the Revenue Requirement will be the subject of a PFR-like workshop in the spring, the outcome of which will be used in the final Supplemental Proposal.

Revenue Requirement Updates – Non-REP Costs

Difference in 2009 Revenue Requirements
WP-07 v. Supplemental Proposal

Operating Generation	
CGS	31,440
Long-Term Projects	6,113
Contracted Power Purchases	
DSI Monetized Power Sale	(4,001)
Other Power Purchases (Short-Term)	11,465
Augmentation Power Purchases	16,901
Renewable Generation	11,497
Energy Efficiency	9,067
Transmission Acquisition/Ancillary Srvcs	(5,000)
EN Debt Service	1,318
Depreciation	(7,448)
Amortization	(8,183)
Net Federal Interest	(26,959)
Minimum Required Net Revenues	(35,074)
Planned Net Revenues for Risk	(11,000)
Total -- Amt Supplemental differs from WP-07	(9,863)

Summary of non-REP updates to assumptions for FY 2009 rates, cont.

- Market Price Study
  - No updates were made at this time, largely because there was not a new hydro reg used in the Supplemental Proposal

- Risk Analysis
  - Maintained the same risk tools
    - CRAC
    - DDC
    - NFB Adjustment
    - Emergency NFB Surcharge
  - Changed the AMNR thresholds to reflect BPA's current financial condition and the CRAC cap

CRAC Cap and CRAC and DDC Annual Thresholds for FY 2009
(millions of dollars)

	AMNR Calculated at end of Fiscal Year	CRAC or DDC Applied to Fiscal Year	CRAC or DDC Threshold in AMNR[1]	Approx. Threshold as Measured in Power Services' Reserves	Maximum CRAC Recovery Amount (Cap)
CRAC	2008	2009	($81.4)	$750	$36
DDC	2008	2009	$218.6	$1,050	n/a

[1] Accumulated Modified Net Revenue

Summary of non-REP updates to assumptions for the FY 2009 rates, cont.

- Rate Design not changed; respects the Partial Resolution of Issues
- Costs for Generation Inputs not revised – but revenues from the sale of Within-hour Balancing Service for wind will be folded into the final Supplemental Proposal

Response to the Court’s Opinions

Outline of the Response to the Court's Opinions

There are four major components to BPA's proposal for responding to the Court's opinions

1. Calculate what each IOU received, or would have received, under the REP Settlements
2. Calculate what each IOU would have received under the Residential Exchange Program (REP) absent the REP Settlements
   - Assume the 1984 ASC Methodology for FY 2002-2008 ASCs
   - Calculate PF Exchange rate for FY 2002-2006 and FY 2007-2008 consistent with the 7(b)(2) rate test
   - Assume certain 7(b)(2) issues would have been "live" and assume decisions by BPA
   - Use "backcast" ASCs and REP loads to calculate what each IOU would have received through the REP
3. Calculate the appropriate differences for each IOU
   - Account for deemer balances
   - Account for the Load Reduction Agreements
4. Define how to recover the difference and return it to preference ratepayers

Step #1: What the IOUs Received Under the REP Settlements and LRAs

- The IOUs received ~$1.96 billion from FY02-06 and $168 million for FY 2007 resulting from a combination of:
  - Original REP Settlement Agreements and amendments
    - Settlement Agreements based on 900 aMW of monetary benefits and 1000 aMW of power for FY 2002-2006
    - Only Portland General Electric opted to take power deliveries for all 5 years
    - Settlement Agreements based on 2200 aMW of monetary or power benefits for FY 2007-2011
  - Load Reduction Agreements (LRAs) signed by PacifiCorp and Puget Sound Energy; $1.02 billion
  - Conservation & Renewables Discount and Conservation Rate Credits

Step 2: What each IOU would have Received During FY 2002-2008 under the REP

- In the Supplemental Proposal, BPA assumes implementation of REP for FY02-08
  - Assumes that BPA would have determined rates in Nov. 2000-June 2001
  - Assumes that two issues would therefore be "alive" – the Mid-Columbia and obsolete conservation issues
  - Assumes all IOUs except Idaho Power would have signed Residential Purchase and Sale Agreements (RPSA) in the absence of REP Settlement Agreements
  - Re-forecasts ASCs for purpose of calculating a PF Exchange rate and REP benefits for setting rates
  - Estimates ASC determinations that would have been made for each IOU
  - Compares ASC determinations against the PF Exchange rate and then multiplies the difference by exchangeable loads to estimate annual REP benefits the IOUs would have received

