Alternatives for Tier 1 Rate Design

1. Statement of the Issue

*Tier 1 rate design is a key factor in the success of Regional Dialogue – success measured as both the execution of 20 year contracts **and** their sustainability through the contract period. Different Tier 1 rate designs will have significant cost allocation impacts across BPA's 125+ customers due to their different load profiles. The rate design adopted in the Tired Rates Methodology 7(i) must balance the mitigation of perceived rate inequities without significantly increasing any customer's power bills.*

2. Summary of Regional Dialogue Policy:

The Proposed Regional Dialogue Policy identifies goals that pertain to rate design:

- *Lowest costs and Tier 1 rates*
- *Durability/Stability/Contract Enforceability*
- *Customer/regional support and equity*
- *Promote infrastructure development consistent with the Northwest Power Act*
- *Consistency with BPA stewardship obligations*
- *Simplicity*

Rate Design Principles underlying the Proposed Regional Dialogue Policy:

- *Minimize inter-customer inequities.*
- *Minimize inter-customer cost shifts.*

Customer equity - *customers receiving similar services pay similar prices. Customers pay the costs associated with the particular services they buy. Example inequities:*

- *Energy inequities – Those customers that have more load during expensive months receive more value (market minus PF).*
- *Capacity inequities – Those customers that use relatively more capacity reduce BPA's ability to sell products like the Pac Peaking Contract whose revenues reduce the PF rate. Moreover, as BPA purchases more capacity in the market, the costs raise the Revenue Requirement fore the PF rate.*
- *Load Variance – Load Variance is charged flat across all load following customers, regardless of actual variation from forecast.*

Cost shifts – For this analysis, cost shifts are defined as the *rate difference from WP-07 PF rate design.*

3. Summary of Comments Related to This Issue

Two customer ideas have begun circulation. Both ideas use a Slice-like approach (customer percentage of RevReq), but differ greatly in their recovery of costs for shaping from critical, following load, and serving peak loads. One idea investigates a design that essentially places all services on the margin with the primary differences between a Slice customer and a non-Slice customer being who does the marketing of secondary energy and who provides additional services. The second idea investigates a design that prices as much of the current FBS flexibility at BPA's embedded cost, even at the cost of a lower secondary credit.

Terry Mundorf's presentation at the NWPPA conference set forth the premise that Tier 1 rate design is critical to a successful completion of Regional Dialogue.

4. Description of Alternatives:

Five alternatives are described and ranked based on the identified decision making criteria. The five alternatives were chosen to give fair representation of the most popular Tier 1 rate design opinions. Note: Assumptions made within each alternative can vary greatly and thus can change the ranking outcome – e.g., Market Virtual Slice (#5a) versus HWM Virtual Slice (#5b)

Alternative #1:

Pure WP-07 – No change from the current method used to calculate the WP-07 rates. The WP-07 rates are a combination of a settlement shape and percentage reduction in all billing determinants (Load Variance, HLH Energy, LLH Energy, and Demand).

Alternative #2:

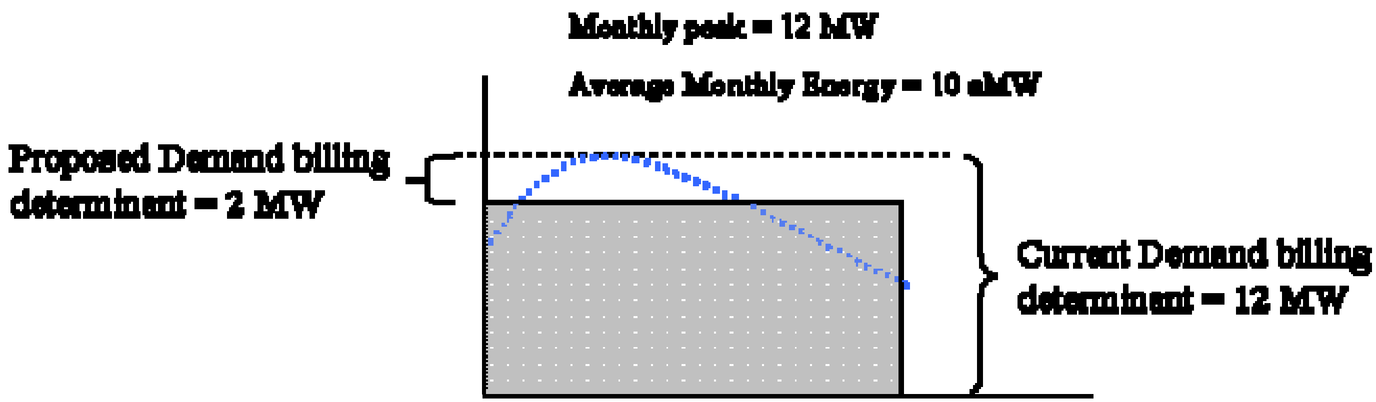
WP-07 Déjà Vu – With the exception of one change, the goal of this rate design is to have very little change from Alternative #1. The change from Alternative #1 is to bill Demand on Customer System Peak (CSP) instead of Generation System Peak (GSP).

