2010 Power Rate Case
Conference Call Workshop

Thursday, December 18, 2008

Pricing of Generation Inputs

Generation Input Costs for Reserves

- Presentation covers Regulating Reserves, Wind Integration – Within-Hour Balancing Reserves and Operating Reserves
- Embedded Costs
  - Same methodology
  - Updated hydroregulation and costs
- Variable Cost
  - Changes in methodology
  - Updated hydroregulation and market price forecast
- Total Reserve Costs
  - Embedded + Variable

Update on Embedded Costs for Generation Inputs for Reserves for the Preliminary Initial Proposal

- Same embedded cost methodology as described in the 23 September and 22 October workshops
- Same forecasted reserve need quantities from 10 September workshop
- Updated for 2010 Rate Case hydroregulation and Revenue Requirement
- Updated embedded costs

Generation Inputs for Operating Reserves Embedded Cost

	Preliminary Embedded Cost Allocation for Generation Inputs for Operating Reserves	
	A	**B**
		Annual Average for FY2010-FY2011
	Reserve Assumptions (MW)	
1	Regulated + Independent Hydro Projects Capacity	8,370
2	Regulating Reserves	105
3	Operating Reserves	513
4	Load Following Reserves	628
5	Wind Integration Reserves	1,045
	Forecast of Hydro Capacity System Uses (MW)	
6	Regulated + Independent Hydro Projects Capacity	8,370
7	Total Power Services Reserve Obligation (Line 2+3+4+5)	2,291
8	Regulated + Independent Hydro Projects Capacity System Uses (Line 6+7)	10,661
	Adjusted Revenue Requirement	
9	Power Services' Revenue Requirement for Regulated + Independent Hydro Projects	$ 910,688,000
10	Regulated + Independent Hydro Projects Capacity System Uses (Line 8)	10,661
11	Total Hydro Project Capacity in kW per month (Line 10 * 12MO * 1000kW/MW)	127,932,000
12	**Per Unit Allocation $/kW/month (Line 9 / Line 11)**	**$ 7.12**
	Revenue Forecast by Product	
13	Operating Reserves (Line 3 * Line 12 * 12 months * 1000 kw/MW)	**$ 43,830,720**

Generation Inputs for Regulating Reserves and Wind Integration: Within-Hour Balancing Reserves Embedded Cost

Preliminary Embedded Cost Allocation for Generation Inputs for Regulating Reserves and Wind Integration - Within-Hour Balancing Reserves		
	A	B
		Annual Average for FY2010-FY2011
	Reserve Assumptions (MW)	
1	Regulated + Independent Hydro Projects Capacity	8,370
2	Regulating Reserves	105
3	Operating Reserves	513
4	Load Following Reserves	628
5	Wind Integration - Within-Hour Balancing Reserves	1,045
	Forecast of Hydro Capacity System Uses (MW)	
6	Hydro Projects Capacity (Line 1 * 91%) Big 10 is 91% of the System	7617
7	Total Power Services Reserve Obligation (Lines 2+3+4+5)	2291
8	Hydro Project Capacity System Uses (Line 6+7)	9908
	Adjusted Revenue Requirement	
9	Power Services' Revenue Requirement for Regulated + Independent Hydro Projects	$ 824,416,000
10	Regulated + Independent Hydro Projects Capacity System Uses (Line 8)	9,908
11	Total Hydro Project Capacity in kW per month (Line 10 * 12MO * 1000kW/MW)	118,892,400
12	**Per Unit Allocation $/kW/month (Line 9 / Line 11)**	**$ 6.93**
	Revenue Forecast by Product	
13	Regulating Reserves (Line 2 * Line 12 * 12 months * 1000 kw/MW)	**$ 8,731,800**
14	Wind Integration - Within-Hour Balancing Reserves (Line 5 * Line 12 * 12 months * 1000 kw/MW)	**$ 86,902,200**

Generation And Reserves Dispatch (GARD) Model:

A Pricing Methodology for Generation Inputs for Regulating Reserves and Wind Integration – Within-Hour Balancing Service

WP-10 Workshop
December 18, 2008

Pre-decisional and for discussion purposes only

Outline

- Variable cost of reserves: overview.
- Specific cost associated with standing ready to provide as well as providing reserves.
- Preliminary results for the total cost as well as the component costs.

