B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N

2007 Wholesale Power Rate Case Initial Proposal

REBUTTAL TESTIMONY

Risk

March 2006

WP-07-E-BPA-33

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Witnesses for Bonneville Power Administration

SUBJECT: RISK

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Section 1: Introduction and Purpose of Testimony

Q. Would you state your names?

A. My name is Michael Normandeau and my qualifications are contained in WP-07-Q-BPA-43.

A. My name is Arnold Wagner and my qualifications are contained in WP-07-Q-BPA-50.

A. My name is Byrne Lovell and my qualifications are contained in WP-07-Q-BPA-32.

A. My name is Sid Conger and my qualifications are contained in WP-07-Q-BPA-10.

A. My name is Randy Russell and my qualifications are contained in WP-07-Q-BPA-47.

A. My name is Alexander Lennox and my qualifications are contained in WP-07-Q-BPA-30

A. My name is Ken Marks and my qualifications are contained in WP-07-Q-BPA-36.

A. My name is Steve Kerns and my qualifications are contained in WP-07-Q-BPA-23.

Q. *Have you previously submitted testimony in this proceeding?*

A. Yes, we submitted direct testimony identified as exhibit WP-07-E-BPA-12 and exhibit WP-07-E-BPA-14. Our direct testimony, as well as this rebuttal testimony, is submitted on behalf of BPA.

Q. What is the purpose of this testimony?

A. This testimony responds to direct testimony submitted by several parties in the WP-07 rate proceeding. The parties are: Columbia River Inter-tribal Fish Commission, Nez Perce Tribe and the Yakama Nation (Tribes)(*See,* Sheets, *et al.,* WP-07-E-CR/NZ/YA-01); NW Energy Coalition/Save Our *Wild* Salmon Coalition (NWEC/SOS) (*See,* Weiss, WP-07-E-JP8-01); The Preference Customer Group (*See,* Saleba, *et al.*, WP-07-E-JP1-01; Carr, *et al.,* WP-07-E-JP5-01); the Joint Customer Group (*See,* Early*, et al.,* WP-07-E-JP9-01; Corwin, *et al.*, WP-07-E-JP9-02; Brattebo, *et al*, WP-07-E-JP9-03); the Public Power Council (PPC) (*See,* Crinklaw, *et al.,* WP-07-E-PP-01); the Joint Party (*See,* Wolverton, *et al.,* WP-07-E-JP10-01); the Springfield Utility Board (SUB) (S*ee,* Nelson, WP-07-E-SP-01); and Western Public Agencies Group (WPAG) (*See,* Saleba and Piliaris, *et al.*, WP-07-E-WA-01).

Q. How is your testimony organized?

A. This testimony is organized into nine sections, including this introductory section. The second section addresses Treasury Payment Probability and is followed by section 3 regarding Operating Risks, section 4 covering Non-Operating Risks, section 5 on Planned Net Revenues for Risk and Liquidity Tools, section 6 regarding Cost Recovery Adjustment Clause and Liquidity Tools, section 7 covering Dividend Distribution Clause, and section 8 on Alternative Risk Mitigation Proposals, and section 9 Rate Level.

Section 2: Treasury Payment Probability (TPP)

Q. NWEC/SOS argues that BPA's risk mitigation mechanisms are not robust enough to accomplish Bonneville's stated risk mitigation goals. (See, Weiss, WP-07-E-JP8-01, at 5.) Do you agree?

A. No. BPA does not agree with NWEC/SOS's position. BPA has developed a robust set of risk mitigation tools. BPA is proposing an additional mitigation tool called the Emergency NFB Surcharge to respond to certain issues raised in these parties' testimony. *See* the testimony of Lovell, *et al*., WP-07-E-BPA-33. Together these risk mitigation tools achieve a 92.6 percent three-year TPP for the risks that BPA has modeled.

Q. NWEC/SOS argue that BPA's risk mitigation tools are designed for non-predictive events and are poorly matched for predictive events. (See, Weiss, WP-07-E-JP8-01, at 6-7.) Do you agree?

A. No. The predictive/non-predictive dichotomy NWEC/SOS presents is overly simple. Few of the risks BPA faces are truly 'predictive' in the sense NWEC/SOS suggests. NWEC proffers an outage at CGS as an illustration of a predictive risk. While it is true, as NWEC/SOS asserts, that BPA would begin to get information about the outage as soon as the outage occurs, this information would fall far short of actually allowing BPA to "predict" when the plant would return to service or how much any needed repairs would cost, which are two of the main determinants of the financial impact of this risk event. BPA's risk mitigation tools are general purpose mechanisms that are well matched for the wide range of risks BPA faces.

Q. Both the NWEC/SOS and the Tribes contend that BPA's failure to evaluate the risk of multiple Treasury deferrals underestimates the risks that BPA faces. (See, Weiss, WP-07-E-JP8-01, at 7; Sheets, et al., WP-07-E-CR/NZ/YA-01, at 58-59.) The NWEC/SOS asserts that BPA has under-represented TPP by about 25 percent. How do you respond?

A. BPA disagrees. BPA and the region chose a definition of TPP in 1992 (the probability that BPA will make all of its Treasury payments within a rate period), and after that, established a standard based on that definition (95% for a two-year rate period), and BPA has used it consistently as a financial standard since 1993. (*See,* 1993 Final ROD, WP-93-A-02, Revenue Requirement Study, WP-93-FS-BPA-02, Appendix C, for a complete copy of BPA's Ten Year Financial Plan.) To calculate TPP, BPA performs a computer simulation with many games, 3000 in this rate case, and calculates the percentage of those games that do not have any deferrals. The Tribes and the NWEC/SOS are arguing for a different definition, perhaps a calculation of the percentage of years in the set of games in which there is no deferral, or a metric that weights more heavily second deferrals than first deferrals in a game. These are not unreasonable definitions, but they are no more reasonable than the definition BPA has been using for over 10 years. If BPA were to adopt an alternate definition, BPA would then need to determine what the appropriate numerical standard would be; there is no reason to assume that such a standard would be 95%. BPA believes it is calculating TPP appropriately.

Q. The NWEC/SOS argues that BPA is unwilling to accept a Treasury deferral under most circumstances, and as a result, needs a higher TPP target to ensure it is able to maintain its public purpose responsibilities without having to declare hydro emergencies. (See Weiss, WP-07-E-JP8-01, at 14-15.) Do you agree?

A. No, we do not. BPA agrees that the agency is not willing to miss a Treasury payment except under extraordinary circumstances. Assuming anything less would be inconsistent with maintaining a high probability of meeting its Treasury obligations. However, we disagree on the definition of "extraordinary." BPA considers the current TPP methodology the appropriate balance between the acceptable risk that BPA will assume and needlessly high power rates.

The NWEC/SOS refers to the declaration of a hydro emergency in 2001 as an example of BPA's unwillingness to miss a Treasury payment. The 2001 hydro emergency brought on by a drought and extraordinarily high market prices was a prudent response by BPA to the region's situation. At that time, BPA relied upon a broad array of financial tools that included load reduction agreements with public agencies, DSIs and IOUs; an irrigation load buy-back program; a jump-start of conservation measures; increased supplies of alternative power sources such as wind generation; a rate increase of 46%; and replacement of certain fish and wildlife spill measures with offsetting measures to mitigate any adverse impacts to fish and wildlife. BPA has declared such a system emergency only once, and then it was as a way of avoiding defaults on payments to commercial creditors, not as a way of avoiding a Treasury miss; the standard for declaring that emergency was a probability of more than 20% of exhausting BPA's financial reserves and therefore being unable to pay creditors, not a probability of being unable to pay Treasury.

Section 3: Operating Risks (RiskMod)

Q. The Public Power Council states that BPA "may have" underestimated its secondary revenues in FY 2006 because of an "artificial cap it placed on its forecasted non-firm revenues in FY06" and that "customers should not be penalized in their rates" for the artificial assumption BPA made. (See, Crinklaw, et al., WP-07-E-PP-01, at 12, line 8-22.) The Joint Customer Group seconds Public Power Council's concern when they state, "we expect BPA to modify in the final study its conservative treatment of FY06 secondary sales, due to the availability of better information regarding expected net secondary revenues." (See, Brattebo, et al., WP-07-E-JP9-03, at 10, line 5-7.) How do you respond?

A. We agree that removal of the cap on secondary revenue is reasonable for the final study. BPA will not be relying on the capped forecast of FY 2006 net secondary revenues in its final proposal. BPA intends to update the FY 2006 forecast of net secondary revenues with actuals to date and will also use updates of the natural gas price forecast, load forecast, hydroelectric generation forecast, and any other related assumptions used to calculate the FY 2006 forecast of net secondary revenues. BPA does not intend to cap FY 2006 net secondary revenues as was done in the initial proposal because there will be greater certainty about the FY 2006 net secondary revenues at the time the final studies are prepared than was available in August of FY 2005.