Alternative #3:

WP-07 Déjà Two– Three changes are made from the Alternative #1. The three changes found in Alternative #3 are a switch to Customer System Peak (CSP) instead of Generation System Peak (GSP), to scale from the shape of the relevant ratecase market forecast instead of the WP-07 settlement shape, and to develop a sustainable method for determining the demand charge. One possible method of calculating a demand rate would be to use the fixed costs of a SCCT as the equivalent market rate for demand and scale that market demand rate *equally with the market energy rates to the level that recovers the revenue requirement. Using the Council's stated SCCT cost and the WP-07 scaling method would result in a demand rate of ~ $3.58/kW/month.*

Alternative #4:

100% Load Factor Benchmark – This rate design attempts to solve a few perceived inequities amoung customers without straying too far from the base concepts found in the WP-07 rate design (Alternative #1). Energy rates are scaled by a constant amount from market rather than with a percentage. Principles of pricing Demand at marginal cost are used but, unlike the WP-07 rate design, demand is charged only on the peak above a 100% (monthly or HLH) load factor. The Demand billing determinant is changed to Customer System Peak (CSP) rather than the Generation System Peak (GSP) used since 1996. The Load Variance Charge is also significantly different from the WP-07 method of applying a posted rate to a customer's Total Retail Load. Instead, a Load Variance charge is applied after-the-fact for deviations from forecast

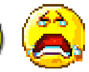


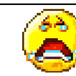
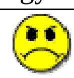
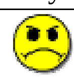
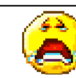
.

Alternative #5:

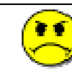
Virtual Slice – This rate design attempts to capture an approach proposed by a few of the customers. A percentage-based rate is established, much like Slice. Costs associated with additional services - such as Load Following, Load Shaping, and Demand - are identified based on cost forecasts. Methods of recovery of these costs vary greatly. The #5a method recovers the costs of the services as either specific market-based charges to each customer based on the quantity of services used or through charges to a group that customers could join at their option. The #5b method would recover the costs of additional services as embedded costs only, even though this would reduce the secondary revenue credit. The rankings that follow are meant to illustrate the spectrum of virtual slice, with #5a tied closely to market and #5b tied to High Water Mark (HWM).