Approach to ASCs for each IOU in Step 2

- ASCs for use in the rate calculations
  - For FY 2002-2006 – revised ASCs for errors only
  - For FY 2007-2008 – revised ASCs for errors only

- ASCs to calculate REP benefit levels for use in calculating Lookback Amounts
  - For FY 2002-2006 – Used filed FERC Form 1 data
  - For FY 2007-2008 – Forecasts based on 2006 FERC Form 1 data

ASCs for each IOU in Step 2, cont.

ASC Re-forecasts and Backcasts for FY 2002- 2006

84 Methodology

	Backcast (Used to calc benefits)					Reforecast (used in RAM)				
	FY2002	FY2003	FY2004	FY2005	FY2006	FY2002	FY2003	FY2004	FY2005	FY2006
Pacific OR	38.37	38.06	41.39	42.65	41.19	44.23	35.21	33.88	35.52	36.56
Portland General	52.54	47.16	44.30	46.99	49.72	53.34	44.08	42.85	45.08	46.27
Pacific ID	33.29	33.13	34.16	36.59	38.59	82.61	51.13	45.19	47.40	48.05
Puget Sound	48.49	46.12	46.97	50.67	55.76	52.28	43.02	42.97	44.28	45.60
IDAHO POWER CO.	44.66	37.52	34.21	33.27	28.36	36.69	37.60	38.54	39.50	40.48
AVISTA (WWP)	44.38	44.54	45.77	42.39	44.47	41.74	42.78	43.85	44.95	46.08
NorthWestern Energy	46.99	46.99	50.43	47.50	52.62	53.86	39.98	37.89	39.66	40.66
Pacific WA	37.25	35.64	37.59	37.92	38.87	44.23	35.21	33.88	35.52	36.56

ASC Re-forecasts and Backcasts for FY 2007- 2008

84 Methodology

	Backcast (Used to calc benefits)		Reforecast (used in RAM)	
	2007	**2008**	**2007**	**2008**
PUGET SOUND ENERGY	53.66	52.69	47.58	48.60
PORTLAND GENERAL	49.04	47.49	47.55	50.10
NORTHWESTERN	51.03	51.98	56.50	59.18
AVISTA	48.28	49.80	45.37	47.02
PACIFICORP WA	41.27	42.17	35.61	37.45
PACIFICORP OR	40.76	41.74	35.61	37.45
PACIFICORP ID	37.26	38.13	35.61	37.45
IDAHO POWER	32.44	32.98	38.26	39.61

Step #3: The Difference = "Lookback Amounts"

- The Lookback Amount is the amount that PF Preference customers were overcharged and therefore should be recovered from IOUs and returned to PF Preference customers
- The Lookback Amount is determined annually for each IOU using the following "rules":

1. First, calculate the amount the IOU keeps

   This is the lesser of

   - Total Settlement benefits (sum of REP settlement benefits, LRA payments, CRD, CRC, value of power purchase)

   -OR-

   - Greater of LRA or "backcast" REP benefits calculated in the absence of the REP settlements

2. Second, subtract the amount the IOU keeps from the total settlement benefits received to get the annual Lookback Amount

Step #3 cont.: Key Assumptions for Calculating the Lookback for each IOU

- Key Assumptions in Calculating the Lookback:
  - Resetting PF Exchange rates for the FY 2002-2006 (WP-02) and FY 2007-2008 (WP-07) periods assumes there would have been an REP in the absence of the REP settlements
  - Treatment of Deemer Accounts
    - Assumes that full amount of FY 2002-2008 benefits would first go to reduce existing deemer balances prior to computing the Lookback Amounts
  - REP Benefits Credited Against Settlement Payments
    - An IOU's "credit" against its Lookback Amount cannot be greater than its Settlement benefits
  - Treatment of Reduction of Risk Discount and Load Reduction Agreements (LRA)
    - Reduction of Risk Discount - recoverable from IOUs through the Lookback calculations
    - LRAs treated as "protected" dollars – IOUs keep the lesser of REP settlement benefits or REP benefits, but not less than the LRA payments