Q The WPAG contends that actual net secondary revenues have exceeded the net secondary revenue credit included in the PF rate. (See, Saleba and Piliaris, WP-07-E-WA-01, at 33, lines 19-21.) WPAG argues that "on average, the secondary revenue credit included in the PF rate was about $252 million less than the secondary revenues actually received by BPA." (Id. at 31, lines 5-7) How to you respond?

A. A review of the data used to calculate the $252 million showed that WPAG's calculation considered the gross secondary sales revenue only. Balancing or short-term power purchase expenses were not considered (IN-WA-001 and IN-WA-001A). The PF rate calculation uses a net secondary revenue concept that includes both secondary revenues and power purchase expenses (for balancing purchases). The comparison of actual to forecasted gross secondary revenue made by the WPAG does not capture the offsetting effect of power purchase expenses and therefore is not meaningful in relation to calculating the PF rate. Therefore, the results presented by WPAG are incorrect.

Section 4: Non-Operating Risk Model (NORM)

Q. In its testimony, the Joint Customer Group makes the recommendation, "BPA should not include the additional risk premium that results form [sic] the calculations in NORM." (See, Brattebo, et al., WP-07-E-JP9-03, at 18, lines 9-10.) Does BPA agree with the Joint Customer Group's conclusion?

A. No. BPA faces risks to its costs and revenues beyond those included in RiskMod. NORM captures additional uncertainties for these "non-operating risks." If BPA were to ignore these risks, the TPP would be overstated; BPA's actual probability of making its Treasury payment would be lower than the TPP calculated by ToolKit.

Q. The first reason the Joint Customer Group gives for not using the NORM results is "BPA should manage to its projected costs rather than accept in advance that, on balance, there are additional costs included in revenue requirements." (See, Brattebo, et al., WP-07-E-JP9-03, at 18, lines 11-12.) Please respond.

A. First, the non-operating risks are not costs that are included in the revenue requirement; they are risks that are modeled in BPA's risk analysis.

Second, many of the costs modeled in NORM are largely outside of BPA's direct control. Of the 16 cost categories modeled in NORM, only four – Energy Efficiency capital, corporate G&A, PBL internal operations, and capital equipment costs – are mainly under BPA's control.

Third, BPA may experience very good years and may also experience unforeseen costs at the same time. Since customers will receive the benefits of positive financial results through the DDC, it is reasonable to expect those who can receive the benefits to pay the costs associated with delivering those benefits.

Fourth, it is appropriate and prudent to include such uncertainties in rate-setting so that BPA can design a package of risk mitigation tools that is sized appropriately for the risks BPA will face in the coming rate period. This helps to ensure that BPA will have the flexibility to respond to new regulatory or legal requirements that may be imposed during the rate period. For example, the costs of complying with OMB Circular A-123 (commonly referred to as "Sarbanes-Oxley for the Federal government") are unknown. A-123 requires Federal agencies to annually assess and document their internal controls over financial reporting. The annual costs of complying with A-123 were unknown when BPA forecast the level of internal costs to be included in the revenue requirement, and are still largely unknown and largely outside of BPA's control. By including a distribution of uncertainty over internal costs, BPA was able to size its risk mitigation tools to be able to respond not only to variations in secondary marketing results but also for externally-imposed costs such as A-123 compliance.

Finally, it is incorrect that NORM only assumes the potential for cost increases. For many cost categories, NORM includes the probability that the costs may be *below* what is included in the revenue requirement.

Q. Later in its testimony the Joint Customer Group states "Incorporating the results of the NORM model into rates provides BPA an outlet to exceed budgeted costs. This outlet reduces the incentive to live within budget amounts. As such, it is counterproductive to a central objective of BPA's customers: To have BPA set its costs at the lowest level and live within those limits." (See, Brattebo, et al., WP-07-E-JP9-03, at 19, lines 14-18.) Please respond.

A. As described in the testimony of Andrews, *et al.,* WP-07-E-BPA-30, BPA has multiple objectives. These are reflected by the four pillars (System Reliability, Low Rates (consistent with sound business principles), Environmental Stewardship, and Regional Accountability) of its strategic plan. *See,* Andrews, *et al.,* WP-07-E-BPA-30 and http://www.bpa.gov/corporate/about_BPA/StratDocs/Strategic_Vision_Brochure_2005.pdf for a description of BPA's strategic direction. BPA's Low Rates objective is consistent with the Joint Customer Group's desire for BPA to live within its budget. However, BPA needs to balance the risks to achieving all of its multiple objectives. Capping its costs at the lowest level is not consistent with sound business principles, if doing so increases the risk that BPA will not be able to achieve its other objectives such as maintaining system reliability.

Q. The second reason the Joint Customer Group gives for not using the NORM results is "BPA's net position is affected by other factors, including offsetting cost reductions or secondary revenue increases that may, in retrospect, render the need for the additional rate adjustment unnecessary." (See, Brattebo, et al., WP-07-E-JP9-03, at 18, lines 13-15.) Does BPA agree with this conclusion?

A. No. BPA currently models its net position by combining the results from both RiskMod and NORM in the ToolKit Model. Through this process, higher- and lower-than-normal costs simulated by NORM are randomly combined with a wide range of operational net revenues simulated by RiskMod. This approach allows higher than normal costs from NORM to be offset by higher-than-normal net secondary revenues in some games. Also, the 16 categories of cost risks simulated by NORM are largely sampled independently, with the result that higher-than-normal costs in some categories are often offset by lower-than-normal costs in other categories. Thus, BPA is already modeling the phenomenon that the Joint Customer Group has identified. As BPA sets actual rate levels by calculating DDC or CRAC adjustments prior to the beginning of each year in the rate period, cost reductions or increases in net secondary revenues that materialize and work to offset cost increases or decreases in net secondary revenues will increase AMNR, which has the effect of reducing the next year's rate through the level of the CRAC or DDC.

Q. The third reason the Joint Customer Group gives for not using the NORM results is "The cost increases here likely are redundant to those that trigger the CRAC. That is, BPA's net revenue streams are protected elsewhere." (See, Brattebo, et al., WP-07-E-JP9-03, at 18, lines 16-17.) The Public Power Council agreed with the Joint Customer Group when they stated, "BPA's proposed risk mitigation package essentially double-counts some of the risks BPA faces." (See, Crinklaw, et al., WP-07-E-PP-01, at 11, lines 13-14.) Does BPA agree with this conclusion?

A. No. It is important to differentiate between how the simulation of cost risks modeled in NORM affects rates, and how the actual costs realized in the future will affect rates. NORM models uncertainty around certain costs and revenues that are not modeled elsewhere in the risk analysis. The NORM results are combined with RiskMod results in ToolKit to determine the TPP, which result is then used to calculate the amount of PNRR needed to meet the TPP standard. The actual level of the CRACs and DDCs will be determined by the actual levels of costs and revenues realized in the previous year. The risks modeled in NORM and RiskMod *should* be parallel to the risks that will play a role in the setting of the CRAC and DDC levels – that is the whole point of the risk analysis, to simulate in rate setting how BPA's risk mitigation tools will respond to future developments. BPA is not double-counting these risks; it is simulating them once in the risk analysis as BPA simulates the real world, and then it will count them once in the actual calculation of CRAC and DDC results in the real (i.e., not simulated) world.

Q. The fourth reason the Joint Customer Group gives for not using the NORM results is "The probabilities associated with levels of exposure, based on staff judgment, are highly subjective and virtually impossible to verify and test." (See, Brattebo, et al., WP-07-E-JP9-03, at 18, lines 18-19.) How do you respond?

A. BPA disagrees with implication by the Joint Customer Group that the method of development of the NORM results was inappropriate. To develop the levels of potential costs/revenues and associated probabilities modeled in NORM, BPA relied on the experience and judgment of the Agency's Subject Matter Experts (SMEs). While the level of potential costs/revenues and the associated probabilities are often based on expert judgment, and can be considered to be subjective, they are not arbitrary. The SMEs are the most knowledgeable people at BPA about the risks in each of their respective subject areas, and it is reasonable to rely on this expert knowledge to quantify the risks.

Q. The Joint Customer Group claims that the NORM data "...were combined to obtain a NORM result, which was added to the revenue requirement. The amount added was approximately $21 million per year, based on the data contained in the NORM output file issued with the ToolKit models." (See, Brattebo, et al., WP-07-E-JP9-03, at 19, lines 9-12.) How do you respond?