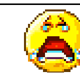
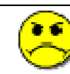
Rate Element	Alt #1 Pure WP-07	Alt #2 WP-07 Déjà Vu	Alt #3 WP-07 Déjà Two	Alt #4 Load Factor Benchmark and Constant Scaling	Alt #5a Market Virtual Slice	Alt #5b HWM Virtual Slice
Energy	Energy rates are scaled by a constant percentage from a settled rate shape until revenue requirement is equal to revenue collected.	Same as Alt#1.	Energy rates are forecast market prices reduced by a constant percentage from market price forecasts until revenue requirement is equal to revenue collected.	Energy rates are equal to forecast market prices for HLH & LLH reduced by a constant. The constant equals market revenues minus the revenue requirement (less demand revenues), with this amount divided by total HLH & LLH billing determinants.	Energy rate is a percentage of Revenue Requirement after netting for demand and load shaping revenues equal to the percentage of forecast annual energy purchase.	Energy rate is a percentage of Revenue Requirement equal to the percentage of forecast annual energy purchase.
Demand	Demand rates are scaled by a constant percentage from a settled rate shape until revenue collected is equal to the Revenue Requirement. Applied to Generation System Peak (GSP).	Same pricing as Alt #1 but applied to Customer System Peak (CSP) and not Generation System Peak.	Demand rate is the fixed cost of an SCCT scaled by the same percentage as the energy rates and applied to the CSP.	Demand rate is equal to the fixed cost of an SCCT applied to the difference between peak and average HLH load at CSP in each month.	Demand rate is set at market and applied to GSP.	No demand charge.
Load Shaping	Load Shaping costs are recovered through the monthly/diurnal shaped energy rates applied to all energy taken and the monthly demand rate(s).	Same as Alt #1.	Same as Alt #1.	Same as Alt #1.	Load Shaping charges are market-based credits for unders and debits for overs as measured by the difference between the monthly/diurnal block load and system output for the period.	No load shaping charge.
Load Variance	Load Variance is a constant rate calculated with deviations from forecast and applied to market prices. Load Variance was percentage scaled in WP-07. The constant rate is applied to Total Retail Load.	Same as Alt #1.	Same as Alt #1.	Load Variance is forecast market-based energy rates applied to the plus or minus deviation of load from a pre-established monthly/diurnal forecast that shapes the customer's HWM. No revenues would be credited against RevReq because base rates would be set on the pre-established forecasts.	Same as Alt #4.	No load variance charge.

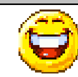
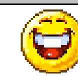
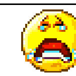
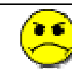
Rank each of the alternatives against the Regional Dialogue List of Interests using from best to worst:     

Regional Dialogue Policy Implementation Decision Criteria	Alt #1 Pure WP-07	Alt #2 WP-07 Déjà Vu	Alt #3 WP-07 Déjà Two	Alt #4 Load Factor Benchmark and Constant Scaling	Alt #5a Market Virtual Slice	Alt #5b HWM Virtual Slice
1. Lowest Tier 1 Costs and Tier 1 Rates						
1a. Minimize cost of balancing purchases (energy).						
	Alt #4 and Alt#5a are relatively better because the value of energy is held constant from market thereby decreasing the chance that the cost of future load shape changes will fall to the Tier 1 rate. Alt #1 through Alt #3 are relatively lower because a percentage scale from market causes higher priced periods to have more value. Alt #5b is the lowest because there are no diurnal/seasonal price signals to optimize load decisions. This could lead to a lower secondary energy credit as more system flexibility is used to meet load.					
1b. Relieve operational costs (capacity and load variance)						
	Alt #4 and Alt #5a are relatively better because both attempt to put the demand rate closer to BPA's marginal cost. Alt #4 and Alt #3 did relatively better than most because demand is billed on CSP, thus increasing the chances that Demand Side Management will be economic for customers. Alt #2 and Alt #1 did not fair well because not only is demand billed on a difficult-to-forecast peak, the price of demand is well below the customer's substitute option. This increases the chance that BPA will see increased peaks and be forced to look beyond the FBS to serve them, or curtail secondary sales that keep Tier 1 rates low. Load Variance is arguably less important to BPA's operational cost since it is even less controllable than a customer's demand. Moreover, there really is not a substitute for load variance.					

Date: 5-18-2007
Purpose/Subject: Tier 1 Rate Design Workshop
Legal Disclaimer: Deliberative and pre-decisional

Regional Dialogue Policy Implementation Decision Criteria	Alt #1 Pure WP-07	Alt #2 WP-07 Déjà Vu	Alt #3 WP-07 Déjà Two	Alt #4 Load Factor Benchmark and Constant Scaling	Alt #5a Market Virtual Slice	Alt #5b HWM Virtual Slice
2. Durability/Stability/Contract Enforceability						
2a. Durability through contract term						
	Because they are more closely tied to market prices, Alt #4 and Alt #5a offer the best chance at surviving the contract term and can adapt best to changing market conditions. Alt #3 is close behind because it too is tied to market, but rates are scaled further from market. Alt #1 and #2 could survive through the 20 year contract, but might be jeopardized by increased cost pressures driving rates higher over time. Once established, all rate designs would provide customers a blend of certainty through contracts and the TRM.					
2b. Stability between rate cases						
	Most alternatives would result in about the same incremental changes between rate cases. Alt #5b is relatively better because it is the least exposed to market price volatility. Alt #5a has more stability than Alt #3 and #4 because although it is tied to market, the costs are spread on an annual basis. Alt #1 and #2 are tied to a settlement shape and not market, thus likely being more stable. For all market-based components, there are mitigation measures that could be instituted to lessen the influence of market price volatility.					