Summary of Lookback Results for each IOU

	FY02-07 Lookback (in 2007 Dollars) *$ millions*
Avista	62.1
Idaho Power	96.6
Northwestern Energy	7.7
Portland General Electric	64.1
PacifiCorp	239.4
Puget Sound Energy	150.5
Total *(including inflation)*	**620.4**

- Assumes that BPA offers, and the IOUs sign, interim agreements that provide payments in 2008, subject to later true-up.
- If an IOU does not receive interim payments, then the REP benefits it is entitled to keep for FY08 will be applied to its accumulated Lookback Amount and will reduce the above amounts accordingly.

Company Specific Lookback Results

A	B	C	D	E	F	G	H	I	J	K	L	M
			2002	2003	2004	2005	2006	2007A	2007B	2008	Total 2002 to 2007B	Total 2002 to 2008
1	**Avista**											
2		Settlement Payments	$ 11.81	$ 8.98	$ 11.90	$ 11.82	$ 11.92	$ 10.58	$ -	$ -	$ 67.01	$ 67.01
3		Settlement Payments Co. *would have received*							**$ 10.56**	**$ 21.01**	$ 10.56	$ 31.57
4		REP Benefits before Deemer Adjust	$ 14.90	$ 8.81	$ 25.85	$ 12.59	$ 15.72	$ 13.30	$ 13.30	$ 33.01	$ 104.46	$ 137.47
5		REP Benefits applied to Deemer Account	$ 14.90	$ 8.81	$ 25.85	$ 12.59	$ 15.72	$ 13.30	$ 3.48	$ -	$ 94.64	$ 94.64
6		REP Benefits after Deemer Adjust (Line 4 - 5)	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.82	$ 33.01	$ 9.82	$ 42.83
7		Amount Company keeps **1/**	$ -	$ -	$ -	$ -	$ -	$ -	$ 9.82	$ 21.01	$ 9.82	$ 30.82
8		Nominal Lookback Amount **2/**	$ 11.81	$ 8.98	$ 11.90	$ 11.82	$ 11.92	$ 10.58	$ (9.82)	$ (21.01)	$ 57.19	$ 36.18
9		Lookback Amount in 2007$ **3/**	$ 13.54	$ 10.08	$ 12.99	$ 12.49	$ 12.22	$ 10.58	$ (9.82)	$ (21.01)	$ 62.09	$ 41.08
10												
11	**Idaho**											
12		Settlement Payments	$ 14.57	$ 12.04	$ 15.93	$ 15.80	$ 15.95	$ 15.89	$ -	$ -	$ 90.18	$ 90.18
13		Settlement Payments Co. *would have received*							**$15.87**	**$31.58**	$ 15.87	$ 47.44
14		REP Benefits before Deemer Adjust	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15		REP Benefits applied to Deemer Account	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
16		REP Benefits after Deemer Adjust (Line 14 - 15)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
17		Amount Company keeps **1/**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
18		Nominal Lookback Amount **2/**	$ 14.57	$ 12.04	$ 15.93	$ 15.80	$ 15.95	$ 15.89	$ -	$ -	$ 90.18	$ 90.18
19		Lookback Amount in 2007$ **3/**	$ 16.71	$ 13.52	$ 17.39	$ 16.71	$ 16.35	$ 15.89	$ -	$ -	$ 96.56	$ 96.56
20												
21	**NorthWestern**											
22		Settlement Payments	$ 3.11	$ 2.38	$ 3.16	$ 3.14	$ 3.17	$ 2.00	$ -	$ -	$ 16.94	$ 16.94
23		Settlement Payments Co. *would have received*							**$ 1.99**	**$ 3.95**	$ 1.99	$ 5.94
24		REP Benefits before Deemer Adjust	$ 5.95	$ 4.22	$ 10.06	$ 7.30	$ 11.08	$ 4.61	$ 4.61	$ 10.25	$ 47.83	$ 58.08
25		REP Benefits applied to Deemer Account	$ 5.95	$ 4.22	$ 10.06	$ 0.98	$ -	$ -	$ -	$ -	$ 21.21	$ 21.21
26		REP Benefits after Deemer Adjust (Line 24 - 25)	$ -	$ -	$ -	$ 6.31	$ 11.08	$ 4.61	$ 4.61	$ 10.25	$ 26.62	$ 36.87
27		Amount Company keeps **1/**	$ -	$ -	$ -	$ 3.14	$ 3.17	$ 2.00	$ 1.99	$ 3.95	$ 10.29	$ 14.24
28		Nominal Lookback Amount **2/**	$ 3.11	$ 2.38	$ 3.16	$ -	$ -	$ -	$ (1.99)	$ (3.95)	$ 6.65	$ 2.70
29		Lookback Amount in 2007$ **3/**	$ 3.56	$ 2.67	$ 3.45	$ -	$ -	$ -	$ (1.99)	$ (3.95)	$ 7.69	$ 3.74
30												

