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

2007 Wholesale Power Rate Case Initial Proposal

Direct Testimony

Book 1

November 2005

BPA Exhibit No.	Witness
WP-07-E-BPA-08	Leathley, Fox, Lefler
WP-07-E-BPA-09	Hirsch, Misley, Klippstein, Clark, Schiewe
WP-07-E-BPA-10	Homenick, Jensen, Steele
WP-07-E-BPA-11	Petty, Anderson, Wagner, Boling
WP-07-E-BPA-12	Wagner, Normandeau, Lovell, Conger, Russell, Marks, Kerns

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TESTIMONY OF

KIMBERLY A. LEATHLEY, ROY B. FOX, AND VALERIE A. LEFLER

Witnesses for Bonneville Power Administration

SUBJECT: FINANCIAL STRATEGY AND RISK TOLERANCE

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TESTIMONY OF