Regional Dialogue Policy Implementation Decision Criteria	Alt #1 Pure WP-07	Alt #2 WP-07 Déjà Vu	Alt #3 WP-07 Déjà Two	Alt #4 Load Factor Benchmark and Constant Scaling	Alt #5a Market Virtual Slice	Alt #5b HWM Virtual Slice
3. Customer/Regional Support and Equity	**Customer equity** - *customers receiving similar services pay similar prices. Customers pay the costs associated with the particular services they buy.* ❖ *Energy inequities – Those customers that have more load during expensive months receive more value (market minus PF).* ❖ *Capacity inequities – Those customers that use more relative capacity reduce BPA's ability to sell products like the Pac Peaking Contract to reduce everyone's rate. Moreover, as BPA is forced to purchase capacity in the market, the costs raise everyone's Revenue Requirement.* ❖ *Load Variance – Load Variance is charged flat across all load following customers, regardless of actual variation.* **Cost shifts** – defined as *rate difference from WP-07 rate design.*					
3a. Minimize or mitigate inter-customer inequities						
	Both Alt #4 and Alt #5b are built on assigning costs to those imposing the costs. Alt #1, Alt #2 and Alt #3 retain current inequities (product to product as well as within-product inequities) but have some semblance of assigning costs appropriately. Alt #5b assumes that all cost responsibility follows the amount of annual energy purchased and that the federal system can meet all customer needs.					
3b. Minimize or mitigate inter-customer cost shifts						
	Cost shifts, defined as changes from today, are lowest with Alt #1, which has no change. Alt #4 can incorporate methods to mitigate the impact on customers. Alt #5a can use mitigation measures, but they can be harder to find due to the substantial changes. Alt #5b creates large shifts with little opportunity to mitigate.					
3c. Contract signing within schedule						
	Alt #1 is assumed to be the best because of zero changes from WP-07 and the WP-07 rate design received customer approval. Alt #2 scored second best because it has only one change from today's rate design. Alt #5a has the strength of bringing Slice and non-Slice customers closer to a common rate basis. Alt #4 retains some current features, but the newness could promote misunderstanding and fear. Alt #5b looks good from a distance, but will suffer greatly when cost shifts and inter-customer inequities are considered with little room for mitigation.					

<table>
<tr><th>Regional Dialogue Policy Implementation Decision Criteria</th><th>Alt #1
Pure WP-07</th><th>Alt #2
WP-07 Déjà Vu</th><th>Alt #3
WP-07 Déjà Two</th><th>Alt #4
Load Factor Benchmark and Constant Scaling</th><th>Alt #5a
Market
Virtual Slice</th><th>Alt #5b
HWM
Virtual Slice</th></tr>
<tr><td rowspan="2">4. Promotes new generating resources</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="6">Tier 1 rates promote infrastructure only when the price signals corresponds to true market alternatives. Most of the Regional Dialogue goal of infrastructure development is via the Tier 2 rate. On an average annual energy basis, all alternatives face the Tier 2 rate. On a capacity basis, those rate designs with demand charges closer to market will do a better job of promoting customers to look beyond BPA for their capacity needs. It is true that a generation integration charge could be used to credit and debit demand effects of resources, but this is an extra step that could be difficult to implement. Ideally, the credit or debit would occur with an avoided or elevated Tier 1 demand charge. Demand credits and debits would also need to apply to DSM, which could prove difficult.</td></tr>
<tr><td rowspan="2">5. Consistency with BPA Stewardship Obligations (conservation, renewables, F&W)</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="6">Larger demand charges will do a better job of promoting Demand-Side Management options. This is why Alt #3 through Alt #5a did well here. Billing on CSP is another improvement. Focused conservation (summer v. winter) is best achieved under Alt #4 since the shape of the PF rate more closely resembles market. The rewards of focused conservation would also be captured in Alt #5a, but because seasonal costs are rolled into on shaping charge, the price signal is less apparent.</td></tr>
<tr><td rowspan="2">6. Simplicity</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td colspan="6">The simplicity of Alt #5b is inherent – one known price for all services. The simplicity of Alt #1 is the minimal change from thirteen years of practice. Alt #4 has some changes, but they are understandable with some explanation. Alt #5a has the most change, which could develop into the most complexity.</td></tr>
</table>