Company Specific Lookback Results, cont.

A	B	C	D 2002	E 2003	F 2004	G 2005	H 2006	I 2007A	J 2007B	K 2008	L Total 2002 to 2007B	M Total 2002 to 2008
31	**Pacific**											
32		Settlement Payments	$ 37.85	$ 26.26	$ 37.95	$ 37.85	$ 37.85	$ 46.29	$ -	$ -	$ 224.04	$ 224.04
33		Settlement Payments Co. *would have received*							**$ 46.29**	**$ 92.58**	$ 46.29	$ 138.87
34		LRA Payments	$ 79.22	$ 83.14	$ 83.37	$ 83.14	$ 83.14	$ -	$ -	$ -	$ 412.00	$ 412.00
35		Total Payments received (Line 32 + Line 34)	$ 117.06	$ 109.40	$ 121.32	$ 120.99	$ 120.98	$ 46.29	$ -	$ -	$ 636.04	$ 636.04
36		REP Benefits	$ -	$ -	$ 17.12	$ 22.10	$ 5.46	$ -	$ -	$ 4.08	$ 44.68	$ 48.76
37		Amount Company keeps **4/**	$ 79.22	$ 83.14	$ 83.37	$ 83.14	$ 83.14	$ -	$ -	$ 4.08	$ 412.00	$ 416.07
38		Nominal Lookback Amount **5/**	$ 37.85	$ 26.26	$ 37.95	$ 37.85	$ 37.85	$ 46.29	$ -	$ (4.08)	$ 224.04	$ 219.96
39		Lookback Amount in 2007$ **3/**	$ 43.40	$ 29.49	$ 41.42	$ 40.02	$ 38.79	$ 46.29	$ -	$ (4.08)	$ 239.41	$ 235.33
40												
41	**PGE**											
42		Settlement Payments	$ 59.01	$ 43.62	$ 62.46	$ 87.65	$ 113.56	$ 39.47	$ -	$ -	$ 405.76	$ 405.76
43		Settlement Payments Co. *would have received*							**$ 39.79**	**$ 78.95**	$ 39.79	$ 118.74
44		REP Benefits	$ 94.42	$ 38.91	$ 45.50	$ 62.92	$ 75.91	$ 31.93	$ 31.93	$ 51.56	$ 381.52	$ 433.09
45		Amount Company keeps **6/**	$ 59.01	$ 38.91	$ 45.50	$ 62.92	$ 75.91	$ 31.93	$ 31.93	$ 51.56	$ 346.12	$ 397.68
46		Nominal Lookback Amount **2/**	$ -	$ 4.71	$ 16.95	$ 24.73	$ 37.65	$ 7.53	$ (31.93)	$ (51.56)	$ 59.64	$ 8.08
47		Lookback Amount in 2007$ **3/**	$ -	$ 5.29	$ 18.50	$ 26.14	$ 38.59	$ 7.53	$ (31.93)	$ (51.56)	$ 64.13	$ 12.57
48												
49	**Puget**											
50		Settlement Payments	$ 56.11	$ 28.42	$ 56.27	$ 56.11	$ 56.11	$ 54.15	$ -	$ -	$ 307.18	$ 307.18
51		Settlement Payments Co. *would have received*							**$ 54.15**	**$ 108.32**	$ 54.15	$ 162.48
52		LRA Payments	$ 116.67	$ 122.50	$ 122.84	$ 122.50	$ 122.50	$ -	$ -	$ -	$ 607.00	$ 607.00
53		Total Payments (Line 50 + Line 52)	$ 172.78	$ 150.92	$ 179.10	$ 178.61	$ 178.61	$ 54.15	$ -	$ -	$ 914.18	$ 914.18
54		REP Benefits	$ 92.80	$ 44.79	$ 94.81	$ 134.14	$ 180.65	$ 72.41	$ 72.41	$ 135.11	$ 692.02	$ 827.13
55		Amount Company keeps **4/**	$ 116.67	$ 122.50	$ 122.84	$ 134.14	$ 178.61	$ 54.15	$ 54.15	$ 108.32	$ 783.06	$ 891.39
56		Nominal Lookback Amount **5/**	$ 56.11	$ 28.42	$ 56.27	$ 44.47	$ -	$ -	$ (54.15)	$ (108.32)	$ 131.12	$ 22.79
57		Lookback Amount in 2007$ **3/**	$ 64.35	$ 31.91	$ 61.42	$ 47.02	$ -	$ -	$ (54.15)	$ (108.32)	$ 150.55	$ 42.22
58												

