2007 Supplemental Wholesale Power Rate Case Initial Proposal

REBUTTAL TESTIMONY

Volume 1

May 2008

BPA Exhibit No.	Witness
WP-07-E-BPA-76	Forman, Bliven, Boling, Brodie, Evans, Marks
WP-07-E-BPA-77	Lefler, Bliven
WP-07-E-BPA-78	Brodie, Bliven, Clark, Doubleday, Homenick
WP-07-E-BPA-79	Fisher, Bliven, Doubleday
WP-07-E-BPA-80	Hirsch, Booth, Clark, Misley, Van Orden
WP-07-E-BPA-81	Russell, Lovell, Marks, Normandeau
WP-07-E-BPA-82	Petty, Anderson, Conger, Wagner

This page intentionally left blank.

Table of Contents

WP-07 Supplemental Wholesale Power Rate Case
Volume 1

Rebuttal Testimony

This is the Table of Contents for this volume of the Rebuttal Testimony.
The Table of Contents for Volume 2 of Rebuttal Testimony follows this page.

Table of Contents

WP-07 Supplemental Wholesale Power Rate Case
Volume 2

Rebuttal Testimony

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 Supplemental Wholesale Power Rate Case Initial Proposal

REBUTTAL TESTIMONY

LOOKBACK POLICY AND IMPLEMENTATION

May 2008

WP-07-E-BPA-76

This page intentionally left blank.

INDEX

REBUTTAL TESTIMONY of

CHARLES W. FORMAN, JR., RAYMOND D. BLIVEN, RODNEY E. BOLING,

PAUL A. BRODIE, ELIZABETH A. EVANS and KENNETH J. MARKS

Witnesses for Bonneville Power Administration

SUBJECT: LOOKBACK POLICY AND IMPLEMENTATION

Page

REBUTTAL TESTIMONY of

CHARLES W. FORMAN, JR., RAYMOND D. BLIVEN, RODNEY E. BOLING,

PAUL A. BRODIE, ELIZABETH A. EVANS and KENNETH J. MARKS

Witnesses for Bonneville Power Administration

SUBJECT: LOOKBACK POLICY AND IMPLEMENTATION

Section 1: Introduction and Purpose of Testimony

Q. Please state your name and qualifications.

A. My name is Charles W. Forman, Jr. My qualifications are contained in WP-07-Q-BPA-62.

A. My name is Raymond D. Bliven. My qualifications are contained in WP-07-Q-BPA-58.

A. My name is Rodney Boling. My qualifications are contained in WP-07-Q-BPA-06.

A. My name is Paul A. Brodie. My qualifications are contained in WP-07-Q-BPA-07.

A. My name is Elizabeth A. Evans. My qualifications are contained in WP-07-Q-BPA-57.

A. My name is Kenneth J. Marks. My qualifications are contained in WP-07-Q-BPA-36.

Q. Have you previously submitted testimony in this Supplemental Proceeding?

A. Yes. Mr. Bliven, Mr. Marks, Mr. Forman, Ms. Evans, Mr. Boling and Mr. Brodie submitted direct testimony, together with other witnesses, identified as Exhibit WP-07-E-BPA-62. Mr. Bliven, Mr. Forman, and Ms. Evans submitted direct testimony, together with other witnesses, identified as Exhibit WP-07-E-BPA-52. Mr. Bliven and Mr. Forman submitted direct testimony, together with other witnesses, identified as Exhibit WP-07-E-BPA-63. Mr. Bliven and Mr. Brodie submitted direct testimony, together with other witnesses, identified as Exhibits WP-07-E-BPA-58, WP-07-E-BPA-60, WP-07-E-BPA-68, and WP-07-E-BPA-70. Mr. Boling and Mr. Bliven submitted direct testimony, together with other witnesses, identified as Exhibit WP-07-E-BPA-57. Mr. Boling submitted direct testimony, together with other witnesses, identified as Exhibit

WP-07-E-BPA-61. Mr. Marks submitted direct testimony, together with other witnesses, identified as Exhibits WP-07-E-BPA-67 and WP-07-E-BPA-73. Mr. Bliven submitted direct testimony, together with other witnesses, identified as Exhibit WP-07-E-BPA-53.

Q. What is the purpose of your testimony?

A. Our testimony responds to the direct testimony filed by several parties regarding the direct testimony and studies of Bliven, *et al.,* WP-07-E-BPA-52 ("Response to Ninth Circuit Decisions"), Burns, *et al*., WP-07-E-BPA-53 ("Response to Court's Remand of FY 2002-2006 Rates") and Marks, *et al.,* WP-07-E-BPA-62 ("Lookback Results, Recovery and Disposition"). Our rebuttal testimony responds to direct testimony filed by the Association of Public Agency Customers (APAC), WP-07-E-AP-1 and WP-07-E-AP-02; the Public Utility Commission of Idaho (IPUC), WP-07-E-ID-1; the Public Utility Commission of Oregon (OPUC); WP-07-E-PU-1; Citizens' Utility Board of Oregon (CUB), WP-07-E-CU-1; the Pacific Northwest Investor-Owned Utilities (IOUs),WP-07-E-JP6-08; Avista Corporation, Idaho Power Company, and Puget Sound Energy, WP-07-E-JP18-01; Cowlitz County PUD and Clark Public Utilities (Clark/Cowlitz); WP-07-E-JP17-01; and the Western Public Agency Group (WPAG); WP-07-E-WA-05, regarding BPA's policy direction for the Lookback analysis, approach to the Lookback analysis and recovery and return of Lookback Amounts.

Q. How is your testimony organized?

A. This testimony has four sections, each of which includes subsections. The first section is this introduction. Section 2 responds to issues raised by the parties regarding policy direction for the Lookback analysis. Section 3 responds to issues raised by the parties regarding the calculation of Lookback Amounts, including the Load Reduction Agreements (LRAs), the "lesser than" rule, deemer balances, and funds provided to the IOUs through the Conservation and Renewable Discount (C&RD) and the Conservation Rate Credit (CRC). Section 4 responds to issues raised by the parties regarding the recovery and return of Lookback Amounts, such as the appropriate repayment period and alternatives proposed by the parties.

Section 2: Policy Direction to Conduct Lookback Approach

Q. Several parties objected to BPA's policy direction to reopen the WP-07 rate proceeding in order to respond to the Ninth Circuit's May and October decisions regarding BPA's 2000 Residential Exchange Program (REP) Settlement Agreements, related agreements and amendments, and BPA's WP-02 wholesale power rates. BPA has proposed to reopen the WP-07 rate proceeding in order to establish the amount of REP settlement costs that were improperly allocated in BPA's WP-02 and WP-07 rates particularly to the PF Preference rate for BPA's public agency customers. Please describe your general approach to responding to the parties' arguments.

A. We have identified the parties' arguments and grouped them by category. Each section following this response has a heading that describes the general nature of the comment or argument raised by a party or parties. Parties' particular arguments and our responses are provided in question and answer format under each heading.

Section 2.1: Retroactive Ratemaking and Lookback Approach

Q. The IPUC and OPUC argue that BPA's proposal constitutes retroactive ratemaking, which they claim is not normally allowed in setting rates. Westerfield, WP-07-E-ID-01 at 4; Hellman and McGovern, WP-07-E-PU-1 at 2. Please respond.

A. First, we believe there is a legal issue regarding whether retroactive ratemaking applies to Federal power marketing agencies. BPA will respond to parties' properly raised legal issues in the Draft and Final Records of Decision (ROD) in this proceeding. Second, BPA's approach to respond to the Ninth Circuit's May and October, 2007, rulings does not occur in the typical context in which retroactive ratemaking issues arise. BPA is not proposing to adjust rates or bills from the past and collect or disburse funds from or to customers based on such adjustments. Rather, BPA is re-running its rate models for the specific purpose of determining the Lookback Amounts for the IOUs that will be dealt with on a prospective, and not retrospective, basis. This is a much different procedure than reestablishing past rates and producing new bills for customers.

Q. The IPUC identifies a number of reasons why retroactive ratemaking should be avoided. Westerfield, WP-07-E-ID-01 at 4-7, 9. Some of the salient points they raise are that it creates uncertainty for both the utility and the consumer, it undermines past decisions, and it harms future ratepayers. Id. Do you agree?

A. We agree the IPUC has identified numerous problems associated with retroactive ratemaking. As noted above, BPA will address parties' properly raised legal issues of retroactive ratemaking in its Draft and Final Records of Decision. We note, however, that the instant case is not the norm, and the issues presented are not ones of assuring cost recovery. The reductions of future REP benefits paid due to Lookback Amounts is a direct transfer of dollars from one class of customers to another and does not jeopardize BPA's ability to recover its costs.

Q. The IPUC argues BPA's proposal in the WP-07 Supplemental Proceeding is a good example of the pitfalls of retroactive ratemaking. Westerfield, WP-07-E-ID-01 at 6. BPA has proposed to recalculate REP benefits, recalculate ASCs, add interest, address treatment of Load Reduction Agreement (LRA) payments, include dormant deemers, and adjust future REP benefits well into the future. Id. In addition, there are numerous smaller issues that are subject to new decisions (calculating loads, new loads, resource stacks, etc.), which are included in the Lookback mechanism. Id. Please respond.

A. We are responding to decisions from a Federal court that found BPA's 2000 REP Settlement Agreements and WP-02 power rates contrary to the Northwest Power Act. The steps we are taking in this process, as noted by the IPUC, are necessary to calculate the amount of REP settlement benefits improperly charged to BPA's preference customers. To do so, we must look to the period in which BPA's WP-02 rates were in effect and recognize that the IOUs would have participated in the REP in the absence of the REP Settlement Agreements. Although many issues must be reviewed in order to respond to the Court's decisions, this is necessary in order to reach a technically and legally defensible result.

Q. *The IPUC notes that no party to the WP-02 rate case asked for a stay of those rates. Westerfield, WP-07-E-ID-01 at 8. Thus, the WP-02 rates remained in effect during most of the litigation period. Id. The IPUC argues that this also makes the Lookback Analysis inappropriate for addressing the May 2007 court decisions. Id. Please respond.*

A. The procedural steps a BPA customer must take to preserve its right to advocate remedies for unlawful settlements or remanded rates is a legal question. BPA will address parties' properly raised legal issues in its Draft and Final Records of Decision. The question of what the Court required in its May 2007 decisions is also a legal issue that will be addressed in BPA's Draft and Final Records of Decision.

Q. *The OPUC notes that if retroactive ratemaking is precluded, there would not be any compensation for, or recovery of, past overcharges to preference customers. Hellman and McGovern, WP-07-E-PU-1 at 3. Please respond.*

A. As previously described, we are presenting a viable approach to accounting for past overpayments to the IOUs by reducing future REP payments and disbursing such overpayments to the consumer-owned utilities (COU) through future reductions in the PF Preference rate. We believe it is appropriate to address and account for the overpayments of REP settlement costs by BPA's preference customers in their WP-02 rates, rather than conclude that there will be no compensation for or recovery of past overcharges to COUs.

Section 2.2: General Ratemaking Policy and the Lookback Approach

Q. Aside from retroactive ratemaking, did the parties raise any additional ratemaking policy arguments opposing BPA's Lookback Analysis?

A. Yes. The OPUC, IPUC, and WPAG raised additional arguments.

Q. What concerns did the OPUC and IPUC raise?

A. The OPUC proposes that, typically, ratemaking is prospective in nature, and therefore BPA should take the direction provided by the Court and revise its ratemaking procedures on a going-forward basis. Hellman and McGovern, WP-07-E-PU-1 at 3. Under this approach, the current rate case would be limited to revising BPA's rates for 2009.

The IPUC similarly recommends that the level of REP benefits be established on a forward-looking basis to take effect in fiscal year 2009 at the conclusion of this proceeding, using the new 2008 Average System Cost (ASC) Methodology. Westerfield, WP-07-E-ID-01 at 10. For the WP-02 rate period, the IPUC recommends that BPA not recalculate anything and assume that "what is done is done." *Id*.

Q. Please respond to these arguments.

A. First, our remedy is following the typical ratemaking paradigm of making only prospective changes. We are not proposing to revisit customer bills that were paid from a prior year, but instead we propose to reduce future payments of REP benefits to the IOUs to recover the overcharges that were improperly collected in the COUs' rates. Future rates for preference customers, not past ones, will consequently be affected by the remedy developed in this case. In this way, our proposal is prospective in nature.

In response to the comment that BPA can simply ignore the past, we believe that this issue hinges on the legal merits of the cases presented by the parties. For purposes of this case, we have assumed that we must conduct a section 7(i) proceeding to determine the amount of the overcharge to COUs. We believe such a proceeding is necessary given the Ninth Circuit's May and October 2007 opinions. Whether BPA can avoid this entire proceeding, and leave "what is done is done," is a legal question. BPA will respond to parties' properly raised legal arguments in the Draft and Final Records of Decision in this proceeding.

Q. WPAG argues that there is no theoretical support for BPA's approach because accepted ratemaking practice does not substantiate an approach that involves re-examination and reversal of many decisions taken in prior proceedings, especially when the rates in question have been applied in a prior rate period, unless doing so is the only way to right the wrong that was committed in the earlier proceeding. Grinberg, et al., WP-07-E-WA-05 at 17. In WPAG's view, such a revisionist approach is neither necessary nor appropriate in this case. Id. Please respond.

A. Ironically, WPAG's argument could be read to support the IPUC's and OPUC's arguments regarding retroactive ratemaking. In any event, however, the issues being reviewed in this proceeding are precisely the issues that must be addressed in order to, as WPAG describes it, "right the wrong that was committed in the earlier proceeding." The "wrong" in this case was the erroneous allocation of REP settlement costs to the COUs, which costs arose from the 2000 REP Settlement Agreements. To right this particular wrong in a reasonable manner requires BPA to reevaluate the record in both the WP-02 and WP-07 cases. Base rates in both cases were built on flawed load and market price forecasts, and on the assumption that the REP settlements, and its associated costs, were valid. Unraveling these factors from those rates is not a simple matter. Indeed, in order to properly resolve the overpayment of REP settlement costs by BPA's preference customers, BPA must determine the amount of the REP settlement benefits provided to the IOUs' residential consumers and the amount of REP benefits the IOUs would have received in the absence of the REP Settlement Agreements. The only way to answer these questions accurately, particularly because the determination of REP benefits depends in large part on the proper establishment of the PF Exchange rate, is to revisit BPA's WP-02 and WP-07 records and BPA's underlying rate decisions. Thus, revisiting BPA's WP-02 and WP-07 ratemaking is both appropriate and necessary for this case.

Section 2.3: Policy Direction to Reopen the WP-02 and WP-07 Rate Records

Section 2.3.1: BPA's Decisions in the WP-02 Supplemental Rate Proceeding

Q. You stated in the direct case the rationale for returning to the winter of 2000 and spring of 2001 as the point in time for revisiting the WP-02 record. Burns, et al., WP-07-E-BPA-53 at 7. APAC, however, argues that the changes in circumstances between the May 2000 ROD and the June 2001ROD do not support BPA's proposed Lookback exercise because BPA factored all the changed circumstances into its June 2001 decision. Wolverton, WP-07-E-AP-1 at 21. Please respond.

A. APAC is mistaken in describing our rationale for conducting this proceeding. We are not justifying the need to conduct the Lookback because of the change in circumstances between May 2000 and June 2001. The Lookback approach results from the need to remove the REP settlement costs from applicable preference customer rates that BPA set for the FY 2002-2006 period. We propose to reevaluate the WP-02 rates in this proceeding as of June 2001, thereby using the most current information that would have been available at that time. The alternatives – for example, recalculating rates as of May 2000 and then recalculating rates as of June 2001 – would introduce even more changes than the approach we propose to use. *See* Burns, *et al*., WP-07-E-BPA-53 at 8. Furthermore, although BPA may have developed an approach (the adoption of Cost Recovery Adjustment Clauses or "CRACs") that responded to the changed circumstances known at the time of the June 2001 rate decisions, those decisions did not remove the REP settlement costs from BPA's rates, which is the changed circumstance we are now trying to reflect.

Q. *APAC argues that the rise in power costs offers no justification for the Lookback exercise because such costs were already known and neutral to the 7(b)(2) rate test calculation. Wolverton, WP-07-E-AP-1 at 34. Do you agree?*

A. We do not agree to the extent that APAC is construing BPA's proposal as stating that higher market prices in the winter of 2000 and spring of 2001 are the justification for the Lookback. The primary justification for the Lookback is the removal of REP settlement costs from rates. We recognize that higher market prices were a factor in BPA's decision to adopt CRACs in June 2001, but that was a different issue than we face today. We also dispute that the 7(b)(2) rate test is neutral to higher market prices. Higher market prices had a significant effect on the forecast ASCs used in the WP-02 ratemaking process. ASC forecasts are an integral part of forecasting the costs of the REP. The costs of the REP have a significant effect on the level of the Program Case rates when conducting the 7(b)(2) rate test. Because the rate test compares the Program Case rates, including the costs of the REP, with the 7(b)(2) Case rates, which exclude the costs of the REP, ultimately the steep increase in market prices would, and should, have a significant role in the rate test, and should not be ignored. In 2001, the REP settlement benefits were not impacted by changes in ASCs, therefore the context of the decision at that time was much different than now.

Q. *APAC states that by making its ratemaking decision in June 2001, when BPA had the opportunity to make changes, the Administrator implicitly reaffirmed the May 2000 decision. Wolverton, WP-07-E-AP-1 at 22. Please respond.*

A. We disagree. BPA's decision in June 2001 to use CRACs to address BPA's potential cost recovery problems under then-proposed WP-02 rates did not affirm BPA's May 2000 decisions. To the contrary, BPA's June 2001 decision affirmed that the May 2000 rates were not properly developed and jeopardized BPA's statutory responsibility to recover its costs. BPA's June 2001 proposal was based on the knowledge available at the time. Now, however, we are faced with a new factor that must be considered, a factor that was not known either in May 2000 or in June 2001; that is, the need to determine rates without the effects of the REP settlements.

Section 2.3.2: The WP-02 Record and the Lookback

Q. Several parties argue that BPA should use the existing WP-02 rates and record in the Lookback calculation. Before addressing their specific arguments, please explain the context for the options for addressing the cost recovery problems BPA faced in winter 2000 to spring 2001.

A. When BPA was deciding in the winter of 2000-2001 how it should revise rates to recover its costs, there were two basic options: (1) using the existing May 2000 record and a supplemental proceeding, develop adjustment clauses that would apply to base rates through periodic adjustments; or (2) completely reopen the record and revise base rates to reflect new load and market price information.

BPA estimated that the increased costs BPA would incur and recover through adjustment clauses could be high enough to require dramatic rate increases. The PF Exchange rate, in particular, could have increased under the CRACs from \$36/MWh to about \$90/MWh. At this level, REP benefits would have been completely eliminated because all of the IOUs' ASC forecasts were below \$90/MWh. That is, no benefits would have been provided to any residential consumers of any IOU in any Pacific Northwest state. As we note later, the consequences of this decision on the PF Exchange rate and REP benefits, however, were not a material consideration because the IOU REP benefits were established by the settlements.

Another option was for BPA to revise its base rates. This option would more fully and completely update the record. At the time, given the existence of the REP settlements, the first option was preferred. It achieved the basic objective of establishing the means to demonstrate cost recovery.

In deciding what BPA would have done absent the settlements, BPA would have had these same two choices. First, BPA could use the May 2000 PF Exchange rate that was based on flawed assumptions and apply adjustment clauses. On the other hand, BPA could reopen the record and revise its base rates, including the PF Exchange rate, in a manner that reflected BPA's then-expected costs and the results of the section 7(b)(2) rate test. When BPA implements the REP, which it would be doing absent the settlements, BPA does so by establishing participating utilities' ASCs under an ASC Methodology and developing a PF Exchange rate through a section 7(i) proceeding that establishes base power rates. In this manner, the PF Exchange rate reflects BPA's then-expected total power costs and the results of the section 7(b)(2) rate test, as well as other rate directives. This latter alternative produces a properly determined PF Exchange rate for purposes of implementing the REP.

In such a context it is an obvious choice to reopen the record and revise base rates in order to fully implement the Northwest Power Act's rate directives and to allow such properly developed rates to be used to implement the programs established by the Act, including the REP.

Q. How did the REP Settlement Agreements make a difference in BPA's decisions regarding the development of BPA's FY 2002-2006 power rates?

A. When BPA was faced with the decision of whether to develop adjustment clauses or revise base rates for its WP-02 supplemental rate proposal, the IOUs had already signed the REP Settlement Agreements. The IOUs could not participate in the REP Settlement Agreements <u>and</u> the REP because the REP Settlement Agreements required the IOUs to collectively choose one or the other. Because the IOUs had signed the settlements, they would be purchasing power at the RL rate and receiving financial benefits, not exchanging power at the PF Exchange rate under the REP. Therefore, the adoption of adjustment clauses that would have dramatically increased the PF Exchange rate was of no consequence to the residential consumers of regional IOUs. This made it easier for BPA to decide to use adjustment clauses as the manner in which to respond to increased loads, drought conditions, and high and volatile market prices. In the absence of the REP Settlement Agreements, however, the consequences surrounding that decision would have been very different.

Q. What do you believe BPA would have done in these circumstances?

A. It is nearly certain that BPA's decision to implement a series of CRACs rather than to reset base rates would have been different if there had been an operating REP because the outcome of the 7(b)(2) rate test would have had a significant impact on the level of benefits payable to the residential customers of the region's exchanging utilities. Because there was no expectation of exchanging utilities, the level of the PF Exchange rate was not an critical consideration in BPA's chosen course of action at that time. Because REP benefits under the REP Settlement Agreements were not implicated by the rate test, the application of CRACs, or the level of the PF Exchange rate, it was therefore decided that the section 7 rate directives were not implicated by the conditions and that the use of the CRACs could be pursued. However, had an active REP been a reality, the section 7 rate directives would have been a much more important factor in the decision-making at the time. The impact of much higher COU loads and augmentation costs would have had significant impacts on the results of the 7(b)(2) rate test. Therefore, because of the interactions among the COU loads, augmentation costs, and the REP, it would have been very important to reset base rates in order to incorporate rate test protection for COU customers and establish the appropriate basis for REP benefits. It is a reasonable and logical assumption that BPA would have chosen to revise base rates in these changed circumstances.

Q. *Turning now to the parties' specific positions, APAC argues that the assessment of the over-collections for FY 2002-2006 should be made on the rates that were in effect at the time and not on a revisionist history of what those rates might have been under differing conditions and assumptions. Wolverton, WP-07-E-AP-1 at 16. That figure – $241 million – subtracted from the total of all the payments made to the IOUs pursuant to the REP Settlement Agreements, is sufficient to establish the damages sustained by the preference customer utilities. Id. Do you agree?*

A. No. APAC's proposal to subtract $241 million from the total of all the payments made to the IOUs pursuant to the REP Settlement Agreements for FY 2002-2006 is simplistic, unfair, and would provide significant, undeserved benefits to BPA's COUs. Beginning with a determination of the amounts paid under the REP settlements is only a starting point for determining the amount of overpayments to be recovered from the IOUs, and is subject to interpretation. The REP settlements involved a number of agreements and amendments. In the *PGE* case, the Court reviewed BPA's 2000 REP Settlement Agreements with the IOUs. The Court did not review any other agreements in that particular litigation. Obviously, there are legal issues regarding which contracts, amendments and other agreements related to the REP Settlement Agreements are still valid in light of the *PGE* and *Snohomish* decisions. Thus, any proposal to simply use all of the payments made to the IOUs pursuant to the REP Settlement Agreements and related agreements would be simplistic and flawed because it would not correctly evaluate the lawfulness of the related agreements. BPA will address the parties' properly raised legal arguments regarding the implications of the *PGE* decision and related decisions in the Draft and Final Records of Decision in this proceeding.

In addition, the assumption that the IOUs would have received $241 million in REP benefits during the FY 2002-2006 period is simply wrong. The rate case does not establish REP benefits; it establishes a *forecast* of REP benefits that is used solely for the ratemaking process. *Actual* payments are based on ASCs determined by BPA, the PF Exchange rate, and actual residential loads of the participating utilities. REP benefit payments can end up higher, lower, or about the same as the forecast, depending on the accuracy of BPA's forecasts of ASCs, assumed PF Exchange rates, and loads used in rate setting. Rarely, if ever, will the level of REP payments match the forecast exactly. When actual REP benefits differ from the amounts forecast in ratemaking, the differences are absorbed through increases or decreases in BPA's financial reserves. Such changes in financial reserves affect the rates the COUs and other customers pay in the next rate period. COUs, therefore, cannot avoid the effects of the REP just because BPA has forecast a particular level of REP benefits in the rate case.

Finally, as explained more fully below, the forecast of REP benefits in the WP-02 rate case necessarily must change to reflect the absence of the REP settlements, which were an inherent assumption in the WP-02 rates. The manner of accounting for this absence is reflected in the facts and legal context established in BPA's testimony, studies, documentation, and other evidence in this case. The Administrator will consider such evidence, as well as the evidence and arguments of the parties, in determining the proper manner of responding to the Court's opinions. The fact that $241 million was the result of a prior flawed rate development process does not require that it be used in this proceeding.

Q. *APAC states that the WP-02 power rates proposed in May of 2000 were approved by FERC in July of 2003. Wolverton, WP-07-E-AP-1 at 18. APAC then asserts that because the PF Exchange rate developed in BPA's WP-02 rate proceeding was a valid, litigated rate approved by FERC, it should not be revisited in this proceeding. Id. at 31. Do you agree?*

A. No. Before further addressing APAC's assertion, we note that FERC approved the whole of BPA's WP-02 rates, *including the June 2001 Supplemental Proposal*, not just BPA's

May 2000 Final Proposal. Indeed, FERC likely would not, and could not, have approved BPA's May 2000 rate proposal given that such rates were fundamentally flawed and failed to ensure the recovery of BPA's costs as required by law. The suggestion that BPA's proposed May 2000 PF Exchange rate was somehow properly developed, despite FERC's inability to approve such a rate (with BPA's other proposed WP-02 rates) in the absence of strong CRACs to supplement BPA's base rates, makes little sense.

APAC's suggestion that the May 2000 PF Exchange rate was in any reasonable sense a "valid" rate is incorrect. First, the May 2000 base rates were found to be fatally flawed shortly after BPA issued the May 2000 ROD. Shortly after the May ROD, BPA (and the region) learned that BPA's load forecast was egregiously in error due to the unanticipated return of over 1,000 aMW of public agency loads after such loads had previously left BPA service during a period of low market prices. *See* WP-02 Supplemental ROD, WP-02-A-09 at 1-11-12. In addition, BPA was soon faced with unprecedented and enormous increases in market prices. BPA's load forecasts and market prices are critical elements in the development of BPA's base rates, including the PF Exchange rate. Such dramatic changes in loads and market prices significantly affect the 7(b)(2) rate test. There is no doubt that the results of the rate test would have been different if BPA had reflected the then-current load and market price forecasts into the rate test. Because any trigger amount is allocated largely to the PF Exchange rate, there is no question the PF Exchange rate would have changed from the May 2000 proposal. BPA knew that its May 2000 base rates were inadequate to recover BPA's costs. BPA was faced with over a thousand aMW of previously unforecasted load that would have to be met in part through significant purchases at record high prices. If BPA's rates do not recover BPA's costs, BPA cannot receive approval of its rates from FERC. If BPA's rates do not receive FERC approval, BPA cannot charge them and recover revenue under them. If BPA cannot recover its costs, BPA cannot meet its statutory repayment obligations. At the time, given the presence of the settlements, BPA responded by adopting CRACs. The CRACs would allow BPA to recover its costs despite the fundamentally flawed base rates BPA established in May 2000. In the absence of the CRACs, BPA's May 2000 base rates, including the PF Exchange rate, could not have been approved. FERC granted approval to BPA's WP-02 rates based on overall cost recovery. It did not decide or otherwise rule on whether the PF Exchange rate or other rates were properly established in and of themselves. Any attempt to substantiate the PF Exchange rate by calling it a "valid, litigated rate approved by FERC" is simply wrong.

Q. *APAC also states that the 7(b)(2) rate test finding in the WP-02 rate case was similarly litigated, subject to a final decision by the BPA Administrator and approved on a final basis by FERC, and therefore, should be used in this proceeding. Wolverton, WP-07-E-AP-1 at 52. Do you agree?*

A. No. First, as noted previously, the implementation of the 7(b)(2) rate test in developing BPA's May 2000 WP-02 base rates was part of the flawed development of the WP-02 base rates, which were insufficient to recover BPA's costs. BPA's base rates were premised on incorrect load assumptions, market price assumptions, and other critical ratemaking elements, not to mention the REP settlements. These same elements were used in the 7(b)(2) rate test, which necessarily was as flawed as the assumptions it used. Use of the results of such a rate test in BPA's Supplemental Proceeding would be unconscionable.

Second, although the rate test included in the WP-02 proceeding was litigated in the May 2000 proceeding, the WP-02 rates included REP settlement costs. In this Supplemental Proceeding, we have removed these costs from the rate determinations. Third, while many of the rate issues were litigated in the WP-02 rate proceeding, certain parties to that case withdrew their challenges before the Ninth Circuit because they were relying on the REP settlements as the manner in which they received REP benefits.

Fourth, when BPA took the path in the WP-02 Supplemental Proceeding of revising only the risk tools and not the base rates, issues related to section 7(b)(2) were not critical because the IOUs had already executed the REP Settlement Agreements, and the impact of the 7(b)(2) rate test on the PF Exchange rate did not affect the benefits the IOUs received under the REP Settlement Agreements. Fifth, as noted in BPA staff's direct testimony in this proceeding, the most important decision regarding the rate test, the exclusion of certain Mid-Columbia resources from the 7(b)(2) Case resource stack, was a moot issue in the WP-02 decisions. *See* Doubleday, *et al.*, WP-07-E-BPA-60 at 18.

Q. APAC claims that the ultimate figure of significance is not the rate, but the total net REP obligation after performing the 7(b)(2) rate test – the $241 million. Wolverton, WP-07-E-AP-1 at 17-18, 22. APAC states that the net REP obligation is the maximum amount that Preference Customers were (or are) required to contribute to the REP in WP-02 rates. Id. at 17, 33. APAC refers to the $241 million also as a "ceiling to their costs of the Exchange." Id. at 18. WPAG makes a similar assertion. Grinberg, et al., WP-07-E-WA-05 at 11. Do you agree?

A. No. First, we have previously explained the reasons why BPA's WP-02 7(b)(2) rate test and resulting PF Exchange rate were improper to use in BPA's Lookback Analysis. The cited $241 million is simply the monetary result of the same flaws and thus equally improper to use in the Analysis. Second, the $241 million figure from the WP-02 Final Proposal was the rate case estimate of REP benefits. As noted in a prior answer, the rate case does not establish the amount of REP benefits received by residential consumers of exchanging utilities; it establishes the PF Exchange rate to be used in the determination of REP benefits. There are three necessary components to determine actual REP benefits: (1) the PF Exchange rate; (2) the participating utility's ASC; and (3) the actual exchange loads, which are determined after-the-fact by the participating utilities based on eligible exchange loads. At the time that BPA's rates are determined, the latter two components are not available. BPA, therefore, forecasts those components in order to determine the PF Exchange rate. As a result, the forecast of REP benefits calculated in the rate case (the $241 million for the WP-02 rate case) is nothing more than an estimate of the REP benefits for FY 2002-2006. Thus, BPA does not know the alleged "maximum obligation of the Preference Customers to pay for the exchange" simply by looking at BPA's May 2000 and June 2001 rate proposals.

Furthermore, we note that now APAC is characterizing BPA's forecast of REP benefits in the WP-02 Final Proposal as a "ceiling to their costs of the Exchange" rather than as the "rate ceiling" they have used elsewhere in their testimony. These concepts illustrate the distinctions we have stated in our prior answers. The $241 million was used in establishing rates through the Rate Design Step of the WP-02 Final Proposal. Even if we were to accept APAC's erroneous argument that there was a specific "rate ceiling" (because there are circumstances where this is not correct), it certainly does not form a "cost ceiling." The difference between these two is significant. A "rate ceiling" would be the maximum amount of forecasted REP benefits allowed to be included in rates. A "cost ceiling" would establish the maximum amount that BPA could pay in REP benefits. However, REP benefits are determined after rates are established and in effect, as described above. There is no basis for a cost ceiling on the amount of REP benefits that BPA may actually pay in implementing the REP in any of BPA's GRSPs, policies, or procedures, subject only to the amount of benefits determined in such implementation.

Q. APAC claims that BPA's decision in the May 2000 ROD sustains a conclusion that the maximum five-year preference customer obligation was $241 million. Wolverton, WP-07-E-AP-1 at 21. Do you agree?

A. No. As we have stated above, the $241 million was the forecast of REP benefits that was used in the WP-02 Final Proposal. As we have also stated, the use of flawed data and the presence of the REP settlements permeated the WP-02 Final Proposal and rendered the rates established in the WP-02 Final Proposal unusable for the purpose of determining the REP benefits in the absence of the REP settlements.

Q. *APAC also asserts that BPA knew that the REP settlements were under challenge and that a judicial determination of the validity of the settlements was not guaranteed. Wolverton, WP-07-E-AP-1 at 30. Consequently, APAC argues there was no basis for undertaking this Lookback exercise if BPA was aware of the facts that would sustain its decision on identical costs from the WP-02 decision. Id. at 50. What is your response to this statement?*

A. It appears that APAC is arguing that BPA knew that the REP settlements were under challenge when it performed the rate test in the WP-02 rate proceeding ("It knew that it had to perform a rate test as if the settlement would be declared invalid." *Id.* at 30.) This is not the case. The 7(b)(2) rate test for the WP-02 Final Proposal was completed prior to the issuance of the WP-02 ROD in May 2000. The first REP Settlement Agreements were not signed until late October 2000, well after the publication of BPA's May 2000 ROD. Therefore, it would have been impossible for BPA to know that the REP settlements were under legal challenge.

Q. *APAC argues that BPA made decisions on the data and forecasts from FY 2002-2006 to establish its June 2001 rates, and now BPA seeks to cover the same ground and make reconstructed and speculative decisions from the same evidence. Wolverton, WP-07-E-AP-1 at 21. Do you agree?*

A. No. First, we have previously explained why it was inappropriate to simply reuse all of BPA's previous decisions from its May 2000 rate proposal. Second, APAC states that "BPA used the information that it had known as of the winter of 2000/2001 and the spring of 2001 to establish its June 2001 rate." Wolverton, WP-07-E-AP-1 at 21. APAC then states that the "information from this period is, incidentally, the same information that BPA proposes in its reconstruction of the FY 2002-2006 rates." *Id*. APAC then draws the conclusion that BPA is making reconstructed and "speculative" decisions. *Id*. APAC's argument makes little sense. If the information is the same, then the reconstruction is not "speculative." As stated above, one critical piece of information was lacking from the June 2001 rate decisions; that is, the removal of the REP settlement costs. The steps we propose are necessary in order to properly calculate the amount of overpayments to IOU residential consumers that must be recovered and provided to BPA's preference customers.

Section 2.3.3: WPAG's "Minimalist Approach"

Q. WPAG argues that BPA should use a "minimalist approach" to determine the amount the COUs were overcharged. Grinberg, et al., WP-07-E-WA-05 at 12. Under this approach, BPA would be limited to the values determined in the WP-02 and WP-07 rate cases through the Rate Design Step, and prior to the imposition of the "Subscription Step." Id. They claim these values reflect what the preference customers should have paid under the proper application of the section 7 rate directives, including the 7(b)(2) rate test, before the imposition of costs associated with the now unlawful REP Settlement Agreements. Id. at 15. Do you agree?

A. No. As noted previously in response to APAC's nearly identical proposal, WPAG's proposal is simplistic, unfair, and would provide significant, undeserved benefits to BPA's COUs. As explained previously, we are comparing the benefits the IOUs' residential consumers received under the REP settlements (as adjusted for benefits that should be retained by the IOUs' residential consumers) with the REP benefits the IOUs would have received under the REP in the absence of the REP settlements. One cannot rationally assume the IOUs would not have participated in the REP in the absence of the settlements. Therefore, BPA must ensure that such REP benefits are accurately estimated by properly establishing the PF Exchange rate. The PF Exchange rate established in

BPA's May 2000 Proposal was based on flawed rate development that failed to incorporate BPA's actual costs and market prices. BPA's WP-02 base rates developed under the Rate Design Step, including the PF Exchange rate, were insufficient to recover BPA's costs. Proposing to use the PF Exchange rate arising out of a flawed Rate Design Step, which included a flawed 7(b)(2) rate test, makes little sense.

Also, as noted previously, the rate case does not establish REP benefits; it establishes the forecast of REP benefits included in the ratemaking process. Actual payments are based on ASCs determined by BPA, the PF Exchange rate, and the residential loads of the participating utilities. To properly calculate what the IOUs would have received under the REP, BPA must have approximations of the ASCs for each IOU. Without this key piece of information, BPA would be basing the IOU's REP benefits entirely on the ASC forecasts, which is not the way the REP payments are determined.

In addition, the rates in effect at the time BPA developed its WP-02 base rates were based on the REP settlements. The effect of the REP settlements must be removed from those rates. Therefore, differing conditions and assumptions must be used in the Lookback analysis for the purpose of calculating the overcharges to the COUs.

Q. WPAG argues there are other reasons that support adopting its minimalist approach. Grinberg, et al., WP-07-E-WA-05 at 12. WPAG argues that adopting an approach that limits the decisions made in the prior proceeding that must be altered results in fewer consumer impacts. Id. Do you agree?

A. No. We do not exactly know what WPAG means by "consumer impacts." If WPAG means retail consumer impacts, WPAG's statement is plainly wrong. Adopting WPAG's one-sided approach to the overcharge calculation would result in an immediate and long-lasting reduction in REP benefits for all of the residential consumers of the IOUs, which would obviously have a significant impact on such consumers.

Second, a minimalist approach might reduce the number of decisions in the prior proceeding that must be changed, but the purpose of BPA's Lookback is to determine the overpayments to IOUs' residential consumers that must be returned to BPA's preference customers. Attempting to limit the number of changes makes no sense if there are numerous decisions that must be made in order to properly determine the overpayments and return overpayments to COUs. The limited approach WPAG proposes would preclude BPA from responsibly and properly performing its function in this Supplemental Proceeding.

In any event, how our proposal affects the respective consumers of the COUs and IOUs is not the driving factor in conducting the Lookback. The prime objectives are to calculate the overcharge to the COUs in a technically accurate, legally defensible and reasonable manner. These objectives can only be met if BPA recognizes the impact that the REP settlements had on BPA's rate decisions.

Q. WPAG argues that making the minimal number of changes increases the likelihood that the underlying equities embedded in the existing rates will not be altered. Grinberg, et al., WP-07-E-WA-05 at 12. Do you agree?

A. No. First, any "underlying equities" embedded in the May 2000 WP-02 base rates should not be retained if such rates were not properly developed. BPA knew during the WP-02 supplemental proceeding that the WP-02 base rates did not reflect correct information in critical areas of BPA ratemaking and, in the absence of CRACs, would not have been sufficient to recover BPA's costs. Any equities established by the flawed base rates, therefore, should not be retained.

Second, it is unclear from WPAG's testimony what "underlying equities" would become altered by our proposal. The underlying equities in the WP-02 case were founded on the assumption that the REP Settlement Agreements were valid. The ensuing seven years of activity by both BPA and the IOUs reflected the belief that these agreements were valid. Now that the Court has ruled otherwise, equity supports our position to revisit the WP-02 rate record to determine what would have happened in the absence of the REP settlements. Otherwise, BPA's calculation of the Lookback amounts would be based on a record that assumes, erroneously, that the IOUs would be participating in the REP Settlement Agreements. We, therefore, do not agree with WPAG's assertion there is an evident link between keeping certain unstated equities and limiting changes in the Lookback process.

A more overriding concern, in our view, is that the REP benefits that the IOUs would have otherwise received be calculated as accurately as possible within the constraints of this case. The results of this proceeding will have impacts on the level of benefits for all of the IOUs for years to come. We, consequently, believe that BPA has a responsibility to ensure that this proceeding gives all parties an opportunity to vet and test the assumptions and calculations that produce the Lookback Amounts. The paradigm WPAG suggests would deny parties the right to test our premise and assumptions, which would diminish the quality, accuracy, and legal defensibility of the final decisions made by the Administrator in this proceeding.

Q. *WPAG also argues that making the minimal number of changes is the most practical approach because it requires the least work and the least amount of change. Grinberg, et al., WP-07-E-WA-05 at 12. Do you agree?*

A. No. Adopting an approach because it requires the least number of changes or the least amount of work is a recipe for disaster. WPAG's request that BPA estimate the overcharges based on a deficient record in return for a lighter workload is not a reasonable tradeoff. BPA's Lookback analysis must be reasonable, technically sound, legally defensible, and supported by a robust record. The only way BPA can achieve this result is if it revisits the relevant portions of its previous ratemaking and determines, as best it can, what the proper development of the PF Exchange rate would have been. This approach, though not the easiest, will assist in ensuring that the final outcome is technically and legally defensible, as well as practical and reasonable.

Section 2.3.4 BPA's Use of New or Updated Information in Lookback Approach

Q. APAC states that, if such a Lookback exercise is to be entertained at all, it must be strictly compliant with the law, known factual conditions, and the Court's remand. Wolverton, WP-07-E-AP-1 at 53. Do you agree?

A. Yes. Furthermore, we believe that our approach has accomplished all of the objectives stated by APAC. We have stated that it is important for the resolution of the remand to be technically and legally defensible. We have constructed the Lookback to be as consistent as possible with the known conditions as of 2001, when the rate decisions were being made. Notwithstanding APAC's admonitions, the Supplemental Proposal is fundamentally sound. BPA will address parties' properly raised legal arguments in the Draft and Final Records of Decision in this proceeding.

Q. *APAC argues BPA is using data that do not exist for certain applications and are inapplicable or wrong for other applications. Wolverton, WP-07-E-AP-1 at 23. APAC argues BPA is using assumptions and model analyses aimed to develop a "New Subscription Step" to replace that which was overturned by the Ninth Circuit. Id. Do you agree?*

A. No. First, we do not understand how we can use data that "does not exist." To the extent APAC argues that the use of BPA's data is inapplicable or wrong, we will address such arguments where APAC has raised specific objections in its testimony.

APAC characterizes our assumptions and analyses as comprising a "New Subscription Step." This makes little sense. The Subscription Step, used in both the WP-02 and WP-07 rate cases, was the rate step that allocated the costs of the REP settlements to the COUs' rates. In this proceeding, we have removed the REP settlements from consideration in the rate calculations. Therefore, there is nothing in our proposal that remotely resembles the Subscription Step. APAC is apparently attempting to characterize our proposal in a pejorative manner by referring to a rate step that was found improper by the Court, despite the absence of anything like the Subscription Step in the Supplemental Proposal. Such statements should affect the weight given to APAC's testimony.

Q. APAC argues that "BPA chooses to ignore actual recorded experience in favor of a reconstructed and necessarily erroneous imaginary 'forecast' of loads." Wolverton, WP-07-E-AP-1 at 14. APAC also states that BPA ignores known data, relying on highly questionable estimates and data when real data are known and available. Id. at 36, 53. APAC concludes that the best projection is what materialized; meaning actual, recorded data during the test or rate period. Id. at 48. No better projection can be made when one has the advantage of knowing what occurred during the relevant period. Id. Do you agree?

A. No. First, our load forecasts for the Lookback analysis are contained in the Supplemental Proposal. *See* Hirsch, *et al*., WP-07-E-BPA-54. They obviously are not "imaginary." We made the choice to reconstruct rates for the FY 2002-2008 period prospectively using the forecasts available at the time rates would have been set, rather than use actual data to reconstruct rates retrospectively. Rates are developed on a prospective basis using forecasts of expected costs and loads during the future rate period. Rates are not established in hindsight. By placing ourselves at the time the WP-02 and WP-07 rates were being developed, we established a consistent perspective and manner in which to reconstruct rates in the absence of the REP settlements. Furthermore, the use of forecasts available at the time the rates were developed resulted in only a few changes to the assumptions driving the rate calculations, whereas the use of historical data would mean that every number used in the rate calculation would need to be researched, collected, entered, and tested in the rate modeling. This would have been an enormous task, requiring many months of work. Because the goal of the reconstruction of the REP benefits in the absence of the REP settlements was to determine the amount of REP settlement costs improperly allocated to the PF Preference rates, the monumental workload of using historical data offered little incremental value.

Q. *APAC argues that the past BPA invents in its Lookback analysis does not comport with the known past because BPA ignores actual, recorded data and loads applicable to the rate case period. Wolverton, WP-07-E-AP-1 at 15. Do you agree?*

A. This argument was addressed in part previously. In addition, APAC's statement could apply to many different aspects of our Lookback analysis, so it is difficult to interpret. For example, our Lookback approach accounts for changes BPA knew and could forecast at the time rates were being calculated for the WP-02 supplemental rate proposal. *See* Bliven, *et al.*, WP-07-E-BPA-52 at 14; Burns, *et al.*, WP-07-E-BPA-53 at 8-9. Far from ignoring actual recorded data, our Lookback analysis incorporates actual financial results, modified for removal of the REP settlements. In this way, the impact of actual loads and revenues is captured in our Lookback analysis. Further, we note that for the 7(b)(2) rate test, the 7(b)(2) Implementation Methodology instructs that "projected" costs be used, not actual costs. Therefore, if we were to adopt APAC's position to use historical data, we would deviate from the 7(b)(2) Implementation Methodology.

Q. *APAC asserts that BPA has "concocted" data and model runs to produce a result that BPA now deems to be more "reasonable." Wolverton, WP-07-E-AP-1 at 25. Id. Do you agree?*

A. No. APAC's *ad hominem* statements undermine its credibility. We have not "concocted" model runs but rather developed such runs based on logic and facts. We recognize that parties may disagree with the Supplemental Proposal. Certainly, a review of the testimony of the IOUs and the state commissions, those most at odds with APAC's position, demonstrates they are not enamored with our proposal. We can address APAC's specific concerns only when they are stated. We cannot respond to generalities and pejorative language in the absence of specific criticisms.

Q. APAC asserts it is unlikely that the data and projections that BPA actually decided upon in the WP-02 proceeding would be substantially different from the data and projections for the Lookback exercise. Wolverton, WP-07-E-AP-1 at 31. The WP-02 decision deliberations were actually made during the winter of 2000/2001 and the spring of 2001. Id. For the Lookback exercise, BPA engages in assumptions and speculation as if BPA was determining rates in the same period of 2000/2001. Id. Please respond.

A. APAC's assertion that data and projections decided in the WP-02 proceeding would not be substantially different than data and assumptions used in the Lookback exercise must be viewed in the entire context of the WP-02 rate proceeding. The assumptions used in the WP-02 proceeding to establish base rates were made prior to the market crisis and the unanticipated massive return of loads to BPA after the base rates were developed. Nevertheless, many data and projections BPA actually decided upon in the WP-02 proceeding are not substantially different from the data and projections being used in the Lookback analysis. That was the intent of our instructions for implementation of the Lookback: to change only those data and projections absolutely necessary to remove the effects of the REP settlements. *See* Burns, *et al*., WP-07-E-BPA-53 at 9. We are unsure how APAC then arrives at its conclusion that such a limitation becomes engaging in "assumptions and speculation." We recognize that the Lookback analysis produces results different from those that occurred in the WP-02 proceeding. However, that is to be expected since a major component of those rates, the REP settlements, is now being removed.

Q. APAC states that, as with virtually any projection, BPA's assumptions in the Lookback analysis are wrong in comparison to recorded, actual data and outcomes which are known and certain. Wolverton, WP-07-E-AP-1 at 31. Do you agree?

A. We do not dispute that any projection will likely be wrong when compared with actual data. However, for the reasons stated above, we do not agree that actual data would be preferable to the limited number of changes that we made to the forecast data that we used in our proposal. Furthermore, we believe the proper determination of the overpayments must be developed from the perspective of circumstances as they existed at the time BPA developed its WP-02 rates, not through hindsight.

Q. APAC states that BPA was criticized in a Ninth Circuit decision because it ignored known events regarding its fish and wildlife projections. Wolverton, WP-07-E-AP-1 at 31. The same warning must be heeded in this circumstance as well. Id. Do you agree?

A. BPA will address parties' properly raised legal arguments in the Draft and Final Records of Decision in this proceeding.

Q. APAC argues that the information BPA uses in its Lookback analysis is no better than what BPA used in its WP-02 decision. Wolverton, WP-07-E-AP-1 at 35. There are higher quality, known data to use, but it is difficult to reconcile BPA's approach with actual recorded data and the knowledge of subsequent events. Id. Do you agree?

A. No. APAC ignores one piece of critical information available to us now, in contrast to that which was known in the WP-02 rate decisions, namely the fact that we must remove the effects of the REP settlements from the rate calculations. We have already spoken to the inappropriate use of actual recorded data in the Lookback.

Q. APAC argues that the Lookback proposal fails to take into account actual circumstances as of the spring of 2001, has to create data where none existed, and has gone far beyond what is a reasonable response to the remand "mandate" of the Ninth Circuit. Wolverton, WP-07-E-AP-1 at 53. How do you respond?

A. We are uncertain what actual circumstances, as of the spring of 2001, we have failed to take into account. If APAC is referring to its criticisms of the load and ASC forecasts, we have responded to that elsewhere. We are also not sure where we have had to create data where none existed. All of the data used in the Lookback reconstruction of the REP benefits in the absence of the REP settlements existed as of 2001, and we have used what we believe is the most appropriate data available at that time. As to whether the Lookback proposal is a reasonable response to the remand "mandate," BPA will address parties' properly raised legal issues in its Draft and Final Records of Decision in this proceeding.

Q. APAC argues that BPA proposes to perform a new rate test using multiple new assumptions and factors. Wolverton, WP-07-E-AP-1 at 23. These include use of a new average system cost methodology for the IOUs, new load forecasts, changes in the modeling of the 7(b)(2) rate test, and changes in power costs. Id. Do you agree with this characterization of BPA's approach?

A. No. First, we are not using a new ASC methodology for the Lookback. We are relying only on the 1984 ASC Methodology. APAC's mischaracterization is refuted in BPA's ASC rebuttal testimony. *See* Boling, *et al.*, WP-07-E-BPA-83. APAC also states that BPA is using new load forecasts. We note that although the load forecast is different than the May 2000 Final Proposal, it is the same load forecast that we used in the final WP-02 Supplemental Proposal. *See* Hirsch, *et al.*, WP-07-E-BPA-54. The changes in the modeling of the rate test are covered in BPA's 7(b)(2) rebuttal testimony. *See* Doubleday, *et al.*, WP-07-E-BPA-85. Changes in BPA's power costs have been addressed in Petty, *et al.*, WP-07-E-BPA-56.

Q. WPAG argues that BPA proposes a "what if" approach where it revisits the major decisions actually taken by BPA during these two periods that bear on how much it was permitted to pay the IOUs and charge the preference customers, and reverses itself on *the ones that matter the most financially. Grinberg, et al., WP-07-E-WA-05 at 13, 46. For example, what if BPA had performed the section 7(b)(2) rate test differently than it did in the WP-02 and WP-07 rate cases; what if it knew in May of 2000 what it knew in the spring of 2001 and used some but not all of that information; what if it had recalculated the PF-02 rate in the WP-02 Supplemental proceeding; what if it had not instituted the FB, LB and SN CRACs; and what if it could establish IOU ASCs based on FERC Form 1 data instead of the jurisdictional rate data required by the 1984 Average System Cost Methodology (1984 ASCM). Id. Please respond.*

A. Our proposal is based on a rational and realistic approach to calculating the overcharges to the COUs due to the REP settlements. Our proposal, as explained in Burns, *et al*., WP-07-E-BPA-53, is predicated on the high likelihood that, had BPA and the IOUs not signed the REP Settlement Agreements, BPA would have taken a different path to revising rates in response to the West Coast energy crisis than it did in the WP-02 Supplemental Proposal. As explained, BPA would have chosen to revise base rates because of the important role of the PF Exchange rate to the proper implementation of the REP. In order to revise base rates, BPA would have had to consider facts that were not the same in the context of the REP settlements. Thus, logically and correctly, the section 7(b)(2) rate test would be implemented differently; BPA would use information available at the time the final WP-02 supplemental rates were established; BPA would have established revised base rates, including the PF-02 rate; BPA would have adopted a CRAC to help ensure revenue recovery; and BPA would have calculated IOU ASCs based on the 1984 ASC Methodology using the best information available absent actual ASC filings, that is, FERC Form 1s.

In reconstructing this necessary path through ratemaking, we believe that we have created a reasonable approach to calculating the overcharges paid by the COUs. The effects of the REP settlements permeate BPA's WP-02 and WP-07 rates. There is no reasonable means of removing the REP settlement costs without examining other underlying rate decisions. Therefore, differing conditions and assumptions must be used in the Lookback analysis for the purpose of calculating the overcharges to the COUs.

Q. *WPAG argues that in calculating the overcharge imposed on BPA's preference customers during the FY 2002-2006 period, BPA has used assumptions that are the opposite of what in fact actually happened during that period. Grinberg, et al., WP-07-E-WA-05 at 16. For example, WPAG claims BPA has reversed its position by assuming the existence of a CRAC that automatically collects any BPA revenue shortfall, which is completely different than the cost-specific CRACs actually adopted by BPA. Id. Also, BPA has reversed by assumption its decision not to perform the 7(b)(2) rate test subsequent to the close of the record in the WP-02 rate case in May, 2000 Id. How do you respond?*

A. The WP-02 rates were remanded to BPA, so the decisions made in that rate case, which includes the WP-02 supplemental proceeding, need to be reviewed. As outlined in Burns, *et al*., WP-07-E-BPA-53, had the REP Settlement Agreements not been signed, BPA would not have taken the path it took in the WP-02 supplemental proceeding where it ultimately developed the three CRAC and DDC system. Our response to the use of the CRAC in the Lookback analysis is addressed elsewhere in our rebuttal testimony.

With regard to section 7(b)(2), we have previously explained that, in the absence of the REP Settlement Agreements, BPA would not have adopted the three CRACs, but would have revised base rates. In order to revise base rates, BPA would have had to conduct the section 7(b)(2) rate test. The rate test would have been conducted with the new data that reflected changes from the WP-02 Final Proposal. WPAG would have BPA use the results of an outdated rate test, which makes no sense when developing revised base rates.

Section 2.3.5: Insufficiency of WP-02 PF Exchange Rate

Q. APAC argues that the PF Exchange rate calculated in the May 2000 Proposal had no ultimate effect because all the investor-owned utilities opted for the Settlement Agreements. Wolverton, WP-07-E-AP-1 at 31. Do you agree?

A. No. The PF Exchange rate calculated in the May 2000 Proposal may not have had any effect on the IOUs, but a PF Exchange rate was necessary for the rate period in case a public utility desired to participate in the REP. In February, 2006, Clark Public Utilities executed an RPSA and filed an Appendix 1 ASC filing with BPA to begin participation in the REP. Although BPA settled the REP claims with Clark, Clark's participation in the REP would have occurred using the PF Exchange rate.

Q. APAC states that REP settlement costs for FY 2002-2006 stem from a settlement agreement that did not follow the provisions of the Northwest Power Act. Wolverton, WP-07-E-AP-1 at 25. BPA cannot calculate a correct PF Exchange rate that relies on the settlement and remain in compliance with the Act. Id. Therefore, there is no way to calculate a "reasonable" PF Exchange rate. Id. Please respond.

A. The relevance of APAC's argument is unclear. The Supplemental Proposal does not propose to calculate a PF Exchange rate that relies on the REP Settlement Agreements. In the absence of the REP settlements, however, calculating a PF Exchange rate is relatively straightforward. We have returned to the rate calculations for the WP-02 rates and removed the effects of the REP settlements. In contrast, APAC argues that BPA should rely on the incomplete WP-02 rates calculated in May 2000, stopping after the Rate Design step. These rates, however, have numerous flaws. For example, the WP-02 base rates did not comprise rates that assured recovery of all of BPA's costs. Further, those rates were based on loads and market price forecasts that became woefully inadequate shortly after they were filed with FERC. This analysis does not rely on these deficiencies.

Q. *Despite the fact that the PF Exchange rate has no meaning in the context of the REP Settlement Agreements, APAC argues that BPA still insists on a Lookback analysis. Wolverton, WP-07-E-AP-1 at 33. Please respond.*

A. As we have previously explained, in the absence of the REP Settlement Agreements, BPA would not have developed CRACs as the sole method of addressing the otherwise fatal cost recovery shortcomings of BPA's WP-02 base rates. Instead, BPA would have revised base rates, including the PF Exchange rate, after conducting a new 7(b)(2) rate test reflecting the changed circumstances that had occurred after the faulty base rates were developed. This is the only manner in which BPA can ensure the proper implementation of the REP.

Q. *WPAG argues that BPA's proposed approach leaves in place a PF-02 Exchange rate that precluded preference customers from receiving REP benefits during the FY 2002-2006 period. Grinberg, et al., WP-07-E-WA-05 at 14. Do you agree?*

A. Issues regarding whether preference customers would have participated in the REP during FY 2002-2006, and the possible impact of such participation on the Lookback, are addressed elsewhere in our rebuttal testimony.

Q. *WPAG argues that BPA's proposed approach changes the amount of REP-related costs it can charge preference customers during FY 2002-2008 from about \$300 million to over \$1.75 billion. Grinberg, et al., WP-07-E-WA-05 at 14. Do you agree?*

A. No. Our Lookback analysis is reducing the REP-related costs it charged, or would have charged, preference customers for FY 2002-2008 from \$2.6 billion to \$1.75 billion. The \$2.6 billion represents the total payments made, or expected to be made, to the IOUs through the REP settlements. This amount was included in the WP-02 and WP-07 PF Preference rates. Our Lookback analysis results in a total of \$1.75 billion of reconstructed REP benefits. WPAG's argument is based on the false assumption that BPA would have failed to revise base rates in the absence of the REP Settlement

Agreements and would have retained the flawed results of the 7(b)(2) rate test used for the May 2000 base rates, which failed to reflect the enormous changes in loads and market prices occurring before BPA's June 2001 WP-02 decision.