5. Resource Shape Adjustment:

Principle: ***Charge preference customer non-federal resources same costs included in the rates for BPA Tier 2 resources.***

Support Service	Alt #1, Alt #2 and Alt #3 WP-07 Variation	Alt #4 Load Factor Demand and Constant Scaling	Alt #5a Camp 1 Virtual Slice	Alt #5b Camp 2 Virtual Slice
Within-Year Planning Variation	Energy above/below annual forecast average generation will be credited/debited at rate case forecast market prices minus PF rate for all diurnal periods. There will also need to be some sort of capacity related debit/credit.	Same as Alt #1 and Alt #3, but less need for a capacity-related credit/debit. There might also need to be some sort of capacity related debit/credit.	Forecast resource shape will change Tier 1 load on BPA. Shaping charges will reflect the cost of new Tier 1 load shape. Depending on demand price chosen, demand may need a debit/credit.	Shape of resource compared to flat annual block and credited/debited based on monthly diurnal forecast market prices. Demand debit/credit system would be critical here because there would be no avoided demand charge.

BPA proposes that current method of forecasting market prices be continued, using AURORA or a similar forecasting model. The same set of price forecasts would be used to shape energy rates for Alt #3 and Alt #4, to set the Forecast/Load Variance rates for Alt #1 through Alt #5a, for determining the Load Shaping rates for Alt #5a, and for setting the Resource Shaping Adjustment.

6. Recommendation and Rationale:

Adopt Alternative #4 because it strikes a good balance between customer equity and customer cost shifts without completely reinventing the methods customers and BPA are familiar with.

The higher demand charge coupled with the switch to Customer System Peak found in Alternative #4 does the best at suppressing future operational costs. In addition to providing a more accurate economic incentive, the move to a billing determinate that a utility will have better control will promote investment into Demand Side Management assets. Furthermore, a larger demand charge will also increase the probability that non-federal capacity resources will be built.

The switch from Generation System Peak to Customer System Peak has another possible benefit. It has recently been identified that a single hour peak might not be the best measurement for assessing BPA's capacity constraints. Instead, capacity studies now refer to a six-hour capacity measurement. It is expected that the diversification of managing each utility peak would better address the multi-hour measurement.

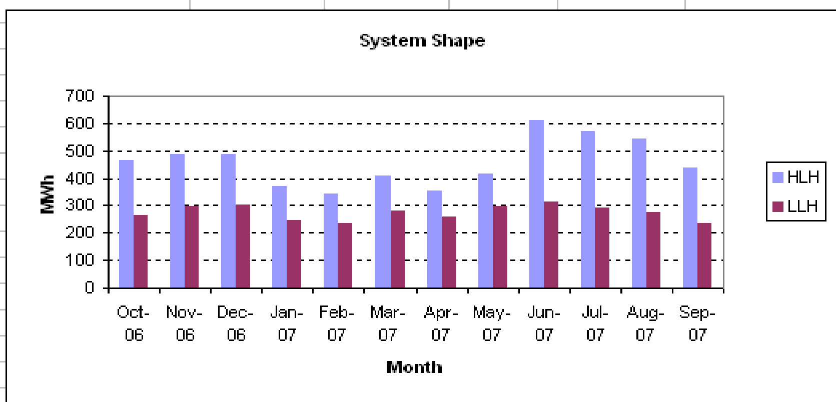
Alternative #4 also has the unique characteristic of having energy rates that hold an equal value (Market minus PF). In addition to solving some perceived inequities, this feature and the higher demand charge will integrate resources more easily - i.e. the forecast generation does not need to be exact to know the month to month costs of integration. Its higher demand charge, relative to the other approaches, also reduces the need to develop a non-federal resource capacity credit/debit system.