Company Specific Lookback Results, cont.

A	B	C	D 2002	E 2003	F 2004	G 2005	H 2006	I 2007A	J 2007B	K 2008	L Total 2002 to 2007B	M Total 2002 to 2008
59	**Total**											
60		Settlement Payments	$ 182.45	$ 121.69	$ 187.67	$ 212.36	$ 238.56	$ 168.38	$ -	$ -	$ 1,111.10	$ 1,111.10
61		Settlement Payments Co. *would have received*							$ 168.65	$ 336.39	$ 168.65	$ 505.03
62		LRA Payments	$ 195.88	$ 205.64	$ 206.20	$ 205.64	$ 205.64	$ -	$ -	$ -	$ 1,019.00	$ 1,019.00
63		Sub Total Settlement + LRA Payments	$ 378.33	$ 327.33	$ 393.87	$ 418.00	$ 444.19	$ 168.38	$ -	$ -	$ 2,130.10	$ 2,130.10
64		REP Benefits before Deemer Adjust	$ 208.07	$ 96.72	$ 193.36	$ 239.04	$ 288.82	$ 122.25	$ 122.25	$ 234.01	$ 1,270.52	$ 1,504.53
65		REP Benefits applied to Deemer Account	$ 20.85	$ 13.03	$ 35.91	$ 13.57	$ 15.72	$ 13.30	$ 3.48	$ -	$ 115.86	$ 115.86
66		REP Benefits after Deemer Adjust	$ 187.22	$ 83.69	$ 157.44	$ 225.47	$ 273.10	$ 108.96	$ 118.78	$ 234.01	$ 1,154.66	$ 1,388.67
67		Amount Company keeps	$ 254.89	$ 244.54	$ 251.71	$ 283.33	$ 340.82	$ 88.08	$ 97.90	$ 188.92	$ 1,561.28	$ 1,750.20
68		Nominal Lookback Amount	$ 123.44	$ 82.79	$ 142.16	$ 134.66	$ 103.37	$ 80.29	$ (97.90)	$ (188.92)	$ 568.82	$ 379.90
69		Lookback Amount in 2007$	$ 141.56	$ 92.96	$ 155.17	$ 142.39	$ 105.95	$ 80.29	$ (97.90)	$ (188.92)	$ 620.43	$ 431.51

Step #4: Recovering Past Overpayments and Returning Amounts to PF Preference ratepayers