Variable Cost of Reserves

- Costs associated with setting up the system to stand ready and respond to reserve need.
- All reserves are referred to as “inc” or “dec” obligations.
  - Inc Reserve: ability to increase generation in order to maintain load-resource balance in the Balancing Authority Area (BAA).
  - Dec Reserve: ability to decrease generation in order to maintain load-resource balance in the Balancing Authority Area (BAA).
- All costs are operations related and do not include items such as O&M.
- There are two broad categories of cost:
  - Stand Ready
  - Deployment

Variable Cost of Reserves

- **Stand ready: Those costs associated with making the reserve available such that the system is capable of instantaneously maintaining load-resource balance 99.5% of the time. Stand ready costs consist of:**
  - Energy shift.
  - Efficiency loss.
  - Base cycling loss.
- **Deployment: Those costs associated with using the reserve in response to the system's need to maintain load-resource balance. Deployment costs consist of the following:**
  - Response losses.
  - Incremental cycling loss.
  - Incremental spill.
  - Incremental efficiency loss.

Notable Changes in Modeling

- **Modeling Non-Spinning Reserves: up to 100% of the imbalance reserve and up to 50% of the load following reserve carried non-spinning, while 100% of the regulating reserve and 50% of the total operating reserve is spinning.**
  - **More accurately mimics FCRPS behavior during instances of large, within hour movements.**
  - **Exchanges costly upfront efficiency loss (stand ready) for less costly, as-needed cycling losses (deployment).**
- **Energy Shift: the modeling of the energy shift cost is tied more tightly to system conditions and operations; accounting for times when shifting energy may be unnecessary.**

Notable Changes in Modeling

- **Explicit modeling of unit cycle cost: unit cycling costs are modeled by project and required generation level given explicit reserve deployment scenarios.**

- **These modifications, combined with updated model inputs, reduce the variable cost associated with reserves as compared to the results shared at earlier workshops.**

Results

- The results are separated by those charges being directly billed to Transmission (load regulation, wind balancing, and operating reserves) and those charges being incorporated into PF rates (load following and imbalance).
- Results do not include embedded cost.
- All results are presented as rate period averages.

Results (con't)

- **The following results summary table contains FY2010-11 average, annual, variable costs based on the WIT team's September 10th study on the amount of reserves needed:**

TOTAL GEN INPUT VARIABLE COST	
LOAD REG 106 MW INC ($)	-3,836,365
LOAD REG 121 MW DEC ($)	-1,921,022
TOTAL LOAD REG ($)	-5,757,387
WIND BAL 1045 ME INC ($)	-10,607,825
WIND BAL 1489 MW DEC ($)	-23,639,686
TOTAL WIND BAL ($)	-34,247,511
OPERATING RESERVES 256.5 MW INC ($)	-2,911,053
TOTAL OR SPINNING ($)	-2,911,053
VARIABLE GEN INPUT COST TO TX ($)	-42,915,952
LD FOLLOWING COST TO POWER RATES ($)	-15,305,111
TOTAL VARIABLE COST ($)	-58,221,062

Results (con't)

- **A similar table to the previous, except broken out by inc and dec for load and wind:**

TOTAL VARIABLE RESERVE COST BY LOAD & WIND

LOAD INC SPINNING ($)	-5,040,477
WIND INC SPINNING ($)	-7,185,946
TOTAL BAL SPINNING ($)	-12,226,423
LOAD INC NON-SPINNING ($)	-2,400,227
WIND INC NON-SPINNING ($)	-3,421,879
TOTAL BAL NON-SPINNING ($)	-5,822,106
LOAD DEC ($)	-13,621,794
WIND DEC ($)	-23,639,686
TOTAL BAL DEC ($)	-37,261,480
OPERATING RESERVE SPINNING ($)	-2,911,053
TOTAL OR SPINNING ($)	-2,911,053
TOTAL VARIABLE COST	-58,221,062