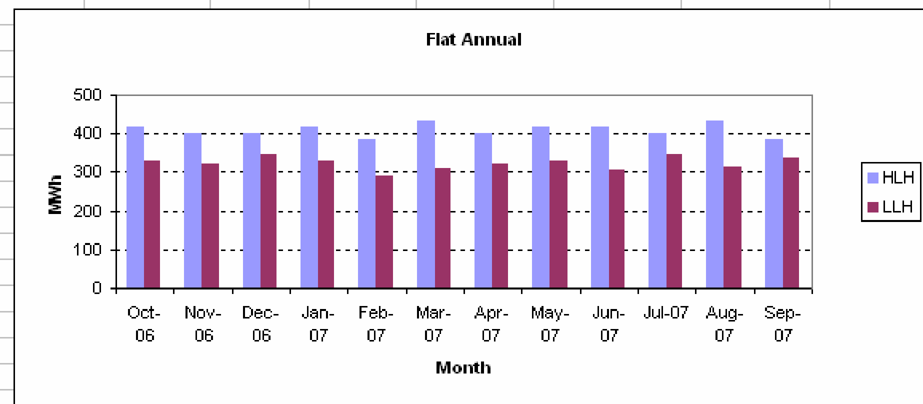
Alternative #5a holds promise such that it could solve some customer inequities and do so in a fashion that does not have cost shifts greater than Alternative #4. The slice-like approach of Alt #5(a and b) also appears to be favorable within a few customer groups, but because it is a dramatic change from today's mentality and because decisions made within Alt #5 can vary greatly, development of this rate design could slow down the region's progress to contract signing within schedule.

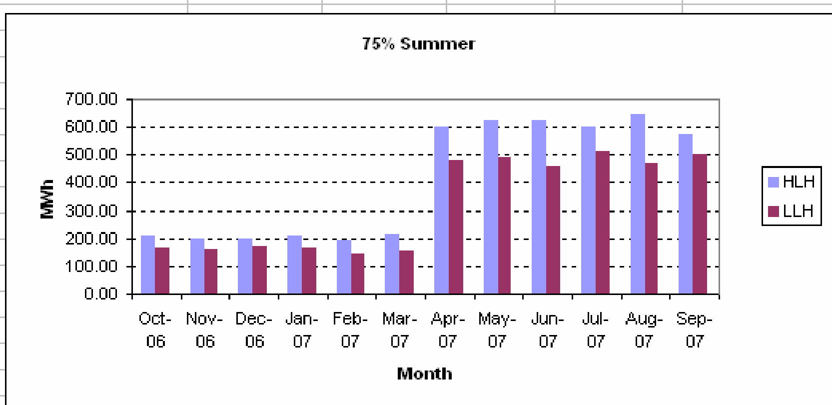
Alternative #1 would be the easiest to implement, simply because it is current practice, thus likely improving the chances of an on schedule contract signing. Clearly, Alt #1 does the best at minimizing cost shifts from WP-07 rate design, but it comes at the cost of contract durability and inter-customer equity. It is also believed that Alternative #1's strengths over Alternative #4 can be overcome with proper decisions and mitigation made within Alternative #4.