Section 2.4: Claims that BPA's Lookback Approach is Results Driven

Q. APAC argues that because the data that could have been used (other than the ASC data) are virtually indistinguishable from the data that were used, it appears that the principal purpose of the Lookback exercise is to obtain a different result from the 7(b)(2) rate test – a different PF Exchange result and a "New Subscription Step" – than what came out of the WP-02 case. Wolverton, WP-07-E-AP-1 at 48. Do you agree?

A. No. APAC's *ad hominem* accusations are unfounded. The purpose of the Lookback exercise is exactly as we have described it to be. We are, in simple terms, determining the REP settlement benefits provided to the IOUs' residential consumers (as adjusted to reflect any benefits from related contracts that should be retained by such consumers) and then comparing that amount with the benefits the IOUs' residential consumers would have received under the REP in the absence of the REP settlements. Because BPA would have revised base rates instead of solely adopting CRACs after recognizing the inability of the WP-02 base rates to recover BPA's costs, BPA necessarily would have had to conduct a new 7(b)(2) rate test. Failure to do so would have precluded BPA from establishing rates in accordance with the Northwest Power Act's rate directives. Finally, BPA has previously addressed in Section 2.3.4 APAC's mischaracterization of BPA's Lookback Approach as a "New Subscription Step."

Q. APAC states that BPA's interpretation of the remand was explained in an e-mail from BPA's Elizabeth Evans to staff. Wolverton, WP-07-E-AP-1 at 23. APAC claims the email said that the objective of the remand was to "[re-set] the base rate to get to a reasonable p[f] exchange rate, so we are updating things we did not udpate [sic] back *then.” Id. APAC argues that BPA’s stated objective is to get a “reasonable” PF Exchange Rate, meaning it is endeavoring to reset the liability of the preference customers. Id.*

A. APAC has grossly mischaracterized the cited email. The email states “We are now re-setting the base rate to get to a reasonable P[F] [E]xchange rate.” *See id*., Attachment AP-1. The email says nothing about any policy objectives of our Lookback approach. The email also does not mention the remand of BPA’s WP-02 rates from the Ninth Circuit. The email is a simple description of one key component of our Lookback approach. In order to calculate what the IOUs’ residential consumers would have received under the REP, BPA must calculate a PF Exchange rate. It is critical that the PF Exchange rate be calculated properly, because it is a critical element in the calculation of REP benefits. Because of this importance and the complexity of establishing the PF Exchange rate, which involves the 7(b)(2) rate test, Ms. Evans advised staff that they needed to “get a reasonable P[F] [E]xchange rate.” This meant what it said - a reasonable result in the context of doing quality analysis. Ms. Evans was not trying to drive the PF Exchange rate in one direction or another. The word “reasonable” means being in accordance with reason or sound thinking. In this regard, the use of the term “reasonable” implies nothing about a desired outcome, but rather that the construction of the PF Exchange rate for use in the Lookback must be logical and sound.

Q. APAC argues that BPA staff’s recognition that constant battling over REP benefits is distracting the region from other important issues, in conjunction with the decisions taken regarding data projections, modeling changes and its post-2008 solution somehow indicates that this whole process is output driven. Wolverton, WP-07-E-AP-1 at 24. Do you agree?

A. No. We fail to see how recognizing that battles over REP benefits distract the region from other pressing issues has anything to do with whether the Supplemental Proposal is somehow driven to some particular result. The Supplemental Proposal, if affirmed, would help resolve bickering over REP benefits as it would establish ground rules that all parties could understand, but this occurs naturally by deciding the issues pending in the proceeding. Our data projections and modeling changes are supported by separate testimony and will rise or fall on their merits. We do not understand APAC's reference to a "post-2008 solution." Presumably this refers to our proposed method for recovering the Lookback Amount by reducing prospective REP benefits. Once again, this is simply our proposed manner in which BPA could return overpayments to IOUs to preference customers. Parties are proposing different approaches in this proceeding, and the Administrator will review and consider all of them. Finally, if our intent were to achieve some particular "output" that favored a particular party, we have failed miserably. The Supplemental Proposal is being criticized by the IOUs, the state commissions, preference customers, and end-use consumer organizations (APAC and CUB) on both sides of the issues. If anything is evident from the parties' testimonies, it is that no party is happy with the "output-driven" solution.

Section 2.5: The Lookback Approach and Calculating the COUs' Overcharges

Q. APAC states that BPA is focusing on the PF Exchange rate charged to the IOUs for their Residential Exchange transactions and not on assessing the overcollections to preference customers. Wolverton, WP-07-E-AP-1 at 24. Do you agree?

A. No. Our initial testimony states the purpose of the Lookback; that is, to calculate the amounts that preference customers were overcharged due to the inclusion of the REP settlement costs in their rates. *See* Bliven, *et al.*, WP-07-E-BPA-52 at 18. As described in that testimony, the Lookback process is focused on calculating the overcharges to the COUs and then developing an approach for recovering those amounts from the IOUs and returning them to the COUs. We recalculate the PF Exchange rate so that we can quantify the amount of REP benefits the IOUs would have received in the absence of the REP settlements in order to help determine the overcharges. A PF Exchange rate without the effects of the REP settlements is a necessary component of the calculation of the overcharges. *See* Burns, *et al*., WP-07-E-BPA-53 at 6-9. In fact, the inclusion of the "lesser than" rule is a prime component that demonstrates that we are more focused on the overpayments by the preference customers than trying to get more benefits to the IOUs. *See* Marks, *et al.*, WP-07-E-BPA-62 at 15; *see also* Bliven, *et al.*, WP-07-E-BPA-52 at 18-19.

Q. *APAC argues it appears that BPA's intent is to establish the PF Exchange rate and a Lookback Amount for a predetermined post-2008 period rather than establish the refund amounts. Wolverton, WP-07-E-AP-1 at 53. How do you respond?*

A. APAC presupposes that BPA's decision in this case is applicable for some predetermined period, which it has indicated is the next twenty years. Although we have discussed the general ability of BPA to return overpayments to preference customers in 20 years or less, this does not predetermine when such repayments will be made. With the exception of the payments made through the Interim Agreements and their ultimate true-up, our proposal covers only this one rate case, and only one year, FY 2009, for the return of the overcharges to the COUs. *See* Marks, *et al*., WP-07-E-BPA-62 at 22. The stated intent of the Lookback is to establish the amount by which preference customers were overcharged due to the presence of the REP settlement costs in past rates. *See* Bliven, *et al.*, WP-07-E-BPA-52 at 18. To do that, we determine a PF Exchange rate consistent with the removal of the REP settlement costs to establish the IOU REP benefits in the absence of the REP settlements, which are deducted from the REP settlement benefits.

Q. *WPAG argues that BPA applies a set of rules to determine the amount that BPA proposes that the IOUs pay back to its preference customers about $380 million of the $2.13 billion paid to the IOUs during the FY2002-2008 period. Grinberg, et al., WP-07-E-WA-*

05 at 48. Or said another way, for every dollar the preference customers paid the IOUs during that period, BPA proposes to return about 18 cents and allow the IOUs to retain about 82 cents. Id. Do you agree?

A. No. Our proposal is that the IOUs return $620 million plus interest to the COUs. Our proposal is predicated on the virtual certainty that five of the six IOUs, in the absence of the REP settlements, would have participated in the REP. *See* Bliven, *et al*., WP-07-E-BPA-52 at 14. Had IOUs participated in the REP, then, subject to section 7(b)(2), some REP costs would properly be included in the PF Preference rate. Hence, the rational alternative to the signing of the REP Settlement Agreements does not result in requiring all costs of the REP settlements be returned to the COUs. Therefore, there will logically be less than a dollar-for-dollar return of REP settlement benefits to the COUs.

Section 2.6: Policy Direction to Use 1984 ASC Methodology

Q. Several parties argued that BPA should not have used the 1984 ASCM when calculating ASCs in the Lookback. The Oregon PUC argues that the 1984 ASCM was viewed by the Ninth Circuit as temporary, shortly after it was adopted in 1984. Hellman and McGovern, WP-07-E-PU-1 at 4. The IOUs similarly argue that the 1984 ASCM, which excluded return on equity and income taxes from ASC, was never sanctioned as a "permanent methodology" when it replaced the original 1981 ASCM. La Bolle, et. al., WP-07-E-JP6-08 at 82. Also, the Idaho PUC states that the 1984 ASCM has never been fully litigated because of the REP Settlement Agreements. Westerfield, WP-07-E-ID-1 at 21. In light of these arguments, do you continue to think it reasonable to direct staff to use the 1984 ASCM when calculating the Lookback?

A. Yes. In 1984, BPA developed a revised ASCM, which replaced the 1981 ASCM. The 1984 ASCM was approved by FERC and affirmed by the Ninth Circuit on appeal in 1986. The 1984 ASCM was used to review all ASC filings made by exchanging utilities from 1984 to the present, and is still in effect. The parties' comments that the 1984 ASCM is "temporary" or "not permanent" refer to the Ninth Circuit's decision affirming the 1984 ASCM. In that case, the Court approved the 1984 ASCM, but stated that it did not sanction a permanent exclusion of certain costs from ASC. Nevertheless, the 1984 ASCM was approved, affirmed and remains in place until revised. It is therefore a reasonable ASCM to use for the Lookback.

Also, practical considerations support our policy direction to staff to use the 1984 ASCM. We were aware that calculating backcast ASCs for six IOUs for an eight-year period would be a daunting task. Each backcast ASC would have to be evaluated to ensure that the utility's costs were being properly functionalized in accordance with the ASCM. We were confident this objective could be achieved because of the familiarity BPA staff had with the substantive provisions of the 1984 ASCM. The treatment BPA staff chose for backcast ASCs could be further tested by regional parties who would also be familiar with the substantive provisions of the 1984 ASCM. If, however, we had directed staff to assume a totally new ASCM, one they and the region were not completely familiar with, we were concerned that both the viability and legitimacy of the backcast ASCs would be called into question.

In light of these considerations, we continue to believe that it is reasonable to assume that the 1984 ASCM – a methodology that has been in place for over two decades, approved by FERC and litigated before the Court, and which BPA and the region are familiar with – should be used in calculating the backcast ASCs for purposes of calculating the Lookback amounts.

Q. *The IOUs argue that had they not entered the REP Settlements they would have vigorously pursued ASCM issues. La Bolle, et. al., WP-07-E-JP6-08 at 82. As a result, BPA would, of necessity, have addressed ASCM issues, including the ASCM issues identified by BPA in the 2008 ASCM Federal Register Notice. Id. Do you agree that the*

ASC Methodology would have been modified in 2000-2001 if the REP Settlement Agreements had not existed?

A. We acknowledge that BPA was in the preliminary stages of informal discussions regarding whether to revise the 1984 ASCM around the time that Subscription contracts were offered. *See Residential Purchase and Sale Agreements with Pacific Northwest Investor-Owned Utilities*, Administrator's Record of Decision, at 24 (October 4, 2000) ("RPSA ROD"). We also acknowledge that if the IOUs had executed the Residential Purchase and Sale Agreements (RPSA) in 2000 instead of the Residential Exchange Settlement Agreements, it is highly likely the IOUs would have vigorously pursued ASCM issues.

Assuming for the sake of argument that BPA would have conducted a consultation proceeding and revised the 1984 ASCM around 2000-2001, it is difficult to determine the revisions that might have been made. Although one could suggest that a revised ASCM would have been similar to the proposed 2008 ASCM BPA is currently developing in a consultation proceeding, this is not certain. Also, BPA has not yet established a final revised ASCM. Therefore, we do not know the exact form a revised methodology would have taken in 2002. The 1984 ASCM, however, was in effect in 2002 (as it had been since 1984) and was a readily available source to use to determine utilities' ASCs.

Q. The OPUC notes that the reasons BPA gave for revising the ASCM in its February 7, 2008, Federal Register Notice were applicable back in 2001. Hellman and McGovern, WP-07-E-PU-1 at 4-6. They conclude that both the impetus and the justification were present for BPA to revise its ASC methodology. Id. Therefore, in conducting its Lookback analysis, BPA should use a new ASCM that allows utilities to exchange return on equity, taxes, and transmission costs." Id. The IPUC makes a similar statement. Westerfield, WP-07-E-ID-1 at 21. Do you agree?

A. No. We acknowledge that the reasons that we give today for changing the methodology existed back in 2001. However, BPA had not yet commenced a new consultation process to adjust the 1984 ASCM. In short, we do not agree that the factors identified in the February 7, 2008, Federal Register Notice require us to assume that the 1984 ASCM would have been modified for purposes of the Lookback calculation.

Q. Assume for the sake of argument that a new ASCM would have been established during the 2000-2008 period. What do you see as the main problem with using a new ASCM approach for purposes of calculating ASCs over the 2000-2008 rate period rather than the 1984 ASCM?

A. The main problem is that we cannot say with any degree of certainty what the new ASC methodology developed in 2000-2001 would have looked like. BPA had taken no affirmative steps at or near the time to put together a proposal for adjustments to the ASCM. There is, therefore, nothing to rely on that is contemporaneous with the WP-02 or even WP-07 cases that would give BPA a basis for assuming that the ASCM would be changed in any particular manner. The IOUs, CUB, OPUC, and IPUC all seem to believe that BPA would have adopted their recommended changes to the ASCM (*i.e.*, inclusion of taxes and equity) without question. But this assertion is not a foregone conclusion. The consultation process would also have necessarily involved input from public agencies, state commissions, the Northwest Public Power Council, and others. We think trying to guess what all these various parties would have said, and how their positions would have modified the 1984 ASCM, is too speculative to use for Lookback purposes.

Q. The IPUC argues that there is no way to reconstruct in 2008 what the IOUs would have done in 2001 absent the opportunity to sign the REP Settlement Agreements they did in fact sign. Westerfield, WP-07-E-ID-1, 8-9. There is also no way to determine in 2008 whether the 1984 ASCM would have been modified or litigated in the WP-02 or the *initial WP-07 BPA rate proceedings if the REP Settlement Agreements had not been offered to the IOUs. Id. Thus, the IPUC concludes that the Lookback analysis is based on the "false assumption" that REP benefits and ASCs would have been determined in both BPA proceedings using the 1984 ASCM when the IOUs might have challenged the use of the 1984 ASCM absent the REP Settlement Agreements. Id. Do you agree that these alleged uncertainties make it a "false assumption" to presume the 1984 ASCM would be in place during these periods?*

A. No. Simply because the 1984 ASCM could have been changed, does not, in our view, mean that using it is a "false assumption." It is true that at this point it is not possible to definitively know how or whether the 1984 ASCM would have changed as a result of litigation. Yet, it is because of this very uncertainty that we have chosen to use the 1984 ASCM for the Lookback period. Because we cannot know if or how the 1984 ASCM would have changed, it is eminently logical and reasonable to use what was known and available at the time - the 1984 ASCM.

Q. As an alternative to using the 1984 ASCM, the IOUs, OPUC, IPUC, and CUB all argue that BPA should use its proposed new ASCM instead of the 1984 ASCM in the Lookback calculation. La Bolle, et. al., WP-07-E-JP6-08 at 81-82; Hellman and McGovern, WP-07-E-PU-1 at 4; Westerfield, WP-07-E-ID-1 at 21; Jenks, WP-07-E-CU-1 at 16. Do you agree?

A. No. BPA's proposed 2008 ASCM, which is being established in a concurrent consultation proceeding, is still being developed. As such, there is no way of knowing whether the proposed methodology will remain in its present form by the end of the consultation process. The first round of official comments on the methodology were filed May 2, 2008. BPA will now review the comments and then issue a Draft ASCM, which may or may not be similar to the methodology published in the Federal Register on February 7, 2008. Parties will then file additional comments on this Draft ASCM. BPA will then review these comments, make appropriate adjustments, and issue a final ASCM. Next, the ASCM will be filed with FERC for approval. If approved, the 2008 ASCM may be challenged in the Ninth Circuit. Because of these uncertainties, we do not consider the 2008 ASCM a reasonable alternative to rely upon for purposes of the Lookback calculation.

Section 2.7: Policy Direction to Calculate Backcast ASCs

Q. Did any party raise concerns with the direction you gave regarding the development of backcast ASCs for the FY 2002-2008 period?

A. Yes. WPAG argued that BPA should not calculate backcast ASCs at all. Grinberg, *et. al.*, WP-07-E-WA-05 at 12. WPAG contends that BPA does not have to take into account the IOUs' ASCs in order to determine the amount each company should be responsible for paying back. *Id*. WPAG argues that because of the operation of the 7(b)(2) rate test and the reallocation of costs to the PF-02 and PF-07 Exchange rates pursuant to 7(b)(3), the ASCs of the various IOUs were not the determining factor in the total amount of REP benefits available to the IOUs. *Id*.

Q. Do you agree?

A. It depends upon the meaning of the term "determining factor." The total amount of REP benefits ultimately recovered from the COUs is a function of the PF Exchange rate and the IOUs' actual ASCs and exchangeable loads for the rate period. Consequently, we cannot calculate an accurate estimate of what the COUs were overcharged unless we can estimate what the PF Exchange rate and backcast ASCs would have been for the Lookback period. Without individual IOU ASCs, we would be missing a key piece of information necessary to calculate the total amount of REP costs that should have been included in COUs' rates.

Q. *WPAG asserts that the ASCs are not necessary because it is reasonable to apportion liability to the IOUs based on the amount of REP Settlement Agreement related payments they received without recourse to their relative ASCs. Grinberg, et al., WP-07-E-WA-05 at 12. WPAG further notes they are more concerned about obtaining from the IOUs as a group the full amount of the overcharge imposed on preference customers with interest, and less so about the relative contribution each IOU makes to those repayments. Id. Do you agree?*

A. No. Contrary to WPAG's statement, we must calculate the individual IOU ASCs to fulfill the primary objective of this proceeding; namely, to determine what the REP benefits would have been had the REP Settlements not been executed. In order to accomplish this objective, we must have all of the relevant data, especially the ASCs of the individual utilities. Without these, BPA would have no way of knowing if or by how much it overcharged the COUs. Apportioning liability among the IOUs based on their respective shares of REP Settlement benefits would not assist in answering this question. The proportion of REP settlement benefits an IOU received may not have any specific relationship to the REP benefits that such utility would have received in the absence of the REP settlements.

WPAG notes that it is more concerned about receiving overcharges from the IOUs as a group, and less about the relative contribution of each IOU. Although WPAG may be indifferent to who ultimately repays the overcharges, we can safely assume that the respective IOUs, their state commissions, and their residential consumers hold a far different view on this matter. More fundamentally, though, WPAG fails to explain the basis upon which BPA could justify requiring one IOU to repay the overpayment made to another.

Q. WPAG and APAC contend that BPA already has ASC information from the WP-02 and WP-07 rate case records that could be relied upon to calculate ASCs. Grinberg, et al., WP-07-E-WA-05 at 11-12; Wolverton, WP-07-E-PA-01 at 10. Do you agree?

A. No. The ASCs WPAG and APAC refer to are forecasts of the IOUs' ASCs that BPA estimates in rate cases for ratemaking purposes. These forecasts are developed from the best available data at the time of the rate case, which in most instances pre-dates the actual year that the utility would be exchanging with BPA by two to seven years. These forecasts are, therefore, no substitute for an ASC that would likely have been determined with more recent information made available during the rate period. In addition, it would not be appropriate to assume that the ASC forecasts constrain or limit the REP benefits the IOUs would have been entitled to under the program. The REP benefit payments are determined by comparing an IOU's ASC with the PF Exchange rate, multiplied by the utility's exchange load. The IOUs could file an ASC within the rate period that had some, little, or no relationship to the ASC BPA had forecast in the rate case. The REP has always operated in this manner. It therefore would not make sense to limit the IOUs' ASCs to just the forecasts.

Q. Is it logical to assume that the IOUs would have filed ASCs with BPA had the IOUs executed RPSAs?

A. Yes. As stated in our direct case, there is every indication that the IOUs would have participated in the REP had the REP Settlement Agreements not been signed. Most of the IOUs had submitted letters notifying BPA of their intent to participate, and the RPSA had been drafted and offered to these utilities. The RPSAs require the utilities to file ASCs with BPA. If we assume the IOUs would have signed the RPSA, it then follows that they would have complied with the contracts and made ASC filings. The alternative, as posited by WPAG and APAC, is for BPA to assume that the IOUs signed the RPSAs, but did not or would not file ASCs within the rate period. We find this latter alternative highly unlikely and illogical considering the IOUs' historical participation in the program.

Q. APAC also argues that because BPA and the IOUs knew that the REP settlements were being challenged, it would have been "prudent" for the IOUs to file ASCs with BPA during the 2002-2008 period. Wolverton, WP-07-E-AP-1 at 44-45. Do you agree?

A. No. BPA and the IOUs entered into the REP Settlement Agreements in the good faith belief that the Agreements would be upheld by the Court, if challenged. The 2000 REP Settlement Agreements received general support during the Subscription process, although certain parties proposed different levels of benefits for the Agreements. More importantly, when one is a party to an agreement, one does not act as if one is not a party to an agreement. It is therefore unreasonable to assume that BPA or the IOUs would go through the time and expense of implementing the REP when it was inactive. Furthermore, this was one of the very reasons for entering into the settlements in the first place. In addition, during the Subscription process, the WP-02 rate proceeding, and the initial WP-07 rate proceeding, no party (including APAC) ever suggested that BPA and the IOUs should simultaneously implement the REP Settlement Agreements and the REP. Similarly, we, in turn, could ask APAC, when it complains that our approach denied it the right to intervene in the state rate cases that would have formed the basis of ASC under the 1984 ASCM, why it did not, to be prudent, intervene in every IOU retail rate case in every PNW state in order to gather information to better understand the ASC filings the IOUs never made and BPA never reviewed.

Q. APAC contends that utilities' ASCs would have been "undoubtedly" different had the IOUs made filings under the 1984 ASCM. Wolverton, WP-07-E-AP-1 at 44-45. In what way they would be different, however, APAC cannot say. Id. APAC claims that this result occurs because it is "virtually impossible to revisit all the rate-setting decisions that each jurisdiction made." Id. Please respond to this statement.

A. We generally agree that it would be virtually impossible to perfectly recreate ASCs using the jurisdictional approach in the 1984 ASCM. APAC correctly notes that the primary difficulty would be revisiting every rate order issued by four state utility commissions for each of the six IOUs over a span of eight years. Even if all of the rate orders could be collected and reviewed, it is highly doubtful whether BPA could even make a preliminary estimate of these ASCs without engaging in extensive discovery of the IOUs to obtain the underlying data. *See* Boling, *et al.*, WP-07-E-BPA-83 at 44-48.

This problem with the jurisdictional rate filings, however, was the very reason we gave the direction to staff to reconstruct ASCs using the 1984 ASCM. In giving this direction, we were well aware of some of the practical problems that would occur because one cannot participate in past retail rate hearings or review ASC filings that were never made. We left it to staff to determine whether there was a "practicable" way of calculating ASCs using the 1984 ASCM. It was our view that staff would have met our policy objective if the resulting ASCs complied with the substantive provisions of the 1984 ASCM. That, in fact, is what staff has done. Although APAC is correct that we can never know exactly how the estimates would have compared to actually filed ASCs, we believe the backcast ASCs generated in this case meet the substantive requirements of the 1984 ASCM, and therefore, are reasonable approximations of what the ASCs would have been over the period. Further, comparing staff's estimated backcast ASCs with benchmarks mentioned by the parties demonstrates that these backcast ASCs are generally very reasonable. *See* Boling, *et al.*, WP-07-E-BPA-83 at 13-14, 15-16, 18-21, 22-25.

Section 2.8: Recommendation Agreement Between IOUs and COUs

Q. The OPUC notes that it does not support the Recommendation Agreement because the recommendation does not contemplate that benefits for the IOUs should grow over time *to account for the value of money (inflation) or changes in overall value of the BPA system. Hellman and McGovern, WP-07-E-PU-1 at 7. Under the proposed settlement, the share of the Federal system benefits flowing through to the region's citizens served by IOUs will likely become negligible if for no other reason than the effect of inflation. Id. How do you respond?*

A. We respect the OPUC's opinion regarding the "Recommendations of Representatives of the Investor-Owned and Certain Consumer Owned Utilities Regarding the Residential Exchange Benefit for Customers Served by the Pacific Northwest Investor-owned Utilities," but BPA has not adopted the Recommendations Agreement as its Supplemental Proposal.

Q. The OPUC notes that it has concerns regarding the process of the settlement discussions themselves. Hellman and McGovern, WP-07-E-PU-1 at 7. Commissions and customer advocacy groups such as the Citizens' Utility Board are strong advocates for residential customers, but such groups were excluded from the settlement discussions. Id. Thus, one should not presume that the settlement among the COUs and IOUs represents consensus or an equitable resolution of the residential exchange issue. Id. The OPUC recommends that in the future, in regional discussions seeking settlement, PNW parties should include interest groups who have a direct interest in matters that could significantly affect those group, and notes that BPA's encouragement in this regard would be appreciated. Id. How do you respond?

A. We acknowledge that the proposed Recommendations did not represent a regional consensus. We also recognize, however, the desirability of regional collaboration as we pursue the best approach to responding to the Court's rulings on the REP settlements and BPA's WP-02 rates. We encourage parties to include, to the greatest extent practicable, representatives of all regional interests potentially affected by settlement discussions in their discussions. BPA has proposed to schedule settlement discussions regarding BPA's

Supplemental Proposal at the close of clarification, which is likely to occur on May 14, 2008, and encourages all parties to attend.

Section 3: Calculation of Lookback Amounts

Section 3.1 Valuation of the Power Sale to PGE

Q. The OPUC argues that the power component of PGE's REP Settlement Agreement should be valued at BPA's valuation rather than PGE's valuation. Hellman and McGovern, WP-07-E-PU-1 at 10. The OPUC argues that this treatment is necessary because the value PGE placed on the power sale through its rates, either in the form of cash or power, is not directly relevant in answering what REP benefits BPA should have included in its rates. Id. at 11. Please respond.

A. To be clear, we did not present our "own" valuation of the PGE power sale in the initial Supplemental Proposal. Rather, we tested the reasonableness of PGE's valuation by comparing it to market purchases at the Mid-Columbia (Mid-C) Index. *See* Marks, *et al*., WP-07-E-BPA-62 at 6. The mark-to-market valuation with the Mid-C Index was not intended to be a competing valuation but simply a benchmark to compare PGE's valuation. Because it appeared that PGE's valuation was higher than one based on the cost of market purchases, we concluded that using PGE's own valuation in the Supplemental Proposal was reasonable.

We, however, are not opposed to considering other valuations. The OPUC makes a fair point in noting that how PGE valued the sale does not necessarily reflect the costs of the power sale BPA included in the COUs' rates. Therefore, we concur that other reasonable methods for calculating the value of the PGE power sale exists. For example, BPA could use the mark-to-market approach mentioned by the OPUC and referenced by BPA in the Lookback Study Documentation, WP-07-E-BPA-44A at 1021, n.1. This option represents the market value of the power sold to PGE, minus the revenues received at the Residential Load (RL) rate.

Another reasonable option is to value the PGE sale based on BPA's average augmentation cost. This valuation method reflects the fact that BPA does not purchase power from the market to serve an individual customer or contract. Rather, BPA purchases power to serve its total load obligations. Using the average augmentation cost would be a reasonable approach because the cost of serving the PGE sale was captured in the Load-Based (LB) CRAC paid by the COUs. This particular rate mechanism increased the COUs' rates to recover the increased power purchase expenses BPA incurred for FY 2002-2006. After accounting for the revenues paid to BPA for power purchased at the RL rate, the cost contained in the CRAC'd PF Preference rate for the RL sale to PGE using the average cost of augmentation would be $109,908,707, compared to the $187,131,671 million included in the Lookback Study Documentation, WP-07-E-BPA-44A at 1021. Derivation of this $109.9 million number is shown in Table 1, along with the two other approaches to valuing the BPA RL power sale to PGE already discussed. All of the foregoing approaches will be reviewed when making final decisions based on the full record of the case.

Table 1

PGE RL Power Sale Valuation - "Look Back" Valuation Alternatives

	PGE's Valuation	Mid-C Valuation Basis			Valuation Based on BPA's Purchase Cost Average Cost Pricing		
		(A)	(B)	(C)	(D)	(E)	(F)
				(B) - (A)			(D) - (E)
	Valuation Used in the Lookback Analysis - Valuation of the Net Benefits - Per Annual REP Benefits Accounting[1]	What PGE Paid BPA for RL Power Purchases	Dow Jones Mid-C Value of Power Purchases[2]	Net Benefit Value Mid-C less BPA Purchase Price	Data Response WA-BPA-38 BPA's Purchase Cost for PGE's RL Power Purchases Using Average Cost Pricing[3]	What PGE Paid BPA for RL Power Purchases	Net Cost to BPA
FY 2002	$ 15,239,610	$ 56,585,215	$ 41,171,910	$ (15,413,305)	$ 71,630,468	$ 56,585,215	$ 15,045,253
FY 2003	$ 15,042,817	$ 65,384,487	$ 83,637,111	$ 18,252,624	$ 71,456,517	$ 65,384,487	$ 6,072,030
FY 2004	$ 18,623,863	$ 64,990,690	$ 90,765,973	$ 25,775,283	$ 84,752,875	$ 64,990,690	$ 19,762,185
FY 2005	$ 48,430,052	$ 60,617,317	$ 110,532,121	$ 49,914,804	$ 90,468,870	$ 60,617,317	$ 29,851,553
FY 2006	$ 89,795,329	$ 58,855,720	$ 119,940,103	$ 61,084,383	$ 98,033,405	$ 58,855,720	$ 39,177,685
Totals	$ 187,131,671	$ 306,433,429	$ 446,047,218	$ 139,613,789	$ 416,342,136	$ 306,433,429	$ 109,908,707
Net Value of RL Power Benefits	**$ 187,131,671**			**$ 139,613,789**			**$ 109,908,707**

Note 1 - This is the annual value that PGE used in making an annual accounting to BPA of the benefits that BPA paid/distributed to PGE and the amount that they in turn distributed to their eligible residential and small farm customers. They determined this "forward market" value of the RL power for all 12 months of the calendar year (PGE's Y/E) approximately 2 months before the start of the calendar year. It is a risk adjusted forecast value.

Note 2 - The Dow Jones value is based on the average daily closing prices and then weighted by the individual day's trades to get an average market price for the month. This information was obtained from BPA's trading floor.

Note 3 - The valuation methodology of average costing for augmentation purchases reflects BPA's accounting pracitice. This was discussed in BPA's response to data request WA-BPA-25, and was also used in responding to AP-BPA-64.

Q. *The OPUC argues that if BPA chooses to use the mark-to-market valuation of the RL sale, it should make a special adjustment for FY 2002. Hellman and McGovern, WP-07-E-PU-1 at 11. This adjustment would remove an alleged "excess" from the power component that occurred in this year only. Id. According to PGE, the 2002 difference between BPA's and PGE's valuation of the power benefit is $30.6 million, so the "excess" value of power adjustment that should be made for the 2003 to 2006 time period is $47.5 million minus $30.6 million or $16.9 million. Id. Do you agree?*

A. If we understand this argument correctly, the OPUC is requesting a special adjustment to the value of the RL sale for FY 2002. This adjustment would reflect the fact that the mark-to-market value of the RL sale for FY 2002 was actually *below* the RL rate that BPA charged PGE. In other words, the RL rate PGE paid was higher than the market price for the power in this one year. The OPUC is requesting that the "excess" that PGE paid be spread out over the later years of the rate period.

We find this particular adjustment troubling. The OPUC previously asked BPA to adopt a market-based valuation of the RL sale rather than use PGE's valuation. Now the OPUC is requesting that if BPA adopts the market valuation, it should also make an additional adjustment to the RL revenues BPA received from PGE that effectively negates the impact of adopting the market-based valuation for FY 2002. We do not see the logic in selectively choosing which years the market valuation will have meaning and which years it will not. We believe that a more reasonable approach would be to apply the valuation methodology, whatever it may be, to all years.

Section 3.2 The "Lesser Than" Rule

Q. *Several parties objected to BPA's "lesser than" rule. Before responding, please briefly describe this rule.*

A. The "lesser than" rule is one of the underlying rules we used to calculate the Lookback Amounts for the IOUs. In general, the "lesser than" rule limits the amount of REP benefits BPA would credit to the IOUs for FY 2002-2008 period when calculating their respective Lookback Amounts. The limit is based on the REP settlement benefits the respective IOUs received in a given year. For example, if an IOU received $30 million in REP settlement payments in FY 2002, but would have received $50 million under BPA's Lookback approach, only $30 million is credited against that IOU's Lookback Amount for that year. This rule is described in greater detail in Bliven, *et al.*, WP-07-E-BPA-52 at 18.

Q. *The IOUs argue that BPA's proposal to cap reconstructed REP benefits based on REP settlement benefits is unsupported and arbitrary. LaBolle, et al., WP-07-E-JP6-08 at 74. CUB similarly criticizes BPA's approach, stating that it "makes no sense." Jenks, WP-07-E-CU-1 at 21. WPAG states that it could think of no basis in ratemaking practice to support the use of the "lesser than rule," that using payments made under a contract that has been declared illegal for any purpose has no basis in ratemaking, and the lesser than rule should be discarded. Grinberg, et al., WP-07-E-WA-05 at 48. Do you agree?*

A. No. The use of the "lesser than" rule, or proposed cap on reconstructed REP benefits, is both supported and necessary. The purpose of the Lookback analysis is to determine the magnitude of REP settlement costs that were improperly included in the PF Preference rates for FY 2002-2008, and to return those amounts to the COUs. This goal, and our lay understanding of the Court's rulings, is the justification for the "lesser than" rule. Through this proceeding, BPA is attempting to address the harm to the COUs who paid the PF Preference rate. The PF-02 and PF-07 Preference rates included the costs of the

REP settlements. They did not include potential REP costs in excess of the costs of the REP settlements. Therefore, it would be inappropriate to include any additional REP costs in the Lookback analysis. Furthermore, whereas WPAG argues that there is no place in ratemaking for the rule, we respond by noting that we are not using the rule in the ratemaking portions of the Supplemental Proposal, rather we are using the rule after the rates are determined to determine the overpayments made by the COUs.

Q. Several parties questioned BPA's underlying rationale for adopting the "lesser than rule." The IOUs argue that there is nothing wrong with allowing the IOUs to be owed more money than was paid in some years. LaBolle, et al., WP-E-JP6-08 at 75. CUB notes that this result is just a logical extension of BPA's assumption that the IOUs would have signed an RPSA. Jenks, WP-07-E-CU-1 at 20. The OPUC explains that if BPA assumes the full amount of the REP benefits, the COUs are not being overcharged because that is the amount PGE was entitled to receive under a properly conducted REP. Hellman and McGovern, WP-07-E-PU-1 at 8. Cowlitz and Clark similarly note that BPA's approach should be derived as the difference between the REP settlement payments made to each IOU versus what the IOU should have been paid under an "appropriate" PF Exchange rate and the 1984 ASCM. Schoenbeck and Beck, WP-07-E-BPA-JP17-01 at 39. Please respond.

A. These parties are correct that in a *normal* REP benefit determination, a utility exchanging with BPA would not be subject to any sort of cap and would receive REP payments equal to the difference between its approved ASC and BPA's PF Exchange rate multiplied by the utility's residential and small farm load (*i.e.*, its exchange load). The present situation, however, serves a much more limited purpose. BPA's responsibility in this case is to answer the fairly narrow question of whether the COUs paid too much in their rates for the FY 2002-2008 period due to the REP settlements and, if they did, to calculate the amount the COUs were overcharged. To answer this question, we need only look at whether the IOUs were overpaid under the REP settlements when compared to the REP benefits they would have received absent the settlements. The question of whether or not the IOUs were underpaid is not a relevant issue in this case because only the REP settlement costs were included in the PF Preference rate for FY 2002-2008. No additional costs were included in the rates of the COUs to cover a traditional REP "just in case." The results of the comparison we are proposing should be an accurate reflection of the overpayments BPA made to the IOUs (and collected in rates).

The additional step that the parties are requesting us to take is not necessary or warranted to achieve this narrow objective. Indeed, making the offset requested by the parties would make the final result less accurate. Accounting for what the IOUs *might* have received from BPA that is over and above what the IOUs *actually* received, as the parties suggest, skews the end results of the Lookback because it uses hypothetical underpayments to net against actual overpayments. We consider this outcome unreasonable in that it dilutes the effectiveness of the remedy BPA is attempting to achieve through this proceeding, and inappropriately skews the results in the favor of the IOUs.

To summarize, the purpose of the Lookback analysis is not to make the IOUs whole for any benefits they would have received had they signed RPSAs in 2001 instead of the REP Settlement Agreements. Rather, the purpose is to determine the overcharges to the COUs in a reasonable and equitable manner. In fashioning this remedy, we do not believe we must give full and absolute effect to all of the potential REP costs that might have been included in the PF Preference rate under different circumstances. Ultimately, those costs did not occur, so we do not believe that it must diminish the value of the COUs' repayments.

Q. *The OPUC proposes that for companies that do not have the complexity of the Load Reduction Agreements, any Lookback Amounts should be calculated by simply* *taking the aggregate settlement payments (for all the years of each Lookback rate period) and comparing them to what the company would have received in REP benefits under the Northwest Power Act. Hellman and McGovern, WP-07-E-PU-1 at 9. Do you agree?*

A. No. As already indicated, we promote the use of the "lesser than" rule, which results in Lookback Amounts of $0 in cases where the reconstructed REP benefits exceed the settlement benefits actually received by an IOU in any particular year. The OPUC's simple approach would result in negative Lookback Amounts for years when the reconstructed REP benefits exceeded the settlement benefits paid. We do not believe that negative Lookback Amounts are in line with the purpose of calculating the amount of overcharges to the COUs as a result of including the costs of the REP settlements in power rates. Negative Lookback Amounts would negate positive overcharges.

Q. The IOUs argue that by not crediting all REP benefits against REP settlement payments, BPA is "overcorrecting" in favor of the COUs. LaBolle, et al., WP-07-E-JP6-08 at 76. CUB raises a similar concern, arguing that under BPA's approach COUs not only recover any supposed overpayments, but also receive the benefit of paying rates (set retroactively) that include a smaller REP benefit than was actually warranted at the time. Jenks, WP-07-E-CU-1 at 19. The IOUs conclude that BPA's "lesser than" rule results in a windfall to the COUs. LaBolle, et al., WP-07-E-JP6-08 at 76. Do you agree?

A. No. The stated purpose of our proposal is to determine how much the COUs were overcharged due to the REP settlements. We do not believe that the additional purpose of making the IOUs whole for what they would have received via an REP is appropriate in this rate proceeding. The PF-02 rates were remanded to BPA in order to address the Court's ruling that the WP-02 rates improperly included the costs of the REP settlement. It is our understanding that the Court provided no direction regarding what should have been included in the WP-02 rates regarding the cost of an REP. Ultimately, the question of the Court's direction to BPA is a legal issue. BPA will address the parties' properly raised legal arguments in the Draft and Final Records of Decision in this proceeding.

The possibility that an IOU would have received more benefits under an REP than it actually received under the REP settlement is not at issue here. In that situation, the COUs were not overcharged. Furthermore, BPA does not agree that the "lesser than" rule results in a windfall to the COUs. A "windfall" implies that receiving something is in some way undeserved or includes ill-gotten gains. BPA's approach to the Lookback analysis is grounded in the solid and unbiased goal of establishing the amount of REP settlement costs that was improperly included in the PF Preference rates for FY 2002-2008.

Q. CUB criticizes BPA for being allegedly inconsistent. CUB contends that BPA states the goal of the proceeding is to determine the REP benefits, but then limits those benefits by the lesser than rule. Jenks, WP-07-E-CU-1 at 21. CUB concludes that BPA should take a consistent position by netting-out, from the Lookback Amount, the amounts when the reconstructed Residential Exchange was more than the settlement value. Id. Please respond.

A. We are taking a consistent position. CUB's assertion overlooks the multiple steps that we must go through to calculate the Lookback Amounts. In order to make this determination, we must determine (1) the amount of REP settlement benefits the IOUs received from BPA, (2) the amount of REP benefits the IOUs would have received under the REP in the absence of the REP settlements, and (3) the amount that must be returned to the COUs, defined as the Lookback Amount. CUB's assertion that *throughout its testimony* BPA states that the purpose of the Lookback analysis is to determine the benefits residential and small farm customers of regional IOUs would have received under the Residential Exchange in the absence of BPA's 2000 Residential Exchange Settlement Agreements is simply wrong. CUB refers to a statement made in the context of *one step* of the Lookback Analysis (the implementation of the section 7(b)(2) rate test for the FY 2002-2006 and FY 2007-2008 periods) and erroneously elevates it to BPA's ultimate purpose. *See* Doubleday, *et al*., WP-07-E-BPA-60 at 1. In fact, CUB's assertion is not even consistent with its second citation to BPA testimony. Therein BPA staff state that "[t]he FY 2002-2008 Lookback Post-Processor Model determines the level of the PF Exchange Rate for each year of the Lookback period and calculates what the IOUs' REP benefits would have been in the absence of the REP Settlement Agreements. These results are *then used in* the Lookback Study." *See* Brodie, *et al*., WP-07-E-BPA-58 at 15 (emphasis added). Again, the context is one step in a multi-step determination, as we make clear elsewhere in our testimony. *See* Bliven, *et al*., BPA-07-E-BPA-52 at 11-12; Marks, *et al*., BPA-07-E-BPA-62 at 11.

Q. The IOUs argue that the utilities that sold power back to BPA at roughly the same price that BPA charged them, through the so-called 10 percent Load Reduction Agreements (LRAs), in essence surrendered REP settlement benefits they would have received in the form of power and thus received diminished REP settlement benefits. LaBolle, et al., WP-07-E-JP6-08 at 77. The IOUs further argue that the use of the "lesser than" rule in this situation results in an unfair penalty against those utilities that participated in the 10 percent LRAs. Id. Do you agree?

A. BPA has treated the 10 percent LRAs in a manner consistent with its treatment of the LRAs with PacifiCorp and PSE and in the same fashion as it proposes to treat the RL sale to PGE. The amount that is important to the Lookback calculations is the cost of the REP settlements that was improperly included in PF Preference rates charged to the COUs. The fact that the buyback of power from the IOUs at approximately $20/MWh was at a price far less than the market price is irrelevant to the goal of capturing the magnitude of overcharges to the COUs. The COUs were not charged a market price when the PF rate was set – they were charged the purchase price of approximately $20/MWh.

Q. Cowlitz/Clark also argue that BPA limits the amount of reconstructed benefits to the lesser of the reconstructed benefit value or the amount paid under the REP settlements on a year-by-year basis, which does not comply with the 1984 ASCM. Schoenbeck and Beck, WP-07-E-BPA-JP17-01 at 39. Do you agree?

A. No. The 1984 ASCM does not address how BPA is to develop a Lookback Amount. Instead, the 1984 ASCM prescribes how BPA should calculate a utility's ASC for purposes of implementing the REP. In calculating a Lookback Amount, however, BPA must determine the REP settlement benefits received by the IOUs, which involves determining which benefits from which REP settlement contracts should be considered, and how such payments should be reflected in the Lookback Amount. In addition, as previously discussed, BPA must determine what the REP benefits would have been in the absence of the REP settlements in order to establish the Lookback Amount. Calculating the Lookback Amount is the over-arching purpose of the Lookback analysis. BPA will address parties' properly raised legal arguments on this issue in its Draft and Final Records of Decision in this proceeding.

In determining what the IOUs' REP benefits would have been for purposes of calculating the Lookback Amount, we have used the 1984 ASCM. Our use of the 1984 ASCM as part of determining ASCs for the IOUs during the Lookback period is described in detail elsewhere in testimony and such use complies with the substantive provisions of the 1984 ASCM. *See* Boling, *et al.*, WP-07-E-BPA-83. However, whether we appropriately used the 1984 ASCM or not has no bearing on the purpose and rationale supporting the "lesser than" rule, or on our proposal to calculate annual Lookback Amounts instead of a rate period Lookback Amount.

Q. Cowlitz/ Clark state that BPA did not provide the data they needed to calculate all components of the Lookback. Schoenbeck and Beck, WP-07-E-BPA-JP17-01 at 40. In particular, Cowlitz/Clark claim that it is not "possible to calculate an accurate Lookback *amount … from data in BPA's initial proposal[.]" Id. To calculate an accurate Lookback, four elements are needed: the settlement payments, the correct PF Exchange rate giving full effect to section 7(b)(2) for each BPA rate period, ASCs computed pursuant to the 1984 ASCM, and the monthly eligible exchange load for each utility. Id. They claim the only component BPA has calculated in the Supplemental Proposal is the total REP settlement payments. Id. A proper PF Exchange rate cannot be calculated because BPA has notified parties that a new RAM model will be provided. Id. ASCs have not been provided because no filings pursuant to 1984 ASCM have been made. Id. BPA also has not provided the "monthly eligible exchange load for each utility." Id. Please respond.*

A. We disagree with Cowlitz and Clark's characterization of the IOUs' settlement benefits as the only component that we have calculated in our Supplemental Proposal. We have proposed a consistent and integrated approach to calculating the REP benefits the IOUs would have received absent the REP settlements. *See* Marks, et al., WP-07-E-BPA-62.

First, Cowlitz and Clark acknowledge that we have accounted for the REP settlement payments. Second, we have provided the PF Exchange rate for each year of each BPA rate period. *See* Lookback Study Documentation, WP-07-E-BPA-44A at 138 and 935.27. The PF Exchange rates were calculated using the full implementation of the 7(b)(2) rate test using the 1984 7(b)(2) Implementation Methodology with relevant revisions. *See* Doubleday, *et al.*, WP-07-E-BPA-60 at 4. The Supplemental Proposal included the three RAM models we used, which were made available to all parties. The RAM model that we will be providing corrects for a data input error, but does not change the underlying approach to the Lookback analysis.

Third, the fact that the REP was not implemented during FY 2002-2006 does not mean parties are unable to estimate ASCs for the period. Indeed, we included such estimated ASCs, calculated in accordance with the substantive provisions of the 1984

ASCM, in the Supplemental Proposal. *See* Manary, *et al*., WP-07-E-BPA-61 and Boling, et al., WP-07-E-BPA-83.

Fourth, we have also calculated the exchange loads for each utility. *See* Lookback Study Documentation, WP-07-E-BPA-44A at 138 and 935.27. The fact that the REP was not implemented during FY 2002-2006 does not mean parties are unable to estimate exchange loads. It is not necessary to use monthly loads, so BPA used annual exchange loads. *See* Lookback Study, WP-07-E-BPA-44 at 175.

Q. *The OPUC argues that if BPA had carried out its Lookback analysis assuming that BPA had changed its ASC Methodology prior to October 1, 2001, to allow utilities to exchange transmission costs, cost of equity, and taxes, then it is very likely that PGE is entitled to additional residential exchange benefits beyond the $12.98 million owed. Hellman and McGovern, WP-07-E-PU-1 at 17. Do you agree?*

A. We do not disagree with the OPUC that *if* we had assumed the 1984 ASCM would have changed prior to October 1, 2001, *and* the ASCM adopted the cited changes, *then* PGE would likely have higher REP benefits. However, for reasons explained in Section 2.6, we do not believe it is reasonable to use the proposed 2008 ASCM to calculate ASCs for the Lookback analysis. As a minor clarification, we also note that OPUC quotes an FY 2002-2008 Lookback Amount for PGE of $12.98 million when the actual number reported in the Lookback Study Documentation, WP-07-E-BPA-44A at 1042, is $12.57 million in 2007 dollars.

Q. *The OPUC argues that, assuming that retroactive ratemaking is permissible, it is possible for BPA to conclude, using logical assumptions and consistent reasoning, that the Lookback analysis should result in greater Residential Exchange benefits for a utility or utilities and higher rates for public utilities. Hellman and McGovern, WP-07-E-PU-1 at 17. Do you agree?*

A. As we have previously acknowledged, there are numerous ways one might approach the Lookback. It might be theoretically possible that a Lookback analysis could produce the result the OPUC describes, depending on a party's definition of "logical" and "consistent." Such speculation is unnecessary, however, as we have developed a Lookback approach that resolves the purpose of this Supplemental Proceeding - establishing the amount by which the COUs were overcharged during FY 2002-2008 as a result of the unlawful inclusion in the PF rate of REP settlement costs.

Q. The IOUs assert that BPA erroneously assumes the entire cost of REP settlement benefits was included in the PF Preference rate, which has the effect of treating rates other than the PF Preference rate (such as the pre-Subscription FPS rate) as though they were entitled to protection in the section 7(b)(2) rate test. LaBolle, et al., WP-07-E-JP6-08 at 76. Please respond.

A. The IOUs mistakenly broaden our use of the term "rates of COUs." The reference was specifically to the PF Preference rate, not to all rates paid by the COUs. Second, the Supplemental Proposal did not simply assume that all costs of the REP settlement agreement were included in the PF Preference rate. In the Subscription Step, REP settlement costs were allocated to several adjustable rates: the PF Preference rate, the IP rate, and the RL rate. Each of these rates paid their pro rata share of REP settlement costs. Only the PF Exchange rate and the NR rate did not receive allocations of REP settlement costs. Finally, our treatment of the costs of the REP settlement does not equate to protecting all other rates as if they were entitled to section 7(b)(2) rate test protection. As we have stated, each of the rates in the Subscription Step paid their pro rata share of the REP settlement costs. You will note that the FPS rate is not included in this list. Hence those COUs who held a pre-Subscription contract did not cover the costs of the REP settlements. In fact, the rate paid by the pre-Subscription customers was "protected" from quite a few costs due to the collars or formula rates included in the contracts. This shielding from costs is not the same as the rate protection afforded by the section 7(b)(2) rate step.

Section 3.3: The Treatment of the Load Reduction Agreements

Q. CUB argues that BPA's proposed treatment of the LRAs is consistent with the Ninth Circuit's holdings in PGE and Snohomish, but disagrees with BPA's treatment of the Reduction of Risk Discount. Jenks, WP-07-E-CU-1 at 23. Please respond.

A. BPA will address parties' properly raised legal issues regarding the Load Reduction Agreements and the Reduction of Risk Discount in its Draft and Final Records of Decision in this proceeding.

Q. Cowlitz/Clark argue that BPA improperly assumes the 2001 LRAs entered into with PSE and PacifiCorp deserve separate treatment from other settlement payments. Schoenbeck and Beck, WP-07-E-JP17-01 at 38. Cowlitz and Clark argue that the LRAs derive directly from the REP Settlement Agreement and therefore the LRA payments should be treated in the same manner as all other monies paid to the utilities under the REP settlements. Id. Do you agree?

A. No. We stated in our policy testimony that BPA views the LRA payments as valid because the Court dismissed all challenges to the LRAs and did not declare them to be invalid, as it did the 2000 REP Settlement Agreements. Bliven, *et al.,* WP-07-E-BPA-52 at 2-3. However, we understand that our view is not determinative until the Administrator makes his decision based on the record of this proceeding. Therefore, BPA will address the parties' properly raised legal issues associated with these rulings in its Draft and Final Records of Decision in this proceeding.

Q. WPAG argues that these rules of decision regarding the REP Settlement Agreements and the LRAs (protecting the LRA payments and the "lesser than" rule) lack a proper *foundation in ratemaking practice and should be discarded. Grinberg, et al., WP-07-E-WA-05 at 48. Do you agree?*

A. No. First, we are not establishing rates for the FY 2002-2008 period, so evaluating our proposed decision rules on the basis of standard ratemaking practice is inappropriate. Instead, we are determining how best to calculate the REP settlement costs that were improperly charged to BPA's preference customers and how to recover such overcharges and return them to the COUs. Because this goal necessarily involves reviewing the REP settlements that created the misallocated costs, it is quite reasonable that such agreements would be considered in determining overcharges and returning such overcharges to BPA's preference customers.

Second, WPAG is mistaken in asserting that the LRAs have been found "illegal." Although the REP Settlement Agreements were declared inconsistent with the Northwest Power Act, as well as BPA's allocation of REP Settlement Agreement costs to the PF-02 rates, we do not see anything in the Ninth Circuit's decisions that makes a similar finding for the LRAs. BPA will address parties' properly raised issues regarding the lawfulness of BPA's REP settlements, amendments and LRAs in BPA's Draft and Final Records of Decision in this proceeding.

Section 3.4: Treatment of Existing Deemer Balances

Q. Did the IPUC raise any issues regarding BPA's proposed treatment of IOUs' deemer balances?

A. Yes. The IPUC first provides a brief history of the deemer accounts. It notes that the balances stem from the 1981 Residential Purchase and Sale Agreements (RPSA) entered into by three IOUs – Idaho Power, Avista, and NorthWestern Energy. Westerfield, WP-07-E-ID-01 at 11. The IPUC claims that in establishing the REP, the Northwest Power Act did not contemplate the possibility that ASCs for the IOUs could be lower than the PF Exchange rate, but, rather, assumed that the IOUs' ASCs would all be above the PF Exchange rate. *Id.* As a result, the three IOUs entered into 20-year RPSAs in 1981 that included provisions to carry the difference between their lower ASCs and the PF Exchange rate as deemer balances and to not pay REP benefits to the three IOUs until the deemer balances had been satisfied. *Id.*

Q. Do you agree with this overview of the deemer accounts?

A. We note the following points. First, the utilities' ASCs were determined according to the established 1981 and 1984 ASC Methodologies in effect at that time. The PF Exchange rate was determined according to the established ratemaking methodology at that time. A deemer balance accrues whenever the utility's ASC is less than the PF Exchange rate. Whether a deemer balance accrues or not can be calculated by comparing these two numbers.

Second, the deemer account provisions were included in the 1981 RPSAs to deal with situations where a utility's ASC was less than the PF Exchange rate. Such deemer balances would then be reduced during subsequent periods when an IOU's ASC was greater than the PF Exchange rate until the deemer balance was fully repaid. Such deemer balances would accrue interest until fully repaid.

Third, we believe the issue of whether the Northwest Power Act contemplated ASCs being less than the PF Exchange rate is a legal issue. BPA will address parties' properly raised legal issues regarding deemer balances in the Draft and Final Records of Decision in this proceeding.

Q. The IPUC notes that even though the May 2007 decisions did not address deemer accounts, BPA has chosen to include them in the Lookback analysis. Westerfield, WP-07-E-ID-01 at 11. The IPUC argues that inclusion of the deemers constitutes an extreme case of retroactive ratemaking as the deemers arose twenty-seven years ago and *in the case of Idaho Power will adversely affect ratepayers for more than 20 years in the future under BPA' s proposal. Id. Do you agree?*

A. Although we agree that the May 2007 decisions did not specifically address the deemer accounts, it is necessary to take into account the deemer balances to properly calculate the benefits the IOUs would have received over the Lookback period. As noted above, under the traditional implementation of the REP, a utility must exhaust its deemer balance before receiving positive REP benefits. We believe it reasonable and logical to assume that this historical practice would have continued during the Lookback period under the REP in the absence of the REP settlements. It follows that when calculating what amount of REP benefits each utility would have received under a functioning REP, deemer balances must be paid off before positive benefits could flow to the utilities. Absent this assumption, the utilities with deemer balances could receive benefits during a time when, in actuality, they would have received nothing. This would skew the Lookback Amount results, which would be in direct conflict with BPA's overall objective of determining the overcharges to the COUs over the FY 2002-2008 period.

Q. The IPUC notes the results for Avista and Idaho Power from including the deemer balances in the Lookback Analysis. Westerfield, WP-07-E-ID-01 at 12. When the deemer balances are combined with the Lookback amounts, the net result is that Idaho Power's ratepayers receive no benefits over an unacceptable amount of time. Id. The IPUC argues that using the deemers to deprive Idaho's ratepayers of future REP benefits is bad public policy. Id. Do you agree?

A. First, the recognition of deemer balances in the Lookback analysis does not permanently preclude Idaho's ratepayers of prospective REP benefits, although we acknowledge that such benefits are not expected to be provided for some time. More directly, deemer balances have been a longstanding component of the REP. Because deemer balances must be paid off before receiving positive REP benefits, we do not believe considering such balances in the Lookback analysis is bad public policy. We are certainly not "using" the existence of the long-recognized deemer balance of Idaho Power as a way to deprive Idaho's ratepayers of future REP benefits. We are merely following long-standing and established practices of implementing the REP.

Q. The IPUC argues that the deemers are a separate contract matter between the affected IOUs and BPA. Westerfield, WP-07-E-ID-01 at 12-13. Id. The Ninth Circuit did not have the deemer contracts before it, and, thus, including them in the resolution of this proceeding is inappropriate. Id. The May 2007 decisions did not order BPA to fix all past problems, just those associated with the WP-02 rates and the Settlement Agreements. Id. Avista and Idaho Power raise similar concerns, arguing deemers are beyond the scope of this rate proceeding and, therefore, issues regarding the purported deemer accounts should not be addressed. LaBolle, et al., WP-07-E-JP6-08 at 87. How do you respond?

A. We have explained previously why we believe deemer balances must be considered in the Lookback analysis. BPA, however, is not resolving the deemer account balances as part of this proceeding. Our assumptions about the deemer balances are made only for purposes of this Supplemental Proceeding and, in particular, the calculation of the Lookback Amount. Also, we agree that the deemer balances are contract issues to be resolved by the contract parties as part of the implementation of the REP. The reflection of assumed deemer balances in this proceeding is not intended to constitute a final determination of such balances by BPA. We agree that the Ninth Circuit did not have the 1981 RPSAs or other agreements involving deemer balances before it when deciding the *PGE* and *Golden Northwest* cases. Nevertheless, deemer balances are an aspect of the REP and thus, in reviewing the implementation of the REP in the absence of the REP settlements, we cannot ignore them and must make some assumptions regarding the deemer balances for ratemaking purposes. For example, in our reconstruction of REP benefits, we had to assess whether or not an IOU would have signed an RPSA. Given the magnitude of the deemer balances of Avista, Idaho Power and NorthWestern, we assumed that Idaho Power would not have signed an RPSA while Avista and NorthWestern would have. We then proceeded to treat the deemer balances as they would have been treated had these utilities signed, or not signed, the RPSAs.