Results (con't)

- The following table shows the total variable cost for various combinations of inc and dec reserve obligation. Also presented is a preliminary version presented at the September workshop of the same table.
- In addition to the revised methodology discussed above, the original table did not use a current hydro reg and did not have project specific models for shaping energy into HLH.
- Latest version of the total variable costs by inc and dec combination:

TOT BAL DEC \ TOT BAL INC	0	575	1150	1725	2300
0	0	-6,730,331	-12,511,459	-21,603,548	-36,443,275
-575	-6,316,478	-9,127,233	-14,673,732	-23,689,963	-38,387,640
-1150	-12,537,419	-15,608,216	-20,829,342	-29,555,347	-43,834,926
-1725	-23,760,466	-27,747,909	-34,310,434	-41,786,086	-55,611,407
-2300	-43,581,084	-46,367,889	-51,084,545	-57,717,805	-71,660,911

Results (con't)

- For reference, the old version:

TOTAL	0 MW	500 MW	1000 MW	1500 MW	2000 MW
0 MW	0	-3,929,261	-15,927,855	-35,539,794	-59,924,888
-500 MW	-16,075,821	-19,180,286	-30,288,028	-49,894,692	-74,697,623
-1000 MW	-31,898,170	-34,519,079	-44,949,061	-64,180,132	-89,378,545
-1500 MW	-47,736,001	-50,275,466	-59,925,043	-78,629,097	-104,095,491
-2000 MW	-63,837,544	-66,017,218	-75,187,642	-93,409,013	-119,342,653

- As well as the latest version with the same scale:

TOT BAL DEC	TOT BAL INC				
	0	500	1000	1500	2000
0	0	-4,925,167	-9,439,075	-15,539,166	-25,222,882
-500	-3,560,655	-8,485,822	-12,999,730	-19,099,821	-28,783,537
-1000	-8,908,044	-13,833,211	-18,347,119	-24,447,210	-34,130,926
-1500	-17,308,499	-22,233,666	-26,747,574	-32,847,665	-42,531,380
-2000	-30,028,352	-34,953,519	-39,467,427	-45,567,518	-55,251,233

Preliminary Generation Inputs Costs for Reserves

	Preliminary Initial Proposal		
Generation Input	**Amount**	**Per Unit Cost**	**Annual Revenue Forecast**
Regulating Reserves(MWs)	105	$ 11.50 kW-Mo	$ 14,489,187
Wind Integration - Within-Hour Balancing (MWs)	1045	$ 9.66 kW-Mo	$ 121,149,711
Operating Reserves - Spinning (MWs)	256.5	$ 8.07 kW-Mo	$ 24,826,413
Operating Reserves - Supplemental (MWs)	256.5	$ 7.12 kW-Mo	$ 21,915,360

Detail to Generation Inputs Charts Above	Amount	Per Unit Cost	Annual Revenue Forecast	*Notes*
Regulating Reserves (MWs)	105 inc	$ 6.93 kW-Mo	$ 8,731,800	*Embedded*
Regulating Reserves (MWs)	105 inc 121 dec		$ 5,757,387	*Stand Ready - Energy Shift, Efficiency Loss, Cycling, Spill and Deployment Costs*
Wind Integration - Within-Hour Balancing (MWs)	1045 inc	$ 6.93 kW-Mo	$ 86,902,200	*Embedded*
Wind Integration - Within-Hour Balancing (MWs)	1045 inc 1489 dec		$ 34,247,511	*Stand Ready - Energy Shift, Efficiency Loss, Cycling, Spill and Deployment Costs*
Operating Reserves - Spinning (MWs)	256.5 inc		$ 2,911,053	*Stand Ready - Energy Shift, Efficiency Loss*
Operating Reserves - Spinning and Supplemental (MWs)	513 inc	$ 7.12 kW-Mo	$ 43,830,720	*Embedded*

Preliminary - for information purposes only:

Assuming an annual average amount of wind installed capacity from the 10 September workshop (average of 3155 MW and 4330 MW is 3743 MW) and the current rate design, the rate would be $2.70 per kW per month of installed capacity.