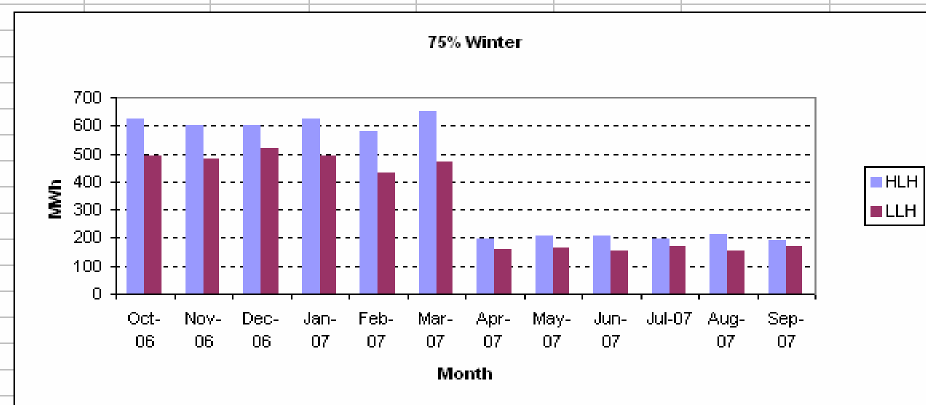
Lastly, Alternative #4 can easily morph back into Alternative #1, 2, or 3, but Alternative #1, 2, and 3 would have a harder time morphing into the next progressive rate construct (1 to 2, 2 to 3, 3 to 4). Between Alternatives #1 through #4, Alternative #4 is also likely the closest to resolving the internal concerns BPA has with rate design (e.g. capacity).

	PF Rates						Value = Market - PF						
	Costs @ Pure WP-07	Costs @ Déjà vu WP-07	Costs @ Déjà Two WP-07	Costs @ Benchmark Load Factor	Net Shaping Charge from Critical	Cost @ Market	Value under Pure WP-07	Value under Déjà vu WP-07	Value under Déjà Two WP-07	Value under aHLHBench mark Load Factor	Value under aMonthly Benchmark Load Factor	Net Shaping Charge MWh equivalent	Base Cost (system shape) plus Net Shaping Charge MWh equivalent
1937 System Shape	$ 26.45	$ 26.15	$ 25.87	$ 25.07	$ -	$ 50.72	$ 24.27	$ 24.57	$ 24.84	$ 25.65	$ 24.95	$ -	$ 25.07
Flat Annual	$ 25.87	$ 25.58	$ 25.21	$ 24.82	$ (2,212.21)	$ 50.46	$ 24.60	$ 24.89	$ 25.25	$ 25.65	$ 25.65	$ (0.25)	$ 24.82
75% Summer	$ 24.44	$ 24.16	$ 24.14	$ 22.20	$ (25,179.48)	$ 47.84	$ 23.41	$ 23.68	$ 23.70	$ 25.65	$ 25.65	$ (2.87)	$ 22.20
75% Winter	$ 27.32	$ 27.01	$ 26.29	$ 27.47	$ 21,008.14	$ 53.12	$ 25.80	$ 26.10	$ 26.82	$ 25.65	$ 25.65	$ 2.40	$ 27.47