Finally, should a resolution of the deemer issues occur before the end of this proceeding, we will take such resolution into account in the preparation of the final Supplemental Proposal. Lacking any resolution, we must continue to forecast the disposition of the deemer balances using the best information at hand. At this time, we have chosen to treat the deemer balances as a reduction of REP benefits, either during the Lookback period or going forward for 2009. Should any settlement occur prior to the development of the final Supplemental Proposal, we will take that settlement into account when formulating final studies. If such settlement occurs after this Supplemental Proceeding, BPA expects to reflect the terms of such settlement in the respective IOUs' Lookback Amounts.

Q. The IPUC notes that the affected IOUs dispute the deemer balances. Westerfield, WP-07-E-ID-01 at 13. In addition, IPUC argues there is nothing in section 5 of the Northwest Power Act that authorizes BPA to create deemer accounts or that authorizes BPA to exchange when an IOU's ASC is less than the PF Exchange rate. Id. Please respond.

A. In the direct case, we acknowledged that BPA and the deemer utilities consider the deemer balances a disputed issue. Although section 5(c) of the Northwest Power Act does not address deemer accounts, such accounts have been part of the implementation of the REP and are properly considered in this proceeding. BPA will address parties' properly raised legal arguments regarding deemer issues in BPA's Draft and Final Records of Decision in this proceeding.

Q. *The IPUC notes that the deemers are recorded in BPA's case for each affected IOU by state. Westerfield, WP-07-E-ID-01 at 13. The IPUC argues this presents a problem with regard to Idaho Power's deemer account. Id. Idaho Power's deemer account indicates a separate balance for Idaho, Oregon, and Nevada. Id. In 2001, Idaho Power sold its Nevada operations to Raft River Rural Electric Cooperative to comply with Nevada's electric restructuring law. Id. Thus, there is no way to assess the Idaho Power-Nevada deemer balance to Nevada customers because the opportunity to do so has long passed. Id. How do you respond?*

A. We thank the IPUC for this information. We were unaware of this particular situation. At this time, we take no position on whether Idaho Power's deemer balance should be reduced because of Idaho Power's sale of its Nevada operations to Raft River.

We do note, however, that Idaho Power knows of its deemer obligation and we question why the issue was not raised during the process of selling the Nevada service territory.

Q. *The IPUC argues that the deemers are not generally accepted financial obligations of the affected IOUs from an accounting standpoint. Westerfield, WP-07-E-ID-01 at 13-14. The IPUC notes that neither BPA nor the IOUs have recorded the deemer balances in their books and accounts. Id. The IPUC claims that the reason BPA and the IOUs chose this accounting treatment is because BPA decided that, if the deemed IOUs' loads and resources were included in the Cost of Service Analysis, then the accounting obligation did not have to be recorded. Id. Please respond.*

A. First, how BPA or the IOUs "book" the deemer account balances has no bearing on whether they are legitimate obligations, which is not being determined in this proceeding in any event. Second, even assuming that this discussion is relevant, BPA has specific reasons for not reflecting the deemer balances on its financial books. Among these, as the IPUC notes, is that BPA views the REP as a resource transaction (meaning an actual sale and purchase of power) rather than an accounting (meaning a strictly financial payment) transaction. As such, BPA has no call on the deemer balances unless the resource transaction takes place. If the REP were an accounting transaction, BPA could seek repayment from the IOUs whether or not they participated in the REP. Implicit in this treatment is the recognition that the only avenue BPA has to recover deemer balances is through the reduction of future REP benefits. Also, in this same regard, even though the deemer balances arise through contract provisions between BPA and the IOUs, the recovery of such deemer balances will ultimately flow through to other BPA ratepayers. This relationship holds today for the recovery of deemer balances through the Lookback analysis. The use of REP benefits to recover deemer balances reduces the rates of other BPA ratepayers. In summary, regardless of whether or how the deemer balances are booked, they are a legitimate consideration for BPA in its Lookback analysis.

Q. The IPUC argues that, from an accounting standpoint, deemers are not a legitimate obligation. Westerfield, WP-07-E-ID-01 at 15. As support, the IPUC argues that allowing the recovery in rates of off-the-books transactions is inconsistent with generally accepted ratemaking principles. Id. Do you agree?

A. No. As we have stated, and as the IPUC has cited, the deemer balance is not an accounting transaction. Therefore, “from an accounting standpoint” has no bearing on the resolution of this contractual issue. As the IPUC notes in its testimony, “[r]atemaking is based on the ability to assess the legitimate costs of a utility by examining its books and records.” Westerfield, WP-07-E-ID-01 at 15. In this case, the appropriate records to be examined are BPA’s RSPAs with the deemer IOUs.

Furthermore, we disagree with the IPUC’s contention that only financial transactions recorded on a utility’s books are recoverable through rates. While we are not fully current with the status of IOU retail rates, we know of at least two instances that contradict this premise, one within the state of Idaho. First, the pass-through of REP benefits is not reflected on the books of a number of PNW utilities, as we have determined by an examination of FERC Form No. 1s, including two utilities (Idaho Power and Avista) operating in the state of Idaho. In these instances, the REP components of the utilities' rates are off-book transactions. This appears to be true for four of the six IOUs. A second example is in the state of Oregon, where the Public Purposes Charge is charged to retail customers, but not, to our knowledge, included on the books of Portland General Electric, PacifiCorp or Idaho Power.

Q. The IPUC argues that because the RPSAs state that REP benefits will not be resumed until the deemer balances are satisfied, a party could argue that the deemer balancess no longer existed when BPA provided REP benefits to Avista and Idaho Power under the REP Settlements Agreements. Westerfield, WP-07-E-ID-01 at 16. Moreover, Avista and Idaho Power terminated their RPSAs in 1993, yet the deemer balances continued to grow. Id. Please respond to these arguments.

A. The IPUC's characterization of the RPSAs is imprecise. Section 10 of the 1981 RPSAs states that "[u]pon termination of this agreement, any debit balance in such separate account shall not be a cash obligation of the Utility, but shall be carried forward to apply to any subsequent *exchange* by the Utility for the Jurisdiction under any new or succeeding agreement." The 2000 REP Settlement Agreements were not *exchanges* as BPA explained at page 118 of its REP Settlement Agreement Record of Decision dated October 4, 2000. It is our understanding that the deemer issue was simply deferred in the 2000 REP Settlement Agreements until such time as the REP was again implemented by BPA. Section 9 of the REP Settlement Agreement is directly relevant to this issue: "As a result of entering this Agreement, neither BPA nor Idaho Power Company has prejudiced its right, if any, to assert that a Deemer Account balance, if any, from the 1981-2001 Residential Purchase and Sale Agreement between BPA and Idaho Power Company is required to be carried over to any subsequent agreement offered by BPA pursuant to section 5(c) of P.L. 96-501." To the extent the IPUC is making a legal argument, BPA will address parties' properly raised legal issues regarding the deemer accounts in the Draft and Final Records of Decision in this proceeding.

With respect to the termination of RPSAs in 1993, we note that the deemer balances have increased because they have continued to accrue interest until satisfied.

Q. *The IPUC argues that BPA follows the U. S. Department of Energy's accounting order RA 6120.2 which requires BPA to abide by generally accepted accounting principles. Westerfield, WP-07-E-ID-01 at 16. The IPUC then argues that under these principles there are no exceptions noted or contemplated for recording legitimate regulatory assets on BPA' s books. Id. IPUC claims that BPA cannot have the deemer balances both ways; either the deemer balances are a contractual obligation creating a regulatory asset that appears on BPA' s books, or the unrecorded deemer balances do not represent a regulatory obligation. Id. Do you agree?*

A. No. BPA has already explained that it does not consider accounting treatment for the deemer balances to have any bearing on the legitimacy of the underlying obligation. Whether the deemer balances are valid is a legal issue, not an accounting one. Also, as explained above, BPA has treated the deemer balances as resource transactions, not accounting transactions. Also as explained above, the deemer balances are not cash obligations of the utilities, but an amount that BPA may contractually set off against future REP benefits. As such, BPA can only recover such amounts if the future resource transaction occurs.

Q. *The IPUC notes that the interest that has accrued on the Idaho Power and Avista deemer balances is significant. Westerfield, WP-07-E-ID-01 at 17. Avista's deemer balance was subject to a simple interest computation, which increased its original deemer balance by 2.5 times. Idaho Power's deemer balance was subject to compound interest, and now has a deemer balance that has increased by 4.2 times. IPUC concludes that allowing* *interest to accrue has had a punitive affect on the utilities and their ratepayers, and that there is no justification for the different interest rate treatment between the utilities. Id. at 18-19. Do you agree?*

A. No. Once again, the IPUC is taking issue with the terms of agreements that Avista and Idaho Power agreed to and signed over a decade ago. Because our interest assumptions are based on these agreements, we believe reflecting such interest for purposes of rate case assumptions is reasonable. We note, however, that BPA has already stated that it will consider discussing resolution of the deemer balances outside of the rate case. We believe this response is sufficient for purposes of this rate proceeding.

Q. The IPUC recommends that, for all the reasons identified in their testimony, the deemer balances should not be included in the resolution of this rate proceeding. Westerfield, WP-07-E-ID-01 at 19-20. Do you agree?

A. No. Fundamentally, it comes down to whether or not it is logical to calculate a Lookback Amount without considering the effects of the deemer balances. Ultimately, rate case assumptions must be driven by the known facts. On the one side are IPUC's arguments about the validity of the underlying deemer obligations, which are primarily legal arguments that cannot be decided as part of this process. On the other side is the fact that the RPSAs, which the IOUs signed, included language requiring that deemer balances be paid off before utilities could receive positive benefits; the fact the implementation of the REP enforced this requirement; the fact that the Idaho utilities accrued deemer balances; the fact that those deemer balances still existed during the Lookback period, though they are disputed; and the fact that BPA's prototype RPSA that was offered in 2000 still contained the requirement that the deemer balances be paid off before receiving positive benefits. We believe that the only reasonable assumption to draw from these facts for purposes of this proceeding is that BPA would have required the IOUs to extinguish their deemer balances during the Lookback period. Consequently, we should take into account the deemer balances when calculating the utilities' Lookback Amounts.

As noted previously, BPA is not deciding and resolving the disputed deemer balances in this proceeding. Rather, we fully anticipate that there will be other opportunities to discuss the merits of IPUC's and the IOUs' arguments through other negotiations or processes. However, the deemer balances, even an assumed amount, must be accounted for in the Lookback calculation to ensure that the final results accurately reflect what the REP benefit payments to the IOUs would have been without the REP Settlement Agreements.

Q. *The IPUC argues that given the inability of BPA and Idaho Power to address the deemer balances, Idaho Power ratepayers are penalized for BPA's and Idaho Power's inability to resolve or address the deemer balance account. Westerfield, WP-07-E-ID-01 at 20. The IPUC strongly encourages Idaho Power and BPA to settle their deemer dispute. Id. Do you agree?*

A. We agree that BPA and the utilities should conduct discussions to try to resolve the deemer issues. We have stated BPA's receptivity to engage in such discussions. Should any settlement occur prior to the development of the final Supplemental Proposal, we will take that settlement into account when formulating final studies. If such settlement occurs after this Supplemental Proceeding, BPA expects to reflect the terms of such settlement in the respective IOUs' Lookback Amounts.

Q. *Avista and Idaho assert that, if it is subsequently determined through negotiation or litigation that BPA's claim that deemer balances exist is not legally valid or is excessive, then BPA will have under-collected its revenue requirement. LaBolle, et al., WP-07-E-JP6-08 at 88. The IOUs suggest BPA should assume that deemer balances are not owed, and calculate rates accordingly. Id. Please respond.*

A. We understand that the resolution of deemer disputes through litigation or settlement could occur outside of a rate proceeding. However, just as the assumption of significant deemer balances would understate REP benefits to be paid if such balances were eventually found invalid, it is equally true that an assumption of no deemer balances would overstate REP benefits paid if such balances were subsequently affirmed. The most appropriate assumption at this time is for us to use the REP records to estimate deemer balances and to reflect such balances in the Supplemental Proposal. Once again, the treatment of deemer balances in this proceeding does not establish the validity or amount of such balances for purposes of implementing the REP.

Section 3.5: Treatment of Funds Provided to the IOUs through the C&RD and the CRC

Q. The OPUC notes that in calculating benefits paid to IOUs in the Lookback analysis, BPA included monies provided to IOUs under BPA's Conservation and Renewables Discount Program (C&RD). Hellman and McGovern, WP-07-E-PU-1 at 12. Is this the case?

A. Yes. In the Supplemental Proposal, we included the payments made to the region's IOUs through the C&RD Program for FY 2002-2006, as well as the Conservation Rate Credit program (CRC) for FY 2007-2008, as REP settlement benefits eligible for inclusion in Lookback Amounts.

Q. The OPUC states that BPA counted the conservation and renewables acquired by the IOUs under the C&RD toward meeting BPA's conservation and renewables targets specified by the Northwest Power Council. Hellman and McGovern, WP-07-E-PU-1 at 12. How do you respond?

A. It is true that BPA counted the conservation acquisitions funded by the IOUs through the C&RD and the CRC toward the Council's conservation targets. The Council's target for BPA of 220 aMW for FY 2002-2006 was for conservation acquisitions only and did not include renewable resources. We are not aware of any BPA renewable target specified by the Council. In addition, there were several conservation programs BPA sponsored in order to meet this target. They included conservation augmentation and market transformation as well as the C&RD. BPA's records indicate that 244 aMW of conservation were acquired by BPA during FY 2001-2006 through the C&RD, which was allowed to start in late FY 2001 due to the West Coast energy crisis. The IOUs efforts were responsible for approximately 17 aMW of that total. Hence, the target of 220 aMW would have been met by BPA's activities even without the efforts funded by the C&RD in the IOUs' service territories.

Q. The OPUC states that it is inequitable for BPA to propose to include the monies associated with the C&RD in the Lookback Amount, and yet retain the benefit of counting the IOUs' conservation and renewable acquisitions under this program in BPA's meeting the Council's targets. Hellman and McGovern, WP-07-E-PU-1 at 12. Had the IOU conservation and renewable resources acquired under the C&RD not been available to BPA, then BPA would have acquired conservation and renewables elsewhere to meet the Council's targets. Id. Therefore these costs would have been incurred by BPA absent any REP, or any settlement in lieu thereof, and therefore would be borne by the COUs independent of any REP. Id. Please respond.

A. The OPUC raises some interesting issues with regard to the appropriate treatment of the C&RD monies in the Lookback analysis. First, we understand that the OPUC does not think it is fair to request the C&RD monies be returned by the IOUs while retaining the benefits of such efforts in its reports on targets. Alternatively, the conservation remains regardless of whether or not the monies should be returned to the preference customers.

With regard to BPA's conservation target, given that BPA exceeded the target without counting the savings from the IOUs through the C&RD, there is no evidence that BPA would have increased efforts through its other programs, at the expense of the preference customers, in order to acquire that conservation elsewhere. In addition, the target would not have changed as it was established in a manner independent of assessments of C&RD activity by the IOUs.

In addition, we recognize that the C&RD payments may be viewed as separate from the REP settlement benefits because those monies were used to purchase conservation and did not affect the credit on the bills of the residential and small farm consumers. However, records show that the majority of the expenditures by the IOUs on conservation were for measures in the residential sector. Therefore, it is reasonable to consider the C&RD payments as a "proxy" for REP settlement benefits. Furthermore, in the absence of the REP settlements, it would appear that the C&RD would not have been available to participants in an REP, based on the WP-02 rate schedules. Hence, it is highly likely that the IOUs would have received no C&RD payments under a traditional REP. The WP-02 GRSPs show that the PF Exchange rate was not eligible for the C&RD. In this case, the C&RD payments would be eligible for the Lookback analysis because they would not have been provided in the absence of the REP settlement. These are all reasonable interpretations of the facts surrounding the C&RD. BPA staff recognizes there are alternative approaches to addressing this issue and will give the issue further consideration.

Q. *Did the OPUC offer any evidence for its statement that BPA would have acquired conservation and renewables elsewhere to ensure that it met the Council's target?*

A. No. When asked in Data Request No. AP-PU-2 (Attachment 1) about supporting information on this point in their testimony, the OPUC offered no supporting evidence.

Q. *The OPUC argues that if BPA retains its proposal to include the C&RD as part of the costs of the exchange settlement, and therefore eligible for return in the Lookback, in calculating the costs for a properly administered REP for the Lookback analysis BPA should assume BPA made the same offer of allowing the exchange loads to be eligible for the C&RD. Hellman and McGovern, WP-07-E-PU-1 at 12-13. The OPUC argues that* *given that the Administrator has concluded that the REP should be treated as a firm power sale, BPA could offer the C&RD credit to the REP sales of the IOUs. Id. This policy would promote the acquisition of conservation and renewables within the PNW. Id. The OPUC sees no legal basis that precludes BPA from offering the C&RD to IOUs. Id. Do you agree?*

A. BPA will address parties' properly raised legal issues regarding offering the C&RD program to IOUs in the Draft and Final Records of Decision in this proceeding.

We note, however, that the GRSPs for the WP-02 rates do not list the C&RD as an eligible adjustment to the PF Exchange rate. This would indicate that BPA did not intend to offer the C&RD program to the IOUs under a traditional REP.

Q. The OPUC argues BPA should adjust its Lookback Amount calculations to remove payments made to the IOUs under the C&RD. Hellman and McGovern, WP-07-E-PU-1 at 14. Do you agree?

A. As discussed previously, there are several different perspectives to consider when deciding the proper treatment of the C&RD program and CRC payments provided to the IOUs in establishing the Lookback Amounts. We recognize there are alternative approaches to addressing this issue and we are not taking a position at this time. BPA staff will review the parties' briefs and the entire record before taking such a position.

Q. The OPUC argues that without the exclusions of the C&RD payments and revisions to the ASCM, the aggregate IOU Lookback Amount for the 2002 to 2006 rate period is $516.52 million. Hellman and McGovern, WP-07-E-PU-1 at 14. Including the adjustment to remove the C&RD for the IOUs reduces the Lookback Amounts to $475.37 million. Do you agree?

A. Assuming *arguendo* that the OPUC's argument prevails, then the arithmetic of subtracting $41.14 million in C&RD program payments from the $516.52 million calculated by the OPUC results in their figure of $475.37 million. However, the OPUC has incorporated other assumptions in developing the $516.52 million Lookback Amount. If we were to exclude the C&RD program payments from our Lookback analysis, we would undoubtedly come up with a Lookback Amount different from the $516.52 million because BPA would continue the use of its other rules.

Q. *The OPUC argues PGE's Lookback Amount for the 2002 to 2006 rate period should be $21 million ($21 = $31.74 - $10.74). Hellman and McGovern, WP-07-E-PU-1 at 16. Do you agree?*

A. No. We do not accept the OPUC's approach to calculating the Lookback Amount. For example, it dismisses the "lesser than" rule and uses a different approach to the valuation of PGE's RL power sale. Treatment of the C&RD payments is something that BPA is taking under consideration.

Q. *The OPUC argues that if BPA were to properly calculate the money owed to PGE for the REP for FY 2007-2008, including the Interim Agreement payments, BPA would owe PGE an additional $33.97 million in residential exchange benefits. (-$33.97 = $43.2 + $38.25 - $115.42). Id. Do you agree?*

A. No. The OPUC's analysis regarding the reconstructed REP benefits presumes that the initial Supplemental Proposal is adopted as the Final Proposal. Our analysis shows an amount of REP benefits due to PGE for FY 2008 of $51.6 million before accounting for any interim payments. If the analysis proposed in the initial Supplemental Proposal remains intact in the final Supplemental Proposal, and after accounting for Interim Payments of $43.2 million then the true-up would result in an additional payment of $8.4 million to PGE at the close of this rate proceeding.

Q. *The OPUC argues PGE's net Lookback Amount for the entire 2002 to 2008 time period, assuming PGE executes the Interim Benefits Agreement, is $12.98 million owing to PGE from BPA. Hellman and McGovern, WP-07-E-PU-1 at 17. The OPUC argues that after 2008, PGE will not have a Lookback obligation; rather, BPA will have an obligation to* *provide PGE with an additional $12.98 million in Residential Exchange benefits. Id. Do you agree?*

A. No. Our proposal shows a Lookback Amount for PGE for FY 2002-2007 of $64.13 million in 2007 dollars. This amount is separate from the Interim Agreement PGE signed that will provide PGE benefits for FY 2008 that will not be rolled into the Lookback Amount. If PGE had not signed the Interim Agreement, their Lookback Amount for FY 2002-2008 would be $12.57 million, in 2007 dollars. *See* Lookback Study Documentation, WP-07-E-BPA-44A at 1042. Then, in FY 2009, according to our proposal, PGE will begin to pay off this $64 million Lookback Amount through reduced REP payments. Those reductions would continue, according to our proposal, according to decisions to be made by the Administrator in each subsequent rate period, until this amount is totally amortized, including interest.

Section 3.6: Treatment of PacifiCorp and its Potential Deemer Status

Q. Cowlitz/Clark argue that BPA should calculate and determine deemer balances during the Lookback period just as it did under the 1984 ASCM prior to the REP Settlement Agreements, which has not been done in the case of PacifiCorp. Schoenbeck and Beck, WP-07-E-JP17-01 at 39. Please explain Cowlitz/Clark's argument.

A. Cowlitz/Clark note that PacifiCorp's reconstructed REP benefits vary from $0 in FY 2002 and FY 2003, to positive amounts in FY 2004 and FY 2005, followed by $0 again in FY 2007, as shown in Table 15.8 in the Lookback Study, WP-07-E-BPA-44 at 203. Cowlitz/Clark argue that the benefits PacifiCorp earns should go first to pay off a deemer balance that PacifiCorp would have incurred had it participated in the REP starting in FY 2002. *Id.*

Q. What is your response to Cowlitz/Clark's argument?

A. It would be unreasonable to assume that PacifiCorp would have executed an RPSA in FY 2002-2003 if it would immediately have been put into deemer status. An exchanging utility rationally would only begin the exchange transaction in circumstances where the utility knew or at least believed it highly likely that it would receive positive REP benefits. A more rational assumption is to assume that PacifiCorp would have waited until at least FY 2004 to enter the REP. Thus, BPA does not agree that PacifiCorp's Lookback Amount should accrue a deemer balance for FY 2002-2003.

Once in the REP, however, PacifiCorp could have accrued a deemer balance in FY 2007. In such were the case, PacifiCorp's FY 2008 REP benefits would have to be used to pay down the prior year's deemer balance before reducing PacifiCorp's overall Lookback Amount. Such treatment would be consistent with the treatment of Avista and NorthWestern's deemer balances. If BPA were to adopt this approach, it would result in a slightly higher Lookback Amount for PacifiCorp.

However, adding a deemer balance on top of a total Lookback obligation may overstate PacifiCorp's actual cost contribution to the COUs' rates. Under BPA's proposal, PacifiCorp's Lookback Amount is equal to its total REP settlement payments for the FY 2002-2008 period. If we add a deemer balance on top of this, PacifiCorp would return not only the overpayments it actually received, but also payments it did not receive. This result is contrary to our stated goal of recovering from the IOUs the overpayments that were included in the COUs' rates.

We recognize there are alternative approaches to addressing this issue and we are not taking a position at this time. BPA staff will review the parties' briefs and the entire record before taking a position.

Section 3.7: Lookback Amounts Calculated on an Annual Basis

Q. CUB argues that BPA's position is arbitrary because it totals comparison amounts between the reconstructed world and the settlement world when circumstances benefit the COUs, but does not total the comparison amounts when circumstances benefit the IOUs. Jenks, WP-07-E-CU-1 at 20. Do you agree?

A. No. We total the annual results of the Lookback analysis after each annual result is determined using the rules that BPA proposes, not when it is to the benefit of one party or the detriment of another. We did not establish the procedures of the Lookback analysis simply to benefit the COUs or to cause harm to the IOUs. Our goal was to construct an approach and rules that would replicate, as closely as practicable, the outcomes of ratemaking and REP benefit determinations as they would have occurred had the REP settlements not been implemented in order to calculate the overcharges to the COUs in a technically and legally defensible manner.

Q. The OPUC argues that it is appropriate to carry out the analysis on an aggregate basis over the five-year-rate period. Hellman and McGovern, WP-07-E-PU-1 at 9. Whether a party is overcharged or not should be viewed as an overall rate period question. Id. During the rate period, there may be times when customers are overcharged and at other times undercharged. Id. What matters is whether rates are just and reasonable in the context of the rate period as a whole. Id. Do you agree?

A. No. BPA constructed its Lookback analysis to mimic the way that an actual REP would have been implemented as a proxy for calculating the amount by which the PF Preference rate was set too high due to the REP settlements. In the Lookback analysis, we are not setting rates that will be used on power bills. Therefore, the OPUC's arguments regarding rate levels and rate periods are not relevant to this situation. Because the PF Exchange rate was subject to the CRACs and DDC, an annual calculation of the reconstructed REP benefits was necessary. Also, the utilities' backcast ASCs varied significantly over the five years, which would have been reflected in the implementation of an REP. The OPUC seems to be arguing for the reconstructed benefits to be calculated based on an average PF Exchange rate, an average ASC for each utility, and then perhaps multiplying the difference by a five-year total of exchange loads. We believe that our approach is more reflective of how an REP would have been implemented over the five years. *See* Bliven, *et al.,* WP-07-E-BPA-52. If BPA were to adopt the OPUC's approach, the COUs would be under-compensated for their years of overcharges for the REP settlements.

Section 3.8 Calculations of Lookback Amounts and Interest

Section 3.8.1 Calculations of Lookback Amounts

Q. Various parties (APAC, OPUC, WPAG) have asserted a variety of calculations of Lookback Amounts based on their respective proposals regarding the assumptions that affect such calculations. Wolverton, WP-07-E-AP-1 at 6 and Attachment 6; Hellman and McGovern, WP-07-E-PU-1 at 15-16; Saleba, et al., WP-07-E-WPAG-05 at 50. Please respond.

A. It is true that various parties have their own proposals regarding the appropriate assumptions or approach to calculating Lookback Amounts. These issues, such as treatment of the LRAs, the "lesser than" rule and deemer balances have all been addressed elsewhere in this testimony and we will not repeat those arguments here. We do not need to dispute the calculations that the parties put forward, because they are the application of their respective positions on a variety of issues. But we have different positions on nearly all of the assumptions or factors that affect such calculations. Suffice it to say that our Lookback Amounts are different from those proposed by the parties. We will properly recalculate the Lookback Amounts in the final Supplemental Proposal incorporating the Administrator's decisions on all issues posed by each of the parties.

Section 3.8.2 Approach to Applying and Calculating Interest

Section 3.8.2.1 Application of Interest is Appropriate

Q. APAC asserts that the correct Lookback Amount is $2.2 billion. WP-07-E-AP-1 at 84. Setting aside for the moment the magnitude of the number which greatly exceeds BPA's proposed $620 million Lookback Amount, do you agree with the computational methods used to arrive at this number?

A. No, we believe there is an error in the way the nominal Lookback Amounts on the line labeled "Difference in Nominal Dollars" on attachment AP-6 are escalated.

Q. Please explain.

A. The error resides on the line labeled "Carrying Charge Factor." We believe each amount starting with the 1.205 amount under the year 2002, is overstated by the factor 1.0178 which comes from the first interest rate input under 2002 on the line labeled "Appropriate Interest Rates."

Here is how the 1.205 is computed in Attachment AP-6 to WP-07-E-AP-1. It is the product the following seven factors:

(1.0178)*(1.0114)*(1.0112)*(1.0275)*(1.0457)*(1.0486)*(1.0278)

These factors are each computed by taking 1 plus the interest rate in the given year. The 1.205 factor is multiplied times the Difference in Nominal dollars in 2002, $349.63, to get the Lookback Amount Contribution, $421.44. This is purported to be the equivalent amount in 2009 dollars.

However, standard escalation procedure assumes that the $349.63 dollar amount for FY 2002 has already earned the amount of the escalation factor, 1.78%; that is the 2002 dollar amount is presumed to have been received at the end of 2002. Therefore to reapply the 1.78% interest rate to this amount is double counting.

Therefore the appropriate factor should be 1.184, which is the product of:

(1.0114)*(1.0112)*(1.0275)*(1.0457)*(1.0486)*(1.0278).

Q. Do you have an example of how this technique is used in the financial community to escalate dollars from nominal dollars into escalated dollars?

A. Yes. Below is a table of the historical change in the CPI from 1997 through 2007. The CPI data in column A are taken from the following website:

http://www.inflationdata.com/inflation/Consumer_Price_Index/HistoricalCPI.aspx.

And the data in column B are taken from:

http://inflationdata.com/inflation/Inflation_Rate/CurrentInflation.asp

	Historical CPI A	**% Change** B	**1+ % Change** C	**Recalc** D
2007	207.340	2.85%	1.028	207.340
2006	201.600	3.23%	1.032	201.600
2005	195.300	3.39%	1.034	195.300
2004	188.900	2.69%	1.027	188.900
2003	183.960	2.27%	1.023	183.960
2002	179.880	1.57%	1.016	179.880
2001	177.100	2.85%	1.028	177.100
2000	172.200	3.36%	1.034	172.200
1999	166.600	2.21%	1.022	166.600
1998	163.000	1.56%	1.016	163.000
1997	160.500	0.00%	1.0000	160.500

In this table we have copied from the first website the actual CPI index data in column A, and from the second website, the annual changes in the CPI index in column B. We then add one to the percentage in column B to fill column C. We then recalculate the numbers (in column A) in column D, by multiplying 160.5 by each number in column C, starting in 1998. If 160.5 was in millions of dollars and the percentages in column B were inflation (or interest) rates, then to get the 1997 amount of $160.5 million to the equivalent in 2007 dollars we start the escalation with the inflation (interest) rate in 1998, not 1997. As another example this holds if we started in 1998 with $163.0 million. We multiply this number by all the factors in column C, starting with 1999, not 1998 to get the appropriate amount in 2007 (dollars).

Q. *When this correction is made to the escalation assumption used in Attachment AP-6, what dollar difference does it make?*

A. Assuming APAC's nominal dollar Lookback Amount of $1.889 billion, it reduces the escalated Lookback Amount by about $54 million.

Q. *APAC asserts that BPA's Lookback proposal ignores the time value of money. Wolverton, WP-07-E- AP-1 at 9. Do you agree?*

A. No.

Q. *Please explain.*

A. The notion of the time value of money is common in finance and economics. Without restating the financial theory here, the time value of money is generally stated in terms of an interest rate, or series of interest rates, each of which consists of two components, an inflation component and a real interest component. For the period between 2002 and 2007, BPA took into account the inflation component of the time value of money when it escalated the 2002 through 2007 Lookback Amounts from nominal dollars to 2007 dollars, using the average rate of inflation for each year starting in FY 2002. In the Lookforward analysis, we considered both components of the time value of money when it proposed using a twenty-year U.S. Treasury Bond average daily interest rate to accumulate interest on the unamortized Lookback amounts.

Q. *What was the source used to determine the average rates of inflation between years 2002 and 2007?*

A. As stated in Marks, *et al.*, WP-07-E-BPA-62 at 10, the inflation rate used was the Gross National Product (GDP) deflator available from the U.S. Department of Commerce. We used an estimate for 2007.

Q. *The IPUC notes that BPA's Lookback Analysis proposes to charge interest on the Lookback amounts calculated for each IOU. Westerfield, WP-07-E-ID-1 at 3. The IPUC argues that although retroactive ratemaking is bad public policy, retroactive ratemaking plus interest is even worse public policy. Additionally, including interest on the Lookback amounts raises the issue of whether future REP benefits should be applied first to the interest or first to the principal. Absent elimination of the Lookback mechanism all together, applying the REP benefits first to the principal is a fairer solution because it reduces future interest. Do you agree?*

A. First, we have addressed retroactive ratemaking earlier in our testimony. Second, it is our understanding that adjusting refunds to take into account the time value of money is not unheard of in the utility industry. In fact, it is our understanding that FERC and the utility commissions themselves regularly allow this policy as part of a refund. Because BPA is, in effect, providing a refund of overcharges to the COUs, it makes sense to us to include in that refund a component that recognizes the time value of money.

We recognize the unique circumstances that have led to the present overcharges. That is why we are adjusting the Lookback Amounts for the IOUs from 2002-2006 only for inflation. Thereafter, once the Lookback Amount is known, we believe using an interest adjustment (as opposed to just an inflation adjustment) is reasonable to ensure that the value of the repayment owed to the COUs is not degraded by the passage of time. If interest is not included, then the COUs' refund amounts would be constantly diminishing in value each year that it remains unpaid in full. Such a result would undermine our overall proposal to recover the overpayments over time from the IOUs through future reduction in REP benefits. Under these circumstances, BPA would have to seriously consider other more immediate methods of collecting these overpayments from the IOUs.

Q. What is your response to the IPUC's recommendation that BPA apply the set off payments first to the principle and then to the interest? Westerfield, WP-07-E_BPA-07-ID-1 at 3.

A. This only works when computing simple interest. As a matter of policy, we are proposing compound interest. Separating principal from interest and paying them separately by selecting one or the other component of the Lookback Amount balance for initial payment, increases the total amortization (principal plus interest) over what it would be if the combined principal and interest balance is paid.

Q. WPAG states that BPA has failed to accrue interest on the amounts it has determined that the individual IOUs were overpaid from the date of the overpayments commenced. Grinberg, et al., WP-07-E-WA-05 at 49. As a consequence, the amount the BPA has proposed be repaid to the preference customers will lose value from October 2002 through October 2008. Id. WPAG recommends that BPA use a published 5-year T-bill rate based on the period of overpayment to calculate the compounded interest owed to the PF customers, which would replace the inflation adjustment proposed by BPA. Id. Do you agree?

A. WPAG is correct in stating that we did not apply an interest rate to the Lookback Amounts, and that we used an annual inflation rate to escalate nominal Lookback Amount dollars into 2007 dollars. However, we do not agree that this will cause the preference customers to lose value from October 2002 through 2008. After careful consideration, we proposed to use an annual average inflation rate to escalate the Lookback Amounts into real 2007 dollars from nominal 2002–2006 dollars because we believed that this retains the value of the Lookback Amounts for the COUs. BPA will address properly raised legal issues regarding the application of an interest rate to the Lookback Amount in the Draft and Final Records of Decision in this proceeding.

Section 3.8.2.2 Interest Rates Applied are Appropriate

Q. *WPAG argues that BPA should replace the inflation adjustment proposed by BPA with a published 5-year T-bill rate based on the period of overpayment to calculate the compounded interest owed to the PF customers. Grinberg, et al., WP-07-E-WA-05 at 49. In addition, APAC states that the Preference Customers are due a rate of prejudgment interest equal to the return or yield on U.S. government securities. Wolverton, WP-07-E-AP-2 at 20. Using a prejudgment interest rate equal to the rate of inflation as proposed by BPA does not compensate the Preference Customers for the loss of the use of the money that they overpaid. Id. Do you agree?*

A. No. Our proposal to use an inflation rate for the 2002-2006 period was influenced by the unique set of circumstances which created the present situation. BPA and the IOUs operated under the REP Settlement Agreements for almost seven years before the agreements were found unlawful. Neither BPA nor the IOUs could have foreseen how long it would take for the challenges to the REP Settlement Agreements to be ultimately decided. During this period, both parties met their respective obligations in the agreements in the good faith belief that the payments were appropriate. BPA does not consider it either fair or reasonable to penalize the IOUs now, seven years after the fact, for complying with the contract by charging them a market-based interest rate for any overpayments.

In addition, we do not believe it reasonable to charge a market based interest rate before the amount of the overpayment is known. It is one thing to require a party to return an overpayment, with full interest, where the party knew or reasonably could have known it was being overpaid. In these instances, the recipient of the payment is culpable because they had a duty to notify the payer of the overpayment. It is quite another thing, though, where as here, the existence of an overpayment and the amount of the overpayment is unknown, and in this instance, will not be known until BPA completes this massive administrative proceeding. In these instances, the policy rationale for requiring a party to pay a market-based interest rate is just not present. This is particularly the case where, as here, the IOUs will not know how much they were overpaid until BPA issues the final Record of Decision.

This is not to say, though, that the COUs should receive no interest for the 2002-2006 period. Indeed, we believe that the COUs' refund amounts should be adjusted to reflect the passage of time after they have been determined. In considering what interest rate to propose, we consider it a reasonable policy position to choose a rate that only preserves the value of the refund amount through the 2002-2006 period rather than to enhance it as APAC suggests. In adopting this proposal, we note that we are unaware of any specific rule or provision that would require BPA to provide the rate of interest APAC requests.

In the absence of such direction, we believe that a reasonable alternative is to recommend an inflation rate that preserves the value of the COU's refund amounts until they are finally determined. This approach ensures that the value of the COU's refund is not degraded by inflationary pressures, but does so in a neutral non-prejudicial fashion that recognizes the special circumstances that led to the present overpayments.

Q. *APAC argues that the function of the carrying charge is to bring forth to May 2007 the estimated overpayments using an interest rate that is consistent with the risks in the underlying cash flows. Villadsen and Wolverton, WP-07-E-AP-2 at 7. Whatever the dispute may be about the amount of the overcharge, once the amount of annual* *overpayments is established the annual cash flows are known and the relevant pre-judgment interest rate should be consistent with the rate on a government-issued security. Id. APAC then goes on to argue that the best estimate of the pre-judgment interest rate is the yield on 3-month T-bills. Id. Do you agree?*

A. We agree with the above statement in theory; that once the amount of cash flow is known, a risk free rate of interest is appropriate. We also agree that it is appropriate to bring the dollar value of the Lookback Amounts up to 2007 dollars. But, as stated above, we do not agree that an interest rate is appropriate here. As stated above, an interest rate contains the two components, an inflation component and a real rate component. In our view it is sufficient to use only the inflationary component of such a rate to make the COUs whole

Q. For the Lookforward analysis, what was the interest rate you proposed and how did you arrive at it?

A. As stated in Marks, *et al.*, WP-07-E-BPA-62 at 17, we proposed a rate of 5.03%, which is the daily average of all daily twenty year T-bill rates starting with October, 1, 2001 and going through September 30, 2007.

Q. What was the data source for these rates and how was the average computed?

A. The daily rates are available on line from the U.S. Treasury at the following link: www.treasury.gov/offices/domestic-finance/debt-management/interest-rate/yield_historical_main.shtml. The average computed was a simple arithmetic average of the 1,506 daily data points.

Q. Why did BPA pick a twenty year U.S. Treasury Bond rate?

A. As stated in Marks, *et al.*, WP-07-E-BPA-62 at 17, it is a neutral rate that does not give advantage to either the COUs or the IOUs. It also reflects the potential Lookback Amount amortization period of up to 20 years.

Q. Did APAC disagree with BPA's interest rate choice?

A. Yes.

Q. What, in APAC's assessment, would be a more appropriate interest rate to apply?

A. APAC claims that a more appropriate interest rate to apply going forward would be one equal to the the typical cost of equity for an integrated electrical utility, which, APAC asserts ranges between 11.25% and 11.75%. Villadsen and Wolverton, WP-07-E-AP-2 at 18. These rates average out to 11.5%, which is the rate proposed by APAC. Wolverton, WP-07-E-AP-1 at 84.

Q. Does BPA take issue with how the 11.5% was calculated?

A. No. The approach taken by APAC seems reasonable. However, we believe that it is completely irrelevant to our current proposal.

Q. Why is it irrelevant?

A. APAC's interest proposal stems from its view that the COU's right to repayment from BPA is similar to the relationship that equity shareholders have in a private company. It states that the risks of repayment are based on the uncertainties of the section 7(b)(2) rate test in any year and that this *is a highly speculative risk, greater than that faced by equity shareholders*. *See* Wolverton, WP-07-E-AP-1 at 84, emphasis added. APAC also argues that the Preference Customers receive payment only after all of BPA's other costs have been covered (including interest) and after the allocation of a preset amount of REP benefits to the relevant IOUs. Such a residual claimant's position is usually held by equity holders and requires an equity-type return. Villadsen and Wolverton, WP-07-E-AP-2 at 11.

BPA does not agree with APAC's contentions that the risk faced by the COUs is equal to the risk an equity owner of an integrated electric utility faces. We believe that the risk factor is a great deal less than this risk.

Q. Please explain.

A. First, APAC's statement that Preference Customers receive payment only after all of BPA's other costs have been covered (including interest) and after the allocation of a preset amount of REP benefits to the relevant IOUs is categorically untrue. Our proposal is not to collect money from the COUs and then repay them if there are sufficient funds. The COUs get their repayment through rate reductions, which put them in a priority position over all of BPA's operating costs and debt service requirements, including Energy Northwest bond holders. Realizing the repayments through rate reduction means the COUs receive the repayment before they even pay their BPA power bill.

Further, APAC also mischaracterizes the risk faced by the COUs as the same risk faced by equity shareholders in a privately held company.

Q. Why is comparing the COUs to equity shareholders of a privately held company a mischaracterization?

A. Equity owners of a privately held company, by the very definition of the term, have made monetary investments in a company; and these investments depend on two aspects of equity ownership to generate a return: (1) appreciation of their stock's value through increasing share price; and (2) a cash return in the form of a cash dividend distribution from that company. Neither one of these aspects applies to the COUs. First, BPA is part of the United States government, and as such, has no stock to sell to the COUs to make them equity investors. Therefore, comparing the COU's return risk profile to that of an equity investor's return is completely inapposite.

The second aspect is possibly more relevant to the instant case. We infer that the comparison APAC is attempting to make between COUs and equity shareholders is with the dividend payout shareholders may receive from time to time. In theory, equity holders must wait until the company has paid out all of its operating expenses and debt service costs to get a dividend distribution. This concept of equity holders being last in line is correctly stated by APAC. Here, however, is where APAC's comparison breaks down. Unlike equity shareholders, the COUs are *not last* in line to get their payment; rather they are *first* in line. The COUs will get their repayment through a reduction in their power rates. This shows that the COUs are in a much better position to be paid than an equity shareholder.

To summarize, we completely disagree with the notion that the COUs are entitled to an interest rate that is based on an equity shareholder relationship. As we've noted, the COUs stand in a completely different risk posture than that of a typical shareholder of a private company. Characterizing the COUs in such a position, in our opinion, is a plain mischaracterization.

Q. Is there some risk, though, that the COUs will not get the full value of the Lookback Amount repaid to them?

A. Yes. Our proposal makes no guarantee that the COUs will get their full payout over twenty years. This issue of guaranteed repayment is discussed at length later in this testimony.

Q. Given that the COUs will experience some risk of non-payment, is it reasonable to apply a risk-free interest rate on the Lookback balances going forward?

A. While we have stated reasons for proposing a risk free rate in the Supplemental Proposal, we will consider APAC's arguments concerning using a risk adjusted rate of interest. We will consider this issue and make a proposal to the Administrator based on the complete record of this proceeding.

Q. APAC states that full compensation requires that the carrying charge reflect the time value of money and the risk of the repayment cash flows. If the carrying charge is too low, the present value of the repayments will be less than the present value of the overpayments. Villadsen and Wolverton, WP 07 E AP 2 at 21. How do you respond?

A. We agree in concept that the nominal dollar Lookback Amounts should be escalated to escalate them to current dollars, and that going forward, repayment of the Lookback Amounts should come at some reasonable rate of interest that reflects the risk of their recovery. As stated previously in this testimony, we proposed a reasonable rate to escalate the Lookback Amounts into current dollars – that is the average annual rate of inflation for these years – and then another reasonable rate going forward – that is a twenty-year T-bill rate. As we stated, this rate is a neutral rate that shows no bias to either the COUs or the IOUs. *See* Marks, *et al.*, WP-07-E-BPA-62 at 17. Because the twenty-year T-bill rate proposed is a risk free rate, and because we will consider APAC's argument that this proposal is not risk free, we will consider whether it be reasonable to add a risk premium to our going-forward interest rate to compensate the COUs for the risk they face of not fully recovering their overpayments after 2008.

Q. Having said that you will consider a risk premium, what might that be?

A. If we were to propose a risk premium, we would consider a rate approaching the one proposed by APAC, which averages out at around 7.5%, to be close to right. *See* Villadsen and Wolverton, WP-07-E-AP-2 at 19. That would be a risk premium of about 250 basis points over our currently proposed rate.

Q. How did APAC arrive at that rate, and what, if anything, does their reasoning tell you about how high the risk premium should go?

A. APAC argued that this was an appropriate rate if the Preference Customers receive compensation for damages ahead of payments for the REP. *Id.* at 18. Based on this assessment, we consider 250 basis points to be the upward bound on any risk premium we might propose to add to our post-2008 Lookback balance interest rate.

Section 4: Recovery and Return of Lookback Amounts

Section 4.1: General Approach

Q. The IPUC argues that because the IOUs involved in the REP simply pass through the benefits to their retail ratepayers, ratepayers bear the entire brunt of the retroactive ratemaking treatment proposed in the Lookback Analysis through reduced future REP benefits. Westerfield, WP-07-E-ID-01 at 9. The IPUC notes that the impact of reduced *future REP benefits is significant. Id. Although PacifiCorp and Avista will still be eligible for REP benefits pursuant to the calculations in the Lookback Analysis, these benefits are reduced to reflect the difference between benefits received and benefits that would have been received using the 1984 ASCM. Id. Thus, using the Lookback Analysis harms their current and future residential and small farm ratepayers through reduced benefits. Id. Do you agree?*

A. We agree that the residential consumers of the IOUs are those who will ultimately "bear the entire brunt" of the application of the Lookback Amounts to reduce future REP benefits paid. We also agree that the impact may be significant. Nonetheless, we believe determining Lookback Amounts and recovering them by reducing future REP benefits paid to IOUs' residential consumers is the best course of action. But agreeing the residential consumers of the IOUs may bear a significant future burden is not the same as agreeing that it is inappropriate for them to bear that burden. To the extent the benefits paid under the REP settlements exceeded the reconstructed REP benefits, we believe that the appropriate response is to recover, to the extent possible, the overpayments and return these amounts to the COUs.

The benefits of the REP settlements accrued to the residential and small farm consumers of the IOUs. Using the information and assumptions provided by CUB regarding PGE (Jenks, WP-07-E-BPA-1 at 15), our proposal would result in approximately 90 percent of PGE's FY 2002 ratepayers who received the overpayments now experiencing a lower REP payment in 2009, and approximately 70 percent experiencing reduced REP benefit payments in FY 2018 – which is past the time that we expect PGE's Lookback Amount to be repaid. So, for PGE at least, there is a reasonably good match between past and future ratepayers. Recovering the excess benefits by reductions in future benefits to residential and small farm customers thus serves to recover the overpayments generally from those who received them. This approach is preferable to available alternatives.

In addition, our approach meets the objectives outlined in Bliven, *et al*., WP-07-E-BPA-52 at 21 – particularly the third, fourth, and sixth objectives. Furthermore, as outlined in the seventh objective (*id*. at 21-22), an approach that requires a more exact match between residential ratepayers receiving the overpayments and those returning the Lookback Amounts would make it more difficult to adapt our proposal to the COU/IOU Recommendations. *See* Bliven., *et al*., WP-07-E-BPA-52 at 26-27. We acknowledge such Recommendations are not binding upon BPA.

Finally, we note to the extent there is a concern with the mismatch between past consumers who received the overpayments and future consumers who will repay the overpayments, it is the state commissions who are in the best position to minimize this mismatch. The fastest BPA could recover the overpayments would be through the elimination of REP benefits until the Lookback Amounts are repaid. The state commission could accelerate the return beyond BPA's ability. They have it in their power to increase residential rates to repay the Lookback Amounts in as short a time as they desire. However, we believe this would be an odious option to the commissions, which makes our point. Trying to find the balance between faster repayment and smaller burdens is not a welcome task. Given that BPA has fewer tools available to it than the state commissions; we believe our proposal balances these interests well.

Q. The IPUC notes that under BPA's proposal, Idaho Power has a Lookback balance (not including deemers) of approximately $95.6 million, and will receive no REP benefits for approximately ten years. Westerfield, WP-07-E-ID-01 at 10. Idaho Power is the only IOU in this situation. Id. The IPUC argues that precluding benefits for Idaho Power is not an acceptable solution for the region. Id. It also notes that the Northwest Power Act contemplated the distribution of REP benefits throughout the Northwest region – not the *skipping over of a substantial number of ratepayers or the skipping over of the majority of IOU customers in the state of Idaho. Id. It concludes that the Lookback Analysis proposes a punitive solution to Idaho ratepayers of all three IOUs, but particularly punitive to Idaho Power's ratepayers. Id. Do you agree?*

A. No. The IPUC appears to assume that we are proposing that all of the eligible REP benefits first go to extinguish an IOU's Lookback Amount before any benefits are provided to residential consumers. We base this conclusion on the fact that, under our proposal, and setting aside the deemer balance issue, Idaho Power's Lookback Amount of $96.6 million divided by its FY 2009 REP benefits of $9.2 million roughly equates to 10 years, before interest. (The IPUC's cited amount of $95.6 million, Westerfield, WP-07-E-ID-1 at 22, seems to be in error.) Although repaying the Lookback Amounts prior to receiving any REP benefits is one approach, it is not the approach we propose. Our proposal calls for attempting to balance the competing goals of continuing to provide some level of benefits to eligible consumers while recovering, to the extent possible, Lookback Amounts from the IOUs over a reasonable period of time. *See* Bliven, *et al*., WP-07-E-BPA-52 at 21-22. Under our proposal, if not for the deemer balance, Idaho Power's residential and small farm consumers could receive REP benefits as early as FY 2009.

In addition, and again setting aside the deemer issue, IPUC's claim that Idaho will not receive REP benefits for ten years is based on assumptions regarding Idaho Power's REP benefits beyond FY 2009 that may or may not occur. Idaho Power's REP benefit levels will be determined by its future ASCs, exchange loads and PF Exchange rates – all of which are unknown at this time. Thus, it cannot be stated for certain that Idaho Power will not receive any REP benefits for the next decade even if BPA adopted an approach whereby all REP benefits first go to extinguish an IOU's Lookback balance.

Regarding IPUC's assertion that the Northwest Power Act contemplated a wide distribution of the REP benefit levels, we note that Congress' intent for the REP is a legal issue. BPA will address parties' properly raised legal issues regarding the distribution of REP benefits in the Draft and Final Records of Decision in this proceeding. We note, however, that Idaho Power last qualified for REP benefits in 1985 and Avista last qualified for REP benefits in 1983. Therefore, during the past 20 plus years (and ignoring the REP settlements), residential consumers in the state of Idaho did not receive REP benefits. Hence, our Lookback approach is no more punitive to Idaho's residential customers than what might otherwise have transpired.

Nonetheless, we believe that a wider overall distribution of REP benefits can be achieved consistent with the law. For example, we are proposing a new section 7(b)(3) allocation method that increases the likelihood that utilities with lower ASCs, such as Avista and Idaho Power, will receive REP benefits. The Supplemental Proposal includes an affirmative step to distributing the REP benefits as widely as possible in a manner consistent with the law. *See* Fisher, *et al.*, WP-07-E-BPA-69.

Finally, we do not agree that our proposed Lookback analysis is "punitive" to Idaho's residential consumers. If our Lookback analysis determines that exchanging Idaho utilities and their residential consumers were overpaid REP benefits, then we do not believe it is punitive to require those same utilities and, to a reasonable extent, the same consumers, to return the overpayments. Indeed, our proposal is particularly reasonable because it proposes to reduce future REP benefits paid rather than to seek immediate repayments from the IOUs.

Q. CUB argues that BPA's proposal is contrary to the policy goal and intent of the Northwest Power Act. Jenks, WP-07-E-CU-1 at 14. CUB argues that the Lookback fails to acknowledge that Residential Exchange benefits go to actual customers. Jenks, WP-07-E-CU-1 at 15. Do you agree?

A. BPA will address parties' properly raised legal issues regarding the intent of Congress in the Draft and Final Records of Decision in this proceeding. Far from ignoring the fact that the benefits of the REP go to actual residential and small farm customers, our proposal expressly recognizes this fact. We propose to recover any overpayments by reducing the amount of future REP benefits paid to IOUs – benefits that contractually and statutorily must be passed on to eligible end-consumers.

Section 4.2: Repayment Period and Intergenerational Equity

Q. CUB argues that the set of customers who would be repaying this alleged overpayment 20 years from now will be vastly different than the set of customers who received the alleged overpayment several years ago. Jenks, WP-07-E-CU-1 at 15. Customers who move into PGE's territory this year should have the expectation, and the assurance, that they will receive the Residential Exchange benefits that they are entitled to under the Northwest Power Act. Id. Do you agree?

A. No. The fact that REP benefits go to the residential consumers of the IOUs was paramount in the construction of our Lookback proposal. We recognize that the IOUs did not keep the monies paid under the REP settlements, but passed them on to residential consumers. This is the reason we structured the recovery of the Lookback Amounts through a reduction of future REP benefits paid rather than seeking repayment directly from the IOUs. Given that the IOUs do not have the monies paid under the REP settlements, we believe the reduction of future REP benefits paid is the most feasible and equitable way to recover the Lookback Amounts from those who generally received the overpayments.

We understand that those future consumers whose REP payments are reduced in order to return the Lookback Amount are not necessarily the exact same consumers as those who received the past REP settlement benefits. However, reducing future REP payments over a longer period of time was one of the few mechanisms available to us that could return overcharges to the COUs while minimizing the effects on current residential customers. We could have chosen a faster recovery of Lookback Amounts, such as suggested by some parties in this proceeding, in order to minimize the so-called mismatch between those who received the Lookback Amounts and those who will receive reduced REP benefits paid as BPA recovers the Lookback Amounts. However, we chose to maintain a relatively stable level of benefits over time rather than zero the benefits for a shorter period of time. Furthermore, in FY 2009, and using the information provided by CUB about PGE (*see* Jenks, WP-07-E-CU-11 at 15-16), our proposal results in approximately 90 percent of the ratepayers who were PGE residential customers in FY 2002 receiving lower benefits in FY 2009. Even 10 years later, when most of the Lookback Amount for most of the IOUs could be repaid, a full 70 percent of PGE's FY 2002 residential customers would be those seeing reduced REP payments. Obviously, for IOUs that are growing more slowly, there is a better match between those ratepayers who received the overpayments and those experiencing the future reductions. Conveniently, Puget Sound Energy, the fastest growing IOU, is also the IOU that repays its Lookback Amount fastest – and it is the second largest Lookback Amount.

Q. CUB notes that new customers did not receive any of the alleged REP overpayments between 2002-2007, but would have their REP benefits cut to make up for someone else's alleged overpayment. Jenks, WP-07-E-CU-1 at 15. Do you agree?

A. We understand there may be consumers who will receive lower REP benefits paid in the future even though they did not receive the previous overpayments. We, however, are unable to ensure that those consumers who received the overpayments are the same consumers that provide the repayments. Ultimately, we believe that BPA is not required to make such a showing for purposes of this proceeding. BPA's business relationship is with BPA's customers, the IOUs, not with the end-use consumers of the IOUs.

Ultimately, it will be up to the IOUs and the state commissions to decide how to spread the REP benefits to residential customers in the future. The IOUs, not BPA, have the information on which residential customers received REP settlement benefits, how much a given residential customer received, and whether or not a residential customer at some period in the future was also a customer that received past REP settlement benefits. Thus, the IOUs and the state commissions, not BPA, arguably have the information and authority to fashion a remedy to mitigate, at least to some degree, the intergenerational equity impacts on residential and small farm customers of the IOUs.

Q. Cowlitz/Clark argue that BPA's proposal to pay off the Lookback Amount in 20 years or less is too long. Schoenbeck and Beck, WP-07-E-JP17-01 at 41. Cowlitz/Clark do not agree with this method because it introduces "intercustomer equity" issues for both IOU and COU customers. Id. The longer the payments are stretched out, the less of the refunds will be made to the consumers who were overcharged, and the less will be paid by those who received the overpayment. Id. The better approach is to recover and payback the Lookback amount as quickly as possible. Id. Cowlitz and Clark recommend as a starting point that seven years be the payback period. Id. If this is insufficient, then the IOUs should supply the remaining amounts owed. Id. Do you agree?

A. We generally agree that "intercustomer" (and intergenerational) impacts are likely to exist for both IOU and COU consumers as a result of our Lookback approach. These issues, however, are not literally "introduced" by our proposal. These issues exist to a greater or lesser degree under any approach available to BPA to recover overpayments from the IOUs and return them to COUs. We acknowledge that shorter repayment periods mitigate the intergenerational issues Cowlitz/Clark describe. We do not agree, however, that the fact that there are intergenerational equity consequences means the best course is to recover and repay the Lookback Amount as quickly as possible. We believe that recovery and repayment of Lookback Amounts should reflect consideration of both the expected time needed to recover and return of overpayments and the provision of a reasonable level of REP benefits to residential consumers of the IOUs to the extent such benefits are allowed by law. *See* Bliven, *et al*., WP-07-E-BPA-52 at 21-22.

We do not agree with Cowlitz/Clark's alternative if the statement, "the IOUs [supplying] the remaining amounts owed," means demanding a lump sum payment. Such an approach is unreasonable for several reasons. *See* Bliven *et al.,* WP-07-E-BPA-52 at 21. The first reason is the IOUs do not have these monies in hand because they were passed on to residential customers. Cowlitz/Clark's recommendation would make perfect sense had the REP settlement payments been maintained in an escrow or fund pending the dispute. BPA will, in fact, disburse certain funds that BPA withheld from IOUs as a result of the Court's May 3, 2007 opinions. But the payments made to the IOUs under the REP settlements have already been passed through to the residential customers. There is, therefore, no ready pool of money held by the IOUs that BPA could attempt to claim and provide the lump sum payment Cowlitz/Clark requests**.**

Furthermore, under one particular set of simplifying assumptions (s*ee* Lookback Study, WP-07-E-BPA-44 at 207,) two IOUs satisfy their Lookback Amounts within seven years, including Puget Sound Energy, which has the second largest Lookback Amount. Three additional IOUs satisfy their Lookback Amounts by 2019 – or within 11 years. Only PacifiCorp – with the largest Lookback Amount – needs the full 20 years to repay its Lookback Amount. In total, nearly one-third of the entire Lookback Amount is repaid within the first seven years.