$121,149,711 / (3743 MW * 12 months * 1000 kW/MW) = $2.70 per kW per month

AURORA, Market Prices, Net Secondary Revenues, and Augmentation Costs

Natural Gas Price Forecast

- From the December 3 Workshop
- "Our current outlook for Henry Hub natural gas prices falls between the low $7.00 range and the low $6.00 range."
  - Recession lowers demand, but supply is relatively resilient, resulting in downward price pressure
  - Unconventional production is growing rapidly and will limit price increases even with economic recovery
- Expected Initial Forecast
- Economic recovery expected by 2010
- Henry Hub, nominal $
  - 2010 = $7.21
  - 2011 = $7.39

Electric Power Market Price Forecast
Model Update

- AURORAxmp is an electric energy market model
  - Primary output is an electric power market price forecast
- Updated model to AURORAxmp version 9.2
- Updates to AURORAxmp's application in WP-10 rate case:
  - 70 historical water years (1929 – 1998) used to model Pacific Northwest hydroelectric generation variability.
  - Risk analysis increased from 3,000 to 3,500 games.

Electric Power Market Price Forecast
AURORAxmp's Primary Uses In WP-10 Rate Case

- **Net Secondary Revenue Forecast – Used for net secondary revenue credit in base rates:**
  - **70 separate AURORAxmp games produce 70 sets of monthly spot market electricity prices (HLH and LLH)**
  - **Each game uses a different water year (1929 – 1998) to reflect different water conditions**
  - **Loads and natural gas prices are kept constant**

Electric Power Market Price Forecast
AURORAxmp's Primary Uses In WP-10 Rate Case (con't)

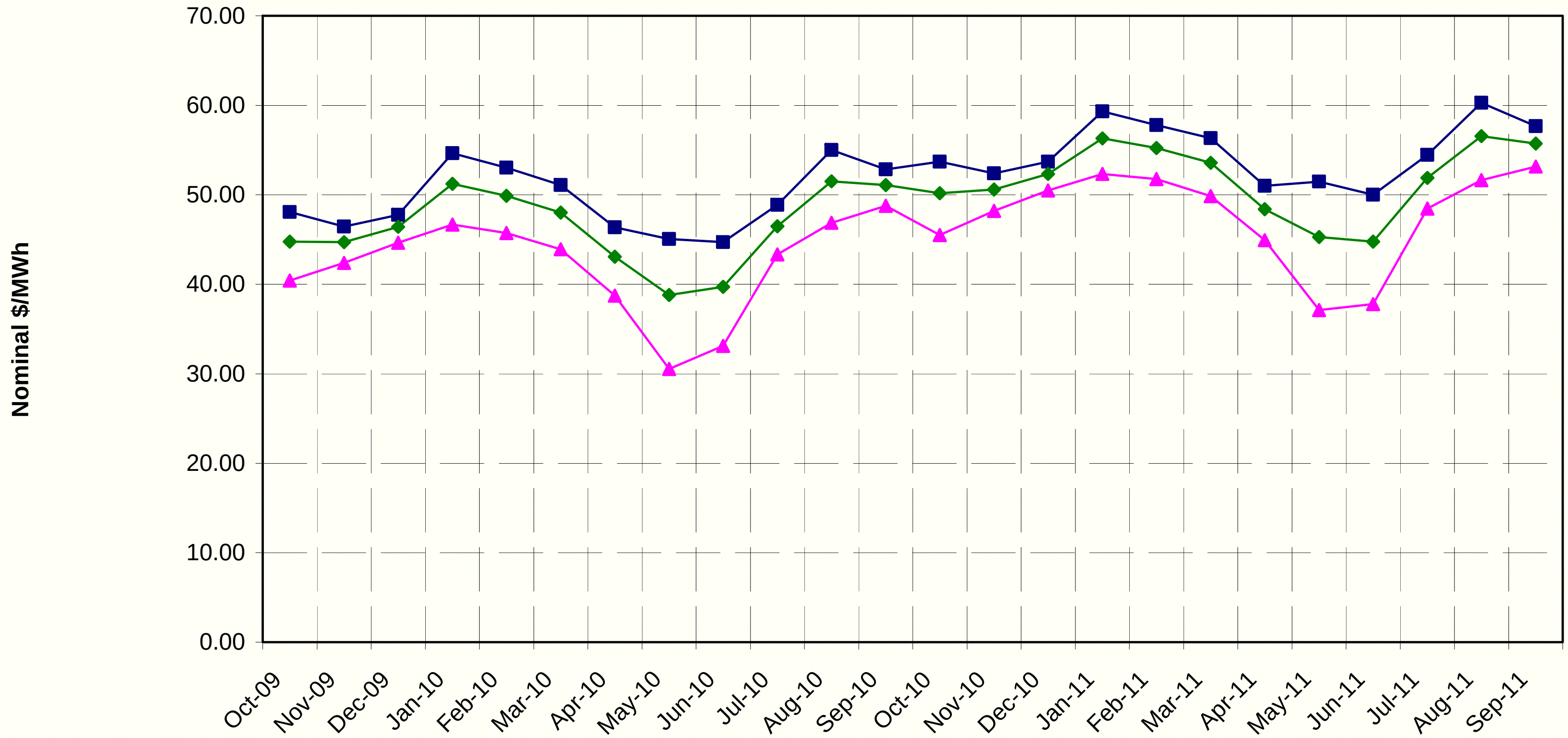
- Risk Analysis Forecast – Used in PNRR, CRAC, TPP and Generation Inputs:
  - 3,500 separate AURORAxmp games produce 3,500 sets of monthly spot market electricity prices (HLH and LLH)
  - Each game uses randomly selected Pacific Northwest (PNW) and California (CA) water years, natural gas prices, PNW and CA loads