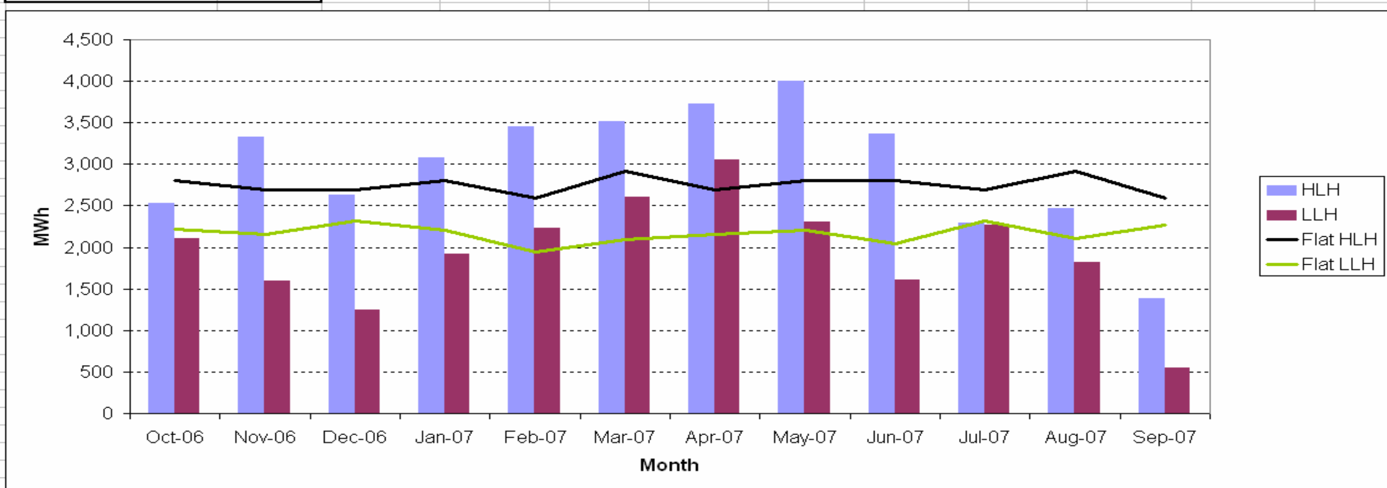








	1	2	3	4	5	6	7	8	9	10	11	12	13
1		Cost of Shaping Non-Federal Energy to Flat											
2		Alt #1 Resource Shaping Costs w/ 07 PF rates	Alt #2 Resource Shaping Costs w/ Déjà vu WP-07	Alt #3 Resource Shaping Costs w/ Déjà Two WP-07	Alt #4 Resource Shaping Costs w/ Benchmark Load Factor	Resource Shaping Costs @ Market							
3	$	$ 13,306	$ 13,314	$ 8,158	$ 0	$ 13,732		aMW	6.74				
4	**$/MWh**	$ 0.23	$ 0.23	$ 0.14	$ 0.00	$ 0.23							
5	**Alt #4 example:**												
6		October	November	December	January	February	March	April	May	June	July	August	September
7	Market HLH	$53.34	$63.03	$66.13	$59.13	$59.27	$56.85	$47.16	$41.76	$41.17	$49.51	$54.63	$56.83
8	Market LLH	$46.08	$52.01	$54.79	$50.01	$52.39	$50.21	$40.56	$35.55	$31.27	$41.07	$46.87	$50.78
9	PF HLH Rate	$27.69	$37.38	$40.48	$33.49	$33.62	$31.20	$21.51	$16.12	$15.53	$23.86	$28.98	$31.18
10	PF LLH Rate	$20.43	$26.36	$29.15	$24.36	$26.74	$24.56	$14.92	$9.90	$5.62	$15.42	$21.23	$25.13
11	HLH Value (Market - PF)	$25.65	$25.65	$25.65	$25.65	$25.65	$25.65	$25.65	$25.65	$25.65	$25.65	$25.65	$25.65
12	LLH Value (Market - PF)	$25.65	$25.65	$25.65	$25.65	$25.65	$25.65	$25.65	$25.65	$25.65	$25.65	$25.65	$25.65
13													
14	Forecast HLH Generation	2,524.6	3,322.7	2,627.5	3,075.8	3,458.6	3,510.6	3,730.0	4,007.4	3,364.3	2,292.5	2,470.1	1,384.2
15	Forecast LLH Generation	2,104.6	1,599.5	1,242.4	1,922.2	2,233.8	2,601.0	3,054.0	2,309.5	1,606.9	2,265.7	1,823.9	547.2
16	Required HLH Generation	2,805.6	2,697.7	2,697.7	2,805.6	2,589.8	2,913.5	2,697.7	2,805.6	2,805.6	2,697.7	2,913.5	2,589.8
17	Required LLH Generation	2,218.8	2,158.1	2,320.0	2,212.1	1,942.3	2,097.4	2,158.1	2,212.1	2,050.2	2,320.0	2,104.2	2,266.0
18	HLH Buy/(Sell)	281.0	-625.1	70.1	-270.2	-868.8	-597.1	-1,032.3	-1,201.8	-558.8	405.2	443.4	1,205.5
19	LLH Buy/(Sell)	114.3	558.7	1,077.6	289.9	-291.5	-503.6	-895.9	-97.4	443.3	54.3	280.3	1,718.9
20													
21	Cost/Benefit	$10,137	-$1,703	$29,437	$505	-$29,758	-$28,230	-$49,452	-$33,321	-$2,960	$11,784	$18,561	$75,001
22	Net Cost under Alt #4	$0											



Date: 5-18-2007
Purpose/Subject: Tier 1 Rate Design Workshop
Legal Disclaimer: Deliberative and pre-decisional