A. It appears that the Joint Customer Group may not completely understand how NORM fits into the risk analysis. NORM provides two sets of data to the ToolKit. First, NORM models the uncertainty around certain costs and revenues that are not modeled elsewhere in the risk analysis. Then NORM is run for 3,000 iterations to produce a set of net revenue deviations. In ToolKit, this set of net revenue deviations is added to the set of 3,000 net revenues from RiskMod to develop the total net revenue distribution used by the ToolKit. In addition, NORM generates a set of 3,000 accrual-to-cash adjustments which are used by ToolKit to turn the net revenue distribution into a cash (financial reserves) distribution. This step is necessary because not all of the changes in costs and revenues modeled in NORM affect cash. As stated previously, ToolKit uses these NORM data, along with all its other inputs, to calculate the TPP and from this, the amounts of annual PNRR needed to meet the TPP standard. NORM affects the revenue requirement through its effect on TPP and subsequently on PNRR, rather than as a direct increase in the revenue requirement.

Section 5: Planned Net Revenues for Risk and Liquidity Tools

Q. The Public Power Council stated in its testimony that "we believe that BPA is currently proposing to collect more PNRR than will be necessary" and is "over-compensating for the risks BPA is facing." (See, Crinklaw, et al., WP-07-E-PP-01, at 7 and 11.) Does BPA agree that it is proposing to collect an unnecessary amount of PNRR?

A. No. BPA is proposing to collect an amount of PNRR that just meets BPA's TPP standard.

Q. The PPC implies that BPA should lower the PNRR because BPA is working to obtain additional liquidity tools. (See, Crinklaw, et al., WP-07-E-PP-01, at 6.) Do you agree?

A. No. BPA will include in its final proposal any new liquidity tools that are available and that can be prudently relied upon at that time. (*See,* Andrews, *et al.,* WP-07-E-BPA-30, at 7) Since BPA cannot at this time count on the availability of these tools, it would be imprudent to unilaterally reduce the PNRR without some corresponding assurance that the liquidity tool is available.

Q. The PPC suggests that BPA should make provisions for allowing the benefits of new liquidity tools to flow to rates if they become available after the final proposal is completed. (See, Crinklaw, et al., WP-07-E-PP-01, at 12.) Do you agree?

A. BPA shares this interest, and will consider whether it is feasible to incorporate the rate-reducing potential of any liquidity tools that become available after completing the final proposal.

Q. What would be the impact on BPA's final proposal if liquidity tools were to become available between the Initial Proposal and the final proposal?

A. In general, assuming that the information is available in time to be included for in the final studies, BPA would incorporate the liquidity tool(s) into the final studies by appropriately adjusting the liquidity reserve level in ToolKit. The liquidity reserve level sets the threshold at which BPA counts a Treasury miss when reserves fall below that threshold. For the Initial Proposal, this was set at $50M for PBL. Generally speaking, other sources of liquidity can substitute for financial reserves for meeting BPA's liquidity needs. This means that the amount of reserves set aside for liquidity needs can be reduced, and some amount of reserves can be freed up to be used to increase TPP. This results in a reduction in the cost of risk in the form of lower PNRR and/or a reduction in the CRAC collection amount.

Q. How would the liquidity reserve level be adjusted in ToolKit if liquidity tools were incorporated into the final studies?

A. That depends on the type, combination, and limitations on the use of the liquidity tool(s). Generally, there is a net benefit to rate payers, but each tool will have a different effect on BPA's need for liquidity reserves. In other words, BPA will reassess PBL's liquidity reserve level in the event that one or more liquidity tools become available in time for completion of the final studies to ensure the TPP calculation remains at 92.6 percent. It should be noted while many of the liquidity tools BPA is pursuing have a simple effect of increasing the liquidity available to BPA, the proposal for Direct Pay of Energy Northwest has two effects. One effect is to increase BPA's supply of liquidity by freeing up money that would under Net Billing be held by Energy Northwest on September 30; the other effect is to increase BPA's need for liquidity by changing the shape of BPA's cash flow through the year. The latter effect would require BPA to increase the liquidity reserve level above the current $50 million to adjust for the major shift in BPA's cash flow pattern and the associated shift in BPA's cash obligations throughout the year. The increase in BPA's need for liquidity would be more than off-set by the benefit of additional liquidity made available through Direct Pay. All of the estimates BPA has made of the rate benefits of Direct Pay have included the impacts of both of these effects.

Q. Why is it appropriate to increase the liquidity reserve level under Direct Pay?

A. BPA's monthly cash flow profile changes significantly under Direct Pay. This is because BPA's responsibilities to EN under Direct Pay reflect the actual shape of EN's monthly operating cash requirements instead of the effect of the net billing agreements. EN is required to make two large bond payments during its fiscal year, one in December and one in July. These debt payments can range from $100M to $200M, depending on whether the EN budget has been refinanced through the Debt Optimization program.

For the other 10 months of its fiscal year, its operating cash requirements are more or less level. If BPA implements Direct Pay, it will be required to make these two debt payments out of the Bonneville Fund, whereas before, EN would have made the payments out of the cash it had collected from the net billed participants. BPA will also have to make all cash payments to EN one month in advance of its operating need date; this means BPA will have to make these debt payments in November and June to allow EN time to make the debt payments to the Bond Trustee.

Q. Are the July and December debt payments of equal concern?

A. No. BPA is concerned mainly about the cash it needs to meet EN's cash requirements in the May to June time frame and is less concerned about the December payment.

Q. Why is this?

A. Recall that the benefit of directly paying EN's operating costs is that BPA receives the cash from its power revenues throughout the year that it would have otherwise sent to EN in the first five or so months of its Net Billing cycle which runs from June through May. This is the reason that Direct Pay could provide such a significant benefit to the ratepayers. Putting it another way, BPA's cash flow in the spring and summer months would change dramatically due to Direct Pay, so that as of the beginning of its fiscal year, it would have approximately $200M more liquidity (in the form of cash) than it would have had under Net Billing at that same time of year. The flip side of this is that by the end of May under Direct Pay, BPA's total cash outflows to EN for the previous twelve months will be identical to those under Net Billing, meaning that this liquidity cash advantage has decreased to zero. Also in the May/June time frame BPA's cash inflow from its power revenues under Net Billing is almost identical to that under Direct Pay because by this time, virtually all Net Billing obligations have been met and virtually all of the power revenue is coming to BPA. Therefore, BPA's June payment to EN, which would include a large debt payment, is made from the fund in the month where it no longer has the extra liquidity cash from Direct Pay and where Bonneville's cash inflows are virtually identical to what they would have been under Net Billing. This is not the case in December.

Q. *Does Bonneville currently have an estimate of the magnitude of this increase in liquidity reserve level?*

A. Yes. BPA has done some preliminary analysis of this issue and has estimated that the increase in liquidity reserve level during the May to June time frame could range from $125 to $200 million. BPA will update this analysis for the final studies.

Q. *How will this affect the benefit of Direct Pay in setting rates?*

A. BPA is likely to assume in its final studies to increase its $50 million liquidity cash need to between $175 and $250 million when computing power rates under Direct Pay if no other liquidity tools are available. The combined effect of Direct Pay and this change in liquidity reserve level still provides the potential for a rate reduction in the PF rate because there is still a large positive net liquidity benefit from Direct Pay, even after accounting for this increase in cash liquidity needs.

Q. *Would BPA's need for liquidity still increase if other liquidity tools become available?*

A. Yes – BPA's *need* for liquidity is increased by the changed shape of its cash flow under Direct Pay, but if other liquidity tools become available, BPA's *supply* of liquidity would also increase. If other liquidity tools can supply as much incremental liquidity as is required by Direct Pay, BPA would not need to increase the liquidity reserve level, and if such tools can supply more incremental liquidity than Direct Pay requires, BPA may even be able to set a lower liquidity reserve level.

Q. *What if BPA does not determine it can rely on any of the liquidity tools with confidence until after the final studies?*

A. As noted in the testimony of Andrews, *et al.*, (WP-07-E-BPA-30), if BPA gains the certainty it needs to rely on any of the liquidity tools, but not until after the final studies are completed, then the Administrator has the ability in the draft record of decision to accommodate the availability of liquidity tools by adopting the proposal by the Public Power Council (*See,*Crinklaw, *et al.,* WP-07-E-PP-01, at 12) to include the "may" language feature of the CRAC methodology or consider some type of contingent re-calculation of the CRAC caps and thresholds, as was done in the SN-03 Final ROD to allow for incorporating IOU REP Settlement benefits into rates.

