NRU Summary of BPA's Rate Design for its Load Following Customers

BPA's rate design for its power sales changed significantly on October 1 2011. In the past BPA had an energy charge (shaped monthly and diurnally), a demand charge with a monthly shape and a load variance charge. Now the rate design for its load following customers (and the block purchases of its Slice customers) has three basic components. The flat customer charges, the load shaping charge and the demand charge. A short description of each follow.

The Customer Charges

The Customer Charges are made up of the Composite Customer Charge, the Non Slice Charge and the Slice Charge. These customer charges cover the bulk of BPA's costs (over 90%) on a flat monthly basis over the year. Each customer's customer charge is based on its percentage share of the Tier 1 system.

The Load Shaping Charge

This forecast market price charge captures the difference between the customers load and the shape of the output of the federal system on a monthly HLH/LLH basis. If a customer's load shape were identical to the shape of the system there would be no charge, if a customer's load shape is different from the shape of the system then the customers will receive a charge. The theory here is that BPA has to go out and purchase power to follow the monthly load shape of the customer. In the past the cost of these shaping purchases was embedded in the revenue requirement and every customer picked up a portion of this cost. Now a customer that has a month to month LLH HLH load shape that is out of sync with the shape of the output of the system will pay more than a customer that is a load that is in sync.

Demand Charge

The demand charge is the customer's system peak demand times the fixed cost of a generic capacity resource (currently a LMS-100 combustion turbine the costs of which are derived from the Council's 6th power plan). In the past the billing determinant was the customer's kW demand at the time of the system peak. The current charge averages \$9.62, in the prior rates the average charge was about \$2 per kW. The billing determinant for demand is as follows (a super peak credit is also allowed)

BillingDemand = max(0,CSP - aHLH - CDQ) where:
BillingDemand = Demand Billing Determinant, expressed in kilowatts
CSP = Customer System Peak (the customer's maximum Actual Hourly Tier 1 Load during the Heavy Load Hours of each month).
aHLH = average Actual Monthly/Diurnal Tier 1 Load (expressed in average kilowatts) served during the Heavy Load Hours of each month
CDQ = Contract Demand Quantity (expressed in kilowatts). A grandfathered demand amount based on the weighted average of each customer's FY 2005-2007 monthly HLH load factors applied to the customer's average adjusted Measured FY 2010 Load for monthly HLH

Price Signals Sent from BPA to Utility

Load Shaping Rates

	HLH - $/MWh	LLH - $/MWh	Delta $/MWh
October	$ 37.86	$ 31.20	$ 6.66
November	$ 38.37	$ 31.40	$ 6.97
December	$ 41.10	$ 33.39	$ 7.71
January	$ 40.03	$ 31.70	$ 8.33
February	$ 40.93	$ 33.17	$ 7.76
March	$ 39.57	$ 32.33	$ 7.24
April	$ 37.53	$ 30.41	$ 7.12
May	$ 35.06	$ 24.40	$ 10.66
June	$ 35.97	$ 23.02	$ 12.95
July	$ 42.07	$ 29.91	$ 12.16
August	$ 44.35	$ 32.15	$ 12.20
September	$ 43.45	$ 33.59	$ 9.86

Demand Rates

	$/kW/mo
October	$ 9.18
November	$ 9.31
December	$ 9.97
January	$ 9.70
February	$ 9.92
March	$ 9.60
April	$ 9.10
May	$ 8.50
June	$ 8.72
July	$ 10.20
August	$ 10.75
September	$ 10.53

CSP - aHLH - CDQ = Billing Determinant

CSP = Customer System Peak (highest hour of energy purchased from BPA in a month by a utility)
aHLH = average Heavy Load Hour (MWh purchased by a utility in HLHs of the month divided by the HLH hours in that month)
CDQ = Contract Demand Quantity (amount of demand grandfathered to a utility as specified in their CHWM Contract)

Example 1: A utility shifts 100 MWh of energy each month from HLH to LLH but does so in hours not coincident with their monthly peak HLH energy purchase from BPA. The lost aHLH energy forces the utility to buy more energy shaping capacity, measured as their peak less their aHLH. The added cost of the capacity (Demand Charge) is more than the HLH to LLH energy savings (Load Shaping Charge).

Example 1: 100 MWh of Load Shift from HLH and LLH each month : No change in Utility Peak						
HLH Hours		Energy Savings	Impact on aHLH (aMW)	Decrease in CSP (MW)	Demand Charge Impact benefit/(cost)	Net benefit/(cost)
416	May	$ 1,066.00	-0.24	0.00	$ (2,043.27)	$ (977.27)
416	June	$ 1,295.00	-0.24	0.00	$ (2,096.15)	$ (801.15)
						$ (1,778.42)
					Cost/MWh	$ (8.89)

Example 2: A utility shifts 100 MWh of energy each month from HLH to LLH and also reduces their monthly peak HLH energy purchase from BPA by 1 MWh. The utility benefits both through reduced energy costs (Load Shaping Charge) and reduced capacity costs (Demand Charge).