Electric Power Market Price Forecast

Summary of Average Price Forecasts

	Net Secondary Revenue Forecast			Risk Analysis Forecast		
	HLH	Flat	LLH	HLH	Flat	LLH
FY2010	$49.49	$46.31	$42.09	$50.91	$46.65	$41.00
FY2011	$54.85	$51.73	$47.60	$57.10	$52.76	$47.01

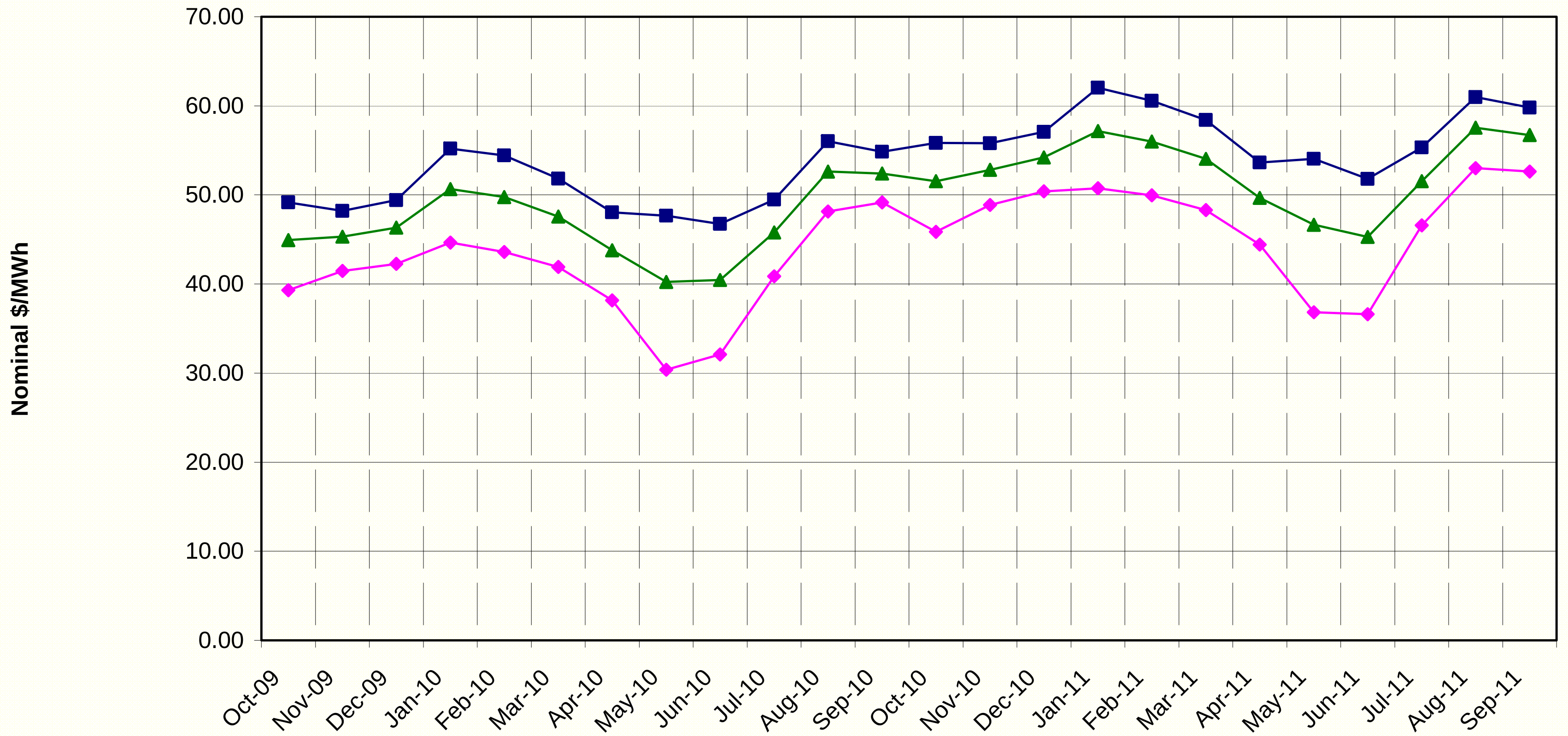
Electricity Price Forecast for Net Secondary Revenues



	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11
WP-10 HLH	48.09	46.46	47.75	54.66	53.03	51.09	46.36	45.04	44.72	48.86	54.99	52.84	53.68	52.39	53.71	59.32	57.80	56.35	51.00	51.46	50.02	54.47	60.29	57.66
WP-10 LLH	40.40	42.37	44.63	46.67	45.71	43.92	38.74	30.53	33.12	43.35	46.88	48.78	45.50	48.20	50.48	52.33	51.77	49.87	44.92	37.11	37.78	48.47	51.63	53.15
WP-10 Flat	44.78	44.71	46.41	51.23	49.89	48.01	43.09	38.80	39.73	46.49	51.50	51.10	50.16	50.59	52.32	56.31	55.21	53.56	48.39	45.29	44.76	51.89	56.57	55.72

Date

Electricity Price Forecast for Risk Analysis



	Oct-09	Nov-09	Dec-09	Jan-10	Feb-10	Mar-10	Apr-10	May-10	Jun-10	Jul-10	Aug-10	Sep-10	Oct-10	Nov-10	Dec-10	Jan-11	Feb-11	Mar-11	Apr-11	May-11	Jun-11	Jul-11	Aug-11	Sep-11
WP-10 HLH	49.14	48.22	49.40	55.19	54.43	51.82	48.03	47.66	46.74	49.48	56.00	54.85	55.84	55.79	57.08	62.02	60.57	58.39	53.64	54.05	51.81	55.32	60.97	59.79
WP-10 LLH	39.32	41.47	42.26	44.63	43.58	41.91	38.15	30.37	32.10	40.87	48.14	49.17	45.86	48.88	50.39	50.73	49.94	48.31	44.42	36.84	36.61	46.57	53.00	52.61
WP-10 Flat	44.92	45.31	46.33	50.65	49.77	47.56	43.78	40.23	40.44	45.78	52.62	52.41	51.55	52.82	54.20	57.17	55.99	54.06	49.67	46.65	45.28	51.55	57.54	56.70