- Recover $620 million Lookback Amount for FY 02-07 from IOUs by reducing future REP benefits
  - The amount to reduce future REP benefits is determined by the Administrator in each rate case
  - Results in lower PF Preference rates for FY 09 and beyond until Lookback Amounts are fully recovered
  - Lookback balances will accrue interest as they are “worked down”
  - Expect to amortize the Lookback Amounts in 20 years or less, with the possible exception of Idaho Power and PacifiCorp
- Return $316 million to PF ratepayers through cash payments in 2008/2009 for their overpayments made through FY 2007-2008 power rates
  - BPA calculated that FY 07 and FY 08 benefits to the IOUs would have been $186M and $189M, respectively, compared to REP settlement payments of $337M, and $336M, respectively.
  - The additional $17M results from the difference between the $168M paid to the IOUs in FY 2007 and their “otherwise” REP benefits of $186M that was rolled into the Lookback Amounts
  - The $316 million is proposed to be disbursed to consumer-owned utilities either via interim agreements in FY 08 (with a true-up in FY 09) or disbursements in 2008/2009
  - Slice portion returned via Slice True-Up in Jan 2009 absent interim agreement
- IOUs received no REP benefits in FY 2008. If offered, they could receive payments via the interim agreements for FY 2008. If not, lesser of Settlement or REP benefits credited against and thereby reducing Lookback Amounts.

Proposed Changes to the 7(b)(2) Implementation Methodology

Proposed changes to the 7(b)(2) Implementation Methodology

Applied to FY 2002 and beyond:

- Treatment of Preference Customer Resources Used to Serve Requirements Loads
- Treatment of BPA-Acquired Conservation

Applied to FY 2009 and beyond:

- Identification and Use of Natural Consequences
- Treatment of Specified 7(g) Costs
- Identification and Treatment of Resources in the 7(b)(2)(D) Resource Stack
- Treatment of REP Settlement Costs in the Rate Test
- Allocation of 7(b)(3) costs to the PF Exchange Rate
  - Creates unique PF Exchange rates for each exchanging utility

Proposed Key Revisions to Section 7(b)(2)

Issue	Current	Proposal	Effect of Proposal
1. Treatment of Preference Customer Resources Used to Serve Requirements Loads (a.k.a. Mid-C resources in/out)	Preference customers' resources not dedicated to serving their own firm loads under section 5(b) are available in the 7(b)(2)(D) resource stack to serve 7(b)(2) load (Mid-Cs in)	Preference customer resources that are dedicated to serve any utility's requirements load under section 5(b) are not available in the 7(b)(2)(D) resource stack (Mid-Cs out)	Increases REP benefits
2. Treatment of BPA-Acquired Conservation	No removal of obsolete conservation	Remove obsolete conservation	Decreases REP benefits
3. Identification and Use of Natural Consequences	Three natural consequences reflected in the rate test: demand elasticities, amount of surplus firm power available and size of non-firm energy markets	Remove demand elasticities	No effect (if BPA sells power to DSIs, then decreases REP benefits)

Proposed Key Revisions to Section 7(b)(2), cont.

Issue	Current	Proposal	Effect of Proposal
4. Treatment of Specified 7(g) Costs	Specified 7(g) costs are removed from Program Case but not from 7(b)(2) Case	7(g) costs removed from both cases prior to the incorporation of the assumptions specified in section 7(b)(2)	No change in REP benefits
5. Identification and Treatment of Resources in the 7(b)(2)(D) Resource stack	Certain resources added in discrete lumps	Remove the effects of the discrete lumps on the rate test by selling excess resources at the cost of the excess resources	Benefit changes vary on case by case basis
6. Treatment of REP Settlement Costs in the Rate Test	Did not address	REP settlement costs are costs that should be excluded from the 7(b)(2) Case	No change in REP benefits

Proposed Changes to the ASC Methodology

Major Proposed Changes to ASC Methodology

- Major proposed changes to the ASC Methodology include:
  - Format for filing ASCs
    - Replaces "jurisdictional approach" with a simpler and more uniform and transparent approach that relies on FERC Form 1 data
    - Alleviates administrative burden and expense for BPA and exchanging utilities
  - Changes to the treatment of transmission costs, taxes and return on equity
  - Sets an exchanging utility's ASC in a public process prior to a BPA rate case
    - ASCs used in setting the PF Exchange rate during a rate case will be the same ASCs used to calculate actual benefits paid to the exchanging utility
    - Exchange loads used to calculate actual benefits paid will be based on actual loads

Treatment of Costs in ASC Methodology

- Changes to the treatment of transmission costs
  - The 1984 Methodology allowed all transmission costs prior to 1984 but only a portion of them after 1984
  - The Proposed ASC Methodology allows all transmission costs in ASC calculation
    - Not allowing all transmission costs may cause inequity between utilities that develop resources close to their service territory and those that develop geographically distant resources.
    - As the region builds new resources, this becomes a significant issue.
  - Treatment of transmission in BPA Exchange rate similar to ASC Methodology

Treatment of Costs in ASC Methodology, cont.