Q. How would adoption of "may" language help to realize rate benefits from liquidity tools?

A. "May" language parallel to similar to that in the SN CRAC rate proposal would add a second step to the calculation of CRAC adjustments. After performing the comparison of AMNR to the CRAC threshold and determining any impacts on PF rates and IOU REP Settlement benefits, the Administrator would have the discretion to reduce the CRAC as long as the resulting PBL TPP for the remainder of the rate period was still at or above the 95% standard (as adapted for the number of years remaining in the rate period).

Q. Would this fully capture the rate benefits of liquidity tools that would have been realized if the tool had become available prior to the final studies?

A. No. This would only allow the reduction of CRAC amounts, so if it turns out that the CRAC is not triggered, the "may" language would not be able to provide any rate relief.

Q. You mentioned a contingent re-calculation. What could be done?

A. A contingent recalculation plan could consist of two parts: 1) a rate package (base rate levels, CRAC cap and CRAC and DDC thresholds, etc.) adopted in the ROD that would go into effect on October 1, 2006 unless altered by the contingency; and 2) a definition of contingent events and a description of the recalculations that would be made. If one of the contingent events occurred, the specified parts of rate package would be recalculated as if the new information generated by the contingent event had been known at the time of the calculation of the rate package described in the ROD. For example, one contingent event might be defined to be the completion of an agreement between BPA and the Treasury which provides additional liquidity instruments for BPA. The recalculation to be performed in this event could be defined to be a recalculation of PNRR and the CRAC cap (or of PNRR, the CRAC cap, and the thresholds for the CRAC and the DDC). The availability of additional liquidity might allow the reduction of the liquidity reserve level from $50 million to $0, which would make $50 million more reserves available for supporting TPP, which would reduce the need for PNRR, and perhaps reduce the cap on the CRAC. The contingent clause language would need to specify what the dependency of the recalculations on the timing of the contingent event. For instance, if a BPA-Treasury agreement were completed in July 2006, there would be time to recalculate the rate package prior to the beginning of the rate period. If the agreement were completed in November 2006, the recalculation might go into effect on January 1, 2007; alternatively, the implementation date might be set for the beginning of the next fiscal year, October 1, 2007.

Section 6: Cost Recovery Adjustment Clause (CRAC)

Q. The Joint Customer Group suggests several changes be made to the CRAC for the final study. Many of the other customer groups agreed with the Joint Customer Group's testimony. Specifically, the Joint Customer Group recommends that BPA adopt limitations on specific expense categories, add "may" language, adjust the timing of the CRAC notice, and include a CRAC rebate similar to that found in the current SN CRAC. (See, Brattebo, et al., WP-07-E-JP9-03, at 2, line 19; Crinklaw, et al., WP-07-E-PP-01, at 8, lines 17-23, and at 9, 1-8.) How does BPA respond to the argument that the CRAC be limited on specific expense categories?

A. BPA strongly disagrees with this aspect of this proposal. In the development of the SN CRAC, BPA was responding to an emergency situation in a period where rates were increasing, in part, due to higher than forecasted expenses. In addition, at that time there was a certain lack of transparency with regard to BPA's costs. These factors lead to significant changes in how BPA addresses cost issues with its customers and constituents. Today, BPA conducts numerous processes to control, reduce, and be accountable for costs, starting with Financial Choices and continuing though Public Power Council monthly meetings, the Customer Collaborative, benchmarking studies, the KEMA initiative and two Power Function Review processes. (*See,* Chapter 2 of the Revenue Requirement Study, WP-07-E-BPA-02.) BPA remains committed to continuing with these efforts and maintaining its vigilance with regard to looking for cost reductions. In light of these ongoing processes, BPA believes it is responding adequately to customers' desires for effective cost control. This intense level of scrutiny has led to an ongoing situation in which the safety margins in BPA's budgets have been scrubbed out. Given that, BPA does not believe it is appropriate or prudent to limit cost recovery in this way, particularly when many of the proposed cost categories are beyond BPA's control.

Q. Do you agree with the Joint Customer Group's proposal to include the "may" language?

A. BPA disagrees with this proposal as well. BPA included the "may" language as part of the SN CRAC methodology because the use of the SN CRAC was a mechanism of last resort and was not intended to recover lost revenues if the agency TPP was above the three-year TPP equivalent of 80 percent. In this rate case, BPA is returning to the traditional business line TPP standard for the next rate period that includes a three-year TPP of 92.6 percent.

Additionally, the formula-based mechanism makes the calculation clear and transparent and allows the agency and the region to focus on other issues during the rate period rather than annual rate adjustments that account for actual financial performance.

Q. *How does BPA respond to the recommendation that the timing of notification of the CRAC be changed?*

A. BPA's original intent for changing the process to later in September was to allow for the most complete financial information to be available before calculating the CRAC or DDC adjustments (if any). The experience in the FY 2002-2006 rate period has led to a number of post-third quarter changes to the rate analysis to account for events in July and August that were not part of the third-quarter review. It is these types of changes that BPA is attempting to account for in the rate calculation that would be presented to customers in September. However, BPA is willing to modify the GRSPs in the final studies and include an August preliminary rate adjustment forecast along with having the final rate announcement on or about September 1 as is stated in the current GRSPs.

Q. *What is BPA's response to the suggestion that the CRAC include a rebate similar to that found in the SN CRAC?*

A. BPA believes the CRAC rebate is a rate design feature that is unnecessary and creates a level of complexity that provides little benefit. BPA believes the DDC sufficiently serves the purpose of returning dollars that are not necessary to maintain BPA's financial stability. The Joint Customer Group's proposal merely adds an additional mechanism that would tend to cause more complexity with little net benefit for the customers. Furthermore, including in rate design an additional mechanism that returns monies to customers would have the unfavorable and offsetting effect of increasing the PNRR. BPA has already increased the availability of the DDC by lowering the threshold from the equivalent of $1.2 billion in the current rate period to $800 million in the initial proposal. This change alone greatly increases the probability that the DDC will trigger and, in turn, return money to customers.

Q. *The Joint Customer Group asserts that BPA's financial CRAC provides a "disincentive for BPA to control costs." How do you respond?*

A. BPA does not agree that BPA's CRAC mechanism is a disincentive for cost control. BPA is vigorously engaged with customers in several arenas (e.g., the Customer Collaborative and the Power Function Reviews) for mutual work on controlling BPA's costs, and believes these are effective and appropriate processes even under our current rate design, which includes three CRACs. *See,* Chapter 2 of the Revenue Requirement Study, WP-07-E-BPA-02. BPA does not believe these efforts will be made less effective by the proposed CRAC mechanism.

Q. The Tribes argue that the proposed CRAC and NFB Adjustment are not adequate to address the costs of implementing the 2004 FCRPS Biological Opinion. They have made various operational assumptions about the Biological Opinion that lead to estimated costs that are greater than those assumed by BPA in its initial proposal and have concluded that these increases will reduce BPA's revenues and consequently lower the TPP below the 92.6 percent standard. (See, Sheets, et al., WP-07-E-CR/NZ/YA-01, at 53, 54-57.) How do you respond?

A. Any increases in fish costs over the current forecast that are identified by the time of the final proposal would be included in the revenue requirement as part of the final studies and would therefore be recovered in base rates, not through the CRAC. The CRAC mechanism is designed to adjust for increased costs or reduced revenues that could not be known at the time rates were set. Simply adding costs to illustrate a lower TPP in ToolKit is not appropriate. Any "known" identified costs such as increased fish costs would be included in the revenue requirement as part of the final studies and therefore recovered in base rates, not through the CRAC or the NFB Adjustment of the CRAC cap. The Tribes analysis incorrectly uses ToolKit to model future known expenses to argue that BPA is accepting a lower TPP.

However, the Tribes have pointed out that the NBF adjustment entails a delay in receiving cash to compensate for the financial impacts of court-ordered (etc.) changes in

BPA's fish and wildlife program (including operations), and BPA has responded by proposing the Emergency NFB Surcharge, *see,* Lovell and Normandeau (WP-07-E-BPA-34).

Q. Are there any other changes that BPA would like to make to the CRAC methodology?

A. Yes. We have noticed that the methodology for accounting for the IOU impact on the CRAC percentage in the GRSPs is incorrect. (*See,* WP-07-E-BPA-07 at 81-82.) BPA is proposing to correct the methodology by replacing the existing formula-based description with a shorter, clearer explanation of the calculation. At the August/September CRAC workshop, BPA will provide an explanation of the calculation of the impact of the CRAC on IOU REP Benefits. The following text is proposed to replace Section II.D.1.c:

> The CRAC percentage will be the lowest percentage that, when applied to HLH and LLH energy and Load Variance, generates additional net revenue (additional PF revenue combined with possible reductions in REP Settlement benefits) in the amount required by the CRAC formula.

This same issue applies to the DDC portion of the GRSPs, and so BPA proposes to replace Section II.F.1c with the following text:

> The DDC percentage will be the lowest (smallest negative) percentage that, when applied to HLH and LLH energy and Load Variance, generates reduced net revenue (reduced PF revenue combined with possible increases in REP Settlement benefits) in the amount required by the DDC formula.

Section 7: Dividend Distribution Clause

Q. The Tribes believe BPA should eliminate the DDC, or modify it to meet a rolling three-year average TPP test under a range of cost assumptions described in their testimony. (See, Sheets et al. WP-07-E-CR/NZ/YA-01, at 65-66) How do you respond?

A. The Tribes are suggesting a change in order to meet a financial standard different from BPA's TPP standard. BPA's rate proposal is sufficient to meet BPA's TPP standard with the DDC mechanism operating in the manner BPA proposed, so it is not necessary to eliminate or modify the DDC. Implementing a rolling three-year TPP test would not be practical because it would require making assumptions about future rate levels long in advance of the setting of those rates. The inclusion of the DDC is based on a policy decision stated in the testimony of Leathley, *et al.,* WP-07-E-BPA-08 at 5, lines 14-15) stating that BPA will not build up reserves higher than necessary for the prudent management of risk.

Section 8: Alternative Risk Mitigation Proposals

Q. The Joint Party witness has proposed a different mechanism for dealing with risk. (See, Wolverton, WP-07-E-JP10-01, at 1-3.) Please explain the Joint Party's proposal.

A. The customers proposed that we include in our rate design a mid-year hydro-related surcharge that would trigger in April based on mid-year forecasts for hydro availability through the end of the year. The surcharge amount would apply to the PF rate, be subject to a $400 million cap, and would not trigger unless forecast modified net revenues were more than $150 million below those forecast in the rate case.

Q. Did BPA have concerns with this approach?

A. Yes. Our first concern was that the proposed surcharge triggered just before the commencement of the EN net billing cycle which begins with June power bills. The vast majority of our preference customers are also Participants in the EN projects and because Net Billing will have all payments during that period go to EN, any extra cash from the surcharge would also go to EN rather than come to BPA. In essence, Net Billing would absorb most of any surcharge benefits that might otherwise accrue to BPA through at least September.

Q. The Public Power Council recognizes that "some customers have put forth a proposal for a risk package that includes a mid-year surcharge that is triggered by certain water forecasts and market prices" and states that a mid-year surcharge is "promising." (See, Crinklaw, et al., WP-07-E-PP-01, at 13, line 1-4.) Does BPA believe that a mid-year proposal is more promising than BPA's proposal?

A. No. BPA's assessment is that the mid-year hydro surcharge would result in higher average rates than BPA's proposed risk mitigation package. One main reason for this is that the mid-year hydro surcharge cannot mitigate any FY 2006 risks, while BPA's CRAC can. The current net billing arrangement largely prevents the mid-year hydro surcharge from providing much benefit unless BPA obtains significant new liquidity tools. Thus, either being able to implement the Direct Pay of EN or obtaining other significant new liquidity tools would strengthen the mid-year hydro surcharge. But additional liquidity tools would also benefit BPA's proposal, and average rates under BPA's proposal would still be lower than under the mid-year hydro surcharge.

Q. Do you have additional concerns regarding a mid-year surcharge?

A. Yes. The mid-year surcharge, as proposed, begins in April. In April, there remains a tremendous uncertainty in BPA's revenues for the remaining year because there is still tremendous uncertainty in the value and timing of the runoff of the snow pack for the year. As a result, rates would need to be adjusted through a true-up in October to address the actual financial outcome of the year. This creates added complexity to the analysis as well as rate volatility within a fiscal year. The Joint Party testimony also proposes that the Administrator would have discretion to reduce a possible increase in the surcharge but does not identify how this would be handled or what the TPP impact might be (*See,* Wolverton, WP-07-E-JP10-01, at 2).

Q. The Joint Party argues that BPA incompletely modeled the mid-year surcharge. (See, Wolverton, WP-07-E-JP10-01, at 3-4.) It also asserts that the analysis by BPA is *different from the analysis BPA and the customers did earlier, namely that unlike the earlier analysis, BPA did not assume any other sources of cash as a short-term bridge and instead modeled the actual cash flow to the Bonneville Fund produced by the surcharge. As a result, BPA's analysis is not a complete portrayal of the Joint Customer Proposal. (See, Wolverton, WP-07-E-JP10-01, at 4.) Do you agree?*

A. No. It is one thing for the Joint Party to say that a crucial requirement is that "cash be made available;" it is another to describe just how this would be done within the constraints of BPA's legislated authorities. BPA is exploring several liquidity tools that could be useful in situations such as this – where BPA's cash receipts lag significantly behind its accrual of revenue. BPA did study the rate impacts of the mid-year hydro surcharge both under the assumption that no additional liquidity tools would be available and under the assumption that additional tools would be available. BPA intends to employ all useful, feasible, and reliable liquidity tools, and the tools BPA is exploring would be useful in reducing rates using BPA's proposed risk mitigation package, not just in the case of a mid-year hydro surcharge. The right comparison here is between BPA's risk mitigation proposal and the mid-year hydro surcharge, using comparable assumptions about liquidity tools, not between BPA's proposal without additional liquidity tools and the mid-year hydro surcharge with additional liquidity tools. BPA's analysis showed that with and ***without*** additional liquidity tools, BPA's proposal results in lower expected value rates than the mid-year hydro surcharge.

Q. In addition to arguing that BPA incompletely modeled the mid-year surcharge, the Joint Party states that BPA's estimate of a $155 million annual PNRR does not intuitively make sense in the analysis provided by BPA. (See, Wolverton, WP-07-E-JP10-01, at 4-5.) Do you agree?

A. BPA cannot meaningfully comment on what a Party's intuition reveals other than to note that a fundamental value of employing computer models is that they sometimes produce counter-intuitive results that are subsequently found to be valid, which should lead to improved intuition in the future. The Joint Party appears to have overlooked the fact that in BPA's modeling of the mid-year hydro surcharge, BPA eliminated the CRAC, believing that was one of the goals the customers had in mind when designing the mid-year hydro surcharge. This eliminated all of the risk mitigation except PNRR for risks other than net secondary revenue. Another factor explaining the $155 million that may not have been noted is that the CRAC in BPA's initial proposal is able to generate additional revenue as early as October 2006 (based on net revenue events in FY 2006), and can begin generating additional cash as early as November 2006. The proposed mid-year hydro surcharge cannot generate additional revenue until April 2007, and little of that would appear as additional cash until October or November of 2007 (FY 2008).

Q. If liquidity tools become available before the completion of the final studies, would the mid-year surcharge be an acceptable alternative to BPA's proposal?

A. No. The analysis of this tool, available as Attachment A to this testimony, entitled "How BPA Approximated the Customer Proposal (Mid-Year Hydro Surcharge)" indicates that the Surcharge results in higher expected value rates than BPA's CRAC proposal. According to that document:

> The results [of this analysis] should be interpreted by comparing a Surcharge case with the corresponding Initial Proposal case using the same set of liquidity tools in order to see the impact of the Surcharge itself.
>
> Net Billing: the three-year average rate is about *$1.50 higher* under the mid-year surcharge.
>
> Direct Pay: the three-year average rate is about *$0.50 higher* under the mid-year surcharge.
>
> (Emphasis added)

Customers have made it abundantly clear to BPA that low rates are a paramount concern for them, and BPA does not believe it would be prudent to adopt a rate design that yields higher rates than BPA's proposal.

Q. The WPAG put forward for discussion and consideration the idea of crediting net secondary revenues as they are actually achieved by BPA during the fiscal year. (See, Saleba and Piliaris, WP-07-E-WA-01, at 29-36.) WPAG believes that a crediting secondary revenues approach would "remove the major risk element from the PF rate, and permit BPA to remove a large portion of the risk premium it currently includes in the PF rate." (See, Saleba and Piliaris, WP-07-E-WA-01, at 32, line 5-6.) How does BPA respond?

A. BPA is encouraged by this proposal since we agree that, if it were implemented correctly, it would remove a large amount of the risk that BPA currently faces. This design would produce a lower effective rate than the initial proposal but would do so at the expense of a higher posted rate and potentially more rate volatility. Aside from WPAG, we are unaware of much customer interest for this idea.

Q. The Preference Customer Group argues that the CRAC and DDC should apply to the Load Variance portion of rates in addition to energy sales, and the Monetary Benefits provided to IOUs and the DSI customers. The NFB portion of the CRAC should be applied to the Demand and Load Variance Charge as well as energy sales, the Monetary Benefits provided to IOUs, and the subsidies provided DSI customers. (See, Carr, et al., WP-07-E-JP5-01, at 5-6.) How do you respond?

A. BPA takes no position on whether this issue was a valid concern, however, in light of the proposed resolution of issues described in WP-07-E-BPA-31, this issue is now moot.

Q. The NWEC/SOS proposes that BPA incorporate a risk mechanism called TK-CRAC (similar to the SN CRAC) that adjusts PNRR when BPA's TPP falls below a one-year standard. The proposal calls for a forward-looking TPP assessment but only allows for *two cost categories, fish costs and major maintenance-related costs of at least $50 million, to be included in the look-forward. (See, Weiss, WP-07-E-JP8-01, at 16-17.) Do you support this approach?*

A. No. The proposal limits the cost categories that can be included in the rate adjustment calculation. There is no supporting evidence that the $50 million trigger for adjusting rates due to specified cost categories is reasonable. There is no analysis to support that BPA would maintain its stated TPP target of 92.6 percent for the three-year rate period as defined in the testimony of Leathley, *et al.,* (WP-07-E-BPA-08) using this approach. These limitations make it impossible for BPA to support this proposal.

Q. The NWEC/SOS claims that under their TK-CRAC proposal, there would no longer be a need for a DDC. How do you respond? (See, Weiss, WP-07-E-JP8-01, at 18.)

A. The NWEC/SOS proposes an annual TPP assessment for adjusting rates. This approach would in fact eliminate the need for a DDC because rates would be adjusted upward or downward to meet the TPP standard and would not require a DDC to return excess dollars to customers. This proposal would be acceptable if BPA adopted the NWEC/SOS TK-CRAC proposal, but that proposal is incomplete and is not compatible with BPA's proposed risk mitigation package.

Q. The NWEC/SOS proposes that BPA implement a surcharge to address extraordinary costs over $100 million known to occur in the first half of the year. (See, Weiss, WP-07-E-JP8-01, at 17-18.) Do you support this approach?

A. No. NWEC/SOS does not define extraordinary costs. There is no analysis to support that such a provision is necessary for BPA to maintain its stated TPP target of 92.6 percent for the three-year rate period.

Q. The NWEC/SOS argues that their proposed risk mechanisms produce a lower rate than BPA's proposal and that it reduces BPA's risks better than BPA's proposal. (See, Weiss, WP-07-E-JP8-01, at 18.) Do you agree?

A. While NWEC/SOS implies that its proposal would produce lower rates, it does not include technical analysis to support that position. Similarly, NWEC/SOS proposes an alternative approach to managing BPA's risks but does not provide supporting analysis that its proposal is better at reducing BPA's risks compared to BPA's proposal. Therefore BPA cannot agree or disagree with these conclusions because BPA cannot evaluate them.

Q. *The Tribes contend that BPA should have a "forward looking" CRAC that would collect additional revenues as soon as the obligations are established. (See, Sheets, et al., WP-07-E-CR/NZ/YA-01, at 62-63.) How do you respond?*

A. BPA disagrees with the Tribes' position that there should be a forward-looking CRAC trigger for "any" obligations tied to the Integrated Fish and Wildlife Program. BPA supportsthe concept of a "forward looking" mechanism for addressing the uncertainty associated with the 2004 FCRPS BiOp litigation and that a forward-looking mechanism should be included as part of the risk mitigation package to address the impact that this risk has on TPP. We refer you to the discussion in Section 7 for additional information on BPA's response.

Section 9: Rate Level Discussion

Q. *WPAG's direct testimony states that, "most preference customer residential rates exceed the residential rates charged by IOUs" (See, Saleba and Piliaris, WP-07-E-WA-01, at 7) and has attached Exhibit WP-07-E-WA-01A to graphically depict this disparity. Do you agree?*

A. No. BPA questions the relevancy of WPAG's statement, since BPA is required by law to set rates that will recover its costs, a standard that does not include any reference to the residential rates charged by IOUs. Also, BPA agrees with WPAG's data response that states, "[m]any factors will contribute to rate disparities between two groups of utilities, including relative service densities, cost of capital, underlying sources of power supply, etc." (*See Attachment B,* Data Response JP6-WA-010.) Given these WPAG-provided factors, BPA finds the methodology used by WPAG is noticeably flawed (*See Attachment C,* BPA-WA-002A). WPAG mistakenly subtracted the average residential exchange discount from an average IOU residential rate that had already reflected this discount – the end result being the double-counting of IOU benefits. Correcting for this oversight raises WPAG's proclaimed $57.22/MWh average IOU retail rate to $66.50/MWh, placing the IOU rate nearly in the exact middle of the 106 preference customer sample that WPAG used. BPA disagrees with WPAG's results.

Q. *Does this conclude your testimony?*

A. Yes.

The following description and analysis is the conclusion to discussions that began last summer regarding a proposed mid-year hydro surcharge mechanism. BPA committed to work with customers to develop rate impacts of a surcharge mechanism based on secondary revenues. This analysis is for informal use only and is not a change in BPA's proposed risk mitigation package presented in the WP-07 Initial Proposal. The following analysis includes the use of liquidity tools that are currently under development but not yet available.

How BPA Approximated the Customer Proposal (Mid-Year Hydro Surcharge)

[The Customer Proposal is not summarized here.]
The Customer-proposed mid-year surcharge presented several challenging complexities that had never been completely worked out. BPA tried to develop an approximation that was true to the spirit of the proposal and that could be quantified without prohibitively extensive modifications to BPA's models.

TPP

The TPP for all analyses was 92.6%.

First Calculation, for April – September rates

For the first calculation of a surcharge, to be in effect April 1 – September 30, BPA used the net secondary revenues from RiskMod for the previous October – March. This assumed that a calculation could be made in March of the actual results for October – February with a fairly accurate forecast of the March results. The actual statistic we used was the balancing sales minus the balancing purchases minus an estimate of the water-year specific transmission expenses for balancing sales (average = $55 - $58M/year). The deviation (Deviation 1) between the 3,000-game average and the results for a specific game was calculated for each game. The 3,000 games of market prices and hydro volumes from BPA's Initial Proposal were used for this estimation.

What limits to use?

BPA decided that since the winter is the time when the exposure to high power purchase costs is the highest, the maximum that could be billed for that half-year would be $300M. The first-half surcharge did not kick in unless the 'deviation' was at least $75M. In the second-half calculation, the original limits (threshold = $150M; maximum = $400M) were imposed. If Deviation 1 was less than $75M, there was no surcharge for the first half. If Deviation 1 was equal to or greater than $75M, then there was a surcharge (Surcharge 1), not to exceed $300M. It was assumed that this would be assessed against the HLH and LLH energy rates of all of the CRACcable loads, including the IOU benefits. For this analysis, a simple approximation of the impact on IOU benefits was used (a "right" calculation was too compex for the time available for this first cut).

Second Calculation, for October – March rates (of next fiscal year)

The second calculation was assumed to take place around September, using actual results for October – August and a forecast for the September results. This calculation took the total balancing sales for the fiscal year, and subtracted the balancing purchases and transmission expenses supporting balancing sales for the fiscal year. This result was subtracted from the

3,000-game average, resulting in Deviation 2. If Deviation 2 was less than $150M, there was no net surcharge (and this resulted in a negative surcharge to refund money if Surcharge 1 was non-zero). If Deviation 2 was greater than $150M but less than Deviation 1, there was a negative surcharge to refund money. If Deviation 2 was greater than $150M and also greater than Deviation 1, there was a positive Surcharge 2. Surcharge 2 was capped so that Surcharge 1 + Surcharge 2 <= $400M.

IOU Benefit Impact Estimation

BPA assumed that the mid-year hydro surcharge should affect the IOU benefits much the way the CRAC in BPA's Initial Proposal would – a surcharge would be calculated that collects the 'right' amount of money, and if that surcharge increased the adjusted PF rate enough that the IOU benefits would be reduced, then some of the surcharge collection would occur through reduction of the IOU benefits. But if the IOU benefits were at the floor, or far above the cap, none of the surcharge would be collected through reduction of the IOU benefits. BPA did not have time to figure out how this would be done on a semi-annual basis, so the following approximation was used.

The statistics from BPA's Initial Proposal indicate that 100% of the expected value of CRAC collection for FY 2007 came from PF loads, and about 90% of the expected value of CRAC collection for FY 2008 and FY 2009 came from PF loads, with about 10% of the collection coming from the IOU benefits in FY 2008 and FY 2009. Therefore, BPA estimated that reduction of the IOU benefits would account for 0% of the surcharge collection for the surcharge based on FY 2007 secondary results, and 10% for the surcharge based on FY 2008 and FY 2009 results.

Rate Estimation

The rate impacts of the mid-year surcharge could not be estimated using logic in the ToolKit. Instead, the rates were estimated by starting with the same base rates in BPA's Initial Proposal, calculated by the Rates Analysis Model, and adjusted in the ToolKit for PNRR, updates in the flat-block broker price for FY 2008 and FY 2009, and for any DDC amounts. After this, the expected values of the surcharge amounts were divided into the amount collected from PF loads and from IOU benefits, and the PF rate impact of the surcharge was estimated.

Cash Impacts

The first-half surcharge went into effect on April 1, affecting power sales for April. BPA would bill for these sales in early May, and receive additional cash as customers paid their bills in late May. Power sales for May are net-billed, and the increased revenue generated by the surcharge for May sales would also be net-billed, and therefore not received by BPA until after the Energy Northwest budget was fully funded. If the EN budget is paid off after three months – May, June, and July – the bills for August sales would be received as cash by BPA before the end of the year. This was deemed unlikely. The bills for September sales are never received in the same fiscal year, because the bills are not sent until October. In summary, only the surcharge revenues from April would be received as cash in the same fiscal year, 1/6 of the total of Surcharge 1. The remaining 5/6 of Surcharge 1 would be received as cash in the following fiscal year. All of Surcharge 2 would be received as cash (or paid out as cash) in the following fiscal year. Note that this means that 11/12 of the surcharge based on FY 2009 secondary marketing results would be received as cash in the subsequent rate period.

Cash Impacts Under EN Direct Pay

The EN Direct Pay plan, if feasible, would reshape BPA's cash flow significantly. BPA would pay EN's monthly budget needs each month, and net billing would not come into play. With this change to BPA's cash, the surcharge amounts billed for April through August would be received as cash by the end of BPA's fiscal year, or 5/6 of the first surcharge amount. 1/6 of the first surcharge amount and all of the second surcharge amount (positive or negative) would be received in the following fiscal year. Note that this means that 7/12 of the surcharge based on FY 2009 secondary marketing results would be received as cash in the subsequent rate period.

Results

The results should be interpreted by comparing a Surcharge case with the corresponding Initial Proposal case using the same set of liquidity tools in order to see the impact of the Surcharge itself.

Net Billing: the three-year average rate is about $1.50 higher under the mid-year surcharge.

Direct Pay: the three-year average rate is about $0.50 higher under the mid-year surcharge.

Net Billing Scenario

Mid-year Hydro Surcharge (Net Billing)

	Oct-Mar 2007	Apr-Sep 2007	Annual 2007	Oct-Mar 2008	Apr-Sep 2008	Annual 2008	Oct-Mar 2009	Apr-Sep 2009	Annual 2009		3-yr Ave
CRACcable PF load, annual			5154			5195			5234		
Semi-annual factors	54%	46%		54%	46%		54%	46%			
CRACcable PF load, semi-annual	2783	2371		2805	2390		2826	2408			
PNRR			155			155			155	$	155
Base rates + PNRR			31.80			31.80			31.80	$	31.80
DDC (PF portion)			0			76			181	$	86
Base rates + PNRR + DDC			31.80			30.13			27.85	$	29.93
Surcharge amounts		81	81	28	68	95	21	63	84	$	87
Base rates + PNRR + DDC + Surcharge	31.80	35.70	33.59	31.27	33.35	32.23	28.69	30.84	29.68	**$**	**31.83**
Ave ending reserves			731			914			946		

BPA Initial Proposal (Net Billing)

	Oct-Mar 2007	Apr-Sep 2007	Annual 2007	Oct-Mar 2008	Apr-Sep 2008	Annual 2008	Oct-Mar 2009	Apr-Sep 2009	Annual 2009		3-yr Ave
CRACcable PF load, annual			5154			5195			5234		
Semi-annual factors	54%	46%		54%	46%		54%	46%			
CRACcable PF load, semi-annual	2783	2371		2805	2390		2826	2408			
PNRR			97			97			97	$	97
Base rates + PNRR			30.62			30.62			30.62	$	30.62
DDC (PF portion)			0			82			145	$	76
CRAC (PF portion)			72			78			38	$	63
Base rates + PNRR + DDC + CRAC			32.22			30.52			28.29	**$**	**30.34**
Ave ending reserves			716			790			759		

Direct Pay

Mid-year Hydro Surcharge + Direct Pay

	Oct-Mar 2007	Apr-Sep 2007	Annual 2007	Oct-Mar 2008	Apr-Sep 2008	Annual 2008	Oct-Mar 2009	Apr-Sep 2009	Annual 2009	3-yr Ave
CRACcable PF load, annual			5154			5195			5234	
Semi-annual factors	54%	46%		54%	46%		54%	46%		
CRACcable PF load, semi-annual	2783	2371		2805	2390		2826	2408		
PNRR			-17			-17			-17	$ (17)
Base rates + PNRR			28.25			28.25			28.25	$ 28.25
DDC (PF portion)			0			47			73	$ 40
Base rates + PNRR + DDC			28.25			27.22			26.66	$ 27.38
Surcharge amounts		81	81	28	68	95	21	63	84	$ 87
Base rates + PNRR + DDC + Surcharge	28.25	32.15	30.04	28.35	30.44	29.31	27.49	29.64	28.48	**$ 29.28**
Ave ending reserves			885			966			917	

BPA Initial Proposal + Direct Pay

	Oct-Mar 2007	Apr-Sep 2007	Annual 2007	Oct-Mar 2008	Apr-Sep 2008	Annual 2008	Oct-Mar 2009	Apr-Sep 2009	Annual 2009	3-yr Ave
CRACcable PF load, annual			5154			5195			5234	
Semi-annual factors	54%	46%		54%	46%		54%	46%		
CRACcable PF load, semi-annual	2783	2371		2805	2390		2826	2408		
PNRR			59			59			59	$ 59
Base rates + PNRR			29.83			29.83			29.83	$ 29.83
DDC (PF portion)			0			127			150	$ 92
CRAC (PF portion)			52			52			34	$ 46
Base rates + PNRR + DDC + CRAC			30.97			28.18			27.29	**$ 28.81**
Ave ending reserves			921			938			854	

Response for Request Number JP6-WA-010

Response by:	Western Public Agencies Group and Members
Response Text:	Many factors will contribute to rate disparities between two groups of utilities, including relative service densities, cost of capital, underlying sources of power supply, etc. We have no reason to believe the service densities of BPA's preference and IOU customers are significantly different. We assume that BPA's preference customers have a lower cost of capital and relatively cheaper source of power supply. That said, assuming that the residential customers of IOUs pay their full cost of service, the only plausible reason we see to explain the portrayed rate disparity is the transfer of benefits from BPA's preference customers to the residential customers of the IOUs under the Subscription contracts and ensuring events.
Additional Comments:	
Response Submitted:	02/16/2006 12:21 PM
Attached File:	**No file attached.**

Attachment C
Summary

79	**Number Above IOU Avg Rate Res ExAdj**
	out of ~ 106 Public Utilities /1

Year	BPA Customer	Utility Name	Avg Res Rate		Owner Type	Residential (mWhs)	Residential Revenues
2004	BPA	Avista Corp	$	64.00	I	1,054,446	$67,485,000
2004	BPA	Avista Corp	$	62.06	I	2,288,471	$142,026,000
2004	BPA	Idaho Power Co	$	60.24	I	4,389,994	$264,433,000
2004	BPA	Idaho Power Co	$	51.91	I	190,343	$9,881,000
2004	BPA	PacifiCorp	$	62.35	I	5,218,863	$325,417,000
2004	BPA	PacifiCorp	$	45.85	I	1,537,055	$70,478,000
2004	BPA	Puget Sound Energy Inc	$	62.80	I	10,007,812	$628,475,000
2004	BPA	Portland General Electric Company	$	80.46	I	7,270,118	$584,984,000
2004	BPA	NorthWestern Energy LLC	$	82.29	I	2,018,578	$166,105,000
						33,975,680	$2,259,284,000

Avg IOU Res Rate	$66.50
Avg Res Ex Discount	$9.28
Avg IOU Res Rate Adj for Rex Ex Benefit	$57.22

/1 Note: If Public Utility multi-state rates were approximately equal for a single utility, it was counted only once.

Attachment C

Number Above IOU Avg Rate Res ExAdj
79

Year	BPA Customer	Utility Name	Avg Res Rate ($/mWh)	Owner Type
2004	BPA	City of Albion	$ 60.13	M
2004	BPA	Alder Mutual Light Co, Inc	$ 64.98	C
2004	BPA	PUD No 1 of Benton County	$ 76.71	P
2004	BPA	Benton Rural Electric Assn	$ 76.98	C
2004	BPA	Big Bend Electric Coop, Inc	$ 54.34	C
2004	BPA	Blachly-Lane Cnty Coop El Assn	$ 85.54	C
2004	BPA	City of Blaine	$ 64.70	M
2004	BPA	City of Bonners Ferry	$ 54.97	M
2004	BPA	City of Burley	$ 70.49	M
2004	BPA	Canby Utility Board	$ 64.01	M
2004	BPA	City of Cascade Locks	$ 76.32	M
2004	BPA	Central Electric Coop Inc	$ 73.76	C
2004	BPA	Central Lincoln People's Ut Dt	$ 59.91	P
2004	BPA	City of Centralia	$ 59.81	M
2004	BPA	City of Cheney	$ 61.52	M
2004	BPA	City of Chewelah	$ 61.92	M
2004	BPA	PUD No 1 of Clallam County	$ 68.86	P
2004	BPA	PUD No 1 of Clark County	$ 78.63	P
2004	BPA	Clearwater Power Company	$ 94.56	C
2004	BPA	Columbia Basin Elec Cooperative, Inc	$ 74.16	C
2004	BPA	Columbia Power Coop Assn Inc	$ 74.62	C
2004	BPA	Columbia Rural Elec Assn, Inc	$ 56.00	C
2004	BPA	Coos-Curry Electric Coop, Inc	$ 77.44	C
2004	BPA	City of Coulee Dam	$ 45.31	M
2004	BPA	PUD No 1 of Cowlitz County	$ 52.79	P
2004	BPA	Consumers Power, Inc	$ 80.76	C
2004	BPA	Douglas Electric Coop, Inc	$ 91.02	C
2004	BPA	City of Drain	$ 68.14	M
2004	BPA	East End Mutual Elec Co Ltd	$ 39.32	C
2004	BPA	Town of Eatonville	$ 64.88	M
2004	BPA	Elmhurst Mutual Power & Light Co	$ 44.53	C
2004	BPA	City of Ellensburg	$ 65.95	M
2004	BPA	Farmers Electric Company, Ltd	$ 37.93	C
2004	BPA	Fall River Rural Elec Coop Inc	$ 89.26	C
2004	BPA	PUD No 1 of Ferry County	$ 75.77	P
2004	BPA	Flathead Electric Coop Inc	$ 78.34	C
2004	BPA	City of Forest Grove	$ 48.29	M
2004	BPA	PUD No 1 of Franklin County	$ 81.50	P
2004	BPA	City of Declo	$ 87.42	M
2004	BPA	PUD No 1 of Grays Harbor Cnty	$ 78.44	P
2004	BPA	City of Hermiston	$ 70.05	M
2004	BPA	Heyburn City of	$ 57.24	M
2004	BPA	Inland Power & Light Company	$ 54.30	C
2004	BPA	Hood River Electric Coop	$ 64.34	C
2004	BPA	Idaho Cnty L&P Coop Assn, Inc	$ 92.37	C
2004	BPA	Idaho Falls City of	$ 69.67	M
2004	BPA	PUD No 1 of Kittitas County	$ 79.16	P
2004	BPA	PUD No 1 of Klickitat County	$ 78.98	P
2004	BPA	Kootenai Electric Coop Inc	$ 60.55	C
2004	BPA	Lakeview Light & Power	$ 53.91	C
2004	BPA	Lane Electric Coop Inc	$ 81.07	C
2004	BPA	PUD No 1 of Lewis County	$ 54.12	P
2004	BPA	Lost River Electric Coop Inc	$ 70.13	C
2004	BPA	Lower Valley Energy Inc	$ 54.60	C
2004	BPA	Harney Electric Coop, Inc	$ 53.11	C
2004	BPA	City of McCleary	$ 61.30	M
2004	BPA	McMinnville City of	$ 44.72	M
2004	BPA	Midstate Electric Coop, Inc	$ 68.52	C

Year	BPA Customer	Utility Name	Avg Res Rate	Owner Type	Residential (mWhs)	Residential Revenues
2004	BPA	Avista Corp	$ 64.00	I	1,054,446	$ 67,485,000
2004	BPA	Avista Corp	$ 62.06	I	2,288,471	$ 142,026,000
2004	BPA	Idaho Power Co	$ 60.24	I	4,389,994	$ 264,433,000
2004	BPA	Idaho Power Co	$ 51.91	I	190,343	$ 9,881,000
2004	BPA	PacifiCorp	$ 62.35	I	5,218,863	$ 325,417,000
2004	BPA	PacifiCorp	$ 45.85	I	1,537,055	$ 70,478,000
2004	BPA	Puget Sound Energy Inc	$ 62.80	I	10,007,812	$ 628,475,000
2004	BPA	Portland General Electric Company	$ 80.46	I	7,270,118	$ 584,984,000
2004	BPA	NorthWestern Energy LLC	$ 82.29	I	2,018,578	$ 166,105,000
					33,975,680	$ 2,259,284,000

Avg IOU Res Rate	$ 66.50
Avg Res Ex Discount	$9.28
Avg IOU Res Rate Adj for Rex Ex Benefit	$ 57.22

Attachment C

Year	BPA Customer	Utility Name	Avg Res Rate	Owner Type
2004	BPA	City of Minidoka	$ 64.96	M
2004	BPA	City of Milton-Freewater	$ 46.35	M
2004	BPA	City of Milton	$ 56.11	M
2004	BPA	Modern Electric Water Company	$ 49.83	C
2004	BPA	City of Monmouth	$ 57.64	M
2004	BPA	Nespelem Valley Elec Coop, Inc	$ 71.73	C
2004	BPA	Northern Lights, Inc	$ 88.46	C
2004	BPA	Northern Wasco County PUD	$ 58.25	P
2004	BPA	Ohop Mutual Light Company, Inc	$ 53.55	C
2004	BPA	PUD No 1 of Okanogan County	$ 51.16	P
2004	BPA	Okanogan County Elec Coop, Inc	$ 81.54	C
2004	BPA	Oregon Trail El Cons Coop, Inc	$ 92.73	C
2004	BPA	Orcas Power & Light Coop	$ 85.99	C
2004	BPA	PUD No 2 Pacific County	$ 70.42	P
2004	BPA	Parkland Light & Water Company	$ 41.98	C
2004	BPA	PUD No 2 of Grant County	$ 41.73	P
2004	BPA	PUD No 1 of Pend Oreille Cnty	$ 39.61	P
2004	BPA	Peninsula Light Company	$ 75.52	C
2004	BPA	PUD No 1 of Asotin County	N/A	M
2004	BPA	Port Angeles City of	$ 58.61	M
2004	BPA	City of Plummer	$ 67.38	M
2004	BPA	PUD No 1 Wahkiakum	$ 71.73	P
2004	BPA	PUD No 3 of Mason County	$ 63.66	P
2004	BPA	City of Richland	$ 64.20	M
2004	BPA	Rupert City of	$ 72.66	M
2004	BPA	Salem City of	$ 67.31	C
2004	BPA	Salmon River Electric Coop Inc	$ 83.86	C
2004	BPA	Seattle City of	$ 67.62	M
2004	BPA	PUD No 1 Skamania	$ 67.97	P
2004	BPA	Snohomish County PUD No 1	$ 77.95	P
2004	BPA	City of Soda Springs	$ 57.61	M
2004	BPA	South Side Electric, Inc	$ 45.45	C
2004	BPA	City of Springfield (SUB)	$ 52.53	M
2004	BPA	Town of Steilacoom	$ 73.48	M
2004	BPA	Surprise Valley Electrification Corp.	$ 70.07	C
2004	BPA	City of Sumas	$ 64.05	M
2004	BPA	Tacoma City of	$ 63.08	M
2004	BPA	Tanner Electric Coop	$ 73.32	C
2004	BPA	Tillamook Peoples Utility Dist	$ 80.24	P
2004	BPA	Umatilla Electric Coop Assn	$ 68.61	C
2004	BPA	United Electric Co-op, Inc	$ 59.77	C
2004	BPA	Vera Irrigation District #15	$ 56.08	P
2004	BPA	Wasco Electric Coop, Inc	$ 65.70	C
2004	BPA	West Oregon Electric Coop Inc	$ 103.92	C
2004	BPA	PUD No 1 of Mason County	$ 79.97	P
2004	BPA	Raft River Rural Elec Coop Inc	$ 66.54	C
2004	BPA	Clatskanie Peoples Util Dist	$ 42.73	P
2004	BPA	Emerald People's Utility Dist	$ 75.45	P
2004	BPA	Columbia River Peoples Ut Dist	$ 67.37	P
2004	BPA	PUD No 1 of Whatcom County	N/A	P

Year	BPA Customer	Utility Name	Avg Res Rate	Owner Type	Residential	Residential Revenues