Date

Procedure for Determining Augmentation Costs

- **The cost for system augmentation is determined by multiplying the purchase price under critical water times the aMW of system augmentation needed.**
- **The amount of system augmentation is determined in the Loads and Resources Study and is calculated on an annual basis, based on critical water.**

Procedure for Determining Augmentation Costs (con't)

1) Use the 70 water year run to determine the Total Purchase Expense for WY 1937 by multiplying the monthly HLH and LLH purchase amounts and prices and then summing them all. The result is an amount of dollars.
2) Determine the annual average purchase amount in MWh from Step 1.
3) Divide the total purchase expense by the annual average purchase amount to get the Weighted Purchase Price in $/MWh.
4) Multiply the Augmentation Purchase Amount (from the L/R Study) by the Weighted Purchase Price to get the total augmentation costs.

Preliminary Net Secondary Revenues and Augmentation Costs

Net Secondary Revenues (See Note 1)

	FY 2009 (WP-07 Supplemental)	FY 2010 (Preliminary WP-10)	FY 2011 (Preliminary WP-10)
Secondary Energy Revenue ($ Thousand)	599,046	599,737	699,967
Surplus Energy Sales (aMW)	1,578	1,630	1,663
Average Sales Price ($/MWh)	$ 43.33	$ 41.99	$ 48.04
Power Purchase Expense ($ Thousand)	69,459	63,288	51,706
Power Purchases (aMW)	137	136	101
Average Purchase Pruce ($/MWh)	$ 57.71	$ 53.14	$ 58.41
Net Secondary Energy Revenue ($ Thousand)	529,586	536,449	648,261
Net Surplus Energy Sales (aMW)	1,441	1,494	1,562

Note 1:
The basis of this calculation is the average of the 50 water year run for the WP-07 Supplemental Proposal and the average of the 70 water year run for the WP-10 Initital Proposal.

Augmentation Purchase Expense (See Note 2)

	FY 2009 (WP-07 Supplemental)	FY 2010 (Preliminary WP-10)	FY 2011 (Preliminary WP-10)
Total Purchases, WY 1937 (aMW)	425	439	417
Total Purchase Expense ($ Thousand)	224,104	205,103	210,878
Weighted Purchase Price ($/MWh)	60.20	53.34	57.70
Augmentation Purchase Amount (aMW)	299	372	599
Augmentation Purchase Expense ($ 000)	157,683	173,834	302,770

Note 2:
The basis of this calculation is critical hydro (I.e., WY 1937) from the 50 water year run for the WP-07 Supplemental Proposal and critical hydro (I.e., WY 1937) from the 70 water year run for the WP-10 Initital Proposal.

Application of the CRAC and DDC to Residential Exchange Program Benefits

CRAC/DDC and Residential Exchange Program Benefits

- BPA staff propose that it is appropriate to find a way to equitably apply the CRAC/ DDC to the level of REP benefits because the PF Exchange rate is calculated based on the same level of PNRR that is in the regular PF rate.

- Therefore, staff is proposing to use a formula for calculating how much of a CRAC (or DDC) would be collected from (or credited to) the PF Preference rate and how much would be collected by reducing (or delivered by increasing) REP benefits

The Proposed Formula

- So that the formula could take into account 7(b)(2) protection, staff used the rates models to calculate what would happen to non-Slice PF rates and to REP benefits if PNRR were increased by $50M, $100M, etc.

- The results were quite linear. About 93% of the CRAC or DDC goes to PF rates and about 11% goes to REP benefits. (The other -4% goes to Slice rates because REP benefits are a true-uppable expense, so if REP rates go up, Slice rates, and BPA's revenue from Slice rates, go down.)

- We expect to update the results with Final Studies data and use them in September to adjust the non-Slice PF rates and REP benefits if there is a CRAC or DDC.