Example 2: 100 MWh of Load Shift from HLH and LLH each month : 1 MW change in Utility Peak						
Hours		Energy Savings	aHLH (aMW)	CSP (MW)	Charge Impact	Net benefit/(cost)
416	May	$ 1,066.00	-0.24	1.00	$ 6,456.73	$ 7,522.73
416	June	$ 1,295.00	-0.24	1.00	$ 6,623.85	$ 7,918.85
						$ 15,441.58
					Benefit/MWh	$ 77.21

Example 3: A utility reduces their energy need by one MWh for every HLH of the month. For May and June, this means 416 MWh of energy shifted from HLH to LLH each month. The utility's shaping capacity need (measured as their peak less their aHLH) remains unchanged since the aHLH amount is reduced by the same amount as their peak. The utility benefits through reduced energy costs (Load Shaping Charge) and leaves their capacity costs unchanged (Demand Charge).

Example 3: 1 MW reduction every HLH hour and replaced with equivalent amount of LLH energy						
HLH Hours		Energy Savings	Impact on aHLH (aMW)	Decrease in CSP (MW)	Demand Charge Impact benefit/(cost)	Net benefit/(cost)
416	May	$ 4,434.56	-1.00	1.00	$ -	$ 4,434.56
416	June	$ 5,387.20	-1.00	1.00	$ -	$ 5,387.20
						$ 9,821.76
					Benefit/MWh	$ 11.81

Example 4: A utility shifts 100 MWh of energy within the HLHs to lower their HLH monthly peak energy purchase from BPA by 1 MWh. There is no loss of aHLH energy and their peak is reduced. This results in an increase in the utility's load factor (aHLH/peak), which is less costly for BPA to serve. The utility benefits through reduced capacity costs (Demand Charge) and leaves their energy costs unchanged (Load Shaping Charge).

Example 4: 100 MWh of Load Shift within the HLH each month : 1 MW change in Utility Peak						
HLH Hours		Energy Savings	Impact on aHLH (aMW)	Decrease in CSP (MW)	Demand Charge Impact benefit/(cost)	Net benefit/(cost)
416	May	$ -	0.00	1.00	$ 8,500.00	$ 8,500.00
416	June	$ -	0.00	1.00	$ 8,720.00	$ 8,720.00
						$ 17,220.00
					Benefit/MWh	$ 86.10

Example 5: A utility reduces their HLH energy need by 100 MWh. The reduced HLH energy is not coincident with their monthly peak HLH energy purchase from BPA. The utility increases its need for shaping capacity (peak purchase less aHLH energy) but benefits from decreased HLH energy purchases. The benefit of the reduced HLH energy purchases (Load Shaping) is greater than the increased capacity costs (Demand Charge).

Example 5: 100 MWh of HLH Load Reduction : No change in Utility Peak						
HLH Hours		Energy Savings	Impact on aHLH (aMW)	Decrease in CSP (MW)	Demand Charge Impact benefit/(cost)	Net benefit/(cost)
416	May	$ 3,506.00	-0.24	0.00	$ (2,043.27)	$ 1,462.73
416	June	$ 3,597.00	-0.24	0.00	$ (2,096.15)	$ 1,500.85
						$ 2,963.58
					Benefit/MWh	$ 14.82

Example 6: A utility reduces their HLH energy need by 100 MWh. The reduced HLH energy reduces their monthly peak HLH energy purchase from BPA by 1 MWh. The utility benefits both through reduced energy costs (Load Shaping Charge) and reduced capacity costs (Demand Charge).

Example 6: 100 MWh of HLH Load Reduction : 1 MW change in Utility Peak						
HLH Hours		Energy Savings	Impact on aHLH (aMW)	Decrease in CSP (MW)	Demand Charge Impact benefit/(cost)	Net benefit/(cost)
416	May	$ 3,506.00	-0.24	1.00	$ 6,456.73	$ 9,962.73
416	June	$ 3,597.00	-0.24	1.00	$ 6,623.85	$ 10,220.85
						$ 20,183.58
					Benefit/MWh	$ 100.92

Example 7: A utility reduces their energy need by one MWh for every HLH of the month. For May and June, this means 416 MWh of less HLH energy purchased each month. The utility's shaping capacity need (measured as their peak less their aHLH) remains unchanged since the aHLH amount is reduced by the same amount as their peak. The utility benefits through reduced energy costs (Load Shaping Charge) and leaves their capacity costs unchanged (Demand Charge).

Example 7: 416 MWh of HLH Load Reduction each month: 1 MW change in Utility Peak						
HLH Hours		Energy Savings	Impact on aHLH (aMW)	Decrease in CSP (MW)	Demand Charge Impact benefit/(cost)	Net benefit/(cost)
416	May	$ 14,584.96	-1.00	1.00	$ -	$ 14,584.96
416	June	$ 14,963.52	-1.00	1.00	$ -	$ 14,963.52
						$ 29,548.48
					Benefit/MWh	$ 35.52

Notes:

1) These calculations are applied only to two months, but a similar calculation could be made for each month of the year using the applicable hours in the month, the monthly Load Shaping, and the Demand rates. The monthly results will vary depending on the HLH and LLH energy spread of the Load Shaping rates and the month specific Demand rate.

2) The benefits in examples 5, 6, and 7 assume the reduced energy need is above-RHWM load. If the reduced energy need was RHWM Load, then the benefits would be decreased by $6.45/MWh (the Load Shaping Charge True-up rate).