- Changes to the treatment of taxes and equity costs
  - The 1984 Methodology did not allow return on equity in ASC calculation but instead allowed the inclusion of the utility’s long-term cost of debt. It also did not allow income taxes in the calculation of ASC
  - The proposed ASC Methodology includes the cost of equity in ASC. The change is based on the fact that the cost of debt is a cost of resources and, in the case of investor-owned utilities, the cost of debt is lowered by the contribution of equity by the company. Without the spreading of risk to shareholders there would be a significant increase in the cost of debt. Therefore, debt alone is not an adequate reflection of the capital cost of a utility's resources
  - Without the cost of capital, a higher cost of debt is needed to reflect the true cost of financing resources
  - In addition, the proposed ASC Methodology includes the cost of Federal taxes in ASC. This change is proposed because it is necessary to have symmetry between treatment of equity and taxes. If the cost of Federal income taxes at the marginal tax rate is not also included, then an investor-owned utility’s cost of resources would be understated

ASC Forecasts for FY 2009

	FY 2009 *ASC Forecast* *$ per MWh*
Avista	50.65
Idaho Power	38.24
Northwestern Energy	53.98
Portland General Electric	49.93
PacifiCorp	47.20
Puget Sound Energy	54.07
Benton PUD	37.35
Grays Harbor PUD	43.23
Snohomish PUD	39.73

Exchanging with BPA in FY 2009

- Requirements to participate in the REP for FY 2009.
  - A utility wanting to exchange with BPA in FY 2009 must give BPA a Notice of Intent to participate in the REP by February 22, 2008. This can be sent to BPAAverageSystemCost@bpa.gov.
  - The utility must file with BPA their 2006 FERC Form 1 ASC data (Appendix 1 of proposed ASC Methodology) by March 3, 2008. If a utility cannot meet the deadline, then BPA will use its proposal of the utility's 2006 FERC Form 1 ASC from the WP-07 Supplemental Proposal as the utility's filing .
  - The filing will go through an expedited public review process to conclude on June 6.
  - Any non-filing entity that wants to participate in the expedited review process must make its request to BPA by March 11, 2008.
  - A detailed calendar of the expedited process can be found at the end of the packet or online at www.bpa.gov/corporate/finance/ascm

Putting all the Pieces Together for FY 2009

Changes to FY09 Power Rates

- Reduction to non-REP program costs of $10M
- Change to REP costs
  - Decreased IOU REP cost by $134 million (from $336 to $202 million)
  - Increased Public REP cost by $2.6 million (from $6.8 to $9.4 million)
- Changes to Risk
  - Changed Thresholds for CRAC and DDC
  - Cap on the CRAC now $36M instead of $300M
- PF rate declines from $27.3/MWh to $26.2/MWh ~ 4 percent decrease

Changes to FY09 Power Rates, cont.

- With $141 million in cost reductions, why is the PF rate not going down more?
  - The $27.3/MWh was an average of rates for FY 2007-2009. If BPA had set an annual rate for FY 2009 it would have been $28.4/MWh
  - For the WP-07 Supplemental Proposal, BPA is setting a one-year rate
  - The $141 million reduction will benefit both the Slice and non-Slice rates
  - Given the “rule of thumb” for costs that benefit both rates, that would mean the PF rate should see a reduction of around $2/MWh ($141 M/$69M)
  - Therefore, using the “rule of thumb,” reducing the FY09 individual rate of $28.4/MWh by $2/MWh would result in a rate of about $26.4/MWh, which is very close to the calculated rate of $26.2/MWh