Q. *APAC states that one goal of any proposal to repay the preference customers for the amount that they were overcharged should be to restore the entities who bore the burden of the overcharges (i.e., the residential, commercial, agricultural and industrial customers who took service from BPA's preference customers) to the position that they* *would have had absent the unlawful payments to the IOUs. Villadsen and Wolverton, WP-07-E-AP-2 at 20. How do you respond?*

A. We generally view our responsibility in this Supplemental Proceeding as calculating, recovering, and returning the Lookback Amounts to the COUs in an expeditious and reasonable manner. *See* Bliven, *et al.*, WP-07-E-BPA-52 at 11-12, 18. APAC continues to confuse wholesale customers and retail consumers, and seems to assume that any return of overcharges that BPA might make to a COU would immediately flow to each COU's retail ratepayers on a dollar for dollar basis. This may or may not occur, and it is not an issue that we believe BPA is in a position to control. How the COUs subsequently return those funds to their ratepayers is not an issue we intend to address or resolve in this proceeding. We are proposing a reasonable approach for returning the Lookback Amounts to preference customers, although we recognize that no such approach is perfect. APAC appears to recognize this point in its testimony when it states "[i]n reality, it is probably impossible to fully match repayments exactly to those entities which bore the burden of overpayments because some of those entities that may have overpaid may no longer be taking service from the Preference Customers. Possibly they moved or closed their businesses and some individuals may have died." *Id.* at 20.

Q. APAC states that achieving this goal as closely as possible would require a repayment period as short as possible subject to other important constraints. Villadsen and Wolverton, WP-07-E-AP-2 at 20. Everything else being equal, APAC's ideal would be an immediate lump-sum repayment of the full amount of the Preference Customers' overpayment including pre-judgment interest. Id. How do you respond?

A. The closest possible option to APAC's ideal that we can consider would be to drain BPA's financial reserves to make a lump-sum payment to the COUs. In general, if BPA makes payments to the COUs from its reserves and such payments reduce reserves to levels that are at odds with other important constraints and objectives, BPA would likely need to increase COUs' rates to replenish reserves, all else being equal. Given this fact, repayment of the full amount of COU overcharges in a lump-sum payment, if possible, would mean BPA would end up charging the COUs for the return of their overcharges through higher rates resulting from lower reserve levels, instead of charging those who received the overpayments, (*i.e.,*the IOU residential consumers). Bliven, *et al.*, WP-07-E-BPA-52 at 22.

Consequently, to avoid the absurd result of the COUs paying for their own refunds, any such lump-sum payment beyond the amount that leaves BPA with sufficient reserves to operate prudently and meet its financial obligations would need to come from the IOUs. . Although BPA has not engaged in discussions with the IOUs on the prospect of returning the Lookback Amounts in a lump sum, we surmise the IOUs, or their state commissions, would likely not support a proposal to do so. To implement APAC's suggestion, BPA would have to commence litigation against the IOUs, which would likely take years to complete. Although all of these steps might conceivably be taken, we believe our approach is a reasonable alternative that should take less time and achieves a similar result. .

Q. *APAC states that as a general rule, the longer the repayment period, the greater the mismatch between the retail customers who overpaid and the retail customers who receive compensation. Villadsen and Wolverton, WP-07-E-AP-2 at 21. APAC argues that a long repayment period means that not all of the customers who were damaged can be restored to the situation as if they had not been overcharged. Id. How do you respond?*

A. We agree that a longer repayment period would likely create a greater mismatch between the *retail* consumers being repaid and the *retail* consumers who overpaid. However, there is virtually no mismatch between the COUs who were overcharged and those who will receive the benefit of the return of those overcharges as the list of BPA's COU customers is virtually unchanged since FY 2002. But again, our primary concern in this case is to propose a remedy for the overcharges paid by the COUs that strikes a balance among the several important objectives we identify in our direct testimony. *See* Bliven, *et al.*, WP-07-E-BPA-52 at 21-22. Our proposal does not calculate overcharges paid by retail consumers of the COUs, nor does it include an approach to returning any such overcharges to retail consumers. Remedying any harm to the retail consumers of COUs after BPA has addressed the overpayments is the responsibility of the individual COUs and is not something we are proposing to address or resolve in this rate proceeding. Indeed, BPA has no way of monitoring or controlling how the COUs choose to use refunds or rate reductions they may receive from BPA. Some may pass these through to retail consumers, while others may use them for operating needs. In either case, it is up to the individual COUs to determine how best to use any return of overcharges provided under BPA's adopted approach at the end of this proceeding.

Q. APAC states that one possible benchmark for repayment might be a period no longer than the period of overpayment. Villadsen and Wolverton, WP-07-E-AP2 at 22. Cowlitz/Clark make a similar recommendation, stating that BPA use as a starting point seven years as the payback period. Schoenbeck and Beck, WP-07-E-JP17-01 at 41. How do you respond?

A. It is certainly possible that during the maximum 20 year period we have proposed for repayment, there could be substantial demographic changes in the region that could increase the mismatch for retail consumers, again assuming that the return of overcharges to COUs is passed immediately on to their retail consumers. We also agree that a way to mitigate a potential mismatch could be to shorten the repayment period. APAC states that the Lookback Amount should be amortized over the same number of years over which COUs were overcharged, which is seven years. Wolverton, WP-07-E-AP-1 at 10. Cowlitz/Clark recommend that BPA use as a starting point seven years as the payback period. Schoenbeck and Beck, WP-07-E-JP17-01 at 41. A seven-year repayment period may not be possible given the policy objectives and uncertainties about future REP benefits we outline in Bliven, *et al.,* WP-07-E-BPA-52 at 21-22.

Q. *Cowlitz/Clark state that simple equity demands that, to the extent reasonably possible, the overpayments should be recovered from those who received them and refunded to those who paid them. Schoenbeck and Beck, WP-07-E- -JP17-01 at 41. One simple solution would be to have BPA promptly provide larger refunds to preference customers up front out of its reserves and to recover the monies from the IOUs over time. Id. This option would require that the cost of any Planned Net Revenues for Risk caused by the reduction in BPA's reserves be paid for by IOUs in the form of reduced REP benefits in the future. Id. Please respond.*

A. Our proposal, in fact, includes one-time payments to the COUs in FY 2008 for those who sign Interim Agreements, with a true-up at the end of this rate proceeding. For those COUs that do not sign Interim Agreements, our proposal provides for a lump sum payment in FY 2009 after this rate proceeding concludes. The interim payments cover a portion of the overcharges incurred by COUs for FY 2007-2008. We believe refunding a portion of the overcharges from reserves is possible and reasonable given the fact that BPA has been collecting the costs of the REP settlement benefits from the COUs and not paying REP settlement benefits to the IOUs since the Court ruled on May 3, 2007. In general, however, returning overcharges to COUs in lump sum payments out of BPA's reserves is self-defeating if such payments result in PF rates that are higher than they would otherwise be to replenish depleted reserves. Beyond this point, return of overcharges to COUs, if possible, would mean that BPA would be charging the COUs for the return of their overcharges instead of charging those who received the overpayments. *See* Bliven, *et al*., WP-07-E-BPA-52 at 22.

Cowlitz/Clark's proposal introduces an interesting twist on our discussion of APAC's ideal solution; that the additional costs of any Planned Net Revenues for Risk be paid by the IOUs in the form of reduced REP payments in the future. To implement such a scheme, we would need to study a number of interrelated factors: how much can BPA draw down reserves before the replenishment exceeds the ability of the IOUs to protect the COUs from rate increases; what happens if the REP benefits are not as robust as expected in the future and are unable to repay past draw downs of reserves; how far can BPA draw down reserves before its financial risk standards are implicated. We will consider Cowlitz/Clark's suggestion based on the entire record of this proceeding.

Q. APAC argues that the Lookback Amount should contain the $168.38 million that was paid to the IOUs in 2007 until payments were halted in May 2007. Wolverton, WP-07-E-AP-01 at 57. The $168.38 million represents an improper, excess payment that should be immediately recovered by preference customers. Id. Please respond.

A. The context for APAC's statement is an analysis of the correct result of the section 7(b)(2) rate test and the resulting refund obligation for the 2007-2008 period. Wolverton, WP-07-E-AP-01 at 54. APAC's "correct result" is that the IOUs are owed zero REP benefits for FY 2007-2008, therefore, all of the COU overcharges in 2007 are due back to the COUs. We disagree with APAC's calculation of the "correct result" for a number of reasons that are stated elsewhere. *See* Doubleday, *et al.*, WP-07-E-BPA-85. We agree, however, that it is appropriate to "immediately" return FY 2007 overcharges, if any, to the COUs, once that amount is determined in this proceeding. Our proposal is to do so through the Interim Agreements with its true-up or a lump sum payment at the close of this rate proceeding.

Q. WPAG argues that industry practice regarding the repayment of overcharges is to effectuate the repayment in the shortest period of time practicable. Grinberg, et al., WP-07-E-WA-05 at 54. Doing so minimizes interest accruals, and serves the equitable *function of increasing the likelihood that those who suffered the overcharge will receive the benefit of the repayment, rather than repaying those that did not endure the overcharge in the first place. Id. The notion of repaying some but not all of an overcharge sporadically over a twenty-year time frame is inconsistent with industry practice, and virtually assures that those who paid the overcharge will not receive full benefit of the repayment. Id. Do you agree?*

A. We have already responded to many of WPAG's assertions in earlier answers to other parties. WPAG argues that our proposal is to repay some but not all of an overcharge sporadically over a twenty year time frame. *Id.* This is not our proposal. We stated an objective to recover all of the Lookback Amount in 20 years or less. *See* Bliven, *et al.*, WP-07-E-BPA-52 at 22. However, our proposal acknowledges the fact that the future level of REP benefits available to recover Lookback Amounts is uncertain and therefore allows repayment amounts to be adjusted in each rate case, thereby increasing the likelihood of meeting the objective of 20 years or less.

Q. WPAG argues that repayment to preference customers should occur as soon as practicable, but should not extend beyond the length of the period during which the overcharges occurred. Grinberg, et al., WP-07-E-WA-05 at 55. In other words, the repayment of the overcharges should be done in not less than 7 years. Id. How do you respond?

A. We have responded above to the same proposals by Cowlitz/Clark and APAC. To those responses we add that we believe it is in the region's interest to seek some balance between the timely return of overcharges incurred by the COUs and the continuation of REP benefits flowing to the residential and small farm customers of the region's IOUs. Bliven, *et al.*, WP-07-E-BPA-52 at 21-22. In addition, BPA and its customers have expressed concern regarding overly volatile rates. *See* O'Meara, *et al.*, WP-07-E-PP-01 at 7.

If BPA were to decide that the repayment should occur within seven years, then it is highly likely that the residential and small farm consumers of the region's IOUs would receive no REP benefit payments for at least the next 2 or more years. In addition, the PF rate would likely drop dramatically for a few years, only to bounce dramatically upward, to higher levels compared to our proposed approach, as Lookback Amounts are extinguished and REP benefit payments, with their associated costs, resume. We believe a better overall approach is to maintain, to the extent possible, some level of REP benefits flowing to eligible residential consumers of the region's IOUs and somewhat greater PF rate stability, even though this results in a longer period to repay overcharges to the COUs. *See* Bliven, *et al*., WP-07-E-BPA-52 at 21-22**.**

Q. WPAG argues that the overcharge repayment obligation calculated by BPA can be repaid with the seven-year period it is recommending, so long as BPA places priority on making its preference customers whole instead of maintaining inordinately high REP payments to the IOUs. Grinberg, et al., WP-07-E-WA-05 at 55. However, it is not possible to make any serious headway in repaying to preference customers even the modest overcharge obligation as calculated by BPA if the level of annual REP payments to the IOUs is five times greater than the proposed annual repayment to the preference customers, as proposed by BPA. Id. Do you agree?

A. We agree there is a high likelihood that the Lookback Amounts for all utilities, with the exception of Idaho Power, could be repaid within seven years if all REP benefits went toward the repayment of Lookback Amounts. Regarding WPAG's opinion that our proposal constitutes "maintaining inordinately high REP payments to the IOUs," we make two observations.

First, the $202 million in REP payments that we propose for FY 2009 is roughly $17 million less than the 1982 though 2001 annual average level of IOU REP benefits and roughly $58 million less than the 1982 through 1996 annual average level of IOU benefits, all in inflation adjusted dollars, and 60 percent of the levels of the REP settlement benefits we are now removing. Although WPAG may believe REP payments, on average, have been inordinately high since the passage of the Northwest Power Act, others likely have a different view.

Second, in November 2007, a significant segment of the COUs and all of the IOUs provided BPA with a set of recommendations regarding future IOU REP benefits. Included, among other elements, was a recommendation that annual REP benefits for IOUs should range between $200 million and $220 million from October 1, 2007, through the term of the Regional Dialogue contracts. *See* Bliven, *et al.,* WP-07-E-BPA-52 at 26-27. Although it would be inappropriate to give undue weight to this $200 million to $220 million per year range in isolation from the other elements of the recommendations, the fact that it was provided by a group representing a broad cross-section of BPA's utility customers, both IOUs and COUs – including WPAG – lends support to the notion that our proposal of $202 million in IOU REP benefit payments for FY 2009 is not "inordinately high."

Finally, we believe that significant headway can be made toward returning the full Lookback Amount to COUs under our proposal. Under an admittedly simple set of assumptions, three of the region's IOUs extinguish their Lookback Amounts in seven years or less and a fourth extinguishes its Lookback Amount within 11 years. Having four of the region's six IOUs extinguish their Lookback Amounts within 11 years would constitute significant headway. The fifth IOU could take close to the full 20 years under our simple set of assumptions, but if the utility's situation with respect to expected REP benefits changes, it could return the overpayments faster. As described earlier, the situation with Idaho Power is unique and the return of its Lookback Amount is possible within 20 years, but dependent upon the resolution of its deemer balance.

Section 4.3: Certainty and Priority of Repayment

Q. *APAC states that a repayment procedure should be constructed such that preference customers have priority for repayment and an absolute right to repayment. Wolverton, WP-07-E-AP-01 at 83. How do you respond?*

A. First, we disagree with APAC that our proposal puts the repayment of preference customers at a lower priority than distributing REP benefits to IOUs. As we have already discussed, the COUs will see their repayment even before any funds are remitted to BPA from the IOUs. This places their repayment before any other obligation of BPA. Second, we cannot create an "absolute right to repayment" given the uncertainty of future events.

Q. *APAC states that BPA puts the payments for the REP as the principal element of its proposal, with drawdown of the Lookback Amount effectively occurring only when residual funds are available. Wolverton, WP-07-E-AP-01 at 85. How do you respond?*

A. APAC's testimony misstates our proposal. We proposed the Lookback approach in order to determine the amounts that COUs were overcharged due to the REP settlements. We have proposed the method to calculate this Lookback Amount in the initial Supplemental Proposal. It is not our proposal to subordinate the repayment of the Lookback Amounts to occur only when residual funds are available. Rather, our proposal is to recover the Lookback Amounts through the reduction of future REP benefit payments. We have not proposed any long-term limits to the reductions in future REP benefits paid, either on the up-side or the down-side. Instead, we have left it to the Administrator to determine the appropriate amount to recover in each rate period in order to exhaust the Lookback Amount in 20 years or less.

Q. *APAC argues that the facilities it represents have also paid the rates deemed unlawful to BPA, and are entitled to assured refunds of those unlawful payments, with appropriate interest, consistent with the recommendations contained in this testimony. Wolverton, WP-07-E-AP-01 at 1-2. Do you agree?*

A. No. APAC's members are not served directly by BPA, are not eligible to purchase power from BPA, and are not charged BPA's wholesale power rates. Therefore, APAC's members have not paid BPA's rates. Although the rates BPA charges the COUs are undoubtedly a significant component of retail rates APAC members pay, in *Golden Northwest* the Court reviewed BPA's wholesale power rates, not the retail rates charged APAC's members by their serving utilities. APAC's concern about its members' rates is a local issue between the companies and their utilities. BPA will address parties' properly raised legal issues regarding any entitlements to refunds in BPA's Draft and Final Records of Decision in this proceeding.

Q. APAC argues that provisions must be made to return overpayments to those consumers who have ceased business and no longer would benefit from a reduced Preference Rate in the future. Wolverton, WP-07-E-AP-01 at 5. Please respond.

A. APAC clarified that the "customers" referenced here are retail consumers of BPA's wholesale customers. First, the only long-time customers of BPA that have ceased business within the BPA service territory are a number of direct service industries. No COU customer of BPA has ceased business – although a few have merged with a neighboring COU. Retail consumers of BPA's customers may have gone out of business for many reasons unrelated to BPA's power rates, particularly given recent and current economic conditions. BPA's responsibilities do not extend to the relationships between end consumers and their serving utilities. BPA will not insert itself into the retail ratemaking of its COUs nor will it insert itself into any debate or process regarding claims by end consumers that may have been incurred due to any BPA overcharges passed on by their local serving utilities. BPA will address properly raised legal issues regarding returning overpayments to customers that have ceased business in its Draft and Final Records of Decision.

Q. APAC states that possible future changes to the 7(b)(2) Implementation Methodology and Legal Interpretation among other factors are recovery risks that APAC and its members find unacceptable to bear. Wolverton, WP-07-E-AP-01 at 81. How do you respond?

A. It is unfortunate that APAC members find the recovery risks unacceptable to bear, but ultimately BPA's relationship is not with APAC's members but with BPA's customer utilities that serve APAC's members. BPA's obligations are to its customers and BPA's customers have obligations to BPA. The resolution of any claims that APAC members have must, of necessity, be between them and their local utility.

We do not deny that it is possible that future changes to the 7(b)(2) rate test procedures creates recovery risks to the COUs. These risks come from a number of sources. They could arise from a successful legal challenge to the Legal Interpretation or Implementation Methodology. The could arise from non-7(b)(2) factors that affect the rate test, such as BPA's costs or IOUs' ASCs. As we have stated, our proposal is not without risk. However, we believe the risks are balanced between COUs and IOUs, as the IOUs (actually their residential consumers) also bear risks of future changes to the 7(b)(2) rate test.

Q. APAC states that if the rate test result is below $210 million (plus interest on the Lookback Amount) or the net REP benefits fall below that level, no amortization of Lookback Amounts can take place. Wolverton, WP-07-E-AP-01 at 82. How do you respond?

A. APAC misunderstands our proposal. Nothing in our proposal would prohibit any repayment of Lookback Amounts in future years if the condition APAC hypothesizes comes to pass. APAC seems to believe that our proposal would result in setting an REP payment limit independent of the 7(b)(2) rate test. In fact, the rate test is conducted first to establish the forecast of REP benefits due IOUs consistent with law, then a determination is made regarding the division of this amount between amounts paid to the

IOUs and amounts applied against Lookback Amounts. Under our proposal, the forecast of REP benefits of $250 million was calculated after the application of the 7(b)(2) rate test. Based in part on this outcome, we proposed that $210 million be paid to IOUs and $40 million be applied toward the Lookback (before consideration of deemer balances). Our proposal is solely for FY 2009; there is no proposal of how much would be repaid in future years or what repayments we would propose if forecast REP benefits were less than any particular amount. However, we are proposing that BPA will commit to recover as much of the Lookback Amounts as possible within 20 years or less.

Q. APAC argues that there is a possibility that no amortization would ever be made if the 7(b)(2) rate test limit is lower than the carrying cost of the Lookback Amount. Wolverton, WP-07-E-AP-01 at 82. Do you agree?

A. We recognize that it is possible that forecast REP benefits in a rate case could be less than the annual interest accrual on the outstanding Lookback Amount balance, but we do not expect such an outcome. However, future conditions are uncertain and BPA cannot guarantee any particular result in the foreseeable future. Should this situation occur, our proposal is that BPA would consider reducing the amount of REP benefits paid to the IOUs in order to maintain progress toward the goal of returning the Lookback Amount to the COUs in 20 years or less. However, our proposal allows BPA to evaluate its options at that time based on the circumstances at hand. We will not speculate what BPA might do under those circumstances.

Q. APAC argues that, regardless of BPA's revenues, if the rate test fails to create sufficient excess, preference customers will not be paid. Wolverton, WP-07-E-AP-01 at 82. How do you respond?

A. Although not a clear statement, we infer that when APAC refers to "sufficient excess," it is referring to REP benefits that remain after the application of the 7(b)(2) rate test. If this is what APAC means, we do not dispute the fact that it is possible that REP benefits after application of the rate test may not be sufficient to repay the Lookback Amounts. Should such conditions occur in the future, our proposal allows BPA to evaluate its options at that time based on the circumstances at hand. We will not speculate what BPA might do under those circumstances.

Q. WPAG argues that BPA has made no commitment whatsoever with regard to repaying preference customers the amounts these customers overpaid during the FY 2002-2006 period beyond the about $40 million in reduced REP benefits in FY 2009. Grinberg, et al., WP-07-E-WA-05 at 52. BPA has reserved the right to decide in each rate proceeding whether to make any repayment at all after the one proposed for FY 2009. Id. Under BPA's approach, the $40 million "payment" in FY 2009 could be both the first and last such repayment ever made to preference customers. Id. Do you agree?

A. No. In our testimony, we state that overcharges should be returned to the COUs in 20 years or less. *See* Bliven, *et al*., WP-07-E-BPA-52 at 22. In each rate case, our proposal allows the Administrator to decide the appropriate amount the IOUs should repay for that rate period, taking into account the level of REP benefits allowed under law, the remaining Lookback balances, and the number of years available to recover the Lookback.

Q. WPAG argues that BPA's approach virtually guarantees that the overcharge amount will never be fully repaid to the preference customers. Grinberg, et al., WP-07-E-WA-05 at 52. Do you agree?

A. No. As already described, our proposal is that BPA will return, to the extent possible, the Lookback Amounts to the COUs in 20 years or less based on decisions in each rate case. *See* Bliven, *et al.,* WP-07-E-BPA-52 at 22. Under the scenario presented in the FY 2002-2008 Lookback Study, WP-07-E-BPA-44, at 206-207, about one-third of the Lookback Amount is repaid within seven years, and over half of it is repaid by 2021 – or within 13 years. Other sets of assumptions would result in shorter or longer repayment periods.

Q. *WPAG argues that economic and market conditions can make the continuation of such repayments less attractive to future Administrators, that it is reasonably predictable that there will be political pressure to provide to the IOUs the full amount of the calculated REP benefits, and that these factors make it virtually certain that voluntary overcharge repayments will not be continued over a twenty-year term. Grinberg, et al., WP-07-E-WA-05 at 53. Do you agree?*

A. No. Just as WPAG can postulate a set of conditions that results in its concerns, there is an equally likely set of conditions that results in opposite results. Future economic and market conditions can make the acceleration of repayments more attractive to future Administrators. Although it is certainly true that there may be political pressure to provide the IOUs with the full amount of REP benefits, there would certainly be political pressure from the COUs to do exactly the opposite. We do not believe WPAG's speculation regarding future economic and market conditions and its predictions regarding political pressure establish any "virtual certainty" regarding the discontinuation of repayments at some time in the future any more than we believe our postulated conditions establish any "virtual certainty" of full repayment.

Q. *WPAG argues that even with a very optimistic assumption of a 2.5 percent per year increase in IOU REP benefits, BPA's calculated overcharge repayment obligation is not extinguished over the 20-year term. Grinberg, et al., WP-07-E-WA-05 at 53. Do you agree?*

A. Our calculations, based on a certain set of reasonable assumptions, show that the Lookback Amount will be extinguished within 20 years for five of the six IOUs. The sixth, Idaho Power, is due to the unique situation in that (in BPA's view) Idaho Power has a significant outstanding deemer balance that must be extinguished before REP benefits would be applied toward its Lookback Amount. Absent some resolution of the disputed deemer balance, BPA has not identified a contractual means to recover Idaho Power's Lookback Amount that BPA believes would be economic for Idaho Power. Therefore, we believe it is better to assume that Idaho Power is unlikely sign an RPSA without a prior resolution of its deemer balance. Without an RPSA, BPA has no means of recovering Idaho Power's Lookback Amount. However, should there be a resolution of Idaho's deemer balance, a different outcome could result that could allow us to implement our proposal and have access to Idaho's Lookback Amount. However, we do not believe that BPA would simply forgive Idaho Power's deemer balance just to achieve greater certainty in accomplishing full repayment of Idaho Power's Lookback Amount. COUs would not be advantaged under such a scenario. Therefore, it is in the COUs' interests to help BPA find a reasonable solution to both Idaho Power's deemer balance and Lookback Amount.

Q. WPAG argues that there is little basis for assuming that the IOU REP benefits will increase at 2.5 percent per year. Grinberg, et al., WP-07-E-WA-05 at 53. WPAG reviewed the rate of growth in IOU REP benefits over the 25 years the REP has been in operation, and although the benefits have gone up and down, the historical record does not support the notion of a steady 2.5 percent increase in benefits. Id. Please respond.

A. It is true that REP benefits have gone up and down since passage of the Northwest Power Act. We also acknowledge that our assumption of 2.5 percent increase in benefits is simplistic. *See* FY 2002-2008 Lookback Study, WP-07-E-BPA-44 at 206. However, we do not believe that the past is necessarily a good predictor of the future in this case. For example, most IOUs rely much more heavily on fossil fuel generation than does BPA. Costs for environmental compliance, including possible future costs associated with CO_2 emissions, arguably will impact IOU costs more than BPA's. IOUs also tend to have higher load growth rates than BPA, resulting in relatively greater costs. There are risks before both the COUs and the IOUs. We believe our proposal gives BPA enough flexibility to address the uncertain future , and respond appropriately to balance both the interests of the COUs and IOUs.

Q. *WPAG argues that the benefits available to IOUs under the REP have tended to oscillate due to economic conditions, resource additions, load growth, as well as changes in BPA's cost structure that impact the PF Exchange rate, such as cost increases and loss of FBS generating capability due to fish mitigation requirements. Grinberg, et al., WP-07-E-WA-05 at 54. Periodic changes to BPA's interpretation of the ASC Methodology and the implementation of 7(b)(2) rate test have also caused REP benefits to oscillate over time. Id. Do you agree?*

A. We agree there are many factors that affect the level of REP benefits, and the approach to calculating some of them may change as a result of this rate proceeding. A separate process is also expected to result in changes to BPA's 1984 ASC Methodology, and therefore resulting ASCs. Factors that affect a utility's ASC may not affect BPA's PF Exchange rate in the same manner, or vice versa. State laws affect an IOU, and often do not affect BPA or its public utility customers, at least in the same way. Factors that affect BPA's cost structure may or may not affect each utility's cost structure. Further, these factors will affect each IOU differently as each utility experiences different rates of load growth. For these reasons and others, we believe good forecasts of factors that will affect future REP benefits are simply not possible at this time. *See* Bliven, *et al.,* WP-07-E-BPA-52 at 21. The lack of good forecasts argues for an approach that can be adjusted over time to reflect improved information and changed circumstances.

Q. *WPAG argues that one thing that is clear is that REP benefits have not increased at a rate of 2.5 percent per year during the history of this program. Grinberg, et al., WP-07-E-WA-05 at 54. As a consequence, it is not plausible to conclude that the repayment approach proposed by BPA will result in the preference customers being* *repaid even the fairly modest overcharge obligation as calculated by BPA. Id. Do you agree?*

A. It is certainly plausible that our approach could result in COUs being repaid in full. However, our approach calls for the amount of future REP benefits going toward repayment of overcharges to be adjusted each rate period to give BPA the flexibility to adjust the return the overcharges to the COUs to be accomplished within a reasonable period of time. In future rate proceedings, the BPA Administrator will assess progress toward repayment of overcharges and determine an appropriate portion of REP benefits to return to COUs and apply against Lookback Amounts. Such repayments will be first proposed by BPA and tested by all parties to the rate proceeding. If the COUs or IOUs believe that BPA's proposal is not properly balancing the goals of both maintaining progress towards repaying the Lookback Amounts and maintaining a reasonable level of REP benefits consistent with the law, parties will have the opportunity to raise the issue in the rate proceeding.

Q. APAC states that its understanding is that BPA's proposal only envisions annual repayments when the REP benefit due to the IOUs exceeds $210 million, and that figure is only a proposal valid for FY 2009. Villadsen and Wolverton, WP-07-E-AP-2 at 22. No payment would be made if the REP benefit due to the IOUs were less than $210 million or a future targeted value. Id. at 23. How do you respond?

A. Although we concur that generally there is no way to guarantee that the COUs will receive full payment of the Lookback Amounts over the 20-year period, we are not proposing a rigid commitment to the $210 million figure. Rather, this figure will be evaluated in light of the REP benefit levels and in view of our overall objective of returning the Lookback Amounts to the COUs in a reasonable time period. As noted before, for each rate period, our proposal allows the Administrator to evaluate progress toward that goal, having reserved the option to make whatever adjustments may be necessary given the 20-year or less repayment goal.

Q. APAC posits three possible reasons why low REP payments might occur: (1) that the Northwest Power Act is reinterpreted to effectively eliminate REP benefits; (2) that there could be a narrowing of the difference between IOU ASCs and BPA's rates reducing REP benefits below the cap; (3) that there could be future decisions by the BPA Administrator to change the underlying methodologies that underlie the REP and the rate test, resulting in a substantial increase or decrease in the available REP benefits due the IOUs. Villadsen and Wolverton, WP-07-E-AP-2 at 23. How do you respond?

A. APAC's list of "possible reasons" does not persuade us that there is an undue amount of risk that would require us to completely reevaluate our proposal. APAC's reasons are very similar to WPAG's, which we have responded to. First, whether the Northwest Power Act may change in the future is irrelevant for purposes of establishing a remedy today. There could be changes in the law that we today cannot anticipate. Trying to create a remedy today that mitigates such possible changes is both impractical and bad policy. It is far more appropriate to assume, as we have done in this case, that the Act, and its interpretation, will remain in its present form.

Second, APAC is correct that REP benefits *could* go down as a result of a narrowing of the difference between the IOUs' ASCs and BPA's PF Exchange rate. The opposite, however, is also true. The gap between the IOUs' ASCs and BPA's PF Exchange rate *could* increase over time, resulting in larger benefits to the IOUs and a faster repayment of the Lookback Amounts. No party has done an exhaustive study of either scenario and, as we have noted elsewhere, good forecasts of future factors affecting REP benefits are not available. We do not think it necessary or appropriate to adopt a remedy based only on the assumption of declining future REP benefits.

Finally, APAC's third reason is theoretically correct, but, is equally unhelpful for this case. BPA's Administrator does not have plenary power to determine how REP benefits are established. Any changes must be based on a formal record and, if challenged, would have to be upheld by the courts. Certainly, BPA could initiate another consultation process to consider changes to methodologies, like the ASCM. But these processes are *public* processes, involving *all parties.* As APAC correctly states, possible future changes in methodologies could result in *either* substantial increases or decreases in the available REP benefits due the IOUs.

To summarize, we agree that the future levels of REP benefits are uncertain. We acknowledge and address this uncertainty by proposing that the determination of the allocation of REP benefits between the amounts paid to IOUs and the amounts applied against Lookback Amounts be established in each rate case, thus allowing the BPA Administrator to adjust amounts as appropriate. We do not agree that future REP benefits are any more likely to be lower because of the "possible reasons" APAC notes in its testimony than they are likely to be higher for the reasons stated above. APAC's reasons are speculative at best, and therefore, in our opinion, do not require us to abandon the payback methodology we have proposed in this case.

Section 4.4: Alternatives for Recovery and Return of Lookback Amounts

Section 4.4.1: Alternatives for Recovering Lookback Amounts from IOUs

Q. WPAG argues it is reasonable to apportion liability to the IOUs for paying back amounts overcharged preference customers based on the amount of REP Settlement Agreement-related payments the IOU received without recourse to their relative ASCs. Grinberg, et al., WP-07-E-WA-05 at 12. Do you agree?

A. No. We previously addressed in Section 2.7 of this testimony WPAG's assertion that calculating the IOUs' ASCs is unnecessary to determine the Lookback Amounts. As we previously noted, WPAG's position seems to disconnect the liability for returning overpayments to the COUs from the comparison between the REP settlement benefits received with the REP benefits the IOUs would otherwise be due, which are a function of the ASCs, the PF Exchange rate, and exchangeable loads.

WPAG's position that BPA can simply "apportion" liability based on the amount of REP settlement payments is also misplaced because it does not account for the possible continued effectiveness of settlement-related contracts. BPA will address properly raised issues regarding the effectiveness of REP settlement-related agreements in the Draft and Final Records of Decision in this proceeding.

Q. The OPUC recommends that BPA use an alternative mechanism for spreading the repayment of the Lookback across the IOUs. Hellman and McGovern, WP-07-E-PU-1 at 36. The OPUC does not see a reason why one IOU should pay off its obligations sooner, or at a faster pace, than another. Id. How do you respond?

A. The OPUC presents an interesting idea worth investigating. However, under OPUC's alternative, the residential consumers of some IOU may receive no benefits in the near-term, while the residential consumers of other IOUs may receive significant benefits. Some IOUs may arguably want to exhaust their Lookback obligations in the same timeframe, others may not. Our approach better serves the objectives of returning Lookback amounts to COUs while providing some REP benefits to residential and small farm consumers.

Section 4.4.2: Alternatives for Returning Lookback Amounts to COUs

Q. APAC states that looking at losses on an individual-utility basis serves to address, in part, some of the intergenerational equity problems of BPA's proposal – where one set of customers has suffered the loss while another enjoys the repayment. Wolverton, WP-07-E-AP-01 at 86. A good example comes from the pre-Subscription customers. Id.

Their rates were limited by provisions of their contracts for FY 2002-2006. Id. Specifically, they did not pay the surcharges that other preference customer utilities were forced to pay through the various cost-recovery adjustment mechanisms, so they did not pay increased rates due to the REP Settlement Agreements. Id. With expiration of most of the pre-Subscription contracts, those utilities become standard PF customers and pay the PF Preference rate. Id. To the extent that rate is lower because of BPA's amortization proposal, those utilities will get the benefits of the amortization without having incurred the losses. Id. Do you agree?

A. We agree with APAC's description of the pre-Subscription customers. We support the objective of mitigating, to the extent practicable, the returning of overpayments to utilities that did not actually pay the overpayments. We are willing to consider an alternative means of repaying Lookback Amounts to the COUs that might, as APAC asserts, achieve this objective.

Q. APAC proposes an alternative approach for returning Lookback Amounts that establishes an amount to be returned for each COU based on each COU's percentage of actual total preference-customer load for each year from 2002 through 2007. Wolverton, WP-07-E-AP-01 at 86. How do you respond?

A. APAC's concept of basing returns to COUs on COU-specific loads from the time period where the overcharges occurred appears feasible and may have merit. As APAC notes, BPA has the billing records needed to implement this concept. This alternative would involve considerably administrative work. For example, BPA would have to compile the historical data and set-up a system of COU-specific accounts that would need to be maintained. Adjustments would have to be made to the billing system to track specific line items on COU power bills. This additional work would need to be compared against expected benefits from the more complicated approach APAC describes.

We believe that if an alternative approach along the lines APAC proposes is adopted, a better basis may be to use each COU's share of total PF Preference rate revenues in the Lookback time period. Our proposal for returning FY 2007 and FY 2008 overcharges to COUs is based on proportional PF Preference rate revenues rather than on loads. Revenues, unlike load, directly reflect each COU's contribution toward BPA's total costs and is therefore a good indicator of relatively how much each utility paid in overcharges. We intend to evaluate these, and any other proposals, submitted by the parties.

Q. Does this conclude your testimony?

A. Yes.

Response is past due after seven (7) days.

Request (click to view)	Exhibit	Requesting Party	Responding Party	Date Filed	Response (click to view)
AP-PU-1	WP-07-E-PU-1	Association of Public Agency Customers	Public Utility Commission of Oregon	4/11/2008 10:30 AM	Select Request to view Response
AP-PU-2	**WP-07-E-PU-1**	**Association of Public Agency Customers**	**Public Utility Commission of Oregon**	**4/11/2008 10:34 AM**	**Select Request to view Response**

You are viewing page 1 of 1

Request Detail

Request ID: AP-PU-2
Page Number: 12
Line Number: 12-18
Exhibit Filing: WP-07-E-PU-1

Contact Name:
Contact Phone:
Contact Email:

Request Text:

Please provide any documents supportig for this statement, including memoranda, reports, emails, analyses and other written materials.

Response Detail

Date Response Filed: 4/18/2008 1:16:01 PM
Contact Name:
Contact Phone:
Contact Email:
Response Text:

The OPUC is not aware of any materials as requested.

Files Submitted for this Response:

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 Supplemental Wholesale Power Rate Case Initial Proposal

REBUTTAL TESTIMONY

SUPPLEMENTAL POLICY DIRECTION FOR FY 2009

May 2008

WP-07-E-BPA-77

This page intentionally left blank.

INDEX

REBUTTAL TESTIMONY of

VALERIE A. LEFLER and RAYMOND D. BLIVEN

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL POLICY DIRECTION FOR FY 2009

Page

This page intentionally left blank.

REBUTTAL TESTIMONY of

VALERIE A. LEFLER and RAYMOND D. BLIVEN

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL POLICY DIRECTION FOR FY 2009

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Valerie A. Lefler and my qualifications are contained in WP-07-Q-BPA-29.

A. My name is Raymond D. Bliven and my qualifications are contained in WP-07-Q-BPA-58.

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

A. Yes. Ms. Lefler and Mr. Bliven have submitted direct testimony, with another witness, identified as exhibit WP-07-E-BPA-63. Mr. Bliven has submitted direct testimony, with other witnesses, identified as exhibits WP-07-E-BPA-52, WP-07-E-BPA-53, WP-07-E-BPA-57, WP-07-E-BPA-58, WP-07-E-BPA-60, WP-07-E-BPA-62, WP-07-E-BPA-68, WP-07-E-BPA-69 (as a replacement for Mr. Keep), and WP-07-E-BPA-70.

Q. How is your testimony organized?

A. It is organized in two sections following this introduction. The first addresses anticipated changes in Fish and Wildlife spending. The second addresses cost increases forecast for CGS.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to respond to the direct testimony filed by NRU, WP-07-E-NR-7, regarding BPA's spending assumptions for Fish and Wildlife costs in its final Revenue Requirement Study. It also responds to the parties' contention that BPA consider its spending assumptions for the Columbia Generating Station as a part of this rate case.

Section 2: Fish and Wildlife

Q. NRU argues that BPA should not change its Fish and Wildlife spending assumptions to be incorporated in the final Revenue Requirement Study because better information will not be available by the time rates are filed with FERC. Saven and Carr, WP-07-E-NR-7 at 2-5. APAC supports this argument as well. Wolverton, WP-07-E-AP-1 at 59. Do you agree?

A. No. As noted in policy testimony, to ensure compliance with the *Golden NW* decision, "BPA will take steps to ensure that its assumptions about fish and wildlife spending levels are as up-to-date as possible for the final Supplemental Proposal, and will provide an opportunity outside this supplemental proceeding for fish and wildlife managers and others to review the information and provide feedback to BPA on the estimates of those fish and wildlife program levels." Lefler, *et al.,* WP-07-E-BPA-63 at 10. NRU notes that the final BiOP will be released to the public on May 5, 2008. Saven and Carr, WP-07-E-NR-7 at 4. The BiOp will contain specific proposed actions, and the cost of the actions can be forecast. In addition, BPA has been negotiating with regional sovereigns regarding related implementation actions to address Endangered Species Act (ESA)-listed species and other fish species. Decisions regarding the proposed Memoranda of Agreement (MOA) are anticipated soon. Should BPA decide to proceed with one or more of the proposed MOAs, their associated costs would be forecast in May 2008.

Q. NRU argues that any changes in costs can and should be dealt with in the 2010-2011 rate case and that BPA's current high probability of making Treasury payments, the existing cost adjustment mechanisms specifically intended to be used to address unexpected *increases in Fish and Wildlife costs, and the fact that this case involves a one-year rate period only, result in relatively small financial implications of costs exceeding assumptions in rates for this process. Saven and Carr, WP-07-E-NR-7 at 5. Do you agree?*

A. We do not believe changes in Fish and Wildlife and CGS costs should be put off until a later rate case. Although the factors mentioned by NRU would reduce the immediate financial implications of increases in Fish and Wildlife and CGS costs, it is proper to reflect costs accurately in rate development. We also believe that it is important, especially given our understanding of the *Golden NW* ruling, to "take steps to ensure that its assumptions about fish and wildlife spending levels are as up-to-date as possible for the final Supplemental Proposal." Lefler, *et al.,* WP-07-E-BPA-63 at 10.

Q. NRU argues that BPA's customers will not have the opportunity in the context of rate development to address these costs until long after the time of discovery, responsive testimony, or cross-examination is over. Saven and Carr, WP-07-E-NR-7 at 5. Do you agree?

A. Although the separate BPA proceeding for public review of these costs, the Integrated Program Review, will occur after the time of discovery and testimony in this proceeding, this should not matter because the rate case is not an appropriate forum for reviewing and discussing these costs and is not where BPA has developed or develops its program costs. We have clearly identified the appropriate process and forums for reviewing BPA's program spending assumptions that will be used in this rate proceeding. Lefler, *et al.,* WP-07-E-BPA-63 at 11. BPA expects to review changes to FY 2009 program spending forecasts in the upcoming Integrated Program Review, which begins on May 15, 2008. In this forum, stakeholders will have the "opportunity to review BPA's updated forecasts, including the forecast of fish and wildlife spending levels, and to provide any additional information they believe BPA may not have captured. BPA will take comment and then issue a close-out report following the workshop. We will reflect the results of this workshop in the FY 2009 revenue requirement in the final Supplemental Proposal." *Id.*

Section 3: Columbia Generating Station

Q. *NRU argues that BPA and Energy Northwest need to provide full justification in this rate case for the $31.5 million increase in Columbia Generating Station costs. Saven and Carr, WP-07-E-NR-7 at 7. How do you respond?*

A. As with Fish and Wildlife costs, the Supplemental Proposal is not the forum for reviewing BPA's program spending assumptions. The Columbia Generating Station spending assumptions for FY 2009 will be reviewed in public and in detail in the Integrated Program Review in May 2008. Although the public review of these costs will occur after the time of discovery and testimony in this proceeding, the comments received in the Integrated Program Review process for FY 2009 costs will be fully considered and reflected in BPA's decision-making prior to being reflected in the final Supplemental Proposal.

Q. Does this conclude your testimony?

A. Yes.

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 Supplemental Wholesale Power Rate Case Initial Proposal

REBUTTAL TESTIMONY

COST OF SERVICE ANALYSIS AND RATE ANALYSIS MODEL (FY 2002-2009)

May 2008

WP-07-E-BPA-78

This page intentionally left blank.

INDEX

REBUTTAL TESTIMONY of

PAUL A. BRODIE, RAYMOND D. BLIVEN, HARRY W. CLARK,

WILLIAM J. DOUBLEDAY, and RON J. HOMENICK

Witnesses for Bonneville Power Administration

SUBJECT: COST OF SERVICE ANALYSIS and

RATE ANALYSIS MODEL (FY 2002-2009)

Page

This page intentionally left blank.

REBUTTAL TESTIMONY of

PAUL A. BRODIE, RAYMOND D. BLIVEN, HARRY W. CLARK, WILLIAM J. DOUBLEDAY, and RON J. HOMENICK

Witnesses for Bonneville Power Administration

SUBJECT: COST OF SERVICE ANALYSIS and RATE ANALYSIS MODEL (FY 2002-2009)

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Paul A. Brodie and my qualifications are contained in WP-07-Q-BPA-07.

A. My name is Raymond D. Bliven and my qualifications are contained in WP-07-Q-BPA-58.

A. My name is Harry W. Clark and my qualifications are contained in WP-07-Q-BPA-09.

A. My name is William Doubleday and my qualifications are contained in WP-07-Q-BPA-11.

A. My name is Ron J. Homenick and my qualifications are contained in WP-07-Q-BPA-17.

Q. Have you previously submitted testimony in this Supplemental Proceeding?

A. Yes. Mr. Brodie, Mr. Bliven, and Mr. Doubleday have submitted direct testimony, with other witnesses, identified as exhibit WP-07-E-BPA-60 and WP-07-E-BPA-68. Mr. Brodie, Mr. Bliven, Mr. Doubleday, and Mr. Homenick submitted direct testimony, with other witnesses, identified as exhibit WP-07-E-BPA-58 and WP-07-E-BPA-70. Mr. Doubleday and Mr. Bliven have submitted direct testimony, with other witnesses, identified as exhibit WP-07-E-BPA-69. Mr. Homenick has also submitted direct testimony, with other witnesses, identified as exhibits WP-07-E-BPA-55, WP-07-E-BPA-59, WP-07-E-BPA-65, WP-07-E-BPA-74 and WP-07-E-BPA-75. Mr. Brodie and Mr. Bliven have submitted direct testimony, with other witnesses, identified as exhibit WP-07-E-BPA-62. Mr. Bliven has also submitted direct testimony with other witnesses identified as exhibits WP-07-E-BPA-52, WP-07-E-BPA-53, WP-07-E-BPA-57, WP-07-E-BPA-63, and WP-07-E-BPA-69 (as a replacement for Mr. Keep.)

Q. *Please state the purpose of your testimony.*

A. The purpose of this testimony is to respond to direct testimony filed by the Public Utility Commission of Oregon (OPUC), WP-07-E-PU-1; Citizens' Utility Board of Oregon (CUB), WP-07-E-CU-1; and the Pacific Northwest Investor-Owned Utilities (IOUs),WP-07-E-JP6-08, regarding the establishment of individual PF Exchange rates and the allocation of the 7(b)(3) reallocation amount to surplus sales.

Q. *How is your testimony organized?*

A. This testimony consists of three sections. Section 1 explains the purpose and scope of the testimony. Section 2 of this testimony responds to issues the OPUC raised regarding BPA's establishment of individual PF Exchange rates. Section 3 responds to the issues raised by CUB and the IOUs regarding the allocation of the 7(b)(3) reallocation amount to surplus sales.

Section 2: Individual PF Exchange Rates

Q. *The OPUC notes BPA's proposal to create utility-specific PF Exchange rates so that utilities that would have received benefits absent the 7(b)(2) "trigger" still receive Residential Exchange Program (REP) benefits. Hellman and McGovern, WP-07-E-PU-1 at 31. The exact calculation of the utility-specific PF Exchange rates is such that the pro rata proportion of benefits under the "triggered" PF Exchange rate is the same as if no trigger occurred. Id. The impact of this policy is to reduce exchange benefits for high cost utilities and increase benefits for low cost utilities. Id. The OPUC notes BPA's reason for the proposal was to: (1) "allow [ ] a greater number of residential and small* *farm consumers of regional utilities to receive a form of benefit from the FCRPS"; (2) "give participating utilities an incentive to minimize their costs"; and (3) "better meet the Recommendations of Representatives of the Investor-Owned and Certain Consumer-Owned Utilities …to more broadly distribute REP benefits among IOUs without increasing REP benefit costs to COUs." Id. Is this an accurate description of BPA's reasoning?*

A. For the most part, yes. We have included as an attachment to this testimony the paper distributed at the October 22, 2007, Residential Exchange workshop when this allocation approach was discussed. In that paper, we discussed three benefits: (1) more utilities will be able to participate in the REP; (2) it gives participating utilities an incentive to minimize their costs; and (3) it does not change the amount of rate protection included in preference customer rates. *See* Attachment 1. In addition, our Supplemental Proposal testimony states that the proposed allocation better achieves BPA's goal of spreading the benefits of the FCRPS as broadly as possible. Fisher, *et al*., WP-07-E-BPA-69 at 7. In this statement, we equate this to the first goal from Attachment 1, allowing more utilities to participate in the REP. The testimony then goes on to repeat the goal of giving "participating utilities an incentive to minimize their costs." *Id*. Finally, the testimony states that the proposed allocation methodology better meets the recommendations of the IOUs and certain consumer-owned utilities (COU) regarding the level and spreading of REP benefits. *Id*. Although we affirm the three goals stated above, the methodology also must be legally sustainable.

Q. The OPUC supports the policy objective to spread the benefits of the FCRPS broadly throughout the PNW, but states that any proposal is not necessarily supportable just because it furthers this objective. Hellman and McGovern, WP-07-E-PU-1 at 31. Do you agree?

A. We agree that, to the extent an action is based solely on such a rationale and the action was somehow contrary to law, it would not be supportable. However, we believe our proposal is lawful. Also, the policy objective to spread the benefits of the FCRPS broadly throughout the Pacific Northwest is but one of the three stated objectives the OPUC cited and the four objectives stated in our prior answer.

Q. The OPUC argues that BPA's proposal does not meet the objective of encouraging utilities to minimize costs. Hellman and McGovern, WP-07-E-PU-1 at 32. BPA's proposal applies to both future and past decisions since they both affect ASC. Id. A proposal today to provide an incentive to minimize costs should be targeted at future decisions because many decisions have already been made and an incentive today will not affect the choice made many years ago. Id. Some utilities may be higher cost not from any actions of their own, but rather from the vagaries of load growth and when such load growth caused the utilities to build resources. Id. Utilities that have relatively higher load growth near term would have had to add resources that cost more in nominal terms than resources built decades ago. Id. Do you agree?

A. Although we recognize that we cannot change past decisions that affect utility ASCs, the cost minimization goal has been a stated objective of the REP since 1984. BPA's Average System Cost Methodology Record of Decision (ROD), June 1984, states: "The ASC methodology must be designed so that BPA does not become the 'deep pocket' to which participating utilities may shift excessive or improper resource costs. The methodology should give participating utilities an incentive to minimize their costs." 1984 ASCM ROD at 9. That we have now proposed a new mechanism to further assist in meeting that goal should not be a surprise to the OPUC or the rest of the region. We recognize that the cost structures of the various participating utilities are a product of many events and decisions, of which BPA's REP is one; hopefully, a minor one. But, as the Administrator stated in 1984, BPA should not become the "deep pocket" for the excessive or improper resource costs. We maintain that the proposed allocation methodology is another way of helping achieve the Administrator's 1984 goal.

Q. *The OPUC argues that BPA's policy will serve to penalize the companies that acquire conservation and renewable resources, particularly those that operate under renewable portfolio standards. Hellman and McGovern, WP-07-E-PU-1 at 33. Further, conservation typically increases ASC through reducing loads. Id. Even though overall generation costs may be lower through acquisition of conservation, ASC may increase. Id. Do you agree?*

A. We do not disagree with the OPUC's underlying statements, but we do not necessarily agree with its conclusions. Conservation and renewable standards will increase the ASCs of those utilities required to participate in such programs relative to those that are not required to participate. However, we do not agree with OPUC's conclusion that our proposed allocation methodology penalizes the utilities so required. At this time, both Washington and Oregon have such standards. Most of the service territories of the participating IOUs are in these two states. Therefore, the majority of IOUs' consumers are already subject to somewhat similar standards. Furthermore, although Idaho has yet to adopt renewable and conservation standards, Idaho Power is actively engaged in pursuing renewable energy sources, as is NorthWestern Energy. We therefore conclude that all of the participating utilities are facing similar cost pressures resulting from these standards.

Q. *The OPUC does not support the third reason stated by BPA – to spread the benefits of the system more broadly while not affecting the rates of consumer-owned utilities. Hellman and McGovern, WP-07-E-PU-1 at 33. Although it is admirable for the high cost investor-owned utilities to offer to spread benefits to low cost investor-owned utilities, we submit the investor-owned utilities do not have the right to independently make such an offer. Id. This is because the benefits are flowed through to customers of the investor-*

owned utilities and the customers are the beneficiaries, not the utilities. Id. Do you agree?

A. We did not propose the allocation methodology in response to an offer of high cost IOUs to spread benefits to low cost IOUs. We developed this proposal during the preparation of this rate case and the reinstitution of the REP. The fact that IOUs generally agreed with the outcome of the allocation methodology did not, in our mind, constitute an offer to share benefits. We acknowledge that residential and small farm consumers are the beneficiaries of the REP. We believe our proposal allows more of them to receive REP benefits than under the prior method.

Q. The OPUC argues that the objective of building support for BPA should rest on those that are the greatest beneficiaries of the federal system – namely the consumer-owned utilities. Hellman and McGovern, WP-07-E-PU-1 at 34. It is not reasonable to charge those customers that least benefit from the federal system, namely customers of investor-owned utilities, with the task of spreading the benefits of the federal system more broadly. Id. Do you agree?

A. Our proposal was not developed to build support for BPA. BPA encourages spreading the benefits of the federal system generally, and not simply for the residential consumers of investor-owned utilities. Our proposal allows a broader distribution of federal REP benefits while not imposing greater costs on BPA's preference customers. The benefits received by BPA's preference customers lie more directly with the establishment of power rates for such customers. Such benefits are governed generally by the Northwest Power Act's rate directives.

Q. The OPUC argues that while BPA states that it has the discretion to implement the policy of utility specific preference exchange rates, the legality of such an action is suspect. Hellman and McGovern, WP-07-E-PU-1 at 34. Do you agree?

A. BPA will address parties' properly raised legal issues regarding BPA's proposed allocation of the section 7(b)(3) reallocation amount in BPA's Draft and Final Records of Decision in this proceeding.

Q. Finally, the OPUC argues that using utility-specific PF Exchange rates would have unintended negative consequences. Hellman and McGovern, WP-07-E-PU-1 at 34. In addition to the intended consequence of shifting benefits from customers of high cost utilities to customers of low cost utilities, the new BPA proposal has the unintended effect noted above of penalizing customers of investor-owned utilities that invest in conservation and renewables, and also has the unintended consequence of lowering consumer-owned utilities' rates in the near term. Id. Reducing a deemer balance does not result in cash flows to Idaho Power's customers because the dollars are not "spent" and thus are available to further reduce the rates for consumer-owned utilities. Id. This result does not "broaden the benefits" across more customers. Id. Taking benefits away from PGE and Puget Sound Energy, Inc., which are high cost investor-owned utilities, and spreading them to consumer-owned utilities, is not spreading the benefits more broadly, just the opposite. Id. Do you agree?

A. No. First, our proposal would not prevent the highest cost utilities from receiving the greatest exchange benefits. Residential consumers of utilities with the highest ASCs will, assuming equal residential load, receive the greatest benefits. Such benefits are simply lower than they would have been under the prior method in relation to the benefits received by the residential consumers of lower cost utilities. Utilities that invest in conservation and renewables will have higher ASCs and receive greater benefits than in the absence of such investments. Our proposed allocation does not provide as great an increase as BPA's previous allocation approach. The fact that benefits to Idaho Power would serve to reduce its deemer balance and would not result in cash flows to Idaho Power's customers does not mean that Idaho Power's residential consumers do not benefit from the allocation. A reduction of a deemer balance allows the utility to move towards receiving positive exchange benefits, which will then be passed through directly to the utility's residential consumers. The allocation increases the likelihood that more utilities would be able to participate in the REP, whether now or in the future, and thus helps to broaden the benefits to more consumers. The fact that applying what might otherwise be positive REP benefits to a deemer balance results in a benefit to consumer-owned utilities is simply a result of implementing BPA's rate directives and contractual commitments in the context of the REP.

Q. The OPUC argues that these unintended consequences are likely to be long lasting, citing Idaho Power's deemer balance. Hellman and McGovern, WP-07-E-PU-1 at 35. Do you agree?

A. No. First, Idaho Power is only one of a number of utilities expected to participate in the REP. Second, Idaho Power disputes its deemer balance. In fact, it has argued that BPA should not reflect the deemer balance in this proposal. Idaho Power has also expressed interest in discussing a settlement of its disputed deemer balance. If any of these happen, OPUC's argument would become less significant or moot. Third, although we have forecast a future possible outcome of Idaho Power not qualifying for any benefits during the Lookback period, there are many possible outcomes in the future. Conditions could occur whereby Idaho Power's residential consumers could receive REP benefits much sooner than after the end of the Lookback period. Fourth, as noted above, the fact that benefits applied to a deemer balance results in a benefit to consumer-owned utilities is simply a result of implementing BPA's rate directives in the context of the REP.

Section 3: Allocation of 7(b)(3) Reallocation Amounts to Surplus Sales

Q. CUB notes that currently BPA uses surplus sales revenue to reduce COU rates, however, the same is true for DSI revenue. Jenks, WP-07-E-CU-1 at 6. For many years BPA used

DSI revenue to help fund the REP. Id. If the REP had not been funded with DSI revenue, then DSI revenue would have been available to reduce preference customers' rates. Id. Do you agree?

A. No. There are a number of problems with CUB's statement. First, CUB implies that the sole use of surplus sales revenues is to reduce COU rates. This is not the case. Under BPA's current ratemaking construct, surplus sales revenues from secondary energy are credited against the costs of the FBS and NR resource pools. Therefore, the costs of the resource pools are lowered, and thereby, the rates of those rate pools that are served by these resource pools. Such rates include the rates paid by the COUs, the PF Preference rate, but also include the rate paid by participants in the REP, the PF Exchange rate; the rate paid by DSIs, the IP rate; and the rate paid by NLSLs and IOU requirements service, the NR rate.

Second, the same is not true for DSI revenue. If DSIs were to purchase under the IP rate, the revenue received from the DSIs would be determined by the application of the IP rate. The IP rate is set in conformance with the direction of section 7(c) of the Northwest Power Act. The IP rate is set based on a cost-based rate, the "applicable wholesale rate" to preference customers, plus a margin. Although the revenues resulting from the margin might be considered extra revenue, BPA's ratemaking history has shown that generally the revenues from the 7(c) rate are less than the costs allocated to the DSIs, resulting in 7(c) delta reallocations to the PF rate.

Third, CUB postulates that for many years BPA used DSI revenue to help fund the REP. *Id.* This was true between 1981 and June 1985; however, since July 1985, the costs of the REP have been borne by all purchasers of BPA power. The DSI rate is set based on the PF Preference rate, plus a margin. In addition, if COUs purchase under the NR rate for NLSLs, those costs would also be factored into the IP rate. Therefore, the DSIs are not specifically paying for the costs of the REP.

Fourth, CUB's conclusion that if the REP had not been funded with DSI revenue, that DSI revenue would have been available to reduce preference customers' rates is incorrect. As we discuss above, the DSI revenue does not lower the rates to the COUs. The DSI revenue pays for its share of BPA's costs that have been allocated to the DSIs as allowed by the application of section 7(c).

Q. *CUB argues that surplus sales have replaced DSI sales as the primary source of reserves and surplus sales are now as significant a source of revenue as DSI revenue ever was. Jenks, WP-07-E-CU-1 at 6. If those who wrote the Northwest Power Act were doing so today, it would not be unreasonable for them to identify surplus sales as a source of revenue to support the Residential Exchange. Id. Do you agree?*

A. No. We do not agree that surplus sales have replaced DSI sales as the primary source of reserves. We acknowledge that surplus sales are a significant source of revenue. As to the reasonableness of a prior Congress identifying surplus sales as a source of revenue to support the REP, such argument is speculative.

Q. *CUB argues that the value of surplus sales will continue to increase. Jenks, WP-07-E-CU-1 at 7. In a carbon-constrained world, carbon-neutral power, such as that from the federal hydropower system, will have great value. Id. The delta between the cost of electricity generated by the federal hydropower system and the market price of electricity will grow. Id. This will greatly increase the margin that BPA makes from surplus sales. Id. Do you agree?*

A. We are not undertaking the current ratemaking exercise to speculate how future events may affect the value of BPA's surplus compared to the market. The issue here is whether we have properly constructed BPA's proposed rates. Even if we assume that CUB is correct, this would not change how BPA should construct its rates. Further, the circumstances described by CUB are not related to whether surplus sales provide reserves in a manner BPA should reflect in ratemaking.

Q. *CUB argues that BPA may be selling surplus power at a consistently high price, thereby generating large revenues. Jenks, WP-07-E-CU-1 at 7. If BPA follows its current practice, and uses the revenue from surplus power sales for the sole purpose of lowering preference rates, we will see preference rates fall. Id. This stands to create a political backlash that could ultimately threaten the strength and integrity of regional control over the federal hydropower system. Id. Do you agree?*

A. No, but we understand CUB's concerns. However, much of BPA's ratemaking practice is governed by the Northwest Power Act and many of the decisions being made in this rate case are legal issues. The proper application of the law should not be swayed by political possibilities. Even if we assume that CUB is correct, this would not change how BPA should construct its rates. Further, the circumstances described by CUB are not related to whether surplus sales provide reserves in a manner BPA should reflect in ratemaking. Also, as stated above, CUB's contention that surplus sales revenues are credited only to the PF Preference rate is not true. Surplus sales revenues are allocated to all loads served by FBS and NR resource pools, not just the PF Preference rate pool.

Q. *CUB notes that under PGE's 2007 Integrated Resource Plan, the company shows that carbon regulation could lead to prices that are above \$100 per megawatthour. Jenks, WP-07-E-CU-1 at 7, n 1. If a \$25 per ton CO_2 is projected, the price of power goes above \$100 per megawatthour in 2023. Id. If a \$40 per ton CO_2 cost is projected, the price goes above \$100 per megawatthour in 2016. Id. If a \$25 per ton CO_2 cost is combined with high natural gas prices, the cost of power goes above \$100 per megawatthour in 2013. Id. Please respond.*

A. We are not undertaking the current ratemaking exercise to speculate how carbon regulation would impact power prices. The issue here is whether we have properly constructed BPA's rates. Even if we assume that CUB is correct, this would not change how BPA should construct its rates. Further, the circumstances described by CUB are not related to whether surplus sales provide reserves in a manner BPA should reflect in ratemaking.

Q. The IOUs argue that the risks of secondary energy sale revenues being less than projected are the same regardless of whether BPA (i) allocates costs to secondary energy sales and credits to the PF rates the net secondary energy sales revenues (secondary energy sales revenues less costs allocated to such sales) or (ii) allocates no costs to secondary energy sales and credits to the PF rates the gross secondary energy sales revenues. LaBolle, et al., WP-07-E-JP6-08 at 56. In either event, if secondary energy sales revenues are less than projected, the effect on BPA's cost recovery will be the same. Id. Do you agree?

A. Yes, the IOUs are correct that BPA's overall cost recovery is not affected by the use of either the current gross secondary sales revenue credit or the IOUs' proposed net secondary sales revenue credit. However, the level of rates and the amount of REP benefits will be different if costs (including the 7(b)(3) reallocation amounts) are allocated to secondary sales, compared to where costs are not allocated to secondary sales.

Q. The IOUs provide two examples to illustrate their point. LaBolle, et al., WP-07-E-JP6-08 at 57. BPA faces the same risks and financial consequences from secondary sales revenues being less than projected, regardless of whether a gross secondary revenue credit or net secondary revenue credit is applied. Id. Do you agree?

A. Yes. If actual secondary energy sales revenues are lower than the forecast credited to rates, BPA's reserves will decrease. If BPA's reserves decrease to the point that it triggers the CRAC, then all of BPA's firm rates will be increased, including the PF Exchange rate. This would result in lower REP benefits to the IOUs. In this way, REP participants share the risk of lower than forecast secondary energy sales.

Q. *The IOUs note that BPA has stated that any allocation of [7(b)(3) reallocation amounts] to surplus sales would reduce the revenue credits to preference customers, and such an allocation would result in the preference customers bearing some of the costs of their own rate protection. LaBolle, et al., WP-07-E-JP6-08 at 58. The IOUs argue the secondary energy sales revenue credit is applied by BPA to reduce the PF rates (both the PF Preference rate and the PF Exchange rate). Id. Accordingly, the secondary energy sales revenue credit does not reduce only the PF Preference rate. Id. Please respond.*

A. Our position is that allocating a portion of the PF Preference rate protection amount to surplus sales, thus reducing the surplus revenue credit to all rates served by FBS and NR resources, will result in the PF Preference rate bearing some of the costs of its own rate protection. The fact that the PF Preference rate is not the only rate affected does not change the effect of the IOUs' proposal to allocate 7(b)(3) reallocation amounts to secondary energy, which would result in some PF Preference rate protection costs being borne by the PF Preference rate.

Q. *The IOUs argue that BPA's argument assumes "any allocation of any costs" to the FPS rate for secondary energy sales would result in the PF Preference rate somehow bearing a section 7(b)(3) reallocation amount, even though no section 7(b)(3) reallocation amount is allocated to the PF Preference rate. LaBolle, et al., WP-07-E-JP6-08 at 58-59. Allocating the section 7(b)(3) reallocation amount to the FPS rate for secondary energy sales appears to, but does not in fact, inappropriately burden the PF Preference rate. Id. The illusion of a burden on the PF Preference rate is created by BPA's error in its sequencing of its ratemaking steps. Id. Do you agree?*

A. We would not characterize our procedures as an "error" in sequencing, but the IOUs approach this issue from a new perspective. Although we have performed the ratemaking steps in the sequence used in many prior rate cases, we had not considered that the sequencing could be viewed from a different perspective.

Q. The IOUs argue that before performing the section 7(b)(2) rate test, BPA provides a gross secondary energy sales revenue credit to the PF rates. LaBolle, et al., WP-07-E-JP6-08 at 59. Providing this gross secondary energy sales revenue credit prior to the performance of the section 7(b)(2) rate test inappropriately and unnecessarily protects the FPS rate from any allocation of the section 7(b)(3) reallocation amount (unless BPA iterates to a solution). Id. Providing this gross secondary energy sales revenue credit prior to the performance of the section 7(b)(2) rate test overstates the amount of secondary energy sales revenue credit that should be available to the PF rates and creates the illusion that allocating the section 7(b)(3) reallocation amount to the FPS rate for secondary energy sales creates a revenue shortfall that would inappropriately burden the PF Preference rate. Id. Please respond.

A. We have credited the secondary sales revenues prior to the section 7(b)(2) rate test in reliance on the language in the proposed Implementation Methodology of Section 7(b)(2) of the Pacific Northwest Power Planning and Conservation Act, which instructs that secondary revenues will be credited in both the Program and 7(b)(2) Cases. *See* Implementation Methodology, WP-07-E-BPA-50, Attachment B.

Q. The IOUs note that BPA asserts the allocation of the section 7(b)(3) reallocation amount is limited to "BPA firm, adjustable loads" for four reasons. LaBolle, et al., WP-07-E-JP6-08 at 60-61. The IOUs state BPA's first rationale is that "firm loads are the loads that are allocated BPA's costs." Id. This rationale is unclear and circular, fails to explain what "firm loads" are referred to, merely states a conclusion, and does not explain why the FPS rate for secondary energy sales is not allocated any section 7(b)(3) reallocation amount. Id. Please respond.

A. Firm loads are clearly identified in BPA's rate proposals, including the Supplemental Proposal. There should be no confusion regarding what is meant by firm loads. Our statement clearly refers to these firm loads. Our statement goes on to specify that costs are allocated only to firm loads. The section 7(b)(3) reallocation amount is the cost of providing the section 7(b)(2) rate protection to the PF Preference rate. Therefore, our statement is clear; this cost is allocated only to firm loads.

Q. The IOUs note that BPA's second rationale is that by "adjustable rate loads," BPA means those loads that pay rates established and therefore adjustable in the section 7(i) process, not loads that pay a rate established and then incorporated in a contract. LaBolle, et al., WP-07-E-JP6-08 at 62. Section 7(b)(3) states that the amounts not charged to PF Preference customers by reason of section 7(b)(2) will be recovered through supplemental rate charges. Id. Therefore, only firm power sold under contracts that allow this type of rate adjustment can be allocated these supplemental rate charges. Id. BPA thus in effect argues that the incorporation of a rate level into a contract prevents BPA from allocating section 7(b)(3) reallocation amounts to that rate. Id. Please respond.

A. The IOUs have misstated our argument. We are not arguing that a contractually specified rate prevents BPA from allocating section 7(b)(3) reallocation amounts to the contract sales. Rather, the contractually specified rate prevents a supplemental rate charge from being added to the contractually specified rate and producing incremental revenue. Because BPA cannot increase the contractually specified rate, the allocation of section 7(b)(3) reallocation amounts to the contract sale would result in a revenue deficiency. This revenue deficiency must then be recovered from other rates, namely the adjustable power rates. Because the revenue deficiency is created by the allocation of section 7(b)(3) reallocation amounts, section 7(b)(3) prevents the allocation of the deficiency to the PF Preference rate. Therefore, the only rates available to recover the revenue deficiency are the adjustable power rates. The resulting rates are the same as if the section 7(b)(3) reallocation amounts were directly allocated to only adjustable power rates. Therefore, our argument removes the extra step of allocating to the contract sales and reallocating the revenue deficiency with a direct allocation to other adjustable power rates only.

Q. *The IOUs argue BPA fails to reconcile its argument with the fact that BPA already allocates costs to services that have rates set forth in contract, for example the FPS contract sales. LaBolle, et al., WP-07-E-JP6-08 at 62. Moreover, BPA already allocates projected costs to sales rates set in contract that are greater than the projected revenues from such sales. Id. For FY 2009, BPA allocates $579 million of projected costs to FPS contract sales for which BPA projects $113 million of revenues. Id. Please respond.*

A. Other costs are allocated to contract sales to establish the correct allocation of resource pool costs to rate pools. After these cost allocations are established, the revenue deficiency (or surplus) is then determined by comparing the revenues from the contract sales to the allocated costs. This revenue deficiency (or surplus) is then reallocated to other firm sales prior to the section 7(b)(2) rate test.

Q. *The IOUs argue BPA's rationale does not explain, for example, why the FPS rate for secondary energy sales is not allocated to any section 7(b)(3) reallocation amount. LaBolle, et al., WP-07-E-JP6-08 at 62. Please respond.*

A. The rationale is the same, although costs are not allocated to the secondary sales. The revenues from secondary sales are credited to rates prior to the section 7(b)(2) rate test. Because secondary sales revenues cannot be increased through supplemental rate charges, any section 7(b)(3) reallocation amounts allocated to secondary sales would create a revenue deficiency. This deficiency would then be allocated to all adjustable power rates other than the PF Preference rate. The result of the reallocation of the revenue deficiency is the same as if the section 7(b)(3) reallocation amounts were not allocated to secondary sales.

Q. *The IOUs note that BPA's third rationale is that the 7(b)(3) reallocation amounts are costs that have to be collected from other (non-PF Preference) sales. LaBolle, et al.,* *WP-07-E-JP6-08 at 63. Therefore, the rates applied to these sales to recover these costs have to be adjusted and set in a section 7(i) process and, if not, then there is a risk of under-recovery of the costs. Id. BPA thus in effect argues that the 7(b)(3) reallocation amounts cannot be allocated to rates that are not set in a section 7(i) process because there is a risk of cost under-recovery. Id. This argument ignores the fact that all of BPA's rates are set in a section 7(i) process and that BPA sets rates in the aggregate during the section 7(i) process to recover its projected costs in the aggregate. Id. Please respond.*

A. We are making a distinction between the firm power rates that have their levels determined in a 7(i) rate proceeding and the market-based FPS rate schedule, which, although subject to a 7(i) rate proceeding, does not have pre-established rate levels. In a 7(i) rate proceeding, the 7(b)(3) reallocation amounts and the level of the resulting supplemental rate charges are part of ratemaking that set the level of the PF Preference, PF Exchange, IP and NR rates. The levels of FPS rates are set either by contract or agreement between BPA and the purchaser. Once the FPS rate is set, there is no contractual or market mechanism by which to add a supplemental rate charge during the contract period. If rates were set assuming a supplemental rate charge on a contractual or market sale that had no mechanism to include the charge, there would be a risk of under-recovery.

Q. The IOUs argue BPA's rationale does not explain why the FPS rates for contract sales and for secondary energy sales are not allocated any section 7(b)(3) reallocation amount since an allocation of section 7(b)(3) reallocation amounts to the FPS rate for secondary energy sales does not increase the risk of under-recovery. LaBolle, et al., WP-07-E-JP6-08 at 63. Do you agree?

A. No, for the reasons stated in our prior answer.

Q. *The IOUs note that BPA's fourth rationale is that if the sales are not firm sales on an annual basis then there is a chance that a part or all of the amounts reallocated to these sales could come back to PF Preference sales because the forecast secondary sales did not materialize. LaBolle, et al., WP-07-E-JP6-08 at 63-64. If one or both of these events were to happen, the rate protection afforded preference customers through section 7(b)(2) of the Northwest Power Act would be limited. Id. To prevent this from happening, 7(b)(3) reallocation amounts are reallocated only to firm, adjustable rate loads. Id. The IOUs argue that BPA thus in effect argues that any allocation of any section 7(b)(3) reallocation amounts to the FPS rate for secondary energy sales could result in PF Preference rate customers somehow bearing a section 7(b)(3) reallocation amount in the PF Preference rate, even though no section 7(b)(3) reallocation amount is allocated to the PF Preference rate. Id. The fact that actual secondary energy sales may be less or different than those projected by BPA in its rate case is irrelevant to the section 7(b)(2) rate test and the allocation of any section 7(b)(3) reallocation amount because the section 7(b)(2) rate test and the allocation of any section 7(b)(3) reallocation amount are based on projected costs and revenues and is not "trued up" by BPA in subsequent rate cases. Id. Do you agree?*

A. Yes.

Q. *The IOUs argue that the entire section 7(b)(3) reallocation amount would not necessarily be recovered under the PF Exchange rate, assuming for purposes of analysis the entire amount were allocated to that rate. LaBolle, et al., WP-07-E-JP6-08 at 64. The total actual revenues or costs under the PF Exchange rate, like any other rate, will typically be greater or lesser than the total projected revenues or costs under such rate. Id. In fact, BPA faces a risk of under-recovery of costs in virtually all of its rates – even rates as to which there is no contractual agreement on the level may not recover the costs allocated to the rates. Id. Do you agree?*

A. We agree that actual revenues and costs can differ from those forecast in a rate case. However, with regard to the 7(b)(3) reallocation of the section 7(b)(2) rate protection amount in the ratemaking process, we believe the full amount of PF Preference rate protection should be allocated away from the PF Preference rate and allocated to all other firm loads with rates capable of accommodating a 7(b)(3) supplemental rate charge. The issue here is not any differences between forecast revenues and the actual revenues from these rates, it is that the level of the rates themselves reflect the proper 7(b)(3) reallocation amounts.

Q. The IOUs argue that BPA does not adjust the section 7(b)(3) reallocation amount determined using projected costs in the section 7(b)(2) rate test to reflect its actual costs. LaBolle, et al., WP-07-E-JP6-08 at 65. BPA determines the section 7(b)(3) reallocation amount based on projected costs in the section 7(b)(2) rate test and does not adjust the section 7(b)(3) reallocation amount to reflect its actual costs. Id. Because the section 7(b)(3) reallocation amount is based on costs and loads projected in the section 7(i) proceeding, the actual costs and loads that BPA experiences and their relationship to the section 7(b)(3) reallocation amount is irrelevant. Id. Do you agree?

A. Again, we agree that actual revenues and costs can differ from those forecast in a rate case. Further, the Implementation Methodology refers to "… the projected amounts to be charged for firm power for the general requirements of public body …" (Emphasis added.) Implementation Methodology, WP-07-E-BPA-50, Attachment B, at IM-1.

Q. The IOUs argue that limiting the allocation of the section 7(b)(3) reallocation amount to "BPA firm, adjustable loads" limits the allocation of such amounts to only the PF Exchange, IP, and NR rates. LaBolle, et al., WP-07-E-JP6-08 at 65. As a result, supplemental rate charges are allocated only to non-preference customers and, therefore, are not allocated to all other power sold by the Administrator to all customers. Id. Do you agree?

A. Yes. In reviewing the IOUs' argument, we now realize that our testimony contained a misstatement. The first emphasized phrase, "non-preference customers" should read "non-PF Preference customers." The Supplemental Proposal does contemplate that some section 7(b)(3) supplemental rate charges can be added to sales to preference customers. This can be clearly be seen in the proposed PF Exchange rate schedule where three preference customers, Benton PUD, Grays Harbor PUD and Snohomish PUD, may be subject to supplemental rate charges should they participate in the REP.

Q. The IOUs argue it is possible for BPA to allocate the section 7(b)(3) reallocation amount (or for that matter any other costs) to rates other than those with firm loads and adjustable rates because BPA already allocates costs to services that have rates fixed that are set forth in contract, for example, the FPS contract sales. LaBolle, et al., WP-07-E-JP6-08 at 66. Please respond.

A. We do allocate costs to the FPS contract sales that can be more (or less) than the expected revenues from such sales. In that instance, BPA's FPS (Surplus)/Shortfall rate design step allocates any under-recovery to other adjustable power rates. If 7(b)(3) reallocation amounts were allocated to these same FPS contract sales, another rate design step analogous to the existing FPS (Surplus)/Shortfall rate design step would be necessary. In his new rate design step, any shortfall due to 7(b)(3) reallocation amounts would necessarily be reallocated to non-PF Preference loads. The end result would likely be very similar to if no 7(b)(3) reallocations were made to the FPS contract sales.

The IOUs present an interesting argument that we will consider. We will review the entire record of this proceeding and make a recommendation to the Administrator that incorporates both the best evidence and the best legal argument.

Q. The IOUs argue that BPA should allocate the 7(b)(3) reallocation amount to all power sold by the Administrator to all customers, other than power sold for the general requirements of PF Preference rate customers, even if that means that some of the

7(b)(3) reallocation amount is allocated to preference customers that purchase power at a rate other than the PF Preference rate. LaBolle, et al., WP-07-E-JP6-08 at 66. Specifically, the section 7(b)(3) reallocation amount should be allocated to the PF Exchange, IP, NR, and FPS rates and in the secondary energy portion of the Slice rate. Id. As discussed above, the Initial Proposal projects that BPA will sell no power at the IP or NR rates in FY 2009. This, however, should not preclude BPA from allocating the section 7(b)(3) reallocation amount to both the PF Exchange rate and the FPS rate, including without limitation FPS contract rates, pre-Subscription contract rates, FPS secondary energy sales rates, and the secondary energy portion of the Slice sales. Id. Please respond.

A. We will consider the IOUs' argument based on the entire record of this proceeding and make the best recommendation to the Administrator.

Q. The IOUs argue that BPA should change the sequencing of its rate design steps to accommodate the allocation of section 7(b)(3) reallocation amounts to all power sold by the Administrator to all customers, other than power sold for the general requirements of PF Preference rate customers. LaBolle, et al., WP-07-E-JP6-08 at 68. The section 7(b)(2) rate test and the allocation of the section 7(b)(3) reallocation amount are sequenced near the end of the RAM process – after the over- and under-recoveries from FPS sales have been reallocated and are reflected in the PF rates. Id. At this point, any allocation of the section 7(b)(3) reallocation amount to the FPS rate for secondary energy sales creates a revenue shortfall that would inappropriately burden the PF Preference rate. Id. Please respond.

A. Our sequencing is based both on past practice and on the instructions in the proposed Implementation Methodology. In addition, there are statutory interpretation issues raised by the IOUs' argument regarding the meaning of "the projected amounts to be charged for firm power" and "the power costs for general requirements of such customers" in section 7(b)(2) of the Northwest Power Act. BPA will address parties' properly raised legal interpretation issues in the Draft and Final Records of Decision in this proceeding. Should the IOUs' argument be adopted by the Administrator, we will make the necessary changes to the Implementation Methodology.

Q. *The IOUs argue that the apparent revenue shortfall is also illusory because the revenue from secondary energy sales and other revenue credits would far exceed the allocated cost, including the section 7(b)(3) allocation amount that would not be allocated to the PF Exchange rate. LaBolle, et al., WP-07-E-JP6-08 at 69. Do you agree?*

A. No. Even if we were to adopt the IOU position, we do not believe that the magnitude of the revenue from secondary energy sales is pertinent to this issue. It might be an issue if the section 7(b)(3) reallocation amount allocated to secondary energy sales exceeded the expected revenues from secondary energy sales, but such is not the case.

Q. *The IOUs propose two potential solutions to the sequencing issue. LaBolle, et al., WP-07-E-JP6-08 at 69-70. The first would be to sequence the allocation of FPS rate secondary energy sales revenues after the section 7(b)(2) rate test and the allocation of the section 7(b)(3) reallocation amount. Id. This sequencing would permit BPA to accommodate the allocation of section 7(b)(3) reallocation amounts to the FPS rates. Id. In other words, it is premature to allocate secondary energy sales revenues until after allocation of the section 7(b)(3) reallocation amount. Id. Please respond.*

A. There are statutory interpretation issues raised by the IOUs' sequencing proposal regarding the meaning of "the projected amounts to be charged for firm power" and "the power costs for general requirements of such customers" in section 7(b)(2). BPA will address parties' properly raised legal interpretation issues in the Draft and Final Records of Decision in this proceeding.

Q. *The second alternative solution proposed by the IOUs is to iterate between the allocation of the section 7(b)(3) reallocation amount and the allocation of the secondary energy*

Paul A. Brodie, Raymond D. Bliven, Harry W. Clark,
William J. Doubleday, and Ron J. Homenick

sales revenue. LaBolle, et al., WP-07-E-JP6-08 at 70. This could be accomplished in the following manner: (1) develop the unbifurcated PF rate (taking the secondary energy sales revenue credit into account) and determine the section 7(b)(3) reallocation amount; (2) allocate the section 7(b)(3) reallocation amount among FPS sales, secondary energy sold under the Slice rate, and the PF Exchange rate; (3) repeat Step 1 (taking into account the reduced secondary energy surplus revenue credit, for example, that results from the allocation of the section 7(b)(3) reallocation amount) and determine a new section 7(b)(3) reallocation amount; (4) repeat Step 2 (allocating the new section 7(b)(3) reallocation amount to all rates other than PF Preference rate); (5) repeat Steps 3 and 4 on an iterative basis until the section 7(b)(3) reallocation amount is unchanged in subsequent repetitions. Id. Please respond.

A. We will consider both of the IOUs' suggestions should the Administrator decide to change the sequencing based on the record of this proceeding.

Q. Does this conclude your testimony?

A. Yes.

This page intentionally left blank.

An Alternative Approach to Allocation of Section 7(b)(3) Costs

BPA has identified an alternative approach to allocating Northwest Power Act section 7(b)(2) rate protection to non-preference loads through section 7(b)(3). Section 7(b)(3) states:

> Any amounts not charged to public body, cooperative, and Federal agency customers by reason of paragraph (2) of this subsection shall be recovered through supplemental rate charges for all other power sold by the Administrator to all customers. …

BPA's current approach is to allocate any 7(b)(3) amount *pro rata* based on loads of all other non-preference power sold, i.e., non-preference loads with adjustable rates including DSI sales at IP rates, Residential Exchange Program (REP) sales at PF Exchange rates, and New Resource sales at NR rates. Market-based sales such as firm surplus or secondary energy sold at FPS rates have not been allocated 7(b)(3) amounts.

This approach results in a single PF Exchange rate applicable to all exchanging utilities. Frequently, application of the current approach results in a PF Exchange rate that exceeds the Average System Cost (ASC) of lower cost utilities, thus eliminating such utilities from qualifying for REP benefits. For example, the WP-07 rate case resulted in a $16.37/MWh increase to the unbifurcated PF rate. This increase eliminated seven of eleven of the potentially qualified exchanging utilities.

An alternative approach would allocate the 7(b)(3) amount *pro rata* based on net exchange benefit amounts established before the section 7(b)(2) rate test. This approach would incorporate each utility's ASC in addition to its eligible REP load into the allocation. Under this approach, any utility that qualifies for REP benefits prior to the rate test would continue to qualify for benefits after the rate test.

The REP benefits for utilities that would receive benefits under this alternative but not under the current approach would come from reduced benefits for higher ASC utilities. One of the principles of the 1984 ASC Methodology was that the Methodology should give participating utilities an incentive to minimize their costs. This principle was never realized in the outcomes of either the ASC Methodology or the ratesetting process. The alternative allocation approach would increase comparative benefits for lower ASC utilities relative to higher ASC utilities and therefore better support the cost minimization principle than the current approach.

The alternative approach would not materially affect the amount of protection afforded to the preference customers, nor would it materially change the PF Preference rate after 7(b)(2) protection has lowered the rate. Due to the interrelationships between loads and costs, including the properties of the modeling and the discrete changes in loads and costs resulting from a utility being either in or out under the current approach, there may be slight differences between the PF Preference rates when comparing the two methodologies.

Another point in favor of this alternative is that it does not open the door for utilities to receive REP benefits that would not receive benefits in the absence of section 7(b)(2). A utility would still need to qualify by having an ASC higher than the PF Exchange rate established prior to the rate test. Further, the alternative would not increase or decrease total net REP benefits. (Note: this statement is true theoretically, but actual results may slightly differ due to the relationship of different ratesetting inputs.)

The alternative approach would produce a different PF Exchange rate for each exchanging utility, i.e., utility-specific "supplemental rate charges" which would be added to the PF Exchange rate that was established before the rate test. This is a departure from past practice of establishing one rate for all exchanging utilities. Thus, there would be no PF Exchange rate established for new utilities applying for REP benefits between rate cases. This limitation could be addressed in REP rules which could state that to receive a Residential Purchase and Sale Agreement (RPSA), a utility would need to have an ASC determined, and the ASC Methodology could state that ASC would be determined only prior to rate cases. This would allow the pairing of the establishment of both the ASC and the supplemental rate charge for new exchanging utilities. It also would allow for the benefits to the new exchanging utility to be established in conjunction with the rate test, thereby minimizing the exposure of preference customers to unanticipated REP costs.

The alternative approach does not address how to allocate 7(b)(3) amounts to DSI or NR loads, which do not have ASCs and therefore no initial benefit allocator. This limitation might be solved by first allocating by loads to each rate class, and then allocate within the REP rate class according to the proposed approach. If no IP or NR loads exist, the supplemental rate charges for the IP and NR rates could be established by using the weighted average PF Exchange supplemental rate charge.

2007 Supplemental Wholesale Power Rate Case Initial Proposal

REBUTTAL TESTIMONY

SUPPLEMENTAL RATE DESIGN

May 2008

WP-07-E-BPA-79

BONNEVILLE
POWER ADMINISTRATION

This page intentionally left blank.

INDEX

REBUTTAL TESTIMONY of

DANIEL H. FISHER, RAYMOND D. BLIVEN, and WILLIAM J. DOUBLEDAY

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL RATE DESIGN

Page

This page intentionally left blank.

REBUTTAL TESTIMONY of

DANIEL H. FISHER, RAYMOND D. BLIVEN, and WILLIAM J. DOUBLEDAY

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL RATE DESIGN

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Daniel H. Fisher and my qualifications are contained in WP-07-Q-BPA-61.

A. My name is Raymond D. Bliven and my qualifications are contained in WP-07-Q-BPA-58.

A. My name is William J. Doubleday and my qualifications are contained in WP-07-Q-BPA-11.

Q. Have you previously submitted testimony in this Supplemental Proceeding?

A. Yes. Mr. Fisher, and Mr. Doubleday, and Mr. Bliven as a replacement for Mr. Keep, have submitted direct testimony, with other witnesses, identified as exhibit WP-07-E-BPA-69. Mr. Bliven, and Mr. Doubleday have submitted direct testimony, with other witnesses, identified as exhibits WP-07-E-BPA-58, WP-07-E-BPA-60, WP-07-E-BPA-68, and WP-07-E-BPA-70. Mr. Bliven has submitted direct testimony, with other witnesses, identified as exhibits WP-07-E-BPA-52, WP-07-E-BPA-53, WP-07-E-BPA-57, WP-07-E-BPA-62, and WP-07-E-BPA-63.

Q. Please state the purpose of your testimony.

A. The purpose of our testimony is to respond to parties' direct testimonies regarding BPA's development of the IP-09R rate. We respond to PNGC's direct testimonies, WP-07-E-PN-06 and WP-07-E-PN-08. We also respond to Alcoa's direct testimony, WP-07-E-AL-04.

Q. How is your testimony organized?

A. This testimony is divided into two sections. Section 1 describes the purpose of this testimony. Section 2 responds to parties' arguments regarding BPA's development of the IP-09R rate.

Section 2: The IP-09R Rate for the DSIs

Q. PNGC states that it finds in BPA's testimony and studies no rationale for reducing the IP rate for FY 2009 in this proceeding, much less to reduce it by more than 30 percent. Prescott and Brawley, WP-07-E-PN-06 at 2. Please respond.

A. First, as we explain later, the IP rate decrease is 29 percent, not more than 30 percent as PNGC claims. Second, although not explicitly stated, the rationale for the IP rate reduction is contained within the Supplemental Proposal. The PNGC-cited reduction in the IP-07R rate is primarily due to our proposed revision to the section 7(b)(3) reallocation of the section 7(b)(2) rate protection amount. All parties, including PNGC, were briefed on this proposed change in pre-rate case public workshops, such as that held on October 22, 2007. *See* Fisher, *et al*., WP-07-E-BPA-69, for a discussion of the change of the reallocation methodology.

In the WP-07 Final Proposal, the section 7(b)(3) reallocation amount was distributed to the PF Exchange, IP and NR rates on a pro rata basis using the forecast loads of the three rates. This pro rata reallocation increased the PF Exchange rate to the point that only four of the potential 12 participating utilities remained in the REP, thereby reducing the PF Exchange loads in FY 2009 from almost 5,961 aMW to 2,551 aMW. For ratemaking purposes, the assumed IP load and NR load were each one-tenth of an average annual kilowatt. Therefore, in the WP-07 Final Proposal, the IP load was allocated about 0.0000039 percent of the section 7(b)(3) reallocation amount.

In the Supplemental Proposal, the section 7(b)(3) reallocation method has been changed. Using the new proposed method, participating utilities that would be eligible for REP benefits prior to the section 7(b)(2) rate test remain viable participants in the REP after the reallocation of the rate protection. This new method has two steps. First, the section 7(b)(3) amount is reallocated on a pro rata basis based on forecast PF Exchange, IP and NR loads. The second step reallocates the section 7(b)(2) rate protection amount allocated to the PF Exchange class among the PF Exchange customers on a pro rata basis using pre-rate test REP benefits. This method results in a much larger PF Exchange load than using the prior method. In the Supplemental Proposal, the PF Exchange load is forecast to be 5,525 aMW. The IP and NR loads remain at one-tenth of an average annual kilowatt. Therefore, the IP rate was allocated 0.0000018 percent of the section 7(b)(3) reallocation amount. Application of this lower allocation amount leads to a reduction in the IP-07R rate.

Q. PNGC is concerned that the proposed IP rate is set at a level that is insufficient to recover the costs and address the risks that BPA will incur in the event that a DSI customer requests and BPA provides service under the IP rate schedule. Prescott and Brawley, WP-07-E-PN-06 at 2. Do you agree?

A. No. The IP rate proposed in the Supplemental Proposal is sufficient to recover the costs allocated to DSI load and is consistent with the rate directions of section 7(c) of the Northwest Power Act. Given the assumptions in the Supplemental Proposal, the proposed IP rate has been established properly.

Q. Is the proposed IP rate designed to recover the full cost of supplying actual power to the DSIs?

A. A properly constructed IP rate that conforms to statutory rate directives may or may not recover the full cost of supplying actual power to DSIs in isolation from all other rates. This is because the IP rate is not designed to recover a specific set of allocated costs. It is determined by reference to the PF Preference rate adjusted for the floor rate test, the value of reserves, and the section 7(b)(3) reallocation of the section 7(b)(2) rate protection amount. The costs of supplying power to the DSIs under the IP rate would be included in BPA's total costs and we would develop all rates to recover all of BPA's costs in a manner consistent with the rate directives.

The rate proposal, as currently designed, does not contemplate actual power sales to the DSIs under the IP rate. As explained to a greater extent below, whether rates would recover the costs of actual power sales to the DSIs depends on the amount of DSI load BPA might agree to serve. Detailed analysis at this time, however, would be speculative because there has not been a Court decision regarding DSI service and BPA has not determined how it might respond to any such decision.

Q. *PNGC argues that since October 1, 2001, it is unlawful for BPA not to recover all of the costs of any sales of power to DSI customers in the rates set for such sales. Prescott and Brawley, WP-07-E-PN-06 at 2. Please respond.*

A. BPA will address legal issues properly raised by the parties in the Draft and Final Records of Decision in this proceeding.

Q. *PNGC argues it is an unwise and inappropriate policy choice for the Administrator to set an IP rate that will be insufficient to recover the costs that BPA would foreseeably incur to provide any actual power service. Prescott and Brawley, WP-07-E-PN-06 at 2. Do you agree?*

A. We do not agree that we have set an IP rate that will be insufficient to recover the costs that BPA may incur should it decide to provide actual power sales to the DSIs instead of the monetized power sale that is currently in place. According to an analysis performed in preparation of the Supplemental Proposal, we estimated that BPA could conceivably provide up to 350 aMW of power to the DSIs at the same cost already included in rates for the monetized power sale currently being made available. This analysis was based on conditions and assumptions existing at that time, and any significant changes in those factors would necessarily change the amount of power that could be made available for a given price. The analysis described was presented at a public workshop on February 13, 2008. *See* Attachment 1; the handout for that workshop is also available on BPA's website. Based on this analysis, we do not agree with PNGC's conclusion that BPA would be unable to recover its costs if an actual power sale was made to the DSIs.

Q. PNGC calculates a rate reduction to the IP rate for FY 2009 by simply averaging the monthly heavy load hour (HLH) and light load hour (LLH) rates set forth in the redlined GRSPs for the IP rate (energy charge). Prescott and Brawley, WP-07-E-PN-06 at 3. Do you believe such an analysis is correct?

A. No. There are other elements of the IP rate than just the energy charges. A more appropriate comparison would be to compare the average annual rates that include all rate components, including the demand rates. The proper comparison would be to compare the WP-07 Final Proposal average annual IP rate of $45.08 per megawatthour, *see* WPRDS Documentation, WP-07-FS-BPA-05A at 36, with the Supplemental Proposal average annual IP rate of $32.07, *see* Supplemental WPRDS Documentation, WP-07-E-BPA-49A at 35. The proper calculation of the rate reduction shows the proposed IP rate is 29 percent lower than the one presented in the WP-07 Final Proposal.

Q. PNGC argues that it is possible that the Court will remand DSI service issues to BPA for reconsideration and that one or more DSIs will request purchases from BPA under the IP rate schedule to be established in this rate case for FY 2009. Prescott and Brawley, WP-07-E-PN-06 at 3. Please respond.

A. Parties' views regarding the Court's future decision are speculative and have little utility at the present time. BPA will respond to any order of the Ninth Circuit based on whatever instructions the Court offers. As stated in the February 13, 2008, workshop, BPA may offer power service to the DSIs should the Court rule against the monetized power sale. Then again, BPA may decide something else.

Q. PNGC argues that BPA was planning to provide "service benefits" in the form of cash subsidies to the DSIs who are aluminum smelters and a below-market, subsidized sale of approximately 17 aMW to Port Townsend Paper, accomplished through a contractual arrangement involving PUD No. 1 of Clallam County, Washington. Prescott and Brawley, WP-07-E-PN-06 at 5. Do you agree?

A. Although we do not characterize the sales as subsidies, BPA is providing a monetized surplus power sale to the smelters and a physically delivered surplus power sale to Clallam Co. PUD for use by Port Townsend Paper.

Q. PNGC argues that BPA has no existing inventory of firm power surplus to its current contractual obligations to serve any DSI load in FY 2009 under the IP rate schedule. Prescott and Brawley, WP-07-E-PN-06 at 6. If BPA were to provide such service, PNGC believes BPA could not do so without engaging in augmentation in addition to that described in the Supplemental Load Resource Study, WP-07-E-BPA-45, as filed with BPA's revised Initial Proposal. Id. Do you agree?

A. Yes. If BPA were to sell power to DSIs in FY 2009, BPA could do so through a sale of firm power under section 5(d) or 5(f) of the Northwest Power Act. As noted previously however, in this Supplemental Proposal we are not forecasting actual power sales to serve DSI load. However, if BPA makes sales to DSIs during FY 2009 under the IP rate, BPA can acquire the firm power to support such sales.

Q. PNGC argues that if BPA decided to grant those DSI power requests, BPA would have to acquire all of that power from the market. Prescott and Brawley, WP-07-E-PN-06 at 7. Do you agree?

A. It is uncertain at this time. BPA would assess its power supply situation at the time. If there were sufficient firm power available, BPA could sell power to the DSIs without making any acquisitions. If firm power were not available, then purchases would be necessary. If BPA does not have firm power available to meet the DSI load then it is not clear what decision BPA would make regarding service to DSI load.

Q. PNGC estimates BPA would lose $22.18/MWh on HLH and $18.86/MWh on LLH in FY 2009 if BPA sold 577 aMW to DSI load under the proposed IP rate, and under-recover the costs of DSI service by approximately $104,224,000. Prescott and Brawley, WP-07-E-PN-06 at 9. PNGC also believes this figure understates BPA's actual losses because it does not take into account performance and credit risks associated with wholesale market transactions or BPA's increased general and administrative costs associated with providing this service. Id. Please respond.

A. PNGC is mistaken. Even if we assume that PNGC has correctly performed all of its calculations and is using the correct market purchase prices, PNGC's calculations ignore the current cost of the monetized power sale that is already in rates. Therefore, assuming, *arguendo*, that BPA were to sell 577 aMW of power to the DSIs at the proposed IP rate, the $55 million cost of the monetized power sale must be netted against the figure computed by PNGC. BPA would not both sell power to the DSIs and provide benefits through a monetized power sale. In addition, the cost of the 17 aMW sale to Clallam for Port Townsend Paper is already in rates. Assuming PNGC's numbers are correct, the cost of the Clallam sale would be almost $8 million. Therefore, under PNGC's reasoning, the cost increase to BPA of providing 577 aMW of IP rate power to the DSIs would be lower than PNGC's estimate by $63 million, resulting in an additional cost of only $41 million – not $104M. PNGC's estimate assumes that all of the additional power would be purchased from the market. However, as already noted, in the event that BPA has any firm power available in FY 2009, even the $41 million would be an overstatement. Account performance and credit risks are items normally addressed in contracts, not in rates.

Q. *PNGC estimates that BPA's proposed IP rate reduction will increase BPA's losses attributable to DSI service under the IP rate, should such service occur in FY 2009, by about $65 million. Prescott and Brawley, WP-07-E-PN-06 at 10. Do you agree?*

A. No. As we have demonstrated above, PNGC has vastly overstated the cost of DSI service, even under the assumption used by PNGC that BPA would provide 577 aMW of power. PNGC calculates its $65 million as the difference between the revenues received at the WP-07 Final Proposal IP rate and the revenues received at the Supplemental Proposal IP rate. Although the rate differential PNGC uses is about right, it presumes that BPA would offer the DSIs a power sale of 577 aMW and it ignores the costs of the current power sales already included in rates.

Q. *PNGC states that it finds no indication that BPA has addressed any risk posed by actual sales under the proposed IP rate. Prescott and Brawley, WP-07-E-PN-06 at 12. Please respond.*

A. The Supplemental Proposal forecast of actual power sales to the DSIs is zero; therefore, we did not address the risk posed by actual sales.

Q. *Does that mean the rate as proposed is defective and could not be used to make physically delivered power sales to DSI load in FY 2009 if BPA decided to do so?*

A. No. The IP rate is set appropriately. It is properly linked to the PF Preference rate and it has been allocated its share of the section 7(b)(3) reallocation amount. The IP rate is not allocated specific costs of resources used to serve DSI loads, except as those costs are reflected in the PF Preference rate. Only if the costs of resources used to serve DSI loads are included in the PF Preference rate would section 7(c) allow those costs into the IP rate.

Q. *PNGC argues that BPA still has an unmanaged, unmitigated risk of at least $47 million to $52 million in FY 2009. Prescott and Brawley, WP-07-E-PN-06 at 12. Do you agree?*

A. No. We have stated earlier that PNGC's assessment ignores costs already in rates, it ignores the likelihood that BPA will have firm power available in FY 2009, and it presumes that BPA would sell 577 aMW of power to the DSIs. Therefore, at best, PNGC's analysis can be considered the worst case scenario. Presumably, we could add $47 to $52 of risk protection to cover the risk perceived by PNGC. However, placing such upward pressure on the PF rate seems excessive given the small probability of the risk ever materializing.

Q. PNGC states that it reads BPA's DSI ROD language to encompass a decision to allocate to the rates paid by public preference customers the costs that BPA would incur, and has since incurred during FY 2007 and FY 2008, to provide service benefits to DSI customers. Brawley, WP-07-E-PN-8 at 2. Do you agree?

A. No. The DSI ROD did not decide any rate matters, including the allocation of costs. The DSI ROD simply states one logical outcome of what would happen if BPA decided to sell power to the DSIs. As indicated earlier, analysis presented at the February 13, 2008, workshop indicates that BPA could sell up to 350 aMW of power at no cost increase to PF customers. This calculation was based on market price assumptions and rate assumptions incorporated into the Supplemental Proposal. Because there are $55 million for the costs of the monetized power sale already incorporated into rates, and that $55 million would not be expended if there were an actual power sale, BPA can sell a substantial amount of power with no further cost impact on PF customers. However, as that analysis also showed, because of the interactions among all of BPA's rates and the workings of the section 7(b)(2) rate test, an actual power sale to the DSIs might increase the REP benefits to participating utilities, primarily the IOUs. Therefore, higher rates to preference customers do not necessarily come from the cost of selling actual power to the DSIs. This is just an example of why the DSI ROD did not provide a decision on allocating the costs of DSI service. It was simply stating a logical conclusion as to why BPA carefully considers all aspects of providing service to the DSIs.

Q. PNGC argues that (1) it is unlawful to allocate DSI service costs to, and thereby inflate, the PF rates and (2) those costs were unlawfully incurred by BPA and costs unlawfully incurred by BPA may not lawfully be allocated to and included in its rates. Brawley, WP-07-E-PN-8 at 2. Please respond.

A. Legal issues properly raised by parties will be addressed in the Draft and Final Records of Decision in this proceeding. We note, however, that the IP rate in the Supplemental Proposal is set in relation to the PF Preference rate through the section 7(c)(2) margin with a section 7(c)(3) credit for any value of reserves and the further adjustment for the reallocation of the section 7(b)(3) rate protection amount.

Q. PNGC argues that the impact of the DSI Service Benefits ROD's decision to allocate "these subsidy costs" to the PF Rates was to inflate the PF rates improperly and unfairly. Brawley, WP-07-E-PN-8 at 2. Do you agree?

A. No. As we have stated, the DSI ROD simply did ***not*** decide how BPA would allocate the costs of the monetized power sale to rates. In the Supplemental Proposal, we proposed to allocate the cost of the monetized power as a section 7(g) cost. Section 7(g) costs are allocated to all classes of service. We have not singled out the PF rate for the allocation of the DSI service costs. The DSI ROD statement is simply a reflection that an increase in costs generally results in an increase in the PF rate. Because a large portion of BPA's expected firm loads are PF loads, one would expect the natural result to be that the a large portion of section 7(g) costs will result in a large portion of the costs being allocated to the PF rate. We further note that preference customers are not the only class of customers that purchase at the PF rate. We are projecting a substantial amount of Residential Exchange sales at the PF rate.

Q. *PNGC argues that it is paying about $3.8 million per year in its BPA rates to cover the costs of the "illegal subsidies" BPA is paying to DSI customers. Brawley, WP-07-E-PN-8 at 3. Do you agree?*

A. No. First, BPA will address legal issues properly raised by the parties in the Draft and Final Records of Decision in this proceeding. Second, PNGC uses an incorrect estimate of the cost of the monetized power sale. PNGC claims the cost is $59 million, but the actual cost is $55 million. Moreover, the $55 million cost was allocated to all firm power rates, not just the PF rates. A final factual error is PNGC's assumption that the PNGC Group pays 6.41 percent of BPA's costs.

Q. *Why do you state that PNGC does not pay 6.41 percent of the cost of the DSI monetized power sale?*

A. To begin with, it is virtually impossible for anyone to calculate how much of any particular BPA cost any particular customer pays. Any attempt to do so is extremely speculative and almost certainly overstated if done in isolation of the total picture of BPA's ratemaking allocations and adjustments.

However, even limiting the discussion to PF purchasers, PNGC's calculation is incorrect. In the Supplemental Proposal, we project that about 7,183 aMW of power will be sold to preference customers at the PF rate in FY 2009. This does not include another 185 aMW of preference customer sales under the FPS rate schedule to those customers with access to the Hungry Horse Reservation. In addition to the preference customers, we expect BPA to sell about 5,525 aMW of PF power to utilities participating in the REP. Assuming that PNGC correctly calculated their purchase share of sales to preference customers as 6.41 percent, this would mean that they are purchasing 7,183 × 6.41%, or 460 aMW. Applying 460 aMW to total PF sales, 12,708 × 6.41%, would result in PNGC's 460 aMW share of PF sales as only 3.6 percent of total PF sales.

Further, in the Supplemental Proposal we assumed that the costs of the monetized power sale to the DSIs was a component of the section 7(b)(2) rate test protection. Although this treatment of the DSI costs is disputed in this proceeding, the PF Preference rates that PNGC pays do not incorporate the full $55 million cost of the monetized DSI power sale. The IOUs have argued that the costs of the DSI monetized power sale fall disproportionately upon the PF Exchange class. In our response to the IOUs, we have calculated that more than half of the DSI costs fall on the IOUs. As a result, the share of the $55 million that PNGC pays is considerably less than the amount it postulates, probably less than one-quarter of its estimate.

Q. PNGC states its position is that BPA lacks legal authority to sell power to DSI customers under section 5(d) of the Northwest Power Act. Brawley, WP-07-E-PN-8 at 5. Please respond.

A. BPA will address legal issues properly raised by the parties in the Draft and Final Records of Decision in this proceeding.

Q. PNGC argues that BPA lacks discretion to sell under section 5(d) when it has no existing inventory of power from FBS resources that is surplus to its obligations to preference and priority and investor-owned utility customers. Brawley, WP-07-E-PN-8 at 5. Please respond.

A. Once again, BPA will address parties' properly raised legal issues in the Draft and Final Records of Decision in this proceeding.

Q. PNGC argues BPA has no legal authority to augment its inventory to create a surplus necessary for a sale under section 5(d). Brawley, WP-07-E-PN-8 at 5. Please respond.

A. BPA will address legal issues properly raised by the parties in the Draft and Final Records of Decision in this proceeding.

Q. PNGC argues that BPA can forecast DSI costs and include them with the forecasted purchased power costs in developing an IP rate schedule that will recover all costs of *serving DSI customers, if and when they request service under the IP rate schedule. Brawley, WP-07-E-PN-8 at 6. Do you agree?*

A. No. As stated above, the Northwest Power Act has specific instructions on how to develop the IP rate. BPA cannot simply choose to allocate costs to the IP rate. Any such allocations must be in conformance with section 7 of the Northwest Power Act. Whether BPA can allocate specific costs as PNGC argues is a legal conclusion. BPA will address parties' properly raised legal issues in the Draft and Final Records of Decision in this proceeding.

Q. PNGC argues that BPA does not need to establish or maintain an IP rate schedule if it believes that it will have no sales to DSI customers under those rates. Brawley, WP-07-E-PN-8 at 7. PNGC states that it is aware of nothing in the Northwest Power Act that requires BPA to establish or maintain an IP rate schedule when it forecasts no sales under that schedule, has allocated no costs to the IP rate pool, and has forecasted no revenues to be realized from those customers. Id. Do you agree?

A. BPA will address parties' properly raised legal issues in the Draft and Final Records of Decision in this proceeding.

Q. Alcoa argues that section 7(c) of the Northwest Power Act provides detailed directives for setting rates applicable to direct service industrial customers. Speer, WP-07-E-AL-04 at 2. Alcoa argues BPA failed to follow these directives in its Initial Proposal for the IP rate, which is the only rate BPA has constructed to serve an aluminum direct service industrial customer's physical load. Id. Please respond.

A. BPA will address the parties' properly raised legal issues in the Draft and Final Records of Decision in this proceeding.

Q. Alcoa argues that the IP rate in the Initial Proposal is considerably higher than a rate that is equitable in relation to the retail rates charged by public bodies and cooperative *customers to their industrial customers in the region. Speer, WP-07-E-AL-04 at 3. Please respond.*

A. Alcoa's argument refers to the direction of section 7(c)(1)(B) of the Northwest Power Act in determining the IP rate. We have applied this direction in developing the IP rate. Also applicable to the determination of the IP rate are sections 7(b)(3), 7(c)(2) and 7(c)(3), which can result in an IP rate that is higher or lower than a simple test of comparing the IP rate to the industrial rates of preference customers. BPA will address the parties' properly raised legal issues in the Draft and Final Records of Decision in this proceeding.

Q. Alcoa argues that instead of simply developing the PF rate charges and making adjustments to those charges as specified in section 7(c)(2) to determine the IP rate charges, BPA used an entirely different methodology that resulted in substantially different IP rate charges. Speer, WP-07-E-AL-04 at 3. Do you agree?

A. No. Our methodology is consistent with section 7(c)(2) and has been established and implemented through many rate proceedings beginning with BPA's WP-85 case.

Q. Alcoa states that BPA considered all of the factors in its 7(c)(2) Industrial Margin Study and determined an adjustment of 0.57 mills per kilowatthour was appropriate. Speer, WP-07-E-AL-04 at 3. Do you agree?

A. Yes. The 0.57 mills per kilowatthour is the result of the Margin Study developed for the WP-07 Final Proposal. We have proposed no changes to the margin in the Supplemental Proposal.

Q. Alcoa argues that BPA should simply add 0.57/kwh to each of the PF HLH and LLH energy charges to determine the corresponding PF energy charges. Speer, WP-07-E-AL-04 at 4. Alcoa argues the PF demand charges should be identical to the corresponding IP demand charges. Id. Please respond.

A. Alcoa presents one method of applying the margin to the PF rate to derive the IP rate. We have, based on past practice, chosen a slightly different method. Normally, the chosen method of applying the section 7(c)(2) margin can be simply characterized as adding the margin to the average annual PF energy rate and then reshaping the 24 monthly/diurnal energy charges based on the results of the Marginal Cost Analysis. The two methods arrive at slightly different monthly/diurnal energy rates, but when applied to a flat annual energy load, such as the DSIs' load would be, the revenues from the two methods would be identical. Normally, we would develop the IP demand rate as Alcoa has stated.

Q. You say "normally." Does that mean that BPA did not do that in the Supplemental Proposal?

A. Yes. As a result of the Partial Resolution of Issues (*see* Evans, *et al*., WP-07-E-BPA-31), the rates developed in the Supplemental Proposal, as with the WP-07 Final Proposal, did not conform exactly to the normal method described above. BPA used the normal method in the WP-07 Initial Proposal, but then the Partial Resolution directed us to scale the individual rate components, that is, the monthly/diurnal energy rates and the monthly demand rates, upward or downward with changes to the overall revenue requirement. In the Supplemental Proposal, the revenue requirement is somewhat lower than the revenue requirement used in the WP-07 Initial Proposal. Therefore, the rate components have been scaled down. As a result, the effective section 7(c)(2) margin applied to the IP rate is actually slightly less than 0.57 mills per kilowatthour. The IP demand rates remain equal to the PF demand rates.

Q. Are there any other factors that must be considered in determining the IP rate?

A. Yes. Alcoa has left out of its testimony critical components in the determination of the IP rate. Alcoa has acknowledged these components in its legal memorandum. *See* Alcoa Legal Memorandum, WP-07-M-AL-88. The IP rate is not final with the application of the section 7(c)(2) margin. Another component is the floor rate test. The floor rate test assures the proposed IP rate is not less than the IP rate in effect during the year ending

June 30, 1985. The floor rate test in this proposal did not result in a change to the proposed IP rate, but there could be circumstances when the floor rate test increases the IP rate to a higher level than the PF rate plus the section 7(c)(2) margin.

A second component is the section 7(c)(3) value of power system reserves credit. This credit, included into the IP rate when the DSIs provide power system reserves to BPA, will result in a lower IP rate. Because we have forecast zero power sales to the DSIs, we have not included any credit for power system reserves to the DSIs. Further, it is unclear whether the DSIs would offer, or BPA would procure, power system reserves if BPA were to offer an actual power sale to the DSIs. Therefore, we believe that it is inappropriate to include a value of reserves credit in the proposed IP rate. The lack of a credit in the IP rate would not inhibit BPA from procuring power system reserves from the DSIs if an actual power sale were to occur and the DSIs offered reserves to BPA. There are other mechanisms by which BPA could purchase reserves from the DSIs.

Another component of IP rate development Alcoa has omitted from testimony is the application of the section 7(b)(3) supplemental rate charge. If the section 7(b)(2) rate test has triggered, as it has in this proposal, the cost of the rate protection afforded to preference customers is applied proportionately to all other power sold by BPA, including power sold under the IP rate schedule. In its legal memorandum, Alcoa raises an alternative theory of allocating the section 7(b)(3) reallocation amount to secondary sales. This identical theory was raised in the testimony of the IOUs, and we have responded. *See* Brodie, *et al*., WP-07-E-BPA-78.

Q. *Alcoa argues that because BPA has determined there is no IP load in this instance, there are no additional section 7(b) charges that can be recovered from the IP rate, and therefore no additional adjustments are required. Speer, WP-07-E-AL-04 at 4. Do you agree?*

A. No. The IP rate should be determined according to all of the provisions of section 7, including all "additional adjustments," regardless of whether BPA expects to make any sales under the IP rate schedule. If we assumed zero sales, we could not compute an IP rate. Therefore, we have assumed that there is one-tenth of an average annual kilowatt of IP sales for ratemaking purposes. As a result, costs can then be properly allocated proportionately to this IP sale to properly develop the IP rate. Then, once the rates are determined, this assumed sale is removed to test for revenue sufficiency. The revenue shortfall from this ratemaking assumption, $28 (twenty-eight dollars) in this proposal, is covered within the rounding error of other rates.

Q. Alcoa argues that in order to develop an appropriate IP rate, BPA must identify the electric power resources it is using to serve the DSI load, and then divide those costs into the DSI load. Speer, WP-07-E-AL-04 at 4. Do you agree?

A. No. The Alcoa argument that the IP rate is simply the unit cost of a resource designated to serve the IP load is incorrect. Section 7(c) of the Northwest Power Act gives direction as to the calculation of the IP rate. For FY 2009, the IP rate is allocated resource costs from the Exchange resource pool as well as the New Resources resource pool. Because these resource pools are expensive compared to the FBS, if the rate development stopped at this point, the IP rate would be over $51 per megawatthour. But the ratemaking steps continue. The next step is to perform the IP-PF link calculation that will establish the section 7(c)(1)(B) rate relationship between the IP rate and the PF rate, as it exists at this point in the ratemaking. After the IP-PF link, the IP rate is about $30 per megawatthour. The next step is the section 7(b)(2) rate test. After the section 7(b)(2) rate test, the section 7(b)(3) reallocation of the rate protection amount to the IP rate class results in a FY 2009 IP rate of about $37 per megawatthour. A second IP-PF link calculation is performed to reestablish the section 7(c)(1)(B) rate relationship. However, this final IP-PF link calculation does not remove the section 7(b)(3) costs from the IP rate. The final FY 2009 IP rate is set at about $32 per megawatthour. The progression of FY 2009 IP rates described above can be seen in the FY2009_RAM model, tab "Start Here."

Q. *Alcoa argues that BPA must determine that the resulting rate meets the requirements of the statute regarding whether the rate is equitable in relation to the rates of those of the industrial customers of public bodies and cooperatives. Speer, WP-07-E-AL-04 at 4. Do you agree?*

A. The IP-PF link calculations described above are designed to establish a cost relationship between the IP rate and the PF rate as a way of achieving the equitable relationship between the IP rate and the rate paid by industrial customers of public body customers of BPA. However, because the IP-PF link cannot remove the section 7(b)(3) costs allocated to the IP rate, if the section 7(b)(2) rate test triggers, the IP rate can be higher than the PF rate.

Alcoa's argument does raise a good point that it is difficult to see the linkage between the IP rate and the PF Preference rate. Therefore, we are modifying our proposed IP rate schedules to show the 7(c)(1)(B)-based IP rate (including any floor rate and value of reserves adjustments, if and when applicable) and also the section 7(b)(3) reallocation amount that is allocated to the IP rate as a supplemental rate charge, as we do with the PF Exchange rates. We will also show the supplemental rate charge for the NR rate. Modified IP and NR rate schedules, based on the Supplemental Proposal as currently filed, are attached to our testimony. *See* Attachments 1 and 2.

Q. *Alcoa argues it is impossible to design a rate with neither the numerator nor the denominator determined. Id. Do you believe it is impossible to design a rate without the numerator or the denominator determined?*

A. Yes. This is why we have assumed one-tenth of an average annual kilowatt as an IP sale for purposes of ratemaking. This small amount of an IP sale is in the denominator and the small amount of costs allocated to that sale is in the numerator, as determined as the pro rata allocation of costs to the IP rate pool.

Q. Alcoa states it is important that BPA appropriately describe the design of the IP rate because it is possible, either due to Court action or BPA's own perception of fairness, that BPA will offer the DSIs physical power in the future. Speer, WP-07-E-AL-04 at 5. The exercise of developing the IP rate may therefore have future significance, and Alcoa does not want to have its silence interpreted as agreeing with the methodology used to develop the proposed, but currently irrelevant, IP rate. Id. Please respond.

A. We have developed the IP rate for sales to DSIs based on our understanding of BPA's ratemaking requirements. We do not believe it matters whether any sales to DSIs are expected to be made during the rate period to calculate an appropriate rate consistent with statutory direction.

Q. Alcoa argues that BPA's proposal ignores amounts collected from DSI customers during the FY 2002-2006 period that result from the REP settlement overpayment. Speer, WP-07-E-AL-04 at 5. Do you agree?

A. Yes. We have constructed the Lookback analysis without respect to DSI customers.

Q. Alcoa is advocating that BPA's net rates to Alcoa in the future should recognize that Alcoa has contributed to the recovery of BPA's costs since BPA's inception. Speer, WP-07-E-AL-04 at 6. Alcoa (and the other last remaining aluminum DSI), alone, should not be relegated to purchasing power in an open market. Id. Alcoa argues such a result is contrary to the ratemaking provisions of the Northwest Power Act and the Regional Preference Act (and related legislation). Id. at 6-7. Please respond.

A. Alcoa's argument raises two issues. The first is a question about whether future IP rates should reflect the return of Lookback Amounts to the DSIs. The second is whether future IP rates should reflect the return of deemer balances to the DSIs.

We have constructed the Lookback without regard to the DSIs. As Alcoa stated, "Alcoa signed a settlement with BPA that accepted the Compromise Approach and in doing so, accepted the level of rates in that approach. Alcoa believes that it struck a deal and it is not seeking a change of rates that applies to the period prior to September 30, 2006." *Id.* at 6. We take this statement to agree with our initial testimony, where we stated "…BPA is proposing that the IP-TAC rates would have been set at a level established consistent with the Compromise Approach. Therefore, there will be no revenue deviations resulting from changes to rates applicable to the DSIs." Bliven, *et al*., WP-07-E-BPA-52 at 15. Based on this position, we concluded "that the DSIs will not receive any Lookback Amounts. In the future, the IP rate will be linked to the PF Preference rate before application of the reduction of the PF Preference rate due to amortization of Lookback Amounts." *Id*. Alcoa is questioning this proposal based on its position that "Alcoa has contributed to the recovery of BPA's costs since BPA's inception." Whether this position is accurate or not, one fact worth noting is that a portion of the Lookback Amounts was accumulated during a period when there were no sales to the DSIs, October 2006 through March 2007. We will take Alcoa's request under consideration and make a recommendation to the Administrator based on the entire record of the proceeding.

The issue of the deemer treatment appears to be a different question than the Lookback application. Whereas the Lookback Amounts were accumulated during a period when the IP rate was developed consistent with the Compromise Approach, the deemer balances were accumulated during a time when most, if not all, of the DSIs were operating, including the three remaining DSIs. In contrast to the Lookback Amounts, the initial deemer balances began to accumulate during the period when the DSIs were paying for the bulk of the REP benefits, the period before July 1, 1985. It seems to be reasonable to consider that the DSIs paid more during the pre-July 1, 1985, period than they would have had the deemer provisions alleviated the IOUs from cash Residential Exchange payments to BPA at that time. Although we have not done an analysis of how much of the deemer balances were accumulated before July 1, 1985, and how much of the REP benefits were paid by the DSIs during that time, it would be our expectation that the DSIs paid more to BPA for REP benefits than they would have if the deemer provision was not present.

Q. Did the DSIs pay for all REP benefits prior to July 1, 1985?

A. Not necessarily. The Northwest Power Act states that

> for the period prior to July 1, 1985, [the IP rate will be] at a level which the Administrator estimates will be sufficient to recover the cost of resources the Administrator determines are required to serve such customers' load and the net costs incurred by the Administrator pursuant to section 5(c), based upon the Administrator's projected ability to make power available to such customers pursuant to their contracts, to the extent that such costs are not recovered through rates applicable to other customers…

16 U.S.C. § 839e(c)(1)(A). It is the last phrase, "to the extent that such costs are not recovered through rates applicable to other customers," that would require substantial analysis. Short of undertaking such an analysis, and given that subsequent to July 1, 1985, the rates for DSIs are calculated in a much different manner, it may be reasonable to conclude that the DSIs paid for a considerable portion of REP benefits, but not all. Therefore, it is also reasonable to conclude that the DSIs might be entitled to some return of the deemer balances.

Q. How might such a return of deemer balances to the DSIs be done?

A. We could separate the application of the Lookback Amounts from the application of the deemer balance repayments in the calculation of the PF Preference rate and reflect the reduction resulting from the deemer balances in the IP rate as well. We could then link the IP rate to the PF Preference rate that reflected the return of the deemer balances.

Q. *That works for the Idaho Power deemer balance, but what about the deemer balances for Avista and NorthWestern Energy?*

A. We did not consider the differences between Lookback Amounts and deemer balances being treated differently with respect to the DSIs when we constructed the proposed Lookback approach. We understand that our Lookback approach has accommodated the payback of the deemer balances for Avista and NorthWestern Energy and, in a sense, converted the deemer balances into Lookback Amounts. Our premise of not adjusting the IP rate to take into account the repayment of Lookback Amounts in the future would deprive the DSIs of any benefit of the repayment of the Avista and NorthWestern Energy deemer balances.

Q. *What do you propose to do about this?*

A. We can think of four options. The first is the method we have already proposed, with no reflection of the Lookback Amounts or deemer balances in the IP rate. The second would reflect the repayment of Idaho's deemer amount by linking the IP rate to a PF Preference rate with the deemer reduction but not the Lookback reduction. The third would separate the Lookback Amounts into deemer repayment and settlement repayment and would link the IP rate to a PF Preference rate that reflects the deemer repayment (and Idaho repayment) but not the settlement repayment. The fourth would link the IP rate to a PF Preference rate that reflects both the settlement repayment and deemer repayment.

Q. *How are the options consistent with section 7(c)?*

A. The first option is inconsistent for the reasons stated above. The second and third options are somewhat more consistent than the first option, but would continue to have a discrepancy between the IP rate and the PF Preference plus the 7(c)(2) margin. The fourth option appears to be most consistent with section 7(c). However, the first three options could become consistent with section 7(c) if the Lookback Amounts and the deemer balances were returned to the PF Preference customers through a mechanism other than a reduction in the PF rate. One such mechanism was proposed by APAC. *See* Wolverton, WP-07-E-AP-1 at 85-87.

Q. Which option are you proposing to choose?

A. We will review the entire record of this proceeding and make a recommendation to the Administrator that incorporates both the best evidence and the best legal argument.

Q. Does this conclude your testimony?

A. Yes.

This page intentionally left blank.

Attachment 1
WP-07-E-BPA-79

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

DSI Heads Up

- How might these results change if the Ninth Circuit rules against BPA in PNGC case?
  - Currently, the DSI $59 million monetary payment is in the Program Case but not the 7(b)(2) Case
  - If BPA sells power at the IP rate, loads and costs end up in both the Program and 7(b)(2) Cases, resulting in the:
    - 7(b)(2) trigger decreasing
    - PF Exchange rate decreasing
    - REP benefits increasing
  - BPA could sell about 350 aMW to DSIs at the IP rate with no net increase in costs. $59 million = Market – IP rate x IP Load
  - Including 350 aMW of IP Load increases REP benefits from $250 million to $300 million
  - Because the REP benefits are being reduced to $210, the increase in REP benefits would be used to reduce the Lookback Amount faster instead of raising the PF rate ($90 million vs. $40 million in Lookback reduction for FY09).

No Surprises Workshop February 13, 2008 38

This page intentionally left blank.

Attachment 2
(Referenced from WP-07-E-BPA-51, page 51)

WP-07-E-BPA-79

B. ENERGY RATE

1. Monthly Energy Rates for FY 2009

1.1 Applicability

These energy rates apply to eligible customers purchasing power.

1.2 Rate Table

Applicable Months	*HLH Rate*	*LLH Rate*
January	33.06 mills/kWh	27.68 mills/kWh
February	33.14 mills/kWh	29.09 mills/kWh
March	31.72 mills/kWh	27.80 mills/kWh
April	26.00 mills/kWh	22.11 mills/kWh
May	22.82 mills/kWh	19.16 mills/kWh
June	22.47 mills/kWh	16.63 mills/kWh
July	27.39 mills/kWh	22.41 mills/kWh
August	30.41 mills/kWh	25.83 mills/kWh
September	31.70 mills/kWh	28.14 mills/kWh
October	29.65 mills/kWh	25.36 mills/kWh
November	35.36 mills/kWh	28.86 mills/kWh
December	37.19 mills/kWh	30.50 mills/kWh

1.3 Section 7(b)(3) Supplemental Rate Charge

A supplemental rate charge of 1.81 mills/kWh shall be added to each IP energy rate in the Rate Table in section 1.2 above.

C. LOAD VARIANCE RATE

The Load Variance Rate for FY 2009 applies to customers purchasing this product consistent with Section III below. The rate for Load Variance is 0.45 mill/kWh.

This page intentionally left blank.

B. ENERGY RATE

1. Monthly Energy Rates for FY 2009

1.1 Applicability

These rates apply to eligible customers purchasing power under this rate schedule.

1.2 Rate Table

Applicable Months	***HLH Rate***	***LLH Rate***
January	58.39 mills/kWh	48.33 mills/kWh
February	58.54 mills/kWh	50.96 mills/kWh
March	55.87 mills/kWh	48.56 mills/kWh
April	45.20 mills/kWh	37.93 mills/kWh
May	39.25 mills/kWh	32.41 mills/kWh
June	38.60 mills/kWh	27.69 mills/kWh
July	47.78 mills/kWh	38.48 mills/kWh
August	53.43 mills/kWh	44.88 mills/kWh
September	55.85 mills/kWh	49.18 mills/kWh
October	52.00 mills/kWh	44.01 mills/kWh
November	62.68 mills/kWh	50.54 mills/kWh
December	66.10 mills/kWh	53.61 mills/kWh

1.3 Section 7(b)(3) Supplemental Rate Charge

A supplemental rate charge of 6.76 mills/kWh shall be added to each NR energy rate in the Rate Table in section 1.2 above.

C. LOAD VARIANCE RATE

The Load Variance Rate for FY 2009 applies to customers purchasing this product consistent with Section III below. The rate for Load Variance is 0.45 mill/kWh.

This page intentionally left blank.

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 Supplemental Wholesale Power Rate Case Initial Proposal

REBUTTAL TESTIMONY
LOAD RESOURCES

May 2008

WP-07-E-BPA-80

This page intentionally left blank.

INDEX

REBUTTAL TESTIMONY of

JON A. HIRSCH, GLEN S. BOOTH, HARRY W. CLARK,

TIMOTHY C. MISLEY, and RICHARD J. VAN ORDEN

Witnesses for Bonneville Power Administration

SUBJECT: LOAD RESOURCE

Page

This page intentionally left blank.

REBUTTAL TESTIMONY of

JON A. HIRSCH, GLEN S. BOOTH, HARRY W. CLARK,

TIMOTHY C. MISLEY, and RICHARD J. VAN ORDEN

Witnesses for Bonneville Power Administration

SUBJECT: LOAD RESOURCE

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Jon a. Hirsch and my qualifications are contained in WP-07-Q-BPA-16.

A. My name is Glen S. Booth and my qualifications are contained in WP-07-Q-BPA-59.

A. My name is Harry W. Clark and my qualifications are contained in WP-07-Q-BPA-09.

A. My name is Timothy C. Misley and my qualifications are contained in WP-07-Q-BPA-41.

A. My name is Richard J. Van Orden and my qualifications are contained in WP-07-Q-BPA-68.

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

A. Mr. Hirsch, Mr. Misley, Mr. Booth and Mr. Van Orden submitted direct testimony, with another witness, identified as Exhibits WP-07-E-BPA-54 and WP-07-E-BPA-64. Mr. Hirsch has submitted direct testimony, with other witnesses, identified as Exhibit WP-07-E-BPA-72.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to respond to direct testimony filed by the Association of Public Agency Customers (APAC) and the Western Public *Agencies Group (WPAG).*

Q. How is your testimony organized?

A. This testimony consists of four sections. Section 1 explains the purpose and scope of the testimony. Section 2 responds to issues parties raised regarding price elasticity in public agency load forecasts. Section 3 responds to issues parties raised regarding availability of data for public agency load forecasts. Section 4 responds to issues parties raised regarding the DSI firm requirements PSC obligation forecasts.

Section 2: Price Elasticity in Public Agency Load Forecasts

Q. APAC criticizes BPA's decision not to consider price elasticity in forecasting PF loads in the FY 2002-2006 Lookback Study. Wolverton, WP-07-E-AP-1 at 36-37. Do you agree that BPA should have included price elasticity in forecasting PF loads?

A. No. We do not include price elasticity in forecasting loads served at the PF rate for three primary reasons. First, although we subscribe to the general economic theory that increasing the real price of a good will often result in decreased demand for that good, the theory only holds if the ultimate consumer is faced with the higher price. Because BPA's rate, and therefore any BPA rate increase, is at the wholesale power level, the retail rates of BPA's public agency customers must reflect the wholesale rate changes for there to be an elasticity effect. Retail rates are influenced by many factors beyond BPA's wholesale power rate, such as transmission costs, distribution costs, purchase power costs for power other that provided by BPA, and equipment, staff and other overhead costs, as well as the desire to build or use reserves. It is unknown whether any particular BPA rate increase will lead to a retail rate increase.

Second, public agency customer loads are influenced by many factors other than consumer responses to rates. Factors such as weather and economic conditions can have a much greater impact on load changes than wholesale power rate changes.

Third, BPA does not track or forecast public agency retail rates and so does not have the relevant prices to include in its forecast models of PF loads. We therefore do not have the information available to incorporate price elasticity into its PF load forecasts.

Q. APAC states that BPA's decision not to include price elasticity in forecasting PF load is a violation of basic economic theory on the impact of prices. Wolverton, WP-07-E-AP-1 at 36. Do you agree?

A. No. Although price elasticity is an established economic theory, there are circumstances when that theory is not applicable. As pointed out in the previous discussion, the relevant price is the retail rate, not the wholesale rate. Because we did not know and had no control over the extent to which BPA's wholesale power rates influence retail rates, a price elasticity assumption would not produce reliable results and thus would not be appropriate.

Q. APAC claims that BPA's statement "the MCA informs BPA's rate design such that BPA's rates send economic price signals" contradicts BPA's decision not to include price elasticity in load forecasts. Wolverton, WP-07-E-AP-1 at 36. APAC also argues that BPA recognizes the impact of price signals, failed to include their effects in its load forecast and offered no defensible reason for its treatment. Id. at 37; Wolverton, WP-07-E-AP-1-E2. Do you agree?

A. No. APAC incorrectly equates price signals with price elasticity. We consider price elasticity to be just one type of response to a price signal. Price elasticity suggests a reduction in the consumption of a good in response to an increase in price. Economic price signals, however, can be useful for reasons other than to reduce total energy use. For example, they can be used to motivate a shift of load usage from a high cost month to a lower cost month, or from on-peak hours to off-peak hours. Therefore, the intent of using rates to send price signals does not necessarily imply that a price elasticity assumption is warranted.

Q. *APAC states that a 50 percent wholesale rate change, as BPA envisioned, would still have a substantial impact at the retail level, particularly on customers served at high voltages with fewer distribution costs in their rates. Wolverton, WP-07-E-AP-1 at 37. Do you agree?*

A. APAC's statement implies that customers would necessarily adjust their retail rates in response to BPA's wholesale power rate changes. We do not agree with this implication. It is our experience that customers could and do take other approaches, including using reserves, cutting other costs, issuing bonds and deferring purchases or projects, to avoid making changes to their retail rates in response to a change in wholesale rates.

The PF-02 base rate was set to remain constant. The variable portion of the WP-02 power rates was a set of three Cost Recovery Adjustment Clauses (CRACs). The CRACs were designed as short-term adjustments to BPA's rates. The Load-Based CRAC was set to change every six months. The Financial-Based CRAC and the Safety Net CRAC, if implemented, would be in effect for one year before being reset. Consumer changes made in response to short-term adjustments, if any, tend to be minimal. In general, consumer investment does not significantly change (*e.g.*, through the purchase of a more energy-efficient appliance) until a long-term price change is apparent.

Q. *APAC claims that BPA failed to provide a reasonable forecast of PF loads because it failed to take into account price impacts. Wolverton, WP-07-E-AP-1 at 38. Actual loads of non-Slice preference customers fell short of BPA's projections by an average of 10 percent in the period 2002-2006. Id. APAC argues it is "undeniable" that price impacts had a substantial effect on those loads. Id. Do you agree that BPA's decision not to include price impacts caused BPA's PF load forecasts to be unreasonable and that price impacts were a substantial reason that non-Slice PF loads were 10 percent less than forecast?*

A. No, to both questions. The national economy succumbed to a recession in the fall of 2001. This recession affected the Pacific Northwest (PNW) economy as well. Total non-farm employment in the PNW (the states of Idaho, Oregon and Washington) for 2001 declined by about 18,000 jobs, or 0.4 percent, from the 2000 level. Job levels fell an additional 63,000, or 1.3 percent, in 2002 and another almost 4,000 in 2003. Total non-farm employment levels did not reach 2000 levels for the combined three states until 2004.[1]

In addition, the weather in the region (as measured by average daily temperature for Portland, Seattle and Spokane) was slightly warmer than normal for FY 2003-2006. This would have resulted in loads less than forecast.

Although it is easy to say that something is "undeniable," statements should be supported by a reasonable evaluation of the facts. Based on our experience, we believe the foregoing factors support the conclusion that the economic recession and more moderate than normal weather were the major reasons loads fell below their projected levels.

Q. WPAG notes that BPA used the load forecasts from the final studies in the supplemental proceeding of the WP-02 rate case, and did not update such forecasts to reflect the changed circumstances for the recalculation of the 7(b)(2) rate test. Grinberg, et al., WP-07-E-WA-05 at 32. WPAG criticizes this approach, stating that the preference customer load forecasts being used by BPA for its recalculation of the 7(b)(2) rate test do not reflect either the substantially higher PF-02 rate that was in the offing in the spring

[1] Employment data were extracted from the US Bureau of Labor Statistics website, www.bls.gov/sae/home.htm, section "GET DETAILED STATE AND METRO AREA STATISTICS". Select the option "Most Requested Statistics". Pick a state and select the table for "Total Nonfarm Seasonally adjusted". This provides monthly data by state that was averaged by year and summed to the three-state total.

of 2001, nor do they reflect the customer response to these higher prices and to the West Coast energy crisis generally. Id. at 32. Please respond.

A. In the spring of 2001 BPA did not have a more current load forecast than the one used for the WP-02 Supplemental Proposal.

Q. WPAG states that BPA was discussing the fact that "2 cents in 2000" was not achievable, and that the PF-02 rate might increase by up to 250 percent. Grinberg, et al., WP-07-E-WA-05 at 32. The PF-02 rate established in the May 2000 WP-02 Record of Decision was initially increased by about 46 percent, and to higher levels through the operation of the CRACs. Id. WPAG claims it was clear in the spring of 2001 that the preference customer loads forecast in the initial WP-02 rate case proceeding were no longer reasonable. Id. Do you agree with WPAG's analysis and conclusion?

A. No. Although BPA was fairly certain that wholesale power rates would need to increase, BPA did not know how much rates would need to increase. In fact, at one point BPA thought the increase could be as high as 250 percent, a level that never materialized.

Further, as WPAG acknowledges in its testimony, it is the retail rate, as opposed to the wholesale rate, to which consumers respond. *Grinberg, et al., WP-07-E-WA-05 at 33* (adjusting the wholesale power cost in its elasticity calculation to total utility cost). BPA did not know, and had no control over, whether public agency customers would reflect BPA's wholesale rate increases in their retail rates. It is clear that BPA's rates are not always passed on to retail customers. As WPAG pointed out in its response to a data request, "Peninsula Light Company absorbed any BPA CRAC rate increase until 2004…" *See* Data Request No. BPA-WA-8, Attachment 1 to this testimony. Hence, price elasticity is an unreliable input given the variables involved, which are outside of BPA's control.

To use the speculative input of price elasticity in forecasting PF loads where no load reduction agreements were in place[2] would be imprudent because it would put BPA at risk of not recovering costs. If we used a price elasticity assumption, but it turned out that BPA's price increases were not passed on to consumers through retail rates, or if consumers did not respond to the increased prices, BPA's actual loads would be higher than forecasted. If BPA experienced higher than expected loads, BPA would have had to buy from the market and/or would have decreased secondary sales, thus decreasing BPA's likelihood of recovering costs.

Given the variables involved, we do not believe price elasticity to be a reliable assumption on which to base its load forecasts used in setting power rates.

Furthermore, the PF load forecasts in the WP-02 Final Proposal were not used in this Lookback study. Instead, the more recent forecasts from the WP-02 Supplemental Proposal (June 2001) were used.

Q. WPAG states that it attempted to estimate the impact that increased power prices had on PF customer load. Grinberg, et al., WP-07-E-WA-05 at 33. Specifically, WPAG estimated the impact of a projected 46 percent BPA rate increase on the forecast loads of full and load following preference customers of BPA, assuming that BPA power costs are 60 percent of total utility costs and using BPA's standard elasticity assumption. Id. WPAG claims this resulted in an average reduction to the forecast loads of the full and load following customers of about 67 aMW in each year of the FY 2002-2006 period. Id. Do you believe WPAG's calculation accurately reflects the impact higher power prices would have on PF customer loads?

[2] Note that the forecasts used to produce the Load-Based Cost Recovery Adjustment Clause (LB CRAC) amounts included load reductions for those customers who signed load reduction agreements (LRA) to increase their retail rates commensurate with the LB CRAC. There were 39 non-pre-Subscription customers who signed an LRA containing a retail rate clause.

A. No. First, BPA does not have a “standard elasticity assumption.” The elasticity assumption WPAG cited in its testimony and provided in Response to Data Request No. BPA-WA-01 was estimated by BPA for use in assigning price impacts only for those public agency customers who signed Load Reduction Agreements, thereby agreeing to raise their retail rates consistent with BPA’s wholesale power rate increase, accomplished through the LB CRAC. These agreements were in place for only 39 utilities with load following contracts (which were not pre-Subscription, for whom the CRACs did not apply) in FY 2002, for seven such utilities in FY 2003, and for no utilities after FY 2003.

In its calculation, WPAG assumes that all of BPA’s full service and load following customers would fully reflect BPA’s rate increase (by 60 percent of a 46 percent rate increase) in their retail rates. Clearly this was not the case, as evidenced by Response to Data Response No. BPA-WA-8, Attachment 1 to this testimony. In its response, WPAG provided data for three utilities: one purchased the Slice/Block product, one purchased the Block product, and one purchased a load following product. Only the customer purchasing load following is relevant to this discussion and that customer did not increase its retail rates to reflect the increased BPA power rates. Thus, we can reasonably surmise that there were other utilities that did not raise their retail rates as well. Therefore, it was impossible to predict with any certainty whether and by how much each utility would change its retail rates to reflect wholesale rate increases.

Furthermore, the WP-02 PF base rate remained constant, and a three CRAC system was being implemented. The Load-Based CRAC was to change every six months. If a Financial-Based CRAC or a Safety Net CRAC was implemented, each would be short-term—in effect for only one year before being reset. It was therefore uncertain what the level of any wholesale rate increase would be over the long term. If consumers expected a rate increase to be short-lived, they might have an incentive to adjust their electricity use somewhat but would probably not invest in efforts to reduce their electricity consumption over the long term. WPAG's use of a 46 percent wholesale rate increase for each year of the five-year period is unfounded.

Thus, we do not believe WPAG's calculation accurately reflects the impact higher power prices would have on PF customer loads.

Q. *With regard to the preference customer forecast loads for recalculating the section 7(b)(2) rate test, WPAG stated that BPA should re-estimate the preference customer loads used for its recalculation of the section 7(b)(2) rate test for the FY 2002-2006 period rate case using the information available to it in the spring and summer of 2001 regarding the expected increases to the PF-02 rate resulting from the West Cost energy crisis. Grinberg, et al., WP-07-E-WA-05 at 33. WPAG claims this should result in preference customer loads that are about 67 aMW lower in each year than those proposed by BPA. Id. Do you agree with WPAG's recommendations and conclusion?*

A. No. We do not agree with WPAG's recommendations and conclusion because, as stated above, we do not believe WPAG's calculation accurately reflects the impact higher power prices would have on PF customer loads.

Section 3: Availability of Data for Public Agency Load Forecasts

Q. *In response to APAC's request for individual utility load data, BPA noted that such information is proprietary and that APAC would have to obtain permission from each utility to access that data. Wolverton, WP-07-E-AP-1 at 37. APAC responded that it was extremely difficult for a single party to accomplish this task. Id. Do you agree that it would be "effectively impossible" for APAC to obtain permission from each utility within a short time?*

A. First, one must recognize that BPA is not the sole source of this information. APAC could have obtained the data for most, if not all, of BPA's customers, from other sources. These sources include the Energy Information Administration (a division of DOE) or subscription services such as PowerDat. Furthermore, APAC represents the industrial customers of public agencies. Thus, APAC's members have close relationships with their serving utilities and share mutual interests on myriad issues in BPA's ratemaking proceedings. If APAC is unable to readily obtain the information from the public agencies, it supports BPA's position respecting the business sensitive nature of the public agencies' load data.

Furthermore, the APAC members have been regular participants in BPA's rate proceedings for many years. Since 1995, BPA has consistently operated under the principle that if any requests are made to BPA for individual utility load data, the entity seeking that data must first provide waivers before any data would be released. This is not a new requirement. Had APAC chosen to request waivers from each utility at the time it commenced its study, obtaining permission from each utility should not have been overwhelming or "effectively impossible."

Q. APAC states that the perfect analyses would provide no better information from the actual recorded data for this period. Wolverton, WP-07-E-AP-1 at 38. Do you agree?

A. Yes. It is unlikely that any forecast would precisely reflect what actually occurred. However, the policy direction (*see* Bliven, *et al*., WP-07-E-BPA-52) for the Lookback analysis was to use the load forecasts that would have been available in the winter/spring of 2000-2001. Therefore, it is not appropriate for us to use the actual recorded data for FY 2002-2006 in the Lookback analysis because such information was not available to BPA prior to the spring of 2001, when BPA would have been setting the PF Preference rate.

Q. APAC notes that BPA does not have documentation of individual utility load forecasts prior to 2002. Wolverton, WP-07-E-AP-1 at 38. Why is that the case?

A. Prior to 2002, workbooks used by BPA to forecast customer loads also stored those forecasts. The individual customer load forecasts were stored only for the time they were considered to be the most current forecasts. Once new forecasts became available, the previous forecasts were replaced with the new forecasts. Only the aggregate load forecast was preserved.

Since that time, BPA has used its data repository – the Load and Resources Information System (LaRIS) – to preserve all of the individual load forecasts, regardless of whether they are the most current. Therefore, all individual load forecasts beginning later in 2002 are available, but not from earlier in 2002, the time frame relevant to the Lookback analysis.

Section 4: DSI Firm Requirements PSC Obligation Forecasts

Q. APAC states that in May 2000, the expected DSI rate was to be below $28.1/MWh, for an average rate of $23.5/MWh. Wolverton, WP-07-E-AP-1 at 39. However, one year later, in June 2001, BPA found that

> *after publication of the May ROD, skyrocketing prices in the electric power markets complicated matters, both in terms of BPA's ability to serve load and the DSIs' ability to survive in the current market. The prospects of survivability for the aluminum smelters dimmed, as did the possibility of avoiding rate increases.*

(citing 2002 Supplemental Power Rate Proposal Administrator's Final Record of Decision, WP-02-A-09) Id. Did BPA increase the DSI load forecast given this situation?

A. BPA has not increased its DSI load forecast for the Lookback analysis. The DSI load forecast for FY 2002-2010 remains 1,440 aMW and arises from BPA's contractual obligation to serve DSI loads for that time period.

Q. APAC notes that in 2001 BPA acknowledged that its customers may pay significantly higher prices under BPA's WP-02 Supplemental Proposal than under BPA's WP-02 Final Proposal. Wolverton, WP-07-E-AP-1 at 39. Do you agree?

A. Yes. BPA expected an increase above the base level but was unsure of the amount. The June 2001 ROD that APAC references also pointed out that BPA did not know what the exact level of BPA's proposed rates would be because the CRAC provisions had not been implemented. There was therefore still uncertainty about final BPA rate levels. At the time, there was discussion that BPA's rate could increase above the established base level by 50 percent to 250 percent.

Q. APAC states that a DSI rate subject to the LB CRAC, FB CRAC, and SN CRAC would be in the range of $43.60, a rate that would no longer be consistent with the Compromise Approach rate of about $23 per megawatthour. Wolverton, WP-07-E-AP-1 at 40. Do you agree that the CRACs would increase the DSI rate, resulting in a rate that is inconsistent with the Compromise Approach rate?

A. The CRAC did increase the base IP rate. Such increases to the base IP rate do not make it inconsistent with the Compromise Approach rate. The CRAC was specifically referenced in the Compromise Approach, making it an important component. The $43.60 DSI rate cited by APAC is not the result of applying the various CRACs to a base IP rate and should not apply in this case.

Q. APAC states that DSI loads declined sharply because of BPA price increases; that electricity is a large part of the cost of aluminum production; and that power prices were a major factor for sustaining loads. Wolverton, WP-07-E-AP-1 at 41. Do you agree that BPA's price increases were a major factor on DSI loads?

A. Obviously, the price of power is a factor in the viability of smelter operations, constituting generally one-third of the cost of production. However, the cost of labor and the general efficiency of a particular smelter are also important factors, as are the market price of aluminum in a competitive global market. Of all of these factors, low aluminum prices, by far, was the major contributing factor resulting in PNW smelters curtailing production or not restarting during the FY 2002 through FY 2004 period. From winter

2000-2001 to fall 2001 there was a significant drop in the price of aluminum sales. BPA's power price was a factor but not a major factor.

Q. APAC states that in the Supplemental Proposal for the period 2002-2006, BPA is not proposing a DSI rate that would justify a load forecast of 1400 aMW. Wolverton, WP-07-E-AP-1 at 41. APAC further states the only mention of how the rate is set "For purposes of the base rates for FY 2002-2006, BPA is proposing that the IP-TAC rates would have been set at a level established consistent with the Compromise Approach." Id. APAC argues there is no evidence presented whatsoever to justify the levels needed under the Compromise Approach, and it is clear from the actual load and BPA price outcome that the rate that eventuated was sufficient to drive most DSIs out of business. Id. Do you agree?

A. We disagree that it was the BPA price that drove the DSIs out of business. There are several economic factors that impact aluminum production and the cost of power is only one of these factors. Of all of those factors – low aluminum prices, by far, was the major contributor that caused PNW smelters to curtail production or not restart during the FY 2002 through FY 2004 period.

Further, in the winter/spring of 2001, BPA's contractual obligation to serve DSIs was 1,440 aMW. BPA did have some analysis that indicated the amount of DSI load that may be "at risk" given various prices for aluminum and various prices for electricity. However, DSI load being theoretically "at risk" does not mean that BPA's obligation to serve DSI load during that time period was any less than the full 1,440 aMW.

Q. APAC argues that BPA cannot assume away the DSI rate problem. Wolverton, WP-07-E-AP-1 at 41. APAC quotes a BPA motion:

> *[t]he DSI Service ROD established how BPA would serve the DSIs with power or service benefits, but BPA did not determine the rates the DSIs would pay for power or how the costs of serving the DSIs would be allocated to BPA's rates. Such separate ratemaking determinations, by*

> *law, can only be made in a hearing conducted pursuant to section 7(i) of the Northwest Power Act."*

(citing WP-07-M-BPA-78, page 1.) Id. Do you have a response to APAC's statement that BPA cannot "assume away the DSI problem"?

A. APAC definition of the "DSI problem" seems to be that the actual DSI load served during FY 2002-2006 was less than the WP-02 forecast, the forecast used in the Lookback analysis. In the WP-02 rate case, BPA properly considered its contractual obligation to serve DSI load for that period and set its load forecast accordingly.

Q. APAC acknowledges that some of the early-year reduction was due to load-reduction agreements but states the fact that the loads never came back and the plants, such as Reynolds–Longview, were shuttered permanently indicates that some of the load reduction payments were unnecessary; that is, load was being otherwise reduced by the economic realities of BPA's rate levels. Wolverton, WP-07-E-AP-1 at 42. The costs of such LRAs became part of the FY 2002 through FY 2006 rates and cost recovery adjustments. Id. Do you agree?

A. It is true that the cost of Load Reduction Agreements became a part of the FY 2002-2006 rates, but we do not agree the Load Reduction Agreements were unnecessary. At the time Load Reduction Agreements were executed with the DSIs (also with industrial customers of the public agencies and irrigators), BPA was facing extremely high forward power market prices. However, aluminum prices were still high, and so there was a reasonable expectation that aluminum smelters could continue to operate. On the other hand, there was uncertainty about whether there would be sufficient reasonably priced energy on the market to meet regional load. In response, BPA implemented a load reduction strategy, which included the DSIs. The DSI Load Reduction Agreements were prudent commercial deals providing the region with large load reductions at a fraction of the purchase price to serve the load at prevailing market prices. Waiting it out and hoping for a better outcome would have foolishly placed the agency and the region at financial and supply risk.

Q. APAC criticizes BPA's DSI load forecast by stating BPA has forecast DSI loads based on rates it could not have provided, and without any apparent consideration of the impact of significant price increases. Wolverton, WP-07-E-AP-1 at 42. These forecasts are completely unrealistic and should not be included in any Lookback analysis. Id. Do you agree?

A. No. The LookBack analysis is projecting DSI loads that would have been used in the WP-02 Rate Case. This is the 1,440 aMW contracted sales from the executed DSI Subscription Contracts. In the Supplemental Proposal, BPA has forecast that this amount of load could have been served at about $29.58/MWh. APAC has adopted the Cowlitz/Clark DSI rate of about $43.60/MWh. *See* Doubleday, *et al.*, WP-07-E-BPA-85 for a discussion about the Cowlitz/Clark DSI rate. This insistence on a much higher DSI rate may be why APAC is having so much trouble with BPA's contractual obligation being the basis for DSI load forecast.

Q. WPAG argues that the assumptions made by BPA in the recalculation of the section 7(b)(2) rate test for the FY 2002-2006 period for both the DSI loads and the loads for preference customers are faulty. Grinberg, et al., WP-07-E-WA-05 at 29. WPAG argues that BPA's assumptions are not consistent with BPA's original treatment of the DSI loads in the WP-02 case. Id. In its 2002 Supplemental Final ROD, BPA assumed it would serve 990 aMW at a base rate, combined with 450 aMW priced at a rate based on actual cost to serve that portion of the load. Id. Do you agree?

A. No. BPA assumed it would sell 1,440 aMW of power at an average IP-TAC rate consistent with the Compromise Approach. BPA did not assume to sell 450 aMW at a marginal cost rate.

Q. *WPAG argues that the DSI loads used in the recalculation of the section 7(b)(2) rate test are not consistent with information available to BPA in the spring of 2001. Grinberg, et al., WP-07-E-WA-05 at 30. Based on information available at that time regarding power prices and BPA's own analysis of DSI viability, load projections for DSI customers should be much lower. Id. Based upon a very conservative analysis of the information available at that time, the average load projected for DSI customers for FY 2002-2006 should be about 460 aMW. Id. Do you agree?*

A. No. As stated above, BPA's contractual obligation to serve DSIs was in the amount of 1,440 aMW. BPA did have some analysis that indicated the amount of DSI load that may be "at risk" given various prices for aluminum and various prices for electricity. However, DSI load being theoretically "at risk" does not mean that BPA's obligation to serve DSI load during that time period was any less than the full 1,440 aMW. The "at risk" analysis did not come to any conclusion as to the actual expected DSI load.

Q. *WPAG projects 460 aMW of DSI load for the FY 2002-2006 period, using a combination of the projected IP rate from the Lookback study and BPA's analysis of DSI viability from the WP-02 rate case. Grinberg, et al., WP-07-E-WA-05 at 30. In the Lookback Study, BPA estimates an average IP rate of $29.58/MWh. WP-07-E-BPA-44A, p. 103. In the WP-02 rate case, BPA indicates it used a projected aluminum price of $0.68/lb to set rates for DSIs. Id. At this price for aluminum, BPA's analysis indicated that 68 percent of DSI loads would be at risk of not operating with a power price of $28/MWh. Id. Reducing the original load estimate of 1,440 aMW by 68 percent results in a DSI load projection of 460 aMW. Id. Do you agree with WPAG's approach?*

A. No. As stated above, the "at risk" analysis did not conclude what the actual DSI load would be and was not sufficient for BPA to assume something other than its contractual obligation to serve 1,440 aMW of power to the DSIs.

Q. WPAG claims its analysis is conservative because first, the cost of power used in the analysis is lower than the IP rate BPA is using in the Lookback study ($28 vs. $29.58). Grinberg, et al., WP-07-E-WA-05 at 30. In BPA's WP-02 testimony, the closest data point at an aluminum price of $0.68/lb was developed using a power price of $28, so this was used in our analysis rather than attempting to extrapolate between numbers at other data points. Id. Using a higher power cost would have resulted in more DSI load being at risk of not operating. Id. Do you agree?

A. The "at risk" analysis did indicate that for a given price of aluminum, as electric prices went up, more DSI load was at risk. WPAG's analysis is not conservative in that they define "at risk" with complete shut-down of facilities. We believe that a plant being at risk may be a necessary aspect of the decision to shutter a plant, but it is not sufficient in itself to shutter the plant.

Q. WPAG claims its analysis is conservative because, second, at the relevant point in time BPA was either negotiating or had signed Load Reduction Agreements with DSI customers that eventually resulted in actual DSI loads for the FY 2002-2003 period that were lower than this projection. Grinberg, et al., WP-07-E-WA-05 at 31. Do you agree?

A. No. Generally, we do agree with WPAG. To the extent that the DSI LRAs were executed by June 21, 2001, it is reasonable that we reflect such LRAs in the Lookback analysis.

Q. WPAG claims its analysis is conservative because, third, the IP rate developed by BPA for the Lookback study is not realistic given the fact that BPA used a combination of cost-based and market-based power costs to develop the DSI rate. Grinberg, et al., WP-07-E-WA-05 at 31. Given the information available to BPA in the spring of 2001, BPA should be using a DSI rate substantially higher than $29.58/MWh in its Lookback Study. Id. Do you agree?

A. No. The sale of power to the DSIs was never to be at two rates, a cost-based rate and a market-based rate, rather the full 1,440 aMW was to be sold at an average IP-TAC rate consistent with the Compromise Approach. Once determined, the IP-TAC rate would change only by application of CRACs. The IP-TAC rate had no provision to change if market prices changed from the levels assumed in setting the IP-TAC rate. Similarly, for the Lookback analysis, BPA is assuming the full 1,440 aMW to be sold at an average IP rate.

Q. WPAG argues that its projection does not result in a DSI load markedly lower than that actually served by the Administrator during this period. Grinberg, et al., WP-07-E-WA-05 at 31. For the FY 2002-2006 period, the DSI load served by BPA averaged just 164 aMW, less than 36 percent of WPAG's conservative projection. Id. Do you agree?

A. BPA agrees that the actual DSI load served was well below the 1,440 aMW BPA was contractually obligated to serve. However, the 1,440 aMW was a forecast made well before the actual rate test period years.

Q. WPAG proposes that BPA should use a maximum average DSI load of 460 aMW for the period from FY 2002-2006 in its recalculation of the section 7(b)(2) rate test. Grinberg, et al., WP-07-E-WA-05 at 31. Do you agree?

A. No. In the winter/spring of 2001, using the total BPA obligation to serve as a forecast for ratemaking purposes was reasonable. Had BPA put more weight on the "at risk" analysis rather than the DSIs themselves were indicating at that time, BPA would have been in danger of setting rates to recover the cost of serving just 460 aMW of DSI load, when the DSIs could have insisted on getting the total 1,440 aMW for which they were contractually entitled.

Q. WPAG states that its projected 460 aMW DSI load does not result in a DSI load markedly lower than that actually served by the Administrator during this period.

Grinberg, et al., WP-07-E-WA-05 at 31. WPAG states that for the FY 2002-2006 period, the DSI load served by BPA averaged just 164 aMW, less than 36 percent of WPAG's projection. Id. Do you agree?

A. Although actual DSI load turned out to be less than either BPA's or WPAG's projection, the policy direction (*see* Bliven, *et al*., WP-07-E-BPA-52) for the Lookback analysis was to use the information that would have been available in the winter/spring of 2000-2001. For the DSI 2001 load projection, actual contract amounts were available. At that time, BPA determined actual contract amounts would be a better measure than the aluminum price forecasts and smelter break even analysis developed in 1999 and used as a basis for WPAG's forecast of 460 aMW. We still believe this is a reasonable position.

Q. Does this conclude your testimony?

A. Yes.

This page intentionally left blank.

Data Request and Response List

Data Request and Response view:

All Requests Answered Requests Unanswered Requests Items Per Page: 10

Search Filings:(Request or Exhibit) BPA-WA-8 Search Reset View

Response is past due after seven (7) days.

Request (click to view)	Exhibit	Requesting Party	Responding Party	Date Filed	Response (click to view)
BPA-WA-8	**WP-07-E-WA-5**	**Bonneville Power Administration**	**Western Public Agencies Group and Members**	**4/10/2008 2:47 PM**	**Select Request to view Response**

You are viewing page 1 of 1

Request Detail

Request ID: BPA-WA-8
Page Number: 2
Line Number: 7-14
Exhibit Filing: WP-07-E-WA-5

Contact Name:
Contact Phone:
Contact Email:

Request Text: Please provide the average retail rate, by year, for the period 1997 through 2006, for each of the utilities listed. In addition, please provide all studies or other information documenting that these utilities raised their retail rates, and the amount by which they did so (as a percent of their 2001 retail rate), in response to BPA's wholesale power rate increase

Response Detail

Date Response Filed: 4/17/2008 4:41:05 PM
Contact Name:
Contact Phone:
Contact Email:
Response Text:

The testimony referred to in the data request refers to the list of WPAG utilities and their load share of BPA's PF power. The retail rate data requested was not used nor relied upon in the preparation of the referenced direct testimony, and except for the information listed below, is not readily available to the witnesses, and its collection would be unduly burdensome and time-consuming. The attached file provides the average rates for the period 1997 through 2006 for Clark Public Utilities, Peninsula Light Company and Grays Harbor PUD. In addition, additional documentation of actual rates charges during this period is attached. The average retail rate increases during the 2001 to 2007 period for Clark Public Utilities were the following: Average retail rate increases 1/15/2001 23.5% 8/1/2001 20% 4/1/2003 5% 10/1/2005 2% Grays Harbor implemented the following rate increases during the same period: Average retail rate increases Jan-01 20.50% Oct-01 26.00% Oct-02 11.00% Nov-04 -3.00% May-06 -3.00% Peninsula Light Company implemented the following rate increases during the same period: Average retail rate increases Apr-01 27.03% Oct-01 11.30% Oct-04 -0.02% Nov-05 0.00% Jun-06 0.01% Peninsula Light Company absorbed any BPA CRAC rate increases until 2004 when such increases were passed through to customers via a Power Cost Adjustment mechanism.

Files Submitted for this Response:
BPA-WA-8.zip

G.H.P.U.D. RATES

EFFECTIVE SEPTEMBER 9, 1993

SCHEDULE 10 - RESIDENTIAL RATE

Customer Charge	$6.00 plus
Energy Charge	$.0437 kwh
Minimum Charge	$15.00 per month

SCHEDULE 50 - SMALL GENERAL SERVICE RATE

Customer Charge	$7.50 plus
Energy Charge	$.0450 per kwh
Minimum Charge	$15.00 per month or $0.65 per kw of system capacity required by customer

SCHEDULE 80 - SMALL INDUSTRIAL RATE

Customer Charge	$10.00 per month, plus
Energy Charge	$.0343 per kwh
Demand Charge	$4.35 per kw per month
Minimum Charge *	$30.00 per month or $0.65 per kw of system capacity required by customer

SCHEDULE 88 - YARD LIGHTING (Effective 10-1-93)

100 Watt High Pressure Sodium	$7.60 per month
200 Watt High Pressure Sodium	$12.10 per month
1,000 Mercury Vapor Light	$29.00 per month

SCHEDULE 55 - LARGE GENERAL SERVICE RATE

Customer Charge	$10.00 per month, plus
Energy Charge	$.0329 per kwh
Demand Charge	$4.35 per kw per month
Minimum Charge *	$30.00 per month

Greater than 200 amp single phase or 35 kw

SCHEDULE 94 - IRRIGATION RATE (Effective 11-1-93)

Customer Charge	$5.00 plus
Energy Charge	$.0231 per kwh, plus
Horsepower Charge	$.65 per h.p. per month
Minimum Charge	$.65 per h.p. per mo., plus $5.00 per mo.

SCHEDULE 98 - TAX ADDITIONS

Customers within city limits of;	Aberdeen	Cosmopolis	Elma	Hoquiam	Montesano	Oakville	Ocean Shores	Westport
Add City Utility Tax:	6%	4.2%	6%**	6%	5.763%	6%	6%	6%

* $.65 per month per kw of system capacity provided by the District to service customer's requirements, whichever is greater.

** On the first $250.00 of revenue per month or $500.00 bimonthly.

G.H.P.U.D. RATES

EFFECTIVE JANUARY 1, 2001

SCHEDULE 10 - RESIDENTIAL RATE

Customer Charge	$7.23 plus
Energy Charge	$.05266 kwh
Minimum Charge	$18.08 per month

SCHEDULE 50 - SMALL GENERAL SERVICE RATE

Customer Charge	$9.04 plus
Energy Charge	$.05423 per kwh
Minimum Charge	$18.08 per month or $0.78 per kw of system capacity required by customer

SCHEDULE 80 - SMALL INDUSTRIAL RATE

Customer Charge	$12.05 per month, plus
Energy Charge	$.04133 per kwh
Demand Charge	$5.24 per kw per month
Minimum Charge *	$30.00 per month $0.78 per kw of installed capacity

SCHEDULE 88 - YARD LIGHTING

100 Watt High Pressure Sodium	$9.16 per month
200 Watt High Pressure Sodium	$14.58 per month
1,000 Mercury Vapor Light	$34.95 per month

SCHEDULE 55 - LARGE GENERAL SERVICE RATE

Customer Charge	$12.05 per month, plus
Energy Charge	$.03964 per kwh
Demand Charge	$5.24 per kw per month
Minimum Charge *	$36.15 per month

Greater than 200 amp single phase or 50 kw

SCHEDULE 94 - IRRIGATION RATE

Customer Charge	$6.03 plus
Energy Charge	$.02784 per kwh, plus
Horsepower Charge	$.78 per h.p. per month
Minimum Charge	$.78 per h.p. per mo., plus $6.03 per mo.

SCHEDULE 98 - TAX ADDITIONS

Customers within city limits of;	ec	Cosmopolis	Elma	Hoquiam	Montesano	Oakville	Ocean Shores	Westport
Add City Utility Tax:	6%	6%	6%**	6%	5.750%	6%	6%	6%

* $.78 per month per kw of system capacity provided by the District to service customer's requirements, whichever is greater.

** On the first $250.00 of revenue per month or $500.00 bimonthly.

G.H.P.U.D. RATES

EFFECTIVE OCTOBER 1, 2001

SCHEDULE 10 - RESIDENTIAL RATE

Customer Charge	$10.00 plus
Energy Charge	$.0664 kwh
Minimum Charge	$23.00 per month

SCHEDULE 50 - SMALL GENERAL SERVICE RATE

Customer Charge	$12.00 plus
Energy Charge	$.06901 per kwh
Minimum Charge	$23.00 per month or $0.90 per kw of system capacity required by customer

SCHEDULE 55 - MEDIUM GENERAL SERVICE RATE

Customer Charge	$20.00 per month, plus
Energy Charge	$.04153 per kwh
Demand Charge	$6.25 per kw per month
Minimum Charge *	$40.00 per month or $0.90 per kw of system capacity required by customer

SCHEDULE 88 - YARD LIGHTING

100 Watt High Pressure Sodium	$9.16 per month
200 Watt High Pressure Sodium	$14.58 per month
1,000 Mercury Vapor Light	$34.95 per month

SCHEDULE 94 - IRRIGATION RATE (effective 11/1/01)

Customer Charge	$10.00 plus
Energy Charge	$.03157 per kwh, plus
Horsepower Charge	$1.00 per h.p. per month
Minimum Charge	$1.00 per h.p. per mo., plus $10.00 per month

SCHEDULE 82 - LARGE GENERAL SERVICE RATE

Customer Charge	$70.0 per month, plus
Energy Charge	$.04899 per kwh
Demand Charge	$6.25 per kw per month
Minimum Charge	$0.90 per mo. per kw of system capacity required by customer

SCHEDULE 98 - TAX ADDITIONS

Customers within city limits of;	Aberdeen	Cosmopolis	Elma*	Hoquiam	Montesano	Oakville	Ocean Shores	Westport
Add City Utility Tax:	6%	6%	6%*	6%	6%	6%	6%	6%

* On the first $250.00 of revenue per month or $500.00 bimonthly.

G.H.P.U.D. RATES
EFFECTIVE OCTOBER 1, 2002

SCHEDULE 10 - RESIDENTIAL RATE

Customer Charge	$11.35 plus
Energy Charge	$.0690 kwh
Minimum Charge	$26.00 per month

SCHEDULE 50 - SMALL GENERAL SERVICE RATE

Customer Charge	$13.60 plus
Energy Charge	$.0720 per kwh
Minimum Charge	$26.00 per month or $1.10 per kw of system capacity required by customer

SCHEDULE 55 - MEDIUM GENERAL SERVICE RATE

Customer Charge	$22.60 per month, plus
Energy Charge	$.0430 per kwh
Demand Charge	$6.18 per kw per month
Minimum Charge	$45.25 per mo. or $1.10 per mo. per kw of system capacity required by customer

SCHEDULE 88 - YARD LIGHTING

100 Watt High Pressure Sodium	$9.62 per month
200 Watt High Pressure Sodium	$15.31 per month
1,000 Mercury Vapor Light	$36.70 per month

SCHEDULE 94 - IRRIGATION RATE (Effective 11-1-02)

Customer Charge	$11.35 plus
Energy Charge	$.0469 per kwh, plus
Horsepower Charge	$0.60 per h.p. per month
Minimum Charge	$0.60 per h.p. per month, plus $11.35 per month

SCHEDULE 82 - LARGE GENERAL SERVICE RATE

Customer Charge	$79.20 per month, plus
Energy Charge	$.0495 per kwh
Demand Charge	$6.18 per kw per month
Minimum Charge	$1.10 per mo. per kw of system capacity required by customer

SCHEDULE 98 - TAX ADDITIONS

Add State Public Utility @ 3.873% and Privilege Tax @ 2.14%

Customers within city limits of;	Aberdeen	Cosmopolis	Elma*	Hoquiam	Montesano	Oakville	Ocean Shores	Westport
Add City Utility Tax:	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%

* On the first $250.00 of revenue per month or $500.00 bimonthly.

G.H.P.U.D. RATES
EFFECTIVE NOVEMBER 1, 2004

SCHEDULE 10 - RESIDENTIAL RATE

Customer Charge	$11.35 plus
Energy Charge	$.067 per kwh
Minimum Charge	$25.24 per month

SCHEDULE 50 - SMALL GENERAL SERVICE RATE

Customer Charge	$13.60 plus
Energy Charge	$.0699 per kwh
Minimum Charge	$25.24 per mo. or $1.10 per mo.per kw of system capacity required by customer

SCHEDULE 55 - MEDIUM GENERAL SERVICE RATE

Customer Charge	$22.60 per month, plus
Energy Charge	$.0417 per kwh
Demand Charge	$6.18 per kw per month
Minimum Charge	$45.25 per mo. or $1.10 per mo. per kw of system capacity required by customer

SCHEDULE 88 - YARD LIGHTING

100 Watt High Pressure Sodium	$9.62 per month
200 Watt High Pressure Sodium	$15.31 per month
1,000 Mercury Vapor Light	$36.70 per month

SCHEDULE 94 - IRRIGATION RATE

Customer Charge	$11.35 plus
Energy Charge	$.0469 per kwh, plus
Horsepower Charge	$0.60 per h.p. per month
Minimum Charge	$0.60 per h.p. per month, plus $11.35 per month

SCHEDULE 82 - LARGE GENERAL SERVICE RATE

Customer Charge	$79.20 per month, plus
Energy Charge	$.04806 per kwh
Demand Charge	$6.18 per kw per month
Minimum Charge	$1.10 per mo. per kw of system capacity required by customer

SCHEDULE 98 - TAX ADDITIONS

Add State Public Utility @ 3.873% and Privilege Tax @ 2.14%

Customers within city limits of;	Aberdeen	Cosmopolis	Elma*	Hoquiam	Montesano	Oakville	Ocean Shores	Westport
Add City Utility Tax:	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%

* On the first $250.00 of revenue per month or $500.00 bimonthly.

G.H.P.U.D. RATES
EFFECTIVE MAY 1, 2006

SCHEDULE 10 - RESIDENTIAL RATE

Customer Charge	$11.35 plus
Energy Charge	$.065 per kwh
Minimum Charge	$25.24 per month

SCHEDULE 50 - SMALL GENERAL SERVICE RATE

Customer Charge	$13.60 plus
Energy Charge	$.0678 per kwh
Minimum Charge	$25.24 per month or $1.10 per kw of system capacity required by customer

SCHEDULE 55 - MEDIUM GENERAL SERVICE RATE

Customer Charge	$22.60 per month, plus
Energy Charge	$.0405 per kwh
Demand Charge	$6.18 per kw per month
Minimum Charge	$45.25 per mo. or $1.10 per mo. per kw of system capacity required by customer

SCHEDULE 82 - LARGE GENERAL SERVICE RATE

Customer Charge	$79.20 per month, plus
Energy Charge	$.0466 per kwh
Demand Charge	$6.18 per kw per month
Minimum Charge	$1.10 per mo. per kw of system capacity required by customer

SCHEDULE 86 - STREET LIGHTING

100 Watt High Pressure Sodium	$8.54 per month
200 Watt High Pressure Sodium	$15.06 per month

SCHEDULE 88 - YARD LIGHTING

100 Watt High Pressure Sodium	$9.62 per month
200 Watt High Pressure Sodium	$15.31 per month
1,000 Mercury Vapor Light	$36.70 per month

SCHEDULE 94 - IRRIGATION RATE

Customer Charge	$11.35 plus
Energy Charge	$.0469 per kwh, plus
Horsepower Charge	$.60 per h.p. per month
Minimum Charge	$.60 per h.p. per month, plus $11.35 per month

SCHEDULE 84 - INDUSTRIAL SERVICE RATE

Customer Charge	$79.20 per month, plus
Energy Charge	$.0353 per kwh
Demand Charge	$6.18 per kw per month
Minimum Charge	$1.10 per mo. per kw of system capacity required by customer

SCHEDULE 98 - TAX ADDITIONS

Add State Public Utility @ 3.873% and Privilege Tax @ 2.14% (*Elma tax on the first $250.00 of revenue per month)

Customers within city limits of;	Aberdeen	Cosmopolis	Elma*	Hoquiam	Montesano	Oakville	Ocean Shores	Westport
Add City Utility Tax:	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%	6.0%

RESOLUTION NO. 6555

A RESOLUTION ADOPTING A REVISED SCHEDULE OF RATES FOR ELECTRIC SERVICE AND REPEALING ALL OTHER RESOLUTIONS, OR PARTS OF RESOLUTIONS IN CONFLICT THEREWITH

WHEREAS, the Commissioners of Public Utility District No. 1 of Clark County, Washington, have periodically established a schedule of rates for electric service to meet changing requirements; and

WHEREAS, wholesale energy costs, operational costs and costs associated with debt obligations are anticipated to exceed future revenues; and

WHEREAS, the Board of Commissioners has reviewed revenue requirement options and cost allocation options; and

WHEREAS, staff studies and reports recommend that the rates should be adjusted to meet future needs of the electrical utility; and

WHEREAS, several public meetings and workshops have given customers the opportunity to testify on the proposed rate changes and alternatives;

NOW, THEREFORE, BE IT RESOLVED by the Commissioners of Public Utility District No. 1 of Clark County, Washington, assembled this 27th day of September, 2005, as follows:

Section 1. The rates and classifications as set forth in the attached schedule is hereby adopted as rate schedules for electric service by the District from and after the effective dates hereof, as set herein.

Section 2. The effective date of Section 1 and application of rates authorized therein is October 1, 2005, and all consumption prior to such date is charged for at the rates in effect prior to the effective date of this resolution. In implementing this resolution, the Utility will prorate bills as if energy consumption occurred at a constant rate during the billing period in which the effective date of this resolution occurs.

Section 3. All other prior resolutions or parts of resolutions in conflict herewith be repealed.

PASSED AND ADOPTED this 27th day of September, 2005.

President

ATTEST:

Secretary

Clark Public Utilities
A customer-owned public utility district

TABLE OF CONTENTS
RATE SCHEDULES FOR ELECTRIC SERVICE

SCHEDULE 7
RESIDENTIAL AND FARM SERVICE

Applicability

To Residential Use, Incidental Residential Use (under 30 kW load), General Farm Use (under 30 kW load), or Incidental General Service Use when combined with Residential Use supplied through a single meter. Temporary Services, where occupancy of the premises will be Residential, will be eligible for this rate.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service - Sixty-Hertz, Alternating Current

The Utility reserves the right to specify the voltage and phase of service supplied under this schedule.

Secondary Point-Of-Delivery - Single-Phase or Three-Phase Service

Residential - The Utility owns and maintains all overhead and residential underground services to the primary residence.

Apartments and mobile home parks - The utility owns and maintains up to and including the distribution transformer or designated secondary junction point.

Incidental services (residential and farm including outbuildings, pools, etc.) – The customer owns and maintains underground services to the building. If overhead secondary conductors are required, the Utility will install, own and maintain the service with the customer paying an Aid-To-Construction fee to cover these costs.

Monthly Rate – The sum of the Basic and Energy charges:

Basic Charge:	$6.40
Energy Charge:	7.36¢ per kWh

The Energy charge includes a credit of 0.59¢ per kilowatt-hour as a pass through benefit of the BPA Residential Purchase and Sale Agreement.

SCHEDULE 34
GENERAL SERVICE

Applicability

To meet requirements of commercial, industrial, and general service customers not provided for in other rate schedules.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service - Sixty-hertz, Alternating Current

The Utility reserves the right to specify the voltage and phase of service supplied under this schedule.

Primary Point-Of-Delivery - Single or Three-Phase Service

A customer having a metered, kilowatt demand consistently averaging 100 kW or more may be served at the primary voltage level (12,470 volts). The customer will be responsible for all costs associated with the primary Point-of-Delivery installation including the metering and primary voltage physical disconnect necessary to isolate the customer's facilities from the Utility's facilities. The customer will be responsible to own, operate and maintain all electrical distribution facilities on the customer side of the Primary Point-of-Delivery (typically established at the primary meter).

Secondary Points-Of-Delivery - Single or Three-Phase Service

The utility owns and maintains distribution facilities up to the Secondary Point-of-Delivery (typically established at the secondary terminals of the transformer or other designed secondary junction point). If conditions require an overhead service, the utility will install, own and maintain the service and the customer will pay an Aid-To-Construction fee to cover these costs.

In existing installations where there is a mixed ownership of primary distribution facilities beyond a primary meter, the Secondary Point-of-Delivery rate will apply. The ownership and maintenance responsibilities of the customer-owned distribution facilities may be conveyed to the Utility subject to Utility review and approval. Primary Point-of-Delivery customers paying the higher Secondary Point-of-Delivery rate will be compensated for transformation losses. The metered kilowatt-hours and reactive kilovolt-ampere hours will be reduced 2% before the rates are applied.

SCHEDULE 34 (continued)

Monthly Rate - The sum of the following Basic, Energy and Demand charges:

First Tier Schedule 34 – Applicable to non-demand metered services and demand metered services with monthly demand less than or equal to 30 kWs.

Basic Charge:	$18.00
Energy Charge:	7.03¢ per kWh

Second Tier Schedule 34 – Applicable to services with a monthly, metered demand greater than 30 kWs.

Basic Charge:	$36.00
Energy Charge:	4.51¢ per kWh Sep - Mar
	4.00¢ per kWh Apr – Aug
Demand Charge:	$6.44 per kW for Secondary Point-of-Delivery
	$5.66 per kW for Primary Point-of-Delivery

Metered Demand

The kW as shown by or computed from the readings of the Utility's power meter for the 15-minute period of customer's greatest use during the month, adjusted for power factor as specified, determined to the nearest kW.

Off - Peak Demand

By special contract with the Utility, off-peak demand is available for customers with demands in excess of 30 kW. Service will be available at a discount rate during the off-peak period, which includes all hours except the hours Monday through Saturday between 7:00 a.m. and 10:00 p.m. The off-peak demand rates are 58¢/kW of demand for each kW the off-peak demand exceeds other recorded monthly demands. The energy rate as listed in the Monthly Rate section applies to all hours.

Adjustment of Demand for Power Factor

Demands will be adjusted to correct for average power factors lower than 95%. Such adjustments will be made by increasing the measured demand l% for each l% or major fraction thereof by which the average power factor is less than 95% lagging.

Metered real energy measured in kilowatt-hours (kWh) and metered reactive energy measured in Kilovolt Ampere-Hours (kVARh) are used to calculate the average monthly power factor as follows:

Power Factor equals

$$\frac{\text{kWh}}{\sqrt{(\text{kWh})^2 + (\text{kVARh})^2}}$$

SCHEDULE 36

SMALL UNMETERED GENERAL USE
ANNUALLY BILLED

Applicability

Small loads that are photo eye or timer controlled with estimated usage up to 1,500 kWh annually for specific isolated uses. The Utility reserves the right to determine the application of this rate schedule.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Annual Rate

The sum of the following Basic and Energy charges:

Annual Basic Charge:	$18.00	
Annual Energy Charge:	$16.80	1 - 500 kWh
Annual Energy Charge:	$51.50	501 – 1,000 kWh
Annual Energy Charge:	$86.25	1,001 – 1,500 kWh

SCHEDULE 38

SMALL METERED GENERAL USE
ANNUALLY BILLED

Applicability

Small general use metered loads that are less than 3,600 kWh annually. The Utility reserves the right to determine the application of this rate schedule.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Annual Rate

The sum of the following Basic and Energy charges:

Annual Basic Charge:	$18.00
Annual Energy Charge:	7.03¢ per kWh

SCHEDULE 35 AND 43

RESIDENTIAL AND COMMERCIAL DRYING

Applicability

Metered power for use in drying structures being prepared for occupancy as a result of residential and commercial building construction.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Monthly Rate

Energy charge: 7.03¢ per kWh

Special Conditions

On completion of the permanent meter installation, a drying rate will be charged until normal occupancy of the building, not to exceed six months. The drying service is not to be used for permanently-installed buildings, appliances, or equipment, recreational vehicles, or mobile homes. If this service is used beyond six months, the account will be reviewed for applicability by the Utility. In the event that service is used for purposes other than described, it will be removed, and the amount of energy used will be rebilled at the applicable rate schedule.

SCHEDULE 85

INDUSTRIAL SERVICE

Applicability

To lighting, heating and power service for customers having measured minimum demands of not less than 1500 kilowatts.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service

Three-phase, sixty-hertz, alternating current at approximately 12,000 volts or higher, as available in the area. The Utility reserves the right to determine the availability of service under this schedule.

Primary Point-Of-Delivery

The customer will be responsible for all costs associated with the primary Point-of-Delivery installation including the metering and primary voltage physical disconnect necessary to isolate the customer's facilities from the Utility's facilities. The customer will be responsible to own, operate and maintain all electrical distribution facilities on the customer side of the Primary Point-of-Delivery (typically established at the primary meter). All transformers, equipment and wiring shall be of types and characteristics acceptable to the Utility. The entire installation and the balance of loads between phases must have the approval of the Utility.

Secondary Points-Of-Delivery - Single or Three-Phase Service

The utility owns and maintains distribution facilities up to the Secondary Point-of-Delivery (typically established at the secondary terminals of the transformer or other designed secondary junction point). If conditions require an overhead service, the utility will install, own and maintain the service and the customer will pay an Aid-To-Construction fee to cover these costs.

In existing installations where there is a mixed ownership of primary distribution facilities beyond a primary meter, the Secondary Point-of-Delivery rate will apply. The ownership and maintenance responsibilities of the customer-owned distribution facilities may be conveyed to the Utility subject to Utility review and approval. Primary Point-of-Delivery customers paying the higher Secondary Point-of-Delivery rate will be compensated for transformation losses. The metered kilowatt-hours and reactive kilovolt-ampere hours will be reduced 2% before the rates are applied.

SCHEDULE 85 (continued)

Transmission Point-Of-Delivery

Transmission Point-of-Delivery customers are served at a transmission voltage level (either 69,000 or 115,000 volts). The customer is responsible for all costs associated with the transmission Point-of-Delivery installation including the metering and transmission voltage physical disconnect necessary to isolate the customer's facilities from the Utility's facilities. The customer will be responsible to own, operate and maintain all electrical facilities on the customer side of the Transmission Point-of-Delivery including the power transformer(s) and distribution transformers. All transformers, equipment and wiring shall be of types and characteristics acceptable to the Utility. The entire installation and the balance of loads between phases must have the approval of the Utility.

Monthly Rate

The sum of the following Customer, Energy and Demand charges:

Customer Charge:	\$120.00
Energy Charge:	4.51¢ per KWH for the months Sep - Mar 4.00¢ per KWH for the months Apr - Aug
Demand Charge:	\$6.44 per KW – Secondary Point-of-Delivery \$5.66 per KW – Primary Point-of-Delivery \$4.37 per KW – Transmission Point-of-Delivery

Off-Peak Demand

By special contract with the Utility, off-peak demand is available for Customers with demands in excess of 1500 KW. Service will be available at a discount rate during the off-peak period, which includes all hours except the hours Monday through Saturday between 7:00 a.m. and 10:00 p.m. The off-peak demand rates are 58¢ per KW of demand for each KW the off-peak demand exceeds other recorded monthly demands. The energy rate as listed in the Monthly Rate section applies to all hours.

Adjustment of Demand for Power

Demands will be adjusted to correct for average power factors lower than 95%. Such adjustments will be made by increasing the measured demand l% for each l% or major fraction thereof by which the average power factor is less than 95% lagging.

Metered real energy measured in kilowatt-hours (kWh) and metered reactive energy measured in Kilovolt Ampere-Hours (kVARh) are used to calculate the average monthly power factor as follows:

$$\text{Power Factor equals} \quad \frac{\text{kWh}}{\sqrt{(\text{kWh})^2 + (\text{kVARh})^2}}$$

SCHEDULE 94
MUNICIPAL LIGHTING

Applicability

Lighting service for locations along public streets, highways, thoroughfares, and public grounds supplied to municipalities, counties, or agencies of federal or state governments where funds for payment for electric service are provided through taxation or special assessment.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service

From dusk to dawn daily, controlled by light sensitive relay.

Specifications

System shall be of overhead construction consisting of an aerial circuit, mast arms and standard luminaires or flood lights, except in areas with existing underground facilities. Underground circuits, wood or ornamental poles will be installed in these areas, with additional charges.

Capital Costs and Monthly Charges

Prior to installation, the capital costs of the lighting materials and labor are to be paid by the municipality, county, agency, or entity initiating the request. Thereafter, the monthly charge will consist of energy, maintenance, and re-lamping, if appropriate. Ownership of the lighting circuit and materials will be that of the requesting agency. Other conditions can be determined by applying the appropriate column or columns. Individual luminaire repair or re-lamping, when appropriate, will be done as soon as reasonably possible after notification by the Customer.

SCHEDULE 95
RESIDENTIAL LIGHTING & LOCAL UTILITY DISTRICTS

Applicability

Off-street lighting service to individual customers for locations on private property, alleys, or other thoroughfares.

Lighting service for locations along public streets, thoroughfares and public grounds where a Local Utility District (LUD) has been formed for payment of capital costs and electric services through taxation or special assessment.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service

From dusk to dawn daily, controlled by light sensitive relay.

Specifications

System shall be underground construction meeting Utility standards, except in areas with existing overhead facilities.

Capital Costs and Monthly Charges

The customer has the choice of payment in full at the time of installation or monthly payments over a 10-year period for the capital costs of the lighting materials and labor for off-street lighting service on private property, alleys, or other thoroughfares. The Utility will own, maintain, and furnish energy for luminaires as shown in the "Total (After 1st 10 years)" column. The Utility will continue to own all street light facilities. Other conditions can be determined by applying the appropriate column or columns. Individual luminaire repair or re-lamping will be done as soon as reasonably possible after notification by the customer.

Costs for labor and materials for the installation of street lights located within a Local Utility District will be capitalized over a 10-year period. During the 10-year period, the Utility will own, maintain, and furnish energy for luminaires at an annual rate established and adopted by the Utility's Board of Commissioners in the individual LUD, and will be billed through special assessment. After the initial 10-year term has been completed, the successive monthly billing will exclude system charges, poles and liuminaires. However, the Utility will continue to own all street light facilities.

SCHEDULE 96
COMMERCIAL LIGHTING

Applicability

Off-street lighting service to commercial Customers for locations on private property and thoroughfares.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service

From dusk to dawn daily, controlled by light sensitive relay.

In general, the Utility does not provide lighting in private commercial applications. New commercial installations will be owned by the private party and energy sold through normal commercial metering.

Specifications

The Utility will continue to maintain preexisting facilities and Customers will be billed under the current energy, maintenance, and capital repayment schedules.

Capital Costs and Monthly Charges

All new installations shall be Customer designed, built, owned and maintained. Energy charges will be included in the Customer's regular metered service.

SCHEDULES 94, 95 AND 96 (continued)

Code	Type	Watts	kWh	Lumens	Energy	Lamp Renewal	System Charges	Total (1st 10 years)	Total (After 1st 10 years)	Capital Cost
Street Lights										
203	Mercury Vapor X	250	100	11,000	8.83	1.79	3.22	13.84	10.62	
204	Mercury Vapor X	400	170	20,000	14.23	1.55	5.53	21.31	15.78	
206	Mercury Vapor X	1,000	400	50,000	35.26	2.40	8.20	45.86	37.66	
210	H.P. Sodium	250	110	30,000	8.97	1.85	3.88	14.70	10.82	357.83
211	H.P. Sodium	400	170	50,000	14.23	1.91	4.93	21.07	16.14	454.34
225	H.P. Sodium	100	40	9,500	3.57	1.85	3.11	8.53	5.42	286.42
226	H.P. Sodium	150	60	16,000	5.27	1.85	3.32	10.44	7.12	305.69
227	H.P. Sodium	200	80	22,000	7.06	1.85	3.36	12.27	8.91	309.59
232	Mercury Vapor X	175	80	7,500	6.31	1.42	3.19	10.92	7.73	
Flood Lights										
207	Mercury Vapor X	175	80	7,500	6.31	1.42	4.86	12.59	7.73	
208	Mercury Vapor X	400	170	20,000	14.23	1.55	5.41	21.19	15.78	
209	Mercury Vapor X	1,000	400	50,000	35.26	2.40	8.60	46.26	37.66	
223	H.P. Sodium	400	170	50,000	14.23	1.92	4.67	20.82	16.15	430.23
228	H.P. Sodium	100	40	9,500	3.57	1.85	4.20	9.62	5.42	386.74
229	H.P. Sodium	200	80	22,000	7.06	1.85	4.49	13.40	8.91	414.16
Post-Top Lights										
230	H.P. Sodium	100	40	9,500	3.57	1.85	2.57	7.99	5.42	236.60
231	Mercury Vapor X	175	80	7,500	6.31	1.42	N/A	7.73	7.73	
241	Acorn style Decorative light	100	40	9,500	3.57	1.85	7.45	12.87	5.42	686.92
242	Acorn style Decorative light Twin Arm	100	80	19,000	7.14	2.70	16.88	26.72	9.84	1,555.61
Yard-Lights										
202	Mercury Vapor X	175	80	7,500	6.31	1.42	1.22	8.95	7.73	
224	H.P. Sodium	70	30	5,800	2.51	1.80	1.13	5.44	4.31	
240	H.P. Sodium	100	40	9,500	3.57	1.85	2.57	7.99	5.42	236.53
X = No new installations										
Poles										
215	20' Direct Burial						4.09	4.09	-	376.82
216	25' Direct Buried Fiberglass						7.47	7.47	-	688.31
217	30' Direct Buried Fiberglass						9.90	9.90	-	912.00
218	25' Single Arm Aluminum						10.68	10.68	-	984.13
219	32' Single Arm Aluminum						11.88	11.88	-	1,095.11
235	30' Treated						6.52	6.52	-	601.21
236	35' Treated						7.63	7.63	-	703.45
243	14.5' Fluted Shaft Fiberglass Direct Burial						7.80	7.80	-	719.17
237	40' Treated						8.38	8.38	-	772.14

SCHEDULES 94, 95 AND 96 (continued)

Special Conditions

Underground service will be provided where practical if the Customer provides trenching and backfill. The Customer will furnish a concrete foundation or conduit where required, according to Utility specifications.

The Utility reserves the right to approve the type and intensity of lighting installed.

The Customer may request a temporary suspension of power for lighting by written notice. During such suspension, the monthly rate will be the system and pole charges portion of the Utility's lighting rate if applicable. A disconnect charge, as provided in the fee schedule, will be charged for disconnecting the first luminaire and an additional charge of $6.00 for each additional luminaire disconnected at the same time and general location. No reconnect fee will be charged upon the Customer's written request for reconnection.

The Customer may pay the entire cost of the lighting service at the time of installation for the lighting fixtures and/or the appropriate poles. In such a case, only energy and/or relamping monthly charges will be applied.

Term of Agreement

Minimum of 10 years for Utility owned fixtures and poles.

SCHEDULE 99
PURCHASE OF ENERGY FROM GENERATING FACILITIES WITH DESIGN CAPACITY OF 100 kW OR LESS

Applicability

The following rate represents Clark Public Utilities' rate for the purchase of energy delivered from generating facilities with design capacities of 100 kW or less.

Purchase Rate

7.03¢ per kWh

Revisions

This rate will be revised periodically as the average system retail rate is modified.

RESOLUTION NO. 6322

A RESOLUTION ADOPTING A REVISED SCHEDULE OF RATES FOR ELECTRIC SERVICE AND REPEALING ALL OTHER RESOLUTIONS, OR PARTS OF RESOLUTIONS IN CONFLICT THEREWITH

WHEREAS, the Commissioners of Public Utility District No. 1 of Clark County, Washington, have periodically established a schedule of rates for electric service to meet changing requirements; and

WHEREAS, wholesale energy costs, operational costs and costs associated with debt obligations are anticipated to exceed future revenues; and

WHEREAS, the Board of Commissioners has reviewed revenue requirement options and cost allocation options; and

WHEREAS, staff studies and reports recommend that the rates should be adjusted to meet future needs of the electrical utility; and

WHEREAS, several public meetings and workshops have given customers the opportunity to testify on the proposed rate changes and alternatives;

NOW, THEREFORE, BE IT RESOLVED by the Commissioners of Public Utility District No. 1 of Clark County, Washington, assembled this 18th day of March, 2003, as follows:

Section 1. The rates and classifications as set forth in the attached schedule is hereby adopted as rate schedule for electric service by the District from and after the effective dates hereof, as set herein.

Section 2. The effective date of Section 1 and application of rates authorized therein is April 1, 2003, and all consumption prior to such date is charged for at the rates in effect prior to the effective date of this resolution. In implementing this resolution, the Utility will prorate bills as if energy consumption occurred at a constant rate during the billing period in which the effective date of this resolution occurs.

Section 3. All other prior resolutions or parts of resolutions in conflict herewith be repealed.

PASSED AND ADOPTED this 18th day of March, 2003.

President

ATTEST:

Secretary

Clark Public Utilities

A customer-owned public utility district

TABLE OF CONTENTS

RATE SCHEDULES FOR ELECTRIC SERVICE

SCHEDULE 7
RESIDENTIAL AND FARM SERVICE

Applicability

To Residential Use, Incidental Residential Use (under 30 kW load), General Farm Use (under 30 kW load), or Incidental General Service Use when combined with Residential Use supplied through a single meter. Temporary Services, where occupancy of the premises will be Residential, will be eligible for this rate.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service - Sixty-Hertz, Alternating Current

The Utility reserves the right to specify the voltage and phase of service supplied under this schedule.

Secondary Point-Of-Delivery - Single-Phase or Three-Phase Service

Residential - The Utility owns and maintains all overhead and residential underground services to the primary residence.

Apartments and mobile home parks - The utility owns and maintains up to and including the distribution transformer or designated secondary junction point.

Incidental services (residential and farm including outbuildings, pools, etc.) – The customer owns and maintains underground services to the building. If overhead secondary conductors are required, the Utility will install, own and maintain the service with the customer paying an Aid-To-Construction fee to cover these costs.

Monthly Rate – The sum of the Basic and Energy charges:

Basic Charge:	$6.40
Energy Charge:	7.36¢ per kWh

SCHEDULE 34
GENERAL SERVICE

Applicability

To meet requirements of commercial, industrial, and general service customers not provided for in other rate schedules.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service - Sixty-hertz, Alternating Current

The Utility reserves the right to specify the voltage and phase of service supplied under this schedule.

Primary Point-Of-Delivery - Single or Three-Phase Service

A customer having a metered, kilowatt demand consistently averaging 100 kW or more may be served at the primary voltage level (12,470 volts). The customer will be responsible for all costs associated with the primary Point-of-Delivery installation including the metering and primary voltage physical disconnect necessary to isolate the customer's facilities from the Utility's facilities. The customer will be responsible to own, operate and maintain all electrical distribution facilities on the customer side of the Primary Point-of-Delivery (typically established at the primary meter).

Secondary Points-Of-Delivery - Single or Three-Phase Service

The utility owns and maintains distribution facilities up to the Secondary Point-of-Delivery (typically established at the secondary terminals of the transformer or other designed secondary junction point). If conditions require an overhead service, the utility will install, own and maintain the service and the customer will pay an Aid-To-Construction fee to cover these costs.

In existing installations where there is a mixed ownership of primary distribution facilities beyond a primary meter, the Secondary Point-of-Delivery rate will apply. The ownership and maintenance responsibilities of the customer-owned distribution facilities may be conveyed to the Utility subject to Utility review and approval. Primary Point-of-Delivery customers paying the higher Secondary Point-of-Delivery rate will be compensated for transformation losses. The metered kilowatt-hours and reactive kilovolt-ampere hours will be reduced 2% before the rates are applied.

SCHEDULE 34 (continued)

Monthly Rate - The sum of the following Basic, Energy and Demand charges:

First Tier Schedule 34 – Applicable to non-demand metered services and demand metered services with monthly demand less than or equal to 30 kilowatts.

Basic Charge:	$18.00
Energy Charge:	6.88¢ per kWh

Second Tier Schedule 34 – Applicable to services with a monthly, metered demand greater than 30 Kilowatts.

Basic Charge:	$36.00
Energy Charge:	4.41¢ per kWh Sep - Mar
	3.91¢ per kWh Apr – Aug
Demand Charge:	$6.30 per kW for Secondary Point-of-Delivery
	$5.54 per kW for Primary Point-of-Delivery

Off - Peak Demand

By special contract with the Utility, off-peak demand is available for customers with demands in excess of 30 kW. Service will be available at a discount rate during the off-peak period, which includes all hours except the hours Monday through Saturday between 7:00 a.m. and 10:00 p.m. The off-peak demand rates are 57¢/kW of demand for each kW the off-peak demand exceeds other recorded monthly demands. The energy rate as listed in the Monthly Rate section applies to all hours.

Adjustment of Demand for Power Factor

Demands will be adjusted to correct for average power factors lower than 95%. Such adjustments will be made by increasing the measured demand l% for each l% or major fraction thereof by which the average power factor is less than 95% lagging.

Metered real energy measured in kilowatt-hours (kWh) and metered reactive energy measured in Kilovolt Ampere-Hours (kVARh) are used to calculate the average monthly power factor as follows:

Power Factor equals

$$\frac{kWh}{\sqrt{(kWh)^2 + (kVARh)^2}}$$

SCHEDULE 36

SMALL UNMETERED GENERAL USE ANNUALLY BILLED

Applicability

Small loads that are photo eye or timer controlled with estimated usage up to 1,500 kWh annually for specific isolated uses. The Utility reserves the right to determine the application of this rate schedule.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Annual Rate

The sum of the following Basic and Energy charges:

Annual Basic Charge:	$18.00	
Annual Energy Charge:	$16.40	1 - 500 kWh
Annual Energy Charge:	$50.40	501 – 1,000 kWh
Annual Energy Charge:	$84.40	1,001 – 1,500 kWh

SCHEDULE 38

SMALL METERED GENERAL USE ANNUALLY BILLED

Applicability

Small general use metered loads that are less than 3,600 kWh annually. The Utility reserves the right to determine the application of this rate schedule.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Annual Rate

The sum of the following Basic and Energy charges:

Annual Basic Charge:	$18.00
Annual Energy Charge:	6.88¢ per kWh

SCHEDULE 35 AND 43

RESIDENTIAL AND COMMERCIAL DRYING

Applicability

Metered power for use in drying structures being prepared for occupancy as a result of residential and commercial building construction.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Monthly Rate

Energy charge: 6.88¢ per kWh

Special Conditions

On completion of the permanent meter installation, a drying rate will be charged until normal occupancy of the building, not to exceed six months. The drying service is not to be used for permanently-installed buildings, appliances, or equipment, recreational vehicles, or mobile homes. If this service is used beyond six months, the account will be reviewed for applicability by the Utility. In the event that service is used for purposes other than described, it will be removed, and the amount of energy used will be rebilled at the applicable rate schedule.

SCHEDULE 85

INDUSTRIAL SERVICE

Applicability

To lighting, heating and power service for customers having measured minimum demands of not less than 1500 kilowatts.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service

Three-phase, sixty-hertz, alternating current at approximately 12,000 volts or higher, as available in the area. The Utility reserves the right to determine the availability of service under this schedule.

Primary Point-Of-Delivery

The customer will be responsible for all costs associated with the primary Point-of-Delivery installation including the metering and primary voltage physical disconnect necessary to isolate the customer's facilities from the Utility's facilities. The customer will be responsible to own, operate and maintain all electrical distribution facilities on the customer side of the Primary Point-of-Delivery (typically established at the primary meter). All transformers, equipment and wiring shall be of types and characteristics acceptable to the Utility. The entire installation and the balance of loads between phases must have the approval of the Utility.

Transmission Point-Of-Delivery

Transmission Point-of-Delivery customers are served at a transmission voltage level (either 69,000 or 115,000 volts). The customer is responsible for all costs associated with the transmission Point-of-Delivery installation including the metering and transmission voltage physical disconnect necessary to isolate the customer's facilities from the Utility's facilities. The customer will be responsible to own, operate and maintain all electrical facilities on the customer side of the Transmission Point-of-Delivery including the power transformer(s) and distribution transformers. All transformers, equipment and wiring shall be of types and characteristics acceptable to the Utility. The entire installation and the balance of loads between phases must have the approval of the Utility.

SCHEDULE 85 (continued)

Monthly Rate

The sum of the following Customer, Energy and Demand charges:

Customer Charge:	$120.00
Energy Charge:	4.41¢ per KWH for the months Sep - Mar 3.91¢ per KWH for the months Apr - Aug
Demand Charge:	$5.54 per KW – Primary Point-of-Delivery $4.28 per KW – Transmission Point-of-Delivery

Off-Peak Demand

By special contract with the Utility, off-peak demand is available for Customers with demands in excess of 1500 KW. Service will be available at a discount rate during the off-peak period, which includes all hours except the hours Monday through Saturday between 7:00 a.m. and 10:00 p.m. The off-peak demand rates are 57¢ per KW of demand for each KW the off-peak demand exceeds other recorded monthly demands. The energy rate as listed in the Monthly Rate section applies to all hours.

Adjustment of Demand for Power

Demands will be adjusted to correct for average power factors lower than 95%. Such adjustments will be made by increasing the measured demand l% for each l% or major fraction thereof by which the average power factor is less than 95% lagging.

Metered real energy measured in kilowatt-hours (kWh) and metered reactive energy measured in Kilovolt Ampere-Hours (kVARh) are used to calculate the average monthly power factor as follows:

$$\text{Power Factor equals} \quad \frac{\text{kWh}}{\sqrt{(\text{kWh})^2 + (\text{kVARh})^2}}$$

SCHEDULES 94 - 95 - 96

MUNICIPAL, RESIDENTIAL, AND COMMERCIAL LIGHTING

Applicability

Off-street lighting service to individuals for locations on private property or to lighting service for public streets, alleys, highways, thoroughfares, and public grounds supplied to Local Utility District, municipalities, counties, or agencies of federal or state governments where funds for payment for electric service are provided through taxation or special assessment.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service

From dusk to dawn daily, controlled by light sensitive relay.

Specifications

System shall be of overhead construction consisting of an aerial circuit, mast arms and standard luminaires or flood lights, except in subdivisions or commercial installations with underground utilities. Underground circuits, wood or ornamental poles will be installed in these areas, with additional charges.

Monthly Rate

During the first seven year period, the Utility will own, maintain, and furnish energy for luminaires as shown in the "Total" column. After the initial seven year term has been completed, the successive monthly billings will exclude system charges and poles if appropriate. However, the Utility always owns all street light facilities. System charges are considered as contributions in aid to construction. Other conditions can be determined by applying the appropriate column or columns. Individual luminaire repair or relamping will be done as soon as reasonably possible after notification by the Customer.

SCHEDULES 94, 95 AND 96 (continued)

Code	Type	Watts	KWh	Lumens	Energy	Lamp Renewal	System Charges	Total (1st 7 years)	Total (After 1st 7 years)	Capital Cost
Street Lights										
203	Mercury Vapor X	250	100	11,000	$8.83	$1.79	$3.22	$13.84	$10.62	
204	Mercury Vapor X	400	170	20,000	$14.23	$1.55	$5.53	$21.31	$15.78	
206	Mercury Vapor X	1,000	400	50,000	$35.26	$2.40	$8.20	$45.86	$37.66	
210	H.P. Sodium	250	110	30,000	$8.97	$1.85	$3.78	$14.60	$10.82	$232.00
211	H.P. Sodium	400	170	50,000	$14.23	$1.91	$3.98	$20.12	$16.14	$244.00
225	H.P. Sodium	100	40	9,500	$3.57	$1.85	$3.06	$8.48	$5.42	$188.00
226	H.P. Sodium	150	60	16,000	$5.27	$1.85	$3.08	$10.20	$7.12	$189.00
227	H.P. Sodium	200	80	22,000	$7.06	$1.85	$3.59	$12.50	$8.91	$220.00
232	Mercury Vapor X	175	80	7,500	$6.31	$1.42	$3.19	$10.92	$7.73	
Flood Lights										
207	Mercury Vapor X	175	80	7,500	$6.31	$1.42	$4.86	$12.59	$7.73	
208	Mercury Vapor X	400	170	20,000	$14.23	$1.55	$5.41	$21.19	$15.78	
209	Mercury Vapor X	1,000	400	50,000	$35.26	$2.40	$8.60	$46.26	$37.66	
223	H.P. Sodium	400	170	50,000	$14.23	$1.92	$5.11	$21.26	$16.15	313.00
228	H.P. Sodium	100	40	9,500	$3.57	$1.85	$4.67	$10.09	$5.42	286.00
229	H.P. Sodium	200	80	22,000	$7.06	$1.85	$4.77	$13.68	$8.91	292.00
Post-Top Lights										
230	H.P. Sodium	100	40	9,500	$3.57	$1.85	$2.72	$8.14	$5.42	167.00
231	Mercury Vapor X	175	80	7,500	$6.31	$1.42	$2.43	$10.16	$7.73	
Yard-Lights										
202	Mercury Vapor X	175	80	7,500	$6.31	$1.42	$1.22	$8.95	$7.73	
224	H.P. Sodium	70	30	5,800	$2.51	$1.80	$1.13	$5.44	$4.31	70.00
240	H.P. Sodium	100	40	9,500	$3.57	$1.85	$1.30	$6.72	$5.42	81.00

X = No new installations

Special Conditions

Underground service will be provided where practical if the Customer provides trenching and backfill. The Customer will furnish a concrete foundation or conduit where required, according to Utility specifications.

The Utility reserves the right to approve the type and intensity of lighting installed.

SCHEDULES 94, 95 AND 96 (continued)

The Customer may request a temporary suspension of power for lighting by written notice. During such suspension, the monthly rate will be the system and pole charges portion of the Utility's lighting rate if applicable. A disconnect charge, as provided in the fee schedule, will be charged for disconnecting the first luminaire and an additional charge of $6.00 for each additional luminaire disconnected at the same time and general location. No reconnect fee will be charged upon the Customer's written request for reconnection.

The Customer may pay the entire cost of the lighting service at the time of installation for the lighting fixtures and/or the appropriate poles. In such a case, only energy and/or relamping monthly charges will be applied.

Capital contribution costs and monthly rates for wood or ornamental poles in accordance with Utility specifications are as follows:

Code		Monthly Rate	Capital Cost
215	20' direct burial ornamental pole	$4.49	$275.00
216	25' ornamental pole (foundation required)	8.57	525.00
217	30' ornamental pole (foundation required)	10.26	629.00
235	30' treated wood pole	3.81	220.00
236	35' treated wood pole	5.15	297.00
237	40' treated wood pole	5.67	327.00

Term of Agreement

Minimum of seven years for Utility owned fixtures and poles.

SCHEDULE 99
PURCHASE OF ENERGY FROM GENERATING FACILITIES WITH DESIGN CAPACITY OF 100 kW OR LESS

Applicability

The following rate represents Clark Public Utilities' rate for the purchase of energy delivered from generating facilities with design capacities of 100 kW or less.

Purchase Rate

6.87¢ per kWh

Revisions

This rate will be revised periodically as the average system retail rate is modified.

RESOLUTION NO. 6177

A RESOLUTION ADOPTING A REVISED SCHEDULE OF RATES FOR ELECTRIC SERVICE AND REPEALING ALL OTHER RESOLUTIONS, OR PARTS OF RESOLUTIONS IN CONFLICT THEREWITH

WHEREAS, the Commissioners of Public Utility District No. 1 of Clark County, Washington, have periodically established a schedule of rates for electric service to meet changing requirements; and

WHEREAS, wholesale energy costs, operational costs and costs associated with debt obligations are anticipated to exceed future revenues; and

WHEREAS, the Board of Commissioners has reviewed revenue requirement options and cost allocation options; and

WHEREAS, staff studies and reports recommend that the rates should be adjusted to meet future needs of the electrical utility; and

WHEREAS, several public meetings and workshops have given customers the opportunity to testify on the proposed rate changes and alternatives;

NOW, THEREFORE, BE IT RESOLVED by the Commissioners of Public Utility District No. 1 of Clark County, Washington, assembled this 25th day of July, 2001, as follows:

Section 1. The rates and classifications as set forth in the attached schedule is hereby adopted as rate schedule for electric service by the District from and after the effective dates hereof, as set herein.

Section 2. The effective date of Section 1 and application of rates authorized therein is August 1, 2001, and all consumption prior to such date is charged for at the rates in effect prior to the effective date of this resolution. In implementing this resolution, the Utility will prorate bills as if energy consumption occurred at a constant rate during the billing period in which the effective date of this resolution occurs.

Section 3. All other prior resolutions or parts of resolutions in conflict herewith be repealed.

PASSED AND ADOPTED this 25th day of July, 2001.

Nancy Barnes
President

ATTEST:

Secretary

Clark Public Utilities

A customer-owned public utility district

TABLE OF CONTENTS

RATE SCHEDULES FOR ELECTRIC SERVICE

SCHEDULE 7
RESIDENTIAL AND FARM SERVICE

Applicability

To Residential Use, Incidental Residential Use (under 30 kW load), General Farm Use (under 30 kW load), or Incidental General Service Use when combined with Residential Use supplied through a single meter. Temporary Services, where occupancy of the premises will be Residential, will be eligible for this rate.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service - Sixty-Hertz, Alternating Current

The Utility reserves the right to specify the voltage and phase of service supplied under this schedule.

Secondary Point-Of-Delivery - Single-Phase or Three-Phase Service

Residential - The Utility owns and maintains all overhead and residential underground services to the primary residence.

Apartments and mobile home parks - The utility owns and maintains up to and including the distribution transformer or designated secondary junction point.

Incidental services (residential and farm including outbuildings, pools, etc.) – The customer owns and maintains underground services to the building. If overhead secondary conductors are required, the Utility will install, own and maintain the service with the customer paying an Aid-To-Construction fee to cover these costs.

Monthly Rate – The sum of the Basic and Energy charges:

Basic Charge:	\$6.40
Energy Charge:	6.98¢ per kWh

SCHEDULE 34
GENERAL SERVICE

Applicability

To meet requirements of commercial, industrial, and general service customers not provided for in other rate schedules.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service - Sixty-hertz, Alternating Current

The Utility reserves the right to specify the voltage and phase of service supplied under this schedule.

Primary Point-Of-Delivery - Single or Three-Phase Service

A customer having a metered, kilowatt demand consistently averaging 100 kW or more may be served at the primary voltage level (12,470 volts). The customer will be responsible for all costs associated with the primary Point-of-Delivery installation including the metering and primary voltage physical disconnect necessary to isolate the customer's facilities from the Utility's facilities. The customer will be responsible to own, operate and maintain all electrical distribution facilities on the customer side of the Primary Point-of-Delivery (typically established at the primary meter).

Secondary Points-Of-Delivery - Single or Three-Phase Service

The utility owns and maintains distribution facilities up to the Secondary Point-of-Delivery (typically established at the secondary terminals of the transformer or other designed secondary junction point). If conditions require an overhead service, the utility will install, own and maintain the service and the customer will pay an Aid-To-Construction fee to cover these costs.

In existing installations where there is a mixed ownership of primary distribution facilities beyond a primary meter, the Secondary Point-of-Delivery rate will apply. The ownership and maintenance responsibilities of the customer-owned distribution facilities may be conveyed to the Utility subject to Utility review and approval. Primary Point-of-Delivery customers paying the higher Secondary Point-of-Delivery rate will be compensated for transformation losses. The metered kilowatt-hours and reactive kilovolt-ampere hours will be reduced 2% before the rates are applied.

SCHEDULE 34 (continued)

Monthly Rate - The sum of the following Basic, Energy and Demand charges:

First Tier Schedule 34 – Applicable to non-demand metered services and demand metered services with monthly demand less than or equal to 30 kilowatts.

Basic Charge:	$18.00
Energy Charge:	6.52¢ per kWh

Second Tier Schedule 34 – Applicable to services with a monthly, metered demand greater than 30 Kilowatts.

Basic Charge:	$36.00
Energy Charge:	4.20¢ per kWh Sep - Mar
	3.72¢ per kWh Apr – Aug
Demand Charge:	$6.00 per kW for Secondary Point-of-Delivery
	$5.28 per kW for Primary Point-of-Delivery

Off - Peak Demand

By special contract with the Utility, off-peak demand is available for customers with demands in excess of 30 kW. Service will be available at a discount rate during the off-peak period, which includes all hours except the hours Monday through Saturday between 7:00 a.m. and 10:00 p.m. The off-peak demand rates are 54¢/kW of demand for each kW the off-peak demand exceeds other recorded monthly demands. The energy rate as listed in the Monthly Rate section applies to all hours.

Adjustment of Demand for Power Factor

Demands will be adjusted to correct for average power factors lower than 95%. Such adjustments will be made by increasing the measured demand l% for each l% or major fraction thereof by which the average power factor is less than 95% lagging.

Metered real energy measured in kilowatt-hours (kWh) and metered reactive energy measured in Kilovolt Ampere-Hours (kVARh) are used to calculate the average monthly power factor as follows:

Power Factor equals

$$\frac{\text{kWh}}{\sqrt{(\text{kWh})^2 + (\text{kVARh})^2}}$$

SCHEDULE 36

SMALL UNMETERED GENERAL USE
ANNUALLY BILLED

Applicability

Small loads that are photo eye or timer controlled with estimated usage up to 1,500 kWh annually for specific isolated uses. The Utility reserves the right to determine the application of this rate schedule.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Annual Rate

The sum of the following Basic and Energy charges:

Annual Basic Charge:	$18.00	
Annual Energy Charge:	$15.60	1 - 500 kWh
Annual Energy Charge:	$48.00	501 – 1,000 kWh
Annual Energy Charge:	$80.40	1,001 – 1,500 kWh

SCHEDULE 38
SMALL METERED GENERAL USE
ANNUALLY BILLED

Applicability

Small general use metered loads that are less than 3,600 kWh annually. The Utility reserves the right to determine the application of this rate schedule.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Annual Rate

The sum of the following Basic and Energy charges:

Annual Basic Charge:	$18.00
Annual Energy Charge:	6.52¢ per kWh

SCHEDULE 35 AND 43

RESIDENTIAL AND COMMERCIAL DRYING

Applicability

Metered power for use in drying structures being prepared for occupancy as a result of residential and commercial building construction.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Monthly Rate

Energy charge: 6.52¢ per kWh

Special Conditions

On completion of the permanent meter installation, a drying rate will be charged until normal occupancy of the building, not to exceed six months. The drying service is not to be used for permanently-installed buildings, appliances, or equipment, recreational vehicles, or mobile homes. If this service is used beyond six months, the account will be reviewed for applicability by the Utility. In the event that service is used for purposes other than described, it will be removed, and the amount of energy used will be rebilled at the applicable rate schedule.

SCHEDULE 85

INDUSTRIAL SERVICE

Applicability

To lighting, heating and power service for customers having measured minimum demands of not less than 1500 kilowatts.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service

Three-phase, sixty-hertz, alternating current at approximately 12,000 volts or higher, as available in the area. The Utility reserves the right to determine the availability of service under this schedule.

Primary Point-Of-Delivery

The customer will be responsible for all costs associated with the primary Point-of-Delivery installation including the metering and primary voltage physical disconnect necessary to isolate the customer's facilities from the Utility's facilities. The customer will be responsible to own, operate and maintain all electrical distribution facilities on the customer side of the Primary Point-of-Delivery (typically established at the primary meter). All transformers, equipment and wiring shall be of types and characteristics acceptable to the Utility. The entire installation and the balance of loads between phases must have the approval of the Utility.

Transmission Point-Of-Delivery

Transmission Point-of-Delivery customers are served at a transmission voltage level (either 69,000 or 115,000 volts). The customer is responsible for all costs associated with the transmission Point-of-Delivery installation including the metering and transmission voltage physical disconnect necessary to isolate the customer's facilities from the Utility's facilities. The customer will be responsible to own, operate and maintain all electrical facilities on the customer side of the Transmission Point-of-Delivery including the power transformer(s) and distribution transformers. All transformers, equipment and wiring shall be of types and characteristics acceptable to the Utility. The entire installation and the balance of loads between phases must have the approval of the Utility.

SCHEDULE 85 (continued)

Monthly Rate

The sum of the following Customer, Energy and Demand charges:

Customer Charge:	$120.00
Energy Charge:	4.20¢ per KWH for the months Sep - Mar 3.72¢ per KWH for the months Apr - Aug
Demand Charge:	$5.28 per KW – Primary Point-of-Delivery $4.08 per KW – Transmission Point-of-Delivery

Off-Peak Demand

By special contract with the Utility, off-peak demand is available for Customers with demands in excess of 1500 KW. Service will be available at a discount rate during the off-peak period, which includes all hours except the hours Monday through Saturday between 7:00 a.m. and 10:00 p.m. The off-peak demand rates are 54¢ per KW of demand for each KW the off-peak demand exceeds other recorded monthly demands. The energy rate as listed in the Monthly Rate section applies to all hours.

Adjustment of Demand for Power

Demands will be adjusted to correct for average power factors lower than 95%. Such adjustments will be made by increasing the measured demand l% for each l% or major fraction thereof by which the average power factor is less than 95% lagging.

Metered real energy measured in kilowatt-hours (kWh) and metered reactive energy measured in Kilovolt Ampere-Hours (kVARh) are used to calculate the average monthly power factor as follows:

$$\text{Power Factor equals} \quad \frac{\text{kWh}}{\sqrt{(\text{kWh})^2 + (\text{kVARh})^2}}$$

SCHEDULE 87
CONTRACTUAL DIRECT ACCESS SERVICE
[SUSPENDED]

Applicability

This service is applicable under separate contract for all customers with a peak billing demand equal to or greater than 4 megawatts during the past 12 months. No more than two points-of-delivery can be combined to meet the four (4) megawatt minimum.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service - Three-Phase, Sixty-Hertz, Alternating Current

Service to be supplied at approximately 12.47 kilovolts or higher. The Utility reserves the right to determine the availability of service under this schedule.

Monthly Rate

The monthly rate shall consist of a Power Supply Charge, Transmission Charge, Delivery Charge, Transition Charge and Load Balancing Charges.

Power Supply Charge - The Power Supply Charge will be passed through to the Customer per contractual arrangements with the Utility. The Customer is responsible for arranging power supply and scheduling to serve their entire load. Contractual arrangements between the power supplier and the Utility must be developed. All power supply costs will be billed to the Utility and the Utility will bill the Customer at the contractual power supply rate for power in accordance with the contract between the Utility and the Power Supplier.

Transmission Charge covers the costs of transmitting the power supply over the Bonneville system to the Utility's service area and associated losses. Transmission losses of 1.9 percent of the monthly, metered kilowatt-hours will be charged at the rates below.

BPA Demand Charge: $1.539 per kW-month

Losses – Energy Charge (per kilowatt-hour):

Contract Year	Aug-Oct	Nov-Mar	Apr-Jul
1999-00	$0.01599	$0.01771	$0.01211
2000-01	$0.01663	$0.01851	$0.01262

SCHEDULE 87 (continued)

Delivery Charge covers the costs of distribution of power, metering, customer accounting and customer service.

Primary Level Point-of-Delivery	$2.20 per kW-month
Transmission Level Point-of-Delivery	$1.20 per kW-month

The Delivery Charge may be adjusted to reflect investments, made by either the Customer or the Utility, in transmission facilities used exclusively to serve the Customer. Adjustments to the above charges will be calculated on a customer by customer basis. Adjustments may result in an increase or decrease in the delivery charge depending on the nature of the investment.

Transition Charge shall be the monthly charge for the costs incurred by the Utility due to previously arranged power supply contracts. This charge will be reviewed annually and adjusted if necessary.

Transition Charge: $0.000 per kWh

Load Balancing Charges cover the cost of deviations from scheduled amounts under the contractual Power Supply arrangement.

When Metered Load ***Exceeds*** *Schedule* - The demand charge is applied to the largest difference between the scheduled Firm Capacity and the actual metered demand occurring from 6 a.m. through 10 p.m. Monday through Saturday. The Energy Charge is applied to the total net kilowatt-hours delivered in the month in excess of Firm Energy scheduled.

Demand Charge:

January-February	$4.00 per kW-month
March-May	$2.40 per kW-month
June-August	$4.00 per kW-month
September-October	$3.15 per kW-month
November-December	$4.00 per kW-month

Energy Charge:

January-March	$0.01618 per kWh
April-July	$0.01116 per kWh
August-October	$0.01538 per kWh
November-December	$0.01693 per kWh

Schedule 87 (continued)

Load Balancing Charges (continued)

When Scheduled Load Exceeds Metered Load - If in any hour the Customer's metered power usage is less than the amount of Firm Power scheduled, the following re-marketing charges apply:

Amount Below Schedule	Per Kilowatt-hour
First 500 kW	$0.000
Next 500 kW	$0.002
Next 1,000 kW	$0.005
Amount over 2,000 kW	$0.008

The foregoing charge is applied to the amount of power by which the scheduled Firm Energy exceeds the Customer's metered power usage in any hour during each month.

Special Conditions

A Remote Metering System (RMS) is required for Retail Access Service. The RMS will provide hourly usage necessary for billing purposes. The Utility will install, own and maintain the RMS. The Customer will reimburse the Utility for the cost of the initial installation.

Reactive Power Charge

The Customer's leading and lagging reactive power requirements will be metered and billed each month based on BPA's reactive power rates.

One Year Minimum Term

Upon signing up for service under Schedule 87, the Customer must remain on the schedule for a minimum of one year.

Taxes

The Customer shall make a payment each month to any and all taxes assessed on or attributable to the sale of any commodity or service to the Customer.

SCHEDULES 94 - 95 - 96

MUNICIPAL, RESIDENTIAL, AND COMMERCIAL LIGHTING

Applicability

Off-street lighting service to individuals for locations on private property or to lighting service for public streets, alleys, highways, thoroughfares, and public grounds supplied to Local Utility District, municipalities, counties, or agencies of federal or state governments where funds for payment for electric service are provided through taxation or special assessment.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service

From dusk to dawn daily, controlled by light sensitive relay.

Specifications

System shall be of overhead construction consisting of an aerial circuit, mast arms and standard luminaires or flood lights, except in subdivisions or commercial installations with underground utilities. Underground circuits, wood or ornamental poles will be installed in these areas, with additional charges.

Monthly Rate

During the first seven year period, the Utility will own, maintain, and furnish energy for luminaires as shown in the "Total" column. After the initial seven year term has been completed, the successive monthly billings will exclude system charges and poles if appropriate. However, the Utility always owns all street light facilities. System charges are considered as contributions in aid to construction. Other conditions can be determined by applying the appropriate column or columns. Individual luminaire repair or relamping will be done as soon as reasonably possible after notification by the Customer.

SCHEDULES 94, 95 AND 96 (continued)

Code	Type	Watts	KWh	Lumens	Energy	Lamp Renewal	System Charges	Total (1st 7 years)	Total (After 1st 7 years)	Capital Cost
Street Lights										
203	Mercury Vapor X	250	100	11,000	$8.41	$1.79	$3.22	$13.42	$10.20	
204	Mercury Vapor X	400	170	20,000	$13.55	$1.55	$5.53	$20.63	$15.10	
206	Mercury Vapor X	1,000	400	50,000	$33.58	$2.40	$8.20	$44.18	$35.98	
210	H.P. Sodium	250	110	30,000	$8.54	$1.85	$3.78	$14.17	$10.39	$232.00
211	H.P. Sodium	400	170	50,000	$13.55	$1.91	$3.98	$19.44	$15.46	$244.00
225	H.P. Sodium	100	40	9,500	$3.40	$1.85	$3.06	$8.31	$5.25	$188.00
226	H.P. Sodium	150	60	16,000	$5.02	$1.85	$3.08	$9.95	$6.87	$189.00
227	H.P. Sodium	200	80	22,000	$6.72	$1.85	$3.59	$12.16	$8.57	$220.00
232	Mercury Vapor X	175	80	7,500	$6.01	$1.42	$3.19	$10.62	$7.43	
Flood Lights										
207	Mercury Vapor X	175	80	7,500	$6.01	$1.42	$4.86	$12.29	$7.43	
208	Mercury Vapor X	400	170	20,000	$13.55	$1.55	$5.41	$20.51	$15.10	
209	Mercury Vapor X	1,000	400	50,000	$33.58	$2.40	$8.60	$44.58	$35.98	
223	H.P. Sodium	400	170	50,000	$13.55	$1.92	$5.11	$20.58	$15.47	313.00
228	H.P. Sodium	100	40	9,500	$3.40	$1.85	$4.67	$9.92	$5.25	286.00
229	H.P. Sodium	200	80	22,000	$6.72	$1.85	$4.77	$13.34	$8.57	292.00
Post-Top Lights										
230	H.P. Sodium	100	40	9,500	$3.40	$1.85	$2.72	$7.97	$5.25	167.00
231	Mercury Vapor X	175	80	7,500	$6.01	$1.42	$2.43	$9.86	$7.43	
Yard-Lights										
202	Mercury Vapor X	175	80	7,500	$6.01	$1.42	$1.22	$8.65	$7.43	
224	H.P. Sodium	70	30	5,800	$2.39	$1.80	$1.13	$5.32	$4.19	70.00
240	H.P. Sodium	100	40	9,500	$3.40	$1.85	$1.30	$6.55	$5.25	81.00

X = No new installations

<u>Special Conditions</u>

Underground service will be provided where practical if the Customer provides trenching and backfill. The Customer will furnish a concrete foundation or conduit where required, according to Utility specifications.

The Utility reserves the right to approve the type and intensity of lighting installed.

SCHEDULES 94, 95 AND 96 (continued)

The Customer may request a temporary suspension of power for lighting by written notice. During such suspension, the monthly rate will be the system and pole charges portion of the Utility's lighting rate if applicable. A disconnect charge, as provided in the fee schedule, will be charged for disconnecting the first luminaire and an additional charge of $6.00 for each additional luminaire disconnected at the same time and general location. No reconnect fee will be charged upon the Customer's written request for reconnection.

The Customer may pay the entire cost of the lighting service at the time of installation for the lighting fixtures and/or the appropriate poles. In such a case, only energy and/or relamping monthly charges will be applied.

Capital contribution costs and monthly rates for wood or ornamental poles in accordance with Utility specifications are as follows:

Code		Monthly Rate	Capital Cost
215	20' direct burial ornamental pole	$4.49	$275.00
216	25' ornamental pole (foundation required)	8.57	525.00
217	30' ornamental pole (foundation required)	10.26	629.00
235	30' treated wood pole	3.81	220.00
236	35' treated wood pole	5.15	297.00
237	40' treated wood pole	5.67	327.00

Term of Agreement

Minimum of seven years for Utility owned fixtures and poles.

SCHEDULE 99
PURCHASE OF ENERGY FROM GENERATING FACILITIES WITH DESIGN CAPACITY OF 100 kW OR LESS

Applicability

The following rate represents Clark Public Utilities' rate for the purchase of energy delivered from generating facilities with design capacities of 100 kW or less.

Purchase Rate

6.54¢ per kWh

Revisions

This rate will be revised periodically as the average system retail rate is modified.

RESOLUTION NO. 6130

A RESOLUTION ADOPTING A REVISED SCHEDULE OF RATES FOR ELECTRIC SERVICE AND REPEALING ALL OTHER RESOLUTIONS, OR PARTS OF RESOLUTIONS IN CONFLICT THEREWITH

WHEREAS, the Commissioners of Public Utility District No. 1 of Clark County, Washington, have periodically established a schedule of rates for electric service to meet changing requirements; and

WHEREAS, wholesale energy costs, operational costs and costs associated with debt obligations are anticipated to exceed future revenues; and

WHEREAS, the Board of Commissioners has reviewed revenue requirement options and cost allocation options; and

WHEREAS, staff studies and reports recommend that the rates should be adjusted to meet future needs of the electrical utility; and

WHEREAS, several public meetings and workshops have given customers the opportunity to testify on the proposed rate changes and alternatives;

NOW, THEREFORE, BE IT RESOLVED by the Commissioners of Public Utility District No. 1 of Clark County, Washington, assembled this 16th day of January, 2001, as follows:

Section 1. The rates and classifications as set forth in the attached schedule is hereby adopted as rate schedule for electric service by the District from and after the effective dates hereof, as set herein.

Section 2. The effective date of Section 1 and application of rates authorized therein is January 15, 2001, and all consumption prior to such date is charged for at the rates in effect prior to the effective date of this resolution. In implementing this resolution, the Utility will prorate bills as if energy consumption occurred at a constant rate during the billing period in which the effective date of this resolution occurs.

Section 3. All other prior resolutions or parts of resolutions in conflict herewith be repealed.

PASSED AND ADOPTED this 16th day of January, 2001.

President

ATTEST:

Secretary

Clark Public Utilities

A customer-owned public utility district

TABLE OF CONTENTS

RATE SCHEDULES FOR ELECTRIC SERVICE

SCHEDULE 7
RESIDENTIAL AND FARM SERVICE

Applicability

To Residential Use, Incidental Residential Use (under 30 kW load), General Farm Use (under 30 kW load), or Incidental General Service Use when combined with Residential Use supplied through a single meter. Temporary Services, where occupancy of the premises will be Residential, will be eligible for this rate.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service - Sixty-Hertz, Alternating Current

The Utility reserves the right to specify the voltage and phase of service supplied under this schedule.

Secondary Point-Of-Delivery - Single-Phase or Three-Phase Service

Residential - The Utility owns and maintains all overhead and residential underground services to the primary residence.

Apartments and mobile home parks - The utility owns and maintains up to and including the distribution transformer or designated secondary junction point.

Incidental services (residential and farm including outbuildings, pools, etc.) – The customer owns and maintains underground services to the building. If overhead secondary conductors are required, the Utility will install, own and maintain the service with the customer paying an Aid-To-Construction fee to cover these costs.

Monthly Rate – The sum of the Basic and Energy charges:

Basic Charge:	$6.40
Energy Charge:	5.73¢ per kWh

Resolution No. 6130
Date of Issue: January 16, 2001

Effective Date:
January 15, 2001

SCHEDULE 34
GENERAL SERVICE

Applicability

To meet requirements of commercial, industrial, and general service customers not provided for in other rate schedules.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service - Sixty-hertz, Alternating Current

The Utility reserves the right to specify the voltage and phase of service supplied under this schedule.

Primary Point-Of-Delivery - Single or Three-Phase Service

A customer having a metered, kilowatt demand consistently averaging 100 kW or more may be served at the primary voltage level (12,470 volts). The customer will be responsible for all costs associated with the primary Point-of-Delivery installation including the metering and primary voltage physical disconnect necessary to isolate the customer's facilities from the Utility's facilities. The customer will be responsible to own, operate and maintain all electrical distribution facilities on the customer side of the Primary Point-of-Delivery (typically established at the primary meter).

Secondary Points-Of-Delivery - Single or Three-Phase Service

The utility owns and maintains distribution facilities up to the Secondary Point-of-Delivery (typically established at the secondary terminals of the transformer or other designed secondary junction point). If conditions require an overhead service, the utility will install, own and maintain the service and the customer will pay an Aid-To-Construction fee to cover these costs.

In existing installations where there is a mixed ownership of primary distribution facilities beyond a primary meter, the Secondary Point-of-Delivery rate will apply. The ownership and maintenance responsibilities of the customer-owned distribution facilities may be conveyed to the Utility subject to Utility review and approval. Primary Point-of-Delivery customers paying the higher Secondary Point-of-Delivery rate will be compensated for transformation losses. The metered kilowatt-hours and reactive kilovolt-ampere hours will be reduced 2% before the rates are applied.

SCHEDULE 34 (continued)

Monthly Rate - The sum of the following Basic, Energy and Demand charges:

First Tier Schedule 34 – Applicable to non-demand metered services and demand metered services with monthly demand less than or equal to 30 kilowatts.

Basic Charge:	$15.00
Energy Charge:	5.43¢ per kWh

Second Tier Schedule 34 – Applicable to services with a monthly, metered demand greater than 30 Kilowatts.

Basic Charge:	$30.00
Energy Charge:	3.50¢ per kWh Sep - Mar
	3.10¢ per kWh Apr – Aug
Demand Charge:	$5.00 per kW for Secondary Point-of-Delivery
	$4.40 per kW for Primary Point-of-Delivery

Off - Peak Demand

By special contract with the Utility, off-peak demand is available for customers with demands in excess of 30 kW. Service will be available at a discount rate during the off-peak period, which includes all hours except the hours Monday through Saturday between 7:00 a.m. and 10:00 p.m. The off-peak demand rates are 45¢/kW of demand for each kW the off-peak demand exceeds other recorded monthly demands. The energy rate as listed in the Monthly Rate section applies to all hours.

Adjustment of Demand for Power Factor

Demands will be adjusted to correct for average power factors lower than 95%. Such adjustments will be made by increasing the measured demand l% for each l% or major fraction thereof by which the average power factor is less than 95% lagging.

Metered real energy measured in kilowatt-hours (kWh) and metered reactive energy measured in Kilovolt Ampere-Hours (kVARh) are used to calculate the average monthly power factor as follows:

Power Factor equals

$$\frac{\text{kWh}}{\sqrt{(\text{kWh})^2 + (\text{kVARh})^2}}$$

SCHEDULE 36

SMALL UNMETERED GENERAL USE
ANNUALLY BILLED

Applicability

Small loads that are photo eye or timer controlled with estimated usage up to 1,500 kWh annually for specific isolated uses. The Utility reserves the right to determine the application of this rate schedule.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Annual Rate

The sum of the following Basic and Energy charges:

Annual Basic Charge:	$15.00	
Annual Energy Charge:	$13.00	1 - 500 kWh
Annual Energy Charge:	$40.00	501 – 1,000 kWh
Annual Energy Charge:	$67.00	1,001 – 1,500 kWh

SCHEDULE 38
SMALL METERED GENERAL USE
ANNUALLY BILLED

Applicability

Small general use metered loads that are less than 3,600 kWh annually. The Utility reserves the right to determine the application of this rate schedule.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Annual Rate

The sum of the following Basic and Energy charges:

Annual Basic Charge:	$15.00
Annual Energy Charge:	5.43¢ per kWh

SCHEDULE 35 AND 43

RESIDENTIAL AND COMMERCIAL DRYING

Applicability

Metered power for use in drying structures being prepared for occupancy as a result of residential and commercial building construction.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Monthly Rate

Energy charge: 5.43¢ per kWh

Special Conditions

On completion of the permanent meter installation, a drying rate will be charged until normal occupancy of the building, not to exceed six months. The drying service is not to be used for permanently-installed buildings, appliances, or equipment, recreational vehicles, or mobile homes. If this service is used beyond six months, the account will be reviewed for applicability by the Utility. In the event that service is used for purposes other than described, it will be removed, and the amount of energy used will be rebilled at the applicable rate schedule.

SCHEDULE 85

INDUSTRIAL SERVICE

Applicability

To lighting, heating and power service for customers having measured minimum demands of not less than 1500 kilowatts.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service

Three-phase, sixty-hertz, alternating current at approximately 12,000 volts or higher, as available in the area. The Utility reserves the right to determine the availability of service under this schedule.

Primary Point-Of-Delivery

The customer will be responsible for all costs associated with the primary Point-of-Delivery installation including the metering and primary voltage physical disconnect necessary to isolate the customer's facilities from the Utility's facilities. The customer will be responsible to own, operate and maintain all electrical distribution facilities on the customer side of the Primary Point-of-Delivery (typically established at the primary meter). All transformers, equipment and wiring shall be of types and characteristics acceptable to the Utility. The entire installation and the balance of loads between phases must have the approval of the Utility.

Transmission Point-Of-Delivery

Transmission Point-of-Delivery customers are served at a transmission voltage level (either 69,000 or 115,000 volts). The customer is responsible for all costs associated with the transmission Point-of-Delivery installation including the metering and transmission voltage physical disconnect necessary to isolate the customer's facilities from the Utility's facilities. The customer will be responsible to own, operate and maintain all electrical facilities on the customer side of the Transmission Point-of-Delivery including the power transformer(s) and distribution transformers. All transformers, equipment and wiring shall be of types and characteristics acceptable to the Utility. The entire installation and the balance of loads between phases must have the approval of the Utility.

SCHEDULE 85 (continued)

Monthly Rate

The sum of the following Customer, Energy and Demand charges:

Customer Charge:	$100.00
Energy Charge:	3.50¢ per KWH for the months Sep - Mar 3.10¢ per KWH for the months Apr - Aug
Demand Charge:	$4.40 per KW – Primary Point-of-Delivery $3.40 per KW – Transmission Point-of-Delivery

Off-Peak Demand

By special contract with the Utility, off-peak demand is available for Customers with demands in excess of 1500 KW. Service will be available at a discount rate during the off-peak period, which includes all hours except the hours Monday through Saturday between 7:00 a.m. and 10:00 p.m. The off-peak demand rates are 45¢ per KW of demand for each KW the off-peak demand exceeds other recorded monthly demands. The energy rate as listed in the Monthly Rate section applies to all hours.

Adjustment of Demand for Power

Demands will be adjusted to correct for average power factors lower than 95%. Such adjustments will be made by increasing the measured demand l% for each l% or major fraction thereof by which the average power factor is less than 95% lagging.

Metered real energy measured in kilowatt-hours (kWh) and metered reactive energy measured in Kilovolt Ampere-Hours (kVARh) are used to calculate the average monthly power factor as follows:

$$\text{Power Factor equals} \quad \frac{kWh}{\sqrt{(kWh)^2 + (kVARh)^2}}$$

Resolution No. 6130
Date of Issue: January 16, 2001

Effective Date:
January 15, 2001

SCHEDULE 87
CONTRACTUAL DIRECT ACCESS SERVICE

Applicability

This service is applicable under separate contract for all customers with a peak billing demand equal to or greater than 4 megawatts during the past 12 months. No more than two points-of-delivery can be combined to meet the four (4) megawatt minimum.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service - Three-Phase, Sixty-Hertz, Alternating Current

Service to be supplied at approximately 12.47 kilovolts or higher. The Utility reserves the right to determine the availability of service under this schedule.

Monthly Rate

The monthly rate shall consist of a Power Supply Charge, Transmission Charge, Delivery Charge, Transition Charge and Load Balancing Charges.

Power Supply Charge - The Power Supply Charge will be passed through to the Customer per contractual arrangements with the Utility. The Customer is responsible for arranging power supply and scheduling to serve their entire load. Contractual arrangements between the power supplier and the Utility must be developed. All power supply costs will be billed to the Utility and the Utility will bill the Customer at the contractual power supply rate for power in accordance with the contract between the Utility and the Power Supplier.

Transmission Charge covers the costs of transmitting the power supply over the Bonneville system to the Utility's service area and associated losses. Transmission losses of 1.9 percent of the monthly, metered kilowatt-hours will be charged at the rates below.

BPA Demand Charge: $1.539 per kW-month

Losses – Energy Charge (per kilowatt-hour):

Contract Year	Aug-Oct	Nov-Mar	Apr-Jul
1999-00	$0.01599	$0.01771	$0.01211
2000-01	$0.01663	$0.01851	$0.01262

Resolution No. 6130
Date of Issue: January 16, 2001

Effective Date:
January 15, 2001

SCHEDULE 87 (continued)

Delivery Charge covers the costs of distribution of power, metering, customer accounting and customer service.

Primary Level Point-of-Delivery	$2.20 per kW-month
Transmission Level Point-of-Delivery	$1.20 per kW-month

The Delivery Charge may be adjusted to reflect investments, made by either the Customer or the Utility, in transmission facilities used exclusively to serve the Customer. Adjustments to the above charges will be calculated on a customer by customer basis. Adjustments may result in an increase or decrease in the delivery charge depending on the nature of the investment.

Transition Charge shall be the monthly charge for the costs incurred by the Utility due to previously arranged power supply contracts. This charge will be reviewed annually and adjusted if necessary.

Transition Charge: $0.000 per kWh

Load Balancing Charges cover the cost of deviations from scheduled amounts under the contractual Power Supply arrangement.

*When Metered Load **Exceeds** Schedule* - The demand charge is applied to the largest difference between the scheduled Firm Capacity and the actual metered demand occurring from 6 a.m. through 10 p.m. Monday through Saturday. The Energy Charge is applied to the total net kilowatt-hours delivered in the month in excess of Firm Energy scheduled.

Demand Charge:

January-February	$4.00 per kW-month
March-May	$2.40 per kW-month
June-August	$4.00 per kW-month
September-October	$3.15 per kW-month
November-December	$4.00 per kW-month

Energy Charge:

January-March	$0.01618 per kWh
April-July	$0.01116 per kWh
August-October	$0.01538 per kWh
November-December	$0.01693 per kWh

Schedule 87 (continued)

Load Balancing Charges (continued)

When Scheduled Load Exceeds Metered Load - If in any hour the Customer's metered power usage is less than the amount of Firm Power scheduled, the following re-marketing charges apply:

Amount Below Schedule	Per Kilowatt-hour
First 500 kW	\$0.000
Next 500 kW	\$0.002
Next 1,000 kW	\$0.005
Amount over 2,000 kW	\$0.008

The foregoing charge is applied to the amount of power by which the scheduled Firm Energy exceeds the Customer's metered power usage in any hour during each month.

Special Conditions

A Remote Metering System (RMS) is required for Retail Access Service. The RMS will provide hourly usage necessary for billing purposes. The Utility will install, own and maintain the RMS. The Customer will reimburse the Utility for the cost of the initial installation.

Reactive Power Charge

The Customer's leading and lagging reactive power requirements will be metered and billed each month based on BPA's reactive power rates.

One Year Minimum Term

Upon signing up for service under Schedule 87, the Customer must remain on the schedule for a minimum of one year.

Taxes

The Customer shall make a payment each month to any and all taxes assessed on or attributable to the sale of any commodity or service to the Customer.

SCHEDULES 94 - 95 - 96

MUNICIPAL, RESIDENTIAL, AND COMMERCIAL LIGHTING

Applicability

Off-street lighting service to individuals for locations on private property or to lighting service for public streets, alleys, highways, thoroughfares, and public grounds supplied to Local Utility District, municipalities, counties, or agencies of federal or state governments where funds for payment for electric service are provided through taxation or special assessment.

Rate schedules apply to the sale of electrical energy for the sole and exclusive use of the Customer. Any redistribution or resale of electrical energy by the Customer must have the approval of the Utility.

Character of Service

From dusk to dawn daily, controlled by light sensitive relay.

Specifications

System shall be of overhead construction consisting of an aerial circuit, mast arms and standard luminaires or flood lights, except in subdivisions or commercial installations with underground utilities. Underground circuits, wood or ornamental poles will be installed in these areas, with additional charges.

Monthly Rate

During the first seven year period, the Utility will own, maintain, and furnish energy for luminaires as shown in the "Total" column. After the initial seven year term has been completed, the successive monthly billings will exclude system charges and poles if appropriate. However, the Utility always owns all street light facilities. System charges are considered as contributions in aid to construction. Other conditions can be determined by applying the appropriate column or columns. Individual luminaire repair or relamping will be done as soon as reasonably possible after notification by the Customer.

SCHEDULES 94, 95 AND 96 (continued)

Code	Type	Watts	KWh	Lumens	Energy	Lamp Renewal	System Charges	Total (1st 7 years)	Total (After 1st 7 years)	Capital Cost
Street Lights										
203	Mercury Vapor X	250	100	11,000	7.01	1.49	3.22	10.67	7.45	
204	Mercury Vapor X	400	170	20,000	11.29	1.29	5.53	16.32	10.79	
206	Mercury Vapor X	1,000	400	50,000	27.98	2.00	8.20	33.98	25.78	
210	H.P. Sodium	250	110	30,000	7.12	1.54	3.78	11.28	7.50	232.00
211	H.P. Sodium	400	170	50,000	11.29	1.59	3.98	15.07	11.09	244.00
225	H.P. Sodium	100	40	9,500	2.83	1.54	3.06	7.01	3.95	188.00
226	H.P. Sodium	150	60	16,000	4.18	1.54	3.08	8.17	5.09	189.00
227	H.P. Sodium	200	80	22,000	5.60	1.54	3.59	9.89	6.30	220.00
232	Mercury Vapor X	175	80	7,500	5.01	1.18	3.19	8.54	5.35	
Flood Lights										
207	Mercury Vapor X	175	80	7,500	5.01	1.18	4.86	10.21	5.35	
208	Mercury Vapor X	400	170	20,000	11.29	1.29	5.41	16.20	10.79	
209	Mercury Vapor X	1,000	400	50,000	27.98	2.00	8.60	34.38	25.78	
223	H.P. Sodium	400	170	50,000	11.29	1.60	5.11	16.21	11.10	313.00
228	H.P. Sodium	100	40	9,500	2.83	1.54	4.67	8.62	3.95	286.00
229	H.P. Sodium	200	80	22,000	5.60	1.54	4.77	11.07	6.30	292.00
Post-Top Lights										
230	H.P. Sodium	100	40	9,500	2.83	1.54	2.72	6.67	3.95	167.00
231	Mercury Vapor X	175	80	7,500	5.01	1.18	2.43	7.78	5.35	
Yard-Lights										
202	Mercury Vapor X	175	80	7,500	5.01	1.18	1.22	6.57	5.35	
224	H.P. Sodium	70	30	5,800	1.99	1.50	1.13	4.30	3.17	70.00
240	H.P. Sodium	100	40	9,500	2.83	1.54	1.30	5.25	3.95	81.00
X = No new installations										

Special Conditions

Underground service will be provided where practical if the Customer provides trenching and backfill. The Customer will furnish a concrete foundation or conduit where required, according to Utility specifications.

The Utility reserves the right to approve the type and intensity of lighting installed.

Resolution No. 6130
Date of Issue: January 16, 2001

Effective Date:
January 15, 2001

SCHEDULES 94, 95 AND 96 (continued)

The Customer may request a temporary suspension of power for lighting by written notice. During such suspension, the monthly rate will be the system and pole charges portion of the Utility's lighting rate if applicable. A disconnect charge, as provided in the fee schedule, will be charged for disconnecting the first luminaire and an additional charge of $6.00 for each additional luminaire disconnected at the same time and general location. No reconnect fee will be charged upon the Customer's written request for reconnection.

The Customer may pay the entire cost of the lighting service at the time of installation for the lighting fixtures and/or the appropriate poles. In such a case, only energy and/or relamping monthly charges will be applied.

Capital contribution costs and monthly rates for wood or ornamental poles in accordance with Utility specifications are as follows:

Code		Monthly Rate	Capital Cost
215	20' direct burial ornamental pole	$4.49	$275.00
216	25' ornamental pole (foundation required)	8.57	525.00
217	30' ornamental pole (foundation required)	10.26	629.00
235	30' treated wood pole	3.81	220.00
236	35' treated wood pole	5.15	297.00
237	40' treated wood pole	5.67	327.00

Term of Agreement

Minimum of seven years for Utility owned fixtures and poles.

SCHEDULE 99
PURCHASE OF ENERGY FROM GENERATING FACILITIES WITH DESIGN CAPACITY OF 100 kW OR LESS

Applicability

The following rate represents Clark Public Utilities' rate for the purchase of energy delivered from generating facilities with design capacities of 100 kW or less.

Purchase Rate

5.45¢ per kWh

Revisions

This rate will be revised periodically as the average system retail rate is modified.

Resolution No. 6130
Date of Issue: January 16, 2001

Effective Date:
January 15, 2001

Peninsula Light Co.

	1997	1998	1999	2000	2001	2002
Retail Sales ($$)	24,073,000	24,777,000	25,103,546	26,355,560	29,952,171	36,426,578
kWh Sales	458,347,000	468,018,000	479,406,949	503,692,137	476,266,717	489,217,983
Avg. Retail Rate ($/kWh)	0.05252	0.05294	0.05236	0.05232	0.06289	0.07446
Average Rate increase above 2001 Rates						18%

	2003	2004	2005	2006
Retail Sales ($$)	36,823,231	37,422,076	37,414,503	38,745,714
kWh Sales	492,762,190	503,915,698	519,425,709	539,890,462
Avg. Retail Rate ($/kWh)	0.07473	0.07426	0.07203	0.07177
Average Rate increase above 2001 Rates	19%	18%	15%	14%

Clark Public Utilities

	1997	1998	1999	2000	2001	2002
Retail Sales ($$)	151,509,066	154,555,411	162,673,332	185,280,033	230,096,901	265,846,109
kWh Sales	3,770,000,000	3,895,000,000	4,078,000,000	4,214,000,000	3,992,000,000	4,029,000,000
Avg. Retail Rate ($/kWh)	0.04019	0.03968	0.03989	0.04397	0.05764	0.06598
Average Rate increase above 2001 Rates						14%

	2003	2004	2005	2006
Retail Sales ($$)	280,022,607	287,438,267	299,494,871	311,202,216
kWh Sales	4,082,000,000	4,202,000,000	4,290,000,000	4,430,000,000
Avg. Retail Rate ($/kWh)	0.06860	0.06841	0.06981	0.07025
Average Rate increase above 2001 Rates	19%	19%	21%	22%

Average retail rate increases (reported to press)

1/15/2001	23.5%
8/1/2001	20%
4/1/2003	5%
10/1/2005	2%

Grays Harbor PUD

	1997	1998	1999	2000	2001	2002
Retail Sales ($$)	44,637,222	46,008,402	48,909,053	48,439,268	56,356,850	67,696,166
kWh Sales	995,053,660	1,688,083,280	1,145,627,293	1,107,843,613	980,540,357	1,002,348,694
Avg. Retail Rate ($/kWh)	0.04486	0.02725	0.04269	0.04372	0.05748	0.06754
Average Rate increase above 2001 Rates						18%

	2003	2004	2005	2006
Retail Sales ($$)	69,254,442	69,083,247	37,414,503	38,745,714
kWh Sales	982,459,220	979,579,994	519,425,709	539,890,462
Avg. Retail Rate ($/kWh)	0.07049	0.07052	0.07203	0.07177
Average Rate increase above 2001 Rates	23%	23%	25%	25%

HISTORICAL RATE ACTION

Jan-01	20.50%	increase
Oct-01	26.00%	increase
Oct-02	11.00%	increase
Nov-04	-3.00%	decrease
May-06	-3.00%	decrease

Peninsula Light Company

P.O. Box 78, Gig Harbor, WA 98335-0078
253 857-5950

Rate Schedules Effective January 1, 2007

Residential

Monthly Customer Service Charge..$14.28
All Energy per kWh at $0.05972

General Service

Monthly Customer Service Charge
Single Phase $12.15
Three Phase...$19.37
All Energy per kWh at $0.05984

Commercial

Monthly Customer Service Charge
Single Phase $19.37
Three Phase...$26.50
All Energy per kWh at $0.03821
All Demand per kW* at $6.36

**Subject to Power Factor Adjustment*

Cable TV Amplifiers...$30.26

Security Lighting

100W High Pressure Sodium per Month $9.62
200W High Pressure Sodium per Month $16.04

Utility Taxes

State Utility Tax on Energy Sales..3.87%
City of Gig Harbor Tax on Energy Sales...............................5.00%

Service Charges Effective January 1, 2007

Account Setup Fee $10.00
Service Call for Collection $15.00
Reconnect - 8:00 a.m. to 4:30 p.m. weekdays
Self Contained Meter $25.00
Current Transformer Meter...$50.00
Unauthorized Reconnect Fee $50.00
Return Check Fee...$20.00
Meter Testing Fee $30.00
Meter Resealing Fee $30.00
Meter Tampering/Diversion Fee..$250.00

Calculating Your Bill

Bills will be mailed to you monthly and calculated in the following manner:

Current Meter Reading 45682
Previous Meter Reading -44108
kWh Usage *1,574*
Charge per kWh .... *x .05972*
Total Energy Charge *$94.00*
Monthly Customer Service Charge.. *+ $14.28*
Total Electric Charge *$108.28*
100W HPS Light .... *+ $9.62*
Total Utility Charges *$117.90*
State Utility Tax 3.87%... *+ $ 4.56*
Total Utility Bill Amount.. *$122.46*

The total utility charges are multiplied by the State Utility Tax rate. If you live within the City of Gig Harbor, you must also multiply the Total Utility Charges by the City of Gig Harbor Tax of 5% to arrive at your Total Utility Bill.

Peninsula Light Company

P.O. Box 78, Gig Harbor, WA 98335-0078
253 857-5950

Large Power Rate Schedules
Effective October 1, 2001

U.S. Navy

Monthly Customer Service Charge.................................... $144.18
All Energy per kWh at $0.05277
Monthly Demand Charge... $6.22
Monthly Minimum Charge:
The Customer Service Charge or $.781 per KVA of Serving Transformer Capacity, whichever is Greater.

Women's Correction Center

Monthly Customer Service Charge.................................... $165.38
All Energy per kWh at $0.03256
Monthly Demand Charge... $5.38
Monthly Minimum Charge:
The Customer Service Charge or $.781 per KVA of Serving Transformer Capacity, whichever is Greater.

Utility taxes

State Utility Tax on Energy Sales.............................3.87%

Power Factor Adjustment

Applicability

This adjustment is applicable to customers billed at the Commercial Rate and who have the necessary metering installed.

Adjustment

For such customers with power factors below 97%, the billed kW demand will be multiplied by 97% and the result divided by the customer's average power factor. The average power factor is determined by the following equation:

$$\text{Average Power Factor (\%)} = \frac{kWh}{\sqrt{\left(kWh^2 + kVARh^2\right)}} \text{ x } 100$$

General Provisions

In applying the above formula, the meter for measurement of reactive kilovolt-ampere-hours (kVARh) will be ratcheted to prevent reverse registration. Peninsula Light Company shall approve all installations of power factor corrective equipment. The customer shall supply, operate and maintain equipment designed to switch automatically with the load. Unless specifically otherwise agreed, the customer shall maintain a power factor between 80% and 100%. The customer at no time shall supply a leading reactive kVA to Peninsula Light Company's distribution system.

Peninsula Light Co.
a mutual corporation

P.O. Box 78, Gig Harbor, WA 98335-0078
253 857-5950

Rate Schedules Effective July 1, 2006

Residential

Monthly Customer Service Charge	$14.28
All Energy per kWh at	$0.05282
Power Cost Adjustment	$0.00781

General Service

Monthly Customer Service Charge	
Single Phase	$12.15
Three Phase	$19.37
All Energy per kWh at	$0.05294
Power Cost Adjustment	$0.00781

Commercial

Monthly Customer Service Charge	
Single Phase	$19.37
Three Phase	$26.50
All Energy per kWh at	$0.03131
Power Cost Adjustment	$0.00781
All Demand per kW at	$6.36
Cable TV Amplifiers	$30.26

Security Lighting

100W High Pressure Sodium per Month	$9.62
200W High Pressure Sodium per Month	$16.04

Utility Taxes

State Utility Tax on Energy Sales	3.87%
City of Gig Harbor Tax on Energy Sales	5.00%

Service Charges Effective August 1, 1995

Account Setup Fee	$10.00
Service Call for Collection	$15.00
Reconnect - 8:00 a.m. to 4:30 p.m. weekdays -	
Self Contained Meter	$25.00
Current Transformer Meter	$50.00
Unauthorized Reconnect Fee	$50.00
Return Check Fee	$20.00
Meter Testing Fee	$15.00
Meter Resealing Fee	$30.00
Meter Tampering/Diversion Fee	$250.00

Calculating Your Bill

Bills will be mailed to you monthly and calculated in the following manner:

Current Meter Reading	*45682*	
Previous Meter Reading	– *44108*	
kWh Usage	*1574*	
Charge per kWh	x *.05282*	
Total Energy Charge		*$83.14*
KWH Usage	*1574*	
Power Cost Adjustment per kWh	x *.00781*	
Total CRAC Charge		*$12.29*
Monthly Customer Service Charge		+ *$14.28*
Total Electric Charge		*$108.28*
100W HPS Light		+ *$9.62*
Total Utility Charges		*$117.90*
State Utility Tax 3.87%		+ *4.62*
Total Utility Bill Amount		*$123.95*

Add 5% to Total Utility Charge if you live within the City of Gig Harbor.

Peninsula Light Co.

a mutual corporation

P.O. Box 78, Gig Harbor, WA 98335-0078
253 857-5950

Rate Schedules Effective November 1, 2005

Residential

Monthly Customer Service Charge $14.28
All Energy per kWh at $0.05282
Power Cost Adjustment $0.0069

General Service

Monthly Customer Service Charge
Single Phase...$12.15
Three Phase $19.37
All Energy per kWh at $0.05294
Power Cost Adjustment $0.0069

Commercial

Monthly Customer Service Charge
Single Phase...$19.37
Three Phase $26.50
All Energy per kWh at $0.03131
Power Cost Adjustment $0.0069
All Demand per kW at $6.36

Cable TV Amplifiers $30.26

Security Lighting

100W High Pressure Sodium per Month...................... $9.62
200W High Pressure Sodium per Month......................$16.04

Utility Taxes

State Utility Tax on Energy Sales 3.87%
City of Gig Harbor Tax on Energy Sales 5.00%

Service Charges Effective August 1, 1995

Account Setup Fee..$10.00
Service Call for Collection $15.00
Reconnect - 8:00 a.m. to 4:30 p.m. weekdays -
Self Contained Meter $25.00
Current Transformer Meter $50.00
Reconnect - All Other Hours $80.00
Unauthorized Reconnect Fee $50.00
Return Check Fee...$20.00
Meter Testing Fee $15.00
Meter Resealing Fee $30.00
Meter Tampering/Diversion Fee.................................. $250.00

Calculating Your Bill

Bills will be mailed to you monthly and calculated in the following manner:

Current Meter Reading	*45682*	
Previous Meter Reading	*– 44108*	
kWh Usage	*1574*	
Charge per kWh	x *.05282*	
Total Energy Charge		*$83.14*
KWH Usage	*1574*	
Power Cost Adjustment per kWh	x *.0069*	
Total CRAC Charge		*$10.86*
Monthly Customer Service Charge		+ *$14.28*
Total Electric Charge		*$108.28*
100W HPS Light		+ *$9.62*
Total Utility Charges		*$117.90*
State Utility Tax 3.87%		+ *4.59*
Total Utility Bill Amount		*$122.49*

Add 5% to Total Utility Charge if you live within the City of Gig Harbor.

Peninsula Light Co.
a mutual corporation

P.O. Box 78, Gig Harbor, WA 98335-0078
253 857-5950

Rate Schedules Effective October 1, 2004

Residential

Monthly Customer Service Charge $14.28
All Energy per kWh at $0.05282
Power Cost Adjustment $0.00742

General Service

Monthly Customer Service Charge
Single Phase..$12.15
Three Phase $19.37
All Energy per kWh at $0.05294
Power Cost Adjustment $0.00742

Commercial

Monthly Customer Service Charge
Single Phase..$19.37
Three Phase $26.50
All Energy per kWh at $0.03131
Power Cost Adjustment $0.00742
All Demand per kW at $6.36

Cable TV Amplifiers $30.26

Security Lighting

100W High Pressure Sodium per Month....................... $9.62
200W High Pressure Sodium per Month.....................$16.04

Utility Taxes

State Utility Tax on Energy Sales 3.87%
City of Gig Harbor Tax on Energy Sales 5.00%

Service Charges Effective August 1, 1995

Account Setup Fee..$10.00
Service Call for Collection $15.00
Reconnect - 8:00 a.m. to 4:30 p.m. weekdays -
Self Contained Meter $25.00
Current Transformer Meter $50.00
Reconnect - All Other Hours $80.00
Unauthorized Reconnect Fee $50.00
Return Check Fee..$20.00
Meter Testing Fee $15.00
Meter Resealing Fee $30.00
Meter Tampering/Diversion Fee $250.00

Calculating Your Bill

Bills will be mailed to you monthly and calculated in the following manner:

Current Meter Reading	*45682*	
Previous Meter Reading	*– 44108*	
kWh Usage	*1574*	
Charge per kWh	*x .05282*	
Total Energy Charge		*$83.14*
KWH Usage	*1574*	
Power Cost Adjustment per kWh	*x .00742*	
Total CRAC Charge		*$11.68*
Monthly Customer Service Charge		*+ $14.28*
Total Electric Charge		*$109.10*
100W HPS Light		*+ $9.62*
Total Utility Charges		*$118.72*
State Utility Tax 3.87%		*+ 4.59*
Total Utility Bill Amount		*$123.31*

Add 5% to Total Utility Charge if you live within the City of Gig Harbor.

Peninsula Light Company

P.O. Box 78, Gig Harbor, WA 98335-0078
253 857-5950
Rate Schedules Effective October 1, 2001

Residential

Monthly Customer Service Charge $14.28
All Energy per kWh at $0.06250

General Service

Monthly Customer Service Charge
Single Phase $12.15
Three Phase $19.37
All Energy per kWh at $0.06262

Commercial

Monthly Customer Service Charge
Single Phase $19.37
Three Phase $26.50
All Energy per kWh at... $0.04099
All Demand per kW at Subject to Power Factor Adjustment $6.36
Cable TV Amplifiers $30.26

Security Lighting

100W High Pressure Sodium per Month.................................... $9.62
200W High Pressure Sodium per Month.................................. $16.04

Utility Taxes

State Utility Tax on Energy Sales 3.87%
City of Gig Harbor Tax on Energy Sales 5.00%

Service Charges Effective August 1, 1995

Account Setup Fee $10.00
Service Call for Collection $15.00
Reconnect - 8:00 a.m. to 4:30 p.m. weekdays
Self Contained Meter.. $25.00
Current Transformer Meter $50.00
Reconnect - All Other Hours $80.00
Unauthorized Reconnect Fee.. $50.00
Return Check Fee $20.00
Meter Testing Fee $15.00
Meter Resealing Fee $30.00
Meter Tampering/Diversion Fee 250.00

Calculating Your Bill

Bills will be mailed to you monthly and calculated in the following manner:
Current Meter Reading 45682
Previous Meter Reading -44108
kWh Usage 1,574
Charge per kWh .... x .06250
Total Energy Charge $98.38
Monthly Customer Service Charge .... + $14.28
Total Electric Charge $112.66
100W HPS Light .... + $9.62
Total Utility Charges $122.28
State Utility Tax 3.87%.. .... + $ 4.73
Total Utility Bill Amount.. .... $127.01

The total utility charges are multiplied by the State Utility Tax rate. If you live within the City of Gig Harbor, you must also multiply the Total Utility Charges by the City of Gig Harbor Tax of 5% to arrive at your Total Utility Bill.

This page intentionally left blank.

2007 Supplemental Wholesale Power Rate Case Initial Proposal

REBUTTAL TESTIMONY

SUPPLEMENTAL RISK ANALYSIS AND MITIGATION

May 2008

WP-07-E-BPA-81

This page intentionally left blank.

INDEX

REBUTTAL TESTIMONY of

RANDY B. RUSSELL, BYRNE E. LOVELL, KENNETH J. MARKS,

and MICHAEL R. NORMANDEAU

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL RISK ANALYSIS AND MITIGATION

This page intentionally left blank.

REBUTTAL TESTIMONY of

RANDY B. RUSSELL, BYRNE E. LOVELL, KENNETH J. MARKS,

and MICHAEL R. NORMANDEAU

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL RISK ANALYSIS AND MITIGATION

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

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

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

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

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

Q. Have you sponsored testimony previously in this Supplemental Proceeding?

A. Yes. Mr. Russell, Mr. Lovell, Mr. Marks, and Mr. Normandeau have submitted direct testimony, together with other witnesses, identified as Exhibit WP-07-E-BPA-67. Mr. Lovell and Mr. Normandeau have submitted direct testimony, together with other witnesses, identified as Exhibit WP-07-E-BPA-73. Mr. Marks has submitted direct testimony, together with other witnesses, identified as Exhibit WP-07-E-BPA-62. Mr. Russell has submitted direct testimony, together with other witnesses, identified as Exhibit WP-07-E-BPA-71.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to respond to direct testimony by the Public Power Council (PPC), WP-07-E-BPA-PP-9, regarding BPA's reserves and their role in ratemaking.

Q. How is your testimony organized?

A. This testimony includes two sections. Section 1 explains the purpose and scope of this testimony. Section 2 responds to issues raised by the PPC regarding BPA's reserve levels and the general role of reserves in ratemaking.

Section 2: Role of Reserves in BPA Ratemaking

Q. PPC states that BPA's agency-wide FY 2009 forecast financial reserves are $1.57 billion, based on BPA's FY 2008 First Quarter Review document, which PPC included in WP-07-E-PP-10, Attachment 6. O'Meara, et al., WP-07-E-PP-9 at 29. Is this the correct number?

A. No. All of PPC's data come from BPA's First Quarter Review report, which is reproduced in Attachment 6 to WP-07-E-PP-10. PPC is looking at BPA's reserves estimate in Column B on page 1 of Attachment 6, which BPA produced in October, 2007 for its Start of Year (SOY) FY 2008 projection for ending FY 2008 reserves (or starting FY 2009). The applicable columns for the First Quarter Review are Columns C and/or D, included under the title *FY 2008 Current Expectation.* On line 5 of this page, in Columns C and D, BPA updated its End of Year (EOY) FY 2008 (or beginning of FY 2009) reserves forecasts, reporting a range of ending reserves of $1.279 billion to $1.665 billion. The average of this range is $1.472 billion. To be completely accurate, PPC should have quoted the range and used it in its subsequent testimony.

Q. PPC states that $1.57 billion is 48 percent of BPA's forecast of gross revenues of $3.327 billion. O'Meara, et al., WP-07-E-PP-9 at 29. Is this correct?

A. No. The $3.327 billion is taken from Column B, line 1 of page 1 of Attachment 6. The appropriate data are located in Columns C and D. In Column C the range was $2.955 billion to $3.762 billion, with an average value of $3.359 billion. In Column D the range is \$2.927 billion to \$3.735 billion. PPC should have used the range in Column C for its computation.

Q. What is the difference between the Gross Sales Revenue ranges in Columns C and D on page 1 of Attachment 6?

A. In Column C, gross sales revenues are reported without FAS 133 bookouts, which are non-cash revenue items. In Column D, these bookouts are included. Because the bookouts are non-cash items, quoting a ratio of ending reserves to the revenues in Column D would be misleading; therefore, the revenue range shown in Column C should be used.

Q. How do these errors impact the remainder of PPC's testimony?

A. PPC computes the ratio of \$1.57 billion to \$3.327 billion as 0.48, suggesting that BPA's forecast ending reserves are 48 percent of forecast gross revenues. First, the ratio is not correct because the data used are not correct. Second, a proper computation would be much more complex. For example, using the ranges quoted above from Column C of page 1 of Attachment 6, one might take the low end of each range and compute a ratio, and then the high end of each range and compute a ratio. That would provide:

$1.279 \div 2.955 = 0.43$ or 43% and

$1.665 \div 3.762 = 0.44$ or 44%.

Or one might take the ratio of the average values: $1.472 \div 3.359 = 0.438$ or 43.8%. In any case, the results are significantly less than the 48 percent PPC calculated.

Q. Why was there a range of ending reserves and gross sales estimates for FY 2008 in BPA's First Quarter Review report?

A. There was a range because as of January of our fiscal year, there is too much uncertainty surrounding our gross revenue forecast – primarily due to the uncertainty in our trading floor sales and purchases – to provide a point estimate. This leads to too much uncertainty surrounding our reserves forecast. For example, the standard deviation around the average value of $1.472 billion was $306 million, which is about 20 percent of the average value. This level of uncertainty does not warrant reporting a point estimate in our view.

Q. *PPC asserts that given the expected level of financial reserves, BPA does not propose using the dividend distribution clause (DDC) to refund any of these reserves to BPA's power customers. O'Meara, et al., WP-07-E-PP-9 at 30. Do you agree?*

A. No. BPA has included a DDC in its Supplemental Proposal. *See* Normandeau, et al., WP-07-E-BPA-73 at11. BPA proposes to calculate in September of 2008 whether that DDC will trigger for application to FY 2009 rates. It is too early in FY 2008 to know whether the DDC will trigger. If it triggers, BPA fully intends to apply it to non-Slice power rates, thereby refunding money to non-Slice power customers.

Q. *PPC asserts that "in its ongoing development of its Financial Plan, BPA is seriously considering implementing "Good Year/Bad Year" planning, where BPA would revenue finance capital investments in years where BPA has high revenues, which would obviously further reduce the chance that the dividend distribution clause would ever trigger." O'Meara, et al., WP-07-E-PP-9 at 30. Do you agree?*

A. No. First, BPA said in its workshops on the Financial Plan that it was considering a variety of possible actions within the concept of "Good Year/Bad Year" planning. Revenue financing was not certain to be any part of the Financial Plan update. Second, BPA stated clearly that no action was planned for the Financial Plan update that would take place before the calculation of the DDC that could apply to FY 2009 rates. Therefore, even if BPA implements anything as a result of the update to the Financial Plan, and even if that implementation includes revenue financing, there cannot be any impact on the only DDC that is a subject of this rate case, *i.e.*, the DDC that could apply to FY 2009 rates.

Q. *PPC makes several statements about how BPA uses its estimates of financial reserves to set rates. O'Meara, et al., WP-07-E-PP-9 at 30. PPC states that "BPA has moved from using financial reserves, an easily measurable, widely understood indicator of BPA's financial health, to an accounting construct that is not widely understood, and is markedly inferior to financial reserves as a measure of BPA's ability to repay Treasury." Id. How do you respond?*

A. Our first response is simply to note that the CRAC that BPA included in the WP-02 Final Proposal (later superseded by the WP-02 Supplemental Proposal) used accumulated net revenue, not reserves, as its metric. Thus, BPA's move away from financial reserves as a metric is old news.

Q. *Do you agree with the remainder of PPC's statement?*

A. No. We take issue with two assertions made above: (1) that BPA's financial reserves are easily measurable or widely understood, and (2) that AMNR is an accounting construct that is not widely understood.

Q. *What is incorrect about these statements?*

A. PPC states that BPA's financial reserves are easily measurable. Stating that BPA's financial reserves are easier to understand or apply in BPA's ratemaking than the AMNR forecasts mischaracterizes the relationship between the two. First, the only time BPA's reserves are "easily" measurable with any degree of accuracy is in looking backward over the year that has just passed. Reserves are certainly not as "easily measurable" as AMNR, because unlike AMNR, BPA's financial reserves are computed from many sources of data other than audited financial data; they are not an accounting metric established according to Generally Accepted Accounting Principles (GAAP); and their calculation requires the application of judgment. On the other hand, BPA's AMNR is established solely from audited financial data. BPA's financial reserves are frequently misunderstood. The reserve balance at any point in time is not only impacted by results from operations but can also be significantly impacted by cash flows originating from sources other than operations. These impacts can skew any easy interpretation of financial results based on financial reserve balances.

Q. Are there other complexities associated with forecasting financial reserves?

A. Yes. To forecast financial reserves, one must start with modified net revenues and then do a series of adjustments, called accrual to cash (ATC) adjustments, to get to a cash flow number. How this is done for ratemaking purposes is explained in the Supplemental Risk Analysis Study, WP-07-E-BPA-48, Section 2.5.3.13. As stated above, many of the ATC adjustments to modified net revenues adjust for cash inflows and outflows from the BPA Fund that are not associated with the results of operations; specifically, with gross sales revenues and operating expenses. Such cash inflows are, for example, funds forwarded to BPA by its customers for the purposes of constructing certain types of facilities. Another example is funds deposited with BPA for the purpose of securing credit. Cash outflows would be the inverse, that is, BPA using the cash forwarded to it for such purposes. Although these funds reside in the BPA Fund, they are not available to BPA to mitigate the operating and financial risks it faces from factors such as streamflow, market prices, and other factors.

Q. PPC states that BPA could easily distinguish between financial reserves generated by the power and transmission sides of the business, and that an adjusted statement of financial reserves would still be far more understandable and a far better measure for BPA's ability to repay Treasury than the current construct. O'Meara, et al., WP-07-E-PP-9 at 31. How do you respond?

A. As with forecasting financial reserves, separating the reserves between the power and transmission business units is not cut-and-dried. Again, many judgment calls go into making such a distinction. There are many complicating factors that go into determining such a split. We believe that justifying any such split for ratemaking purposes would entail as much or more effort than measuring BPA's ability to repay Treasury using the AMNR construct. Although reserves are a more direct measure of BPA's ability to pay the Treasury, as we have said, there are problems with the forecasting of reserves that detract from the usefulness of reserves as the metric for triggering the CRAC or DDC.

Q. PPC states that BPA has created a "false financial test" in calculating TPP by assuming for TPP purposes that the available financial reserves of the power business are the sole asset that can be used to pay Treasury. O'Meara, et al., WP-07-E-PP-9 at 31. Is this accurate?

A. No. For ratesetting, we do not make assumptions about how BPA's cash will actually be used to pay bills. We also do not make an assumption that BPA's Power business might miss a Treasury payment, because the Power business does not make Treasury payments, the Administrator does. What we have done is to ask, "What does it mean to set *power* rates to achieve a 95 percent TPP, when *Power* does not make Treasury payments?" The answer BPA has provided since 1999 is that BPA will set power rates to achieve a 95 percent TPP, acting in this process *as if Power had Treasury payments to make.* Similarly, BPA sets transmission rates to achieve a 95 percent TPP *while acting as if Transmission had Treasury payments to make.* As BPA has testified since 1999, BPA believes that if the Power TPP and the Transmission TPP both meet the standard, then the intent of the TPP standard has been satisfied. *See e.g.*, Lovell, *et al.*, WP-02-E-BPA-14 at 3; Normandeau, *et al.*, WP-07-E-BPA-14 at 3.

Q. PPC states that "there is a single Bonneville fund, and all BPA financial reserves in the Bonneville fund are available to make Treasury payments." O'Meara, et al., WP-07-E-PP-9 at 31. Is this accurate?

A. Yes. This fact, though, does not justify assuming, for purposes of establishing power rates, that funds generated by BPA's Transmission business will be available for paying bills incurred by BPA's Power business.

Q. Would problems result from assuming that all BPA reserves are available for making Treasury payments that are the financial responsibility of the power side of BPA's business?

A. Yes. In times of good financial results, little harm is likely to occur. Consider, though, periods of tougher times. First, consider a situation in which power and transmission rates are not set at the same time, with power rates set first. Suppose BPA assumes some reserves attributed to transmission are available for paying power bills, and this allows power rates to be set lower than otherwise. Subsequently, Power experiences adverse financial conditions, and actually has to draw on reserves attributed to Transmission. Later, Transmission has to set rates, but finds that its reserves are not sufficient to meet the TPP standard, and it has to increase rates to meet the standard, resulting in rates that are higher than they would have been had power not used up some transmission reserves. This would clearly be a situation in which transmission customers paid more than they should have in order to reduce power rates. This sort of subsidy is one of the problems BPA wants to avoid. Next, consider a situation similar to the one BPA faces now, in which power rates (but not transmission rates) are being set for FY 2009, and in which the next rate setting will be for both power and transmission. Suppose BPA assumes reserves attributed to transmission are available for power bills, and accordingly sets power rates lower than they would otherwise have been. Then Power experiences financial adversity and significantly depletes BPA's reserves. Look ahead now to when the rate for FY 2010 are being determined. BPA's reserves are depleted. How much responsibility to increase rates in order to meet the TPP standard should each side of BPA shoulder? This could be a very contentious issue to address. BPA avoids both this issue and the previously illustrated problem by requiring each business function to meet the TPP standard independently.

Q. PPC states "BPA witnesses during clarification stated that no calculation was made of the TPP for the agency as a whole – TPP was calculated solely for the power business as a rate case construct." O'Meara, et al., WP-07-E-PP-9 at 31. Is this accurate?

A. Yes. BPA's TPP standard is a rate-setting standard, so TPP was calculated as a rate case construct. Because it is power rates that are being set, naturally it was a power TPP that was calculated.

Q. PPC, when asked whether using BPA reserves would result in Power being subsidized by Transmission, states "[a]s long as there is some diversity in financial results between the Power and Transmission businesses, the agency as a whole will be more financially stable than either of its two parts. Reflecting this stability in BPA rate cases no more implies that the transmission business is subsidizing the power business than implying that the power business is subsidizing the transmission business." O'Meara, et al., WP-07-E-PP-9 at 32. Do you agree?

A. In part. We agree that reflecting a benefit from aggregating power and transmission risk together would not automatically cause a subsidy of one business by the other. However, we do not agree with PPC's implication that such aggregation *could not* result in a subsidy. The trick is to develop a specific methodology for aggregating the risks, measuring TPP, and setting rates in such a way that subsidies are as well guarded against as in our current approach. Merely recognizing that there might be "some diversity in financial results between the power and transmission businesses" does nothing to prevent either of the two problems we described previously. PPC does not suggest any method for preventing one of BPA's two businesses from benefiting from a subsidy by the other.

Q. Does this conclude your testimony?

A. Yes.

This page intentionally left blank.

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 Supplemental Wholesale Power Rate Case Initial Proposal

REBUTTAL TESTIMONY

SUPPLEMENTAL MARKET PRICE FORECAST

May 2008

WP-07-E-BPA-82

This page intentionally left blank.

INDEX

REBUTTAL TESTIMONY OF

ROBERT J. PETTY, ROBERT W. ANDERSON,

SIDNEY L. CONGER, JR., and ARNOLD L. WAGNER

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL MARKET PRICE FORECAST

Page

This page intentionally left blank.

REBUTTAL TESTIMONY OF

ROBERT J. PETTY, ROBERT W. ANDERSON,

SIDNEY L. CONGER, JR., and ARNOLD L. WAGNER

Witnesses for Bonneville Power Administration

SUBJECT: SUPPLEMENTAL MARKET PRICE FORECAST

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Robert J. Petty. My qualifications are contained in WP-07-Q-BPA-44.

A. My name is Sidney L. Conger, Jr. My qualifications are contained in WP-07-Q-BPA-10.

A. My name is Robert W. Anderson. My qualifications are contained in WP-07-Q-BPA-01.

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

Q. Have you previously submitted testimony in this Supplemental Proceeding?

A. Yes. Mr. Petty, Mr. Conger, and Mr. Anderson submitted direct testimony identified as exhibits WP-07-E-BPA-56 and WP-07-E-BPA-66. Mr. Conger and Mr. Wagner, with other witnesses, submitted direct testimony identified as exhibits WP-07-E-BPA-67 and WP-07-E-BPA-73. Mr. Wagner submitted direct testimony, with other witnesses, identified as exhibits WP-07-E-BPA-72.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to respond to the direct testimony filed by Cowlitz County PUD (Cowlitz), Schoenbeck, WP-07-E-CO-01, regarding BPA's market price forecast. It also responds to the manner in which Cowlitz has described BPA's forecast surplus sales revenues.

Section 2: Forecast Surplus Sales Revenues and the Market Price Forecast

Q. Cowlitz states that BPA's forecast surplus sales revenue for FY 2009 in the Supplemental Proposal is $575.6 million, and $566.4 million in the WP-07 Final Proposal. Schoenbeck, WP-07-E-CO-01 at 1. Are these numbers correct?

A. Yes, but it is important to keep in mind that forecasts of surplus sales revenues and balancing power purchases together comprise forecasts of *net* secondary or *net* surplus revenues. By looking only at the forecast of surplus sales revenues, only part of the net secondary revenue equation is addressed. In addition, BPA sells a considerable amount of secondary energy to consumer-owned utilities under the PF Slice rate. The revenues stated above are after the sale of surplus energy under the PF Slice rate.

Q. What was BPA's forecast of net secondary revenue for FY 2009 in the Supplemental Proposal?

A. The net secondary revenue forecast for FY 2009 in the Supplemental Proposal was $508 million. *See* Supplemental WPRDS Documentation,WP-07-E-BPA-49A at 73, 76.

Q. Cowlitz states it disagrees with BPA's approach used in the assessment of whether the market price forecast should have been updated. Schoenbeck, WP-07-E-CO-1 at 2. Please address this point.

A. Cowlitz disagrees with our approach for two reasons. First, Cowlitz correctly notes that market prices at the Mid-Columbia (Mid-C) trading hub in the Pacific Northwest (PNW), as forecast using the AURORA model, are influenced by load levels and available resources throughout the Western Electricity Coordinating Council (WECC), not just those within the PNW. Cowlitz believes we have failed to take this fact into account. In developing our testimony in this proceeding, however, we did consider forecasted loads and resources throughout the WECC. We highlighted only the PNW loads and resources in our testimony. In addition, later in this rebuttal testimony we address the updated load and resource data for the entire WECC.

Q. What is Cowlitz's second issue with your approach?

A. Cowlitz believes our market price forecast should have reflected an updated natural gas price forecast. Schoenbeck, WP-07-E-CO-1 at 2-3. Cowlitz argues that a re-evaluation of the gas price forecast assumptions through the FY 2009 rate period, along with a cursory review of current forward gas price curves for either the Henry or Sumas trading hubs (which Cowlitz concludes are 50 percent higher than our FY 2009 gas price forecast), would have revealed that a gas price update was warranted.

Q. How do you respond to Cowlitz's arguments?

A. We have reviewed our gas price forecast again, and conclude that based on current information, the gas price forecast for the final Supplemental Proposal will likely increase relative to the Supplemental Proposal. In November 2007, in preparation for the Supplemental Proposal, we reviewed the WP-07 Final Proposal gas price forecast. Since we undertook that review, natural gas prices, and the outlook for natural gas prices, have increased significantly.

In November 2007, the U.S. average wellhead price was \$6.60/MMBtu. The March 2008 average wellhead price was \$9.03/MMBtu, a 37 percent increase from November 2007. Several factors have contributed to this price escalation. First, natural gas storage inventories have declined sharply over the past five months. On November 23, 2007, the Energy Information Administration reported natural gas storage was three percent higher than the equivalent week from the previous year. By April 4, 2008, storage inventories had declined to 22 percent less than the previous year. Year-on-year storage inventory comparisons have a significant impact on expected natural gas prices and this factor has contributed to a higher gas price forecast. This unexpectedly large storage withdrawal was driven by an unusually cold winter and reduced natural gas imports from Canada.

Second, oil prices have also increased approximately 18 percent from November 2007 to April 2008. This has contributed to upward pressure on natural gas prices through substitution effects and the linkages of oil prices to liquefied natural gas (LNG) prices. Increased oil prices and high demand for LNG in European and Asian markets have increased prices for imported U.S. LNG, putting additional upward price pressure on U.S. natural gas prices. In addition, LNG supplies were constrained during the winter of 2007/2008 due to LNG production project delays and liquefaction performance issues. These factors developed during the past winter and, in addition to driving natural gas prices upward, created increased market expectations for natural gas prices over the near term, including FY 2008 and FY 2009.

We have reviewed the fundamental factors affecting the natural gas market. We also reviewed the NYMEX futures market for natural gas and a number of external gas price forecasts. Based on this review, most industry analysts expect natural gas prices for Henry Hub to be in the range of approximately \$7.50/MMBtu to \$11.00/MMBtu (nominal \$) for FY 2008 and FY 2009. We consider it likely that the natural gas price forecast for the final Supplemental Proposal will fall within this range. We will continue to monitor the natural gas market and the resulting gas price forecast for the final Supplemental Proposal will be based on a review of the most current information.

Q. *Cowlitz states BPA should have compared market prices forecast by AURORA for FY 2009 with current forward prices, and examined the AURORA-derived market heat rate with the current market heat rate for the Mid-C hub. Schoenbeck, WP-07-E-CO-1 at 3-4. How do you respond?*

A. We disagree with Cowlitz's assessment. Cowlitz states that the Mid-C market heat rate implicit in our forecast for the Supplemental Proposal is 9,218 Btu/kWh based upon our flat Mid-C price of \$50.68/MWh and projected gas price of \$5.50/MMBtu. This is far greater than the current market heat rate for FY 2009 of about 7,600 Btu/kWh.

Schoenbeck, WP-07-E-CO-1 at 3. The focal point of Cowlitz's testimony is the forecast market price that is used in determining the net secondary revenue forecast. As stated in Petty, *et al*., WP-07-E-BPA-66 at 4, the average forecast market price of 50 different AURORA runs was $48.07/MWh for HLH periods and $41.97/MWh for LLH periods. Using the rule of thumb of 57 percent for HLH periods and 43 percent for LLH periods, this would translate into a flat price of $45.45/MWh. Using the natural gas price of $5.50/MMBtu from the Supplemental Proposal, this would translate into an implied heat rate of 8,263 Btu/kWh. Furthermore, as stated in Petty, *et al*., WP-07-E-BPA-66 at 4, we use 50 different AURORA runs in determining the net secondary revenue forecast. The implied heat rates of all 50 different price forecasts for net secondary revenues show a range from a high of 9,664 Btu/kWh to a low of 6,936 Btu/kWh. Therefore, the 7,600 Btu/kWh implied heat rate falls within the range of implied heat rates that we calculated in determining its net secondary revenue forecast for the Supplemental Proposal. As we have stated above, we will update the natural gas price forecast for the final Supplemental Proposal. Thus, when we update our price forecast and net secondary revenue forecast, these implied heat rates most likely will change.

Q. Cowlitz states that the current flat forward price curve for FY 2009 is about 30 percent higher than the BPA forecast market, and that even the current average forward off-peak price for FY 2009 is higher than BPA's all hour flat price projection. Schoenbeck, WP-07-E-CO-1 at 4. How do you respond?

A. As stated above, we expect that the Henry Hub natural gas price forecast will likely fall into the $7.50/MMBtu to $11.00/MMBtu range. Such an increase in the natural gas price forecast would increase the electricity price forecast.

Q. Cowlitz claims that BPA's net secondary revenue forecast is too low based on its low projection of natural gas prices and electricity prices. Schoenbeck, WP-07-E-CO-1 at 4. Cowlitz projects that if BPA were to incorporate the current forward market heat rate *with an updated natural gas price forecast, a conservative rough estimate of the increase in surplus sales revenue from updating the gas price forecast and current market heat rate expectations is $150 million. Id. How do you respond?*

A. Again, we expect that the natural gas price forecast will likely fall into the $7.50/MMBtu to $11.00/MMBtu range and thus we expect the market price forecast to increase correspondingly. However, as noted earlier in this testimony, Cowlitz erred by only looking at the surplus sales revenues and ignoring the costs of balancing power purchases and augmentation. Thus, although we do expect the surplus revenues to increase, a higher market price forecast also increases the cost of balancing power purchases and augmentation and those costs can be expected to increase as well - all else being held constant. However, we expect BPA to be a net seller on average, and thus we expect the net secondary revenue forecast to increase relative to the forecast in the Supplemental Proposal

Q. Cowlitz asserts that BPA should submit a revised market price forecast as soon as possible using a much more simplified and transparent modeling method, and that parties should be given the opportunity to submit supplemental testimony on the revised price forecast prior to the first hearing day Schoenbeck. WP-07-E-CO-1 at 5. Alternatively, Cowlitz proposes BPA could increase the surplus sales revenue by $150 million as a reasonable resolution of this issue. Id. How do you respond?

A. First, we have used the AURORA model and its methodology for determining net secondary revenue in numerous rate cases including, and since, the WP-02 rate proceeding. The AURORA model remains an accurate tool for forecasting electricity market prices and the best model available at this time, so we do not support changing that methodology for this proceeding. Second, we provided the supporting data in the Supplemental Proposal. Cowlitz has had the opportunity to respond to our forecast through discovery and its direct testimony. In response to Cowlitz's recommendation, we are reviewing and, in fact, adopting some of Cowlitz's proposed changes. Third, we will respond to Cowlitz's concerns regarding the timing of updates by making available the inputs to be updated through data responses. These updates are largely, if not exclusively, with respect to load and resource data, and represent the updates that we noted in our testimony that we did not have time to incorporate into the market price forecast prior to the Supplemental Proposal. *See* Petty, *et al.*, WP-07-E-BPA-66.

Q. Please describe each update.

A. First, as explained above, we will review our natural gas price forecast and expect it to increase for the final Supplemental Proposal. Second, we plan to use the WECC 10-Year Coordinated Plan Summary (2006-2015) for the load forecast. If a new WECC 10-Year Coordinated Plan is released prior to the final Supplemental Proposal, we will use that forecast. We have also updated the resources in the WECC region. Due to the quantity of information contained in this update, we will make available the updated load and resource data in response to data requests.

Q. Please respond to Cowlitz's proposal to simply increase the surplus sales revenue projection by $150 million.

A. BPA uses many models in the ratesetting process. These models include HydSim, AURORA, RiskMod, and ToolKit. It is important, especially when determining net secondary revenues for use in the Risk Analysis, to have electricity prices and hydro conditions correlated. Because there will be a new hydro regulation study for the final Supplemental Proposal, it will be important to run each of these models using the updated hydro generation levels. Also, updated market prices, loads and resources change the risk associated with 3,000 different revenue games that must be addressed in evaluating Treasury Payment Probability. Thus, simply adding $150 million to surplus sales revenues is not a viable option. That said, we have described the inputs that we intend to update, and that we expect the net secondary revenue forecast to increase as a result. The amount that Cowlitz suggests is not an unreasonable expected outcome.

Q. Does this complete your testimony?

A. Yes.

This page intentionally left blank.