FY 2009 IOU REP Benefits

- Assumptions
  - New 7(b)(2) Implementation Methodology
  - New approach to allocating 7(b)(3) amount resulting in utility-specific PF Exchange rates – the calculated REP benefits for FY 2009 total $250M
  - Proposed revised ASC Methodology used for FY 2009 ASC forecasts

- Results for IOU REP Benefits for FY 2009
  - IOU REP calculated benefits after applying the rate test are $250 million
  - BPA then scaled down benefits to $210 million, middle of Customer Recommendations range, with difference applied to Lookbacks.
  - However, Idaho still has an outstanding deemer amount, so its benefits are applied to the deemer instead of reducing its Lookback Amount
  - Combination of benefits applied to Lookbacks and deemer balance means FY 2009 PF rates will only have $202 million in IOU REP costs
  - Amounts applied against Lookbacks consistent with paying Lookbacks off in 20 years or less, including interest, with possible exception of Idaho Power.
  - Allows reasonable REP benefits to IOUs' residential consumers

FY 2009 REP Benefits for each IOU

	FY09 REP Settlement Benefits *$ millions*	**FY09 REP Benefits** (before Deemer and Lookback) *$ millions*	**FY09 REP Benefits** (after Deemer and Lookback) *$ millions*
Avista	21	27.8	23.3
Idaho Power	31.6	9.2	0
Northwestern Energy	4	7.6	6.4
Portland General Electric	79	54.6	45.8
PacifiCorp	92.6	50.8	42.7
Puget Sound Energy	108.3	100.2	84.1
Total	**336.4**	**250.2**	**202.3**

DSI Heads Up

- How might these results change if the Ninth Circuit rules against BPA in PNGC case?
  - Currently, the DSI $55 million monetary payment is in the Program Case but not the 7(b)(2) Case
  - If BPA sells power at the IP rate, loads and costs end up in both the Program and 7(b)(2) Cases, resulting in the:
    - 7(b)(2) trigger decreasing
    - PF Exchange rate decreasing
    - REP benefits increasing
  - BPA could sell about 350 aMW to DSIs at the IP rate with no net increase in costs. $55 million = Market – IP rate x IP Load
  - Including 350 aMW of IP Load increases REP benefits from $250 million to $300 million
  - Because the REP benefits are being reduced to $210, the increase in REP benefits could be used to reduce the Lookback Amount faster instead of raising the PF rate ($90 million vs. $40 million in Lookback reduction for FY09).

Next Steps

- WP-07 Supplemental Proposal Schedule to be set February 19, 2008 at the Prehearing Conference
- FY 2009 ASC Expedited Process Schedule
- ASC Methodology Proposal Schedule

FY09 ASC Expedited Process Schedule

February 22, 2008	Deadline for Notice of Intent to Participate in FY09 ASC filing (for utilities wanting to exchange)
March 3, 2008	FY09 ASC filings due to BPA
March 4, 2008	Post online FY09 ASC filings
March 11, 2008	Petition to intervene deadline
March 14, 2008	ASC data requests due
March 26, 2008	ASC Workshop to deal with data requests
April 10, 2008	ASC FY09 Issues list deadline to BPA
April 24, 2008	ASC FY09 responses to issue list deadline
April 29, 2008	Workshop on FY09 ASC Issues list
May 9, 2008	Draft FY09 ASC Reports out for comment (There will be a separate report for each utility)
May 23, 2008	Comments deadline on draft FY09 ASC Reports
June 6, 2008	Issue Final FY09 ASC Reports
August 2008	If needed, limited review of FY09 ASC Reports (for conformity to final ASC Methodology)
September 30, 2008	If needed, amended Final FY09ASC Reports

ASC Methodology Consultation Schedule

February 7, 2008	Start of comment period on ASC Methodology
March 13, 2008	Workshop - ASC Methodology Issues
March 31, 2008	Workshop - ASC Methodology Issues
April 14, 2008	Workshop - ASC Methodology Issues (tentative)
May 2, 2008	Close of comment period on ASC Methodology
May 16, 2008	Draft ASC Methodology ROD out for comment
May 30, 2008	Comments due on draft ASC Methodology ROD
June 27, 2008	Final ASC Methodology ROD published
July 3, 2008	ASC Methodology FERC filing
September 3, 2008	Interim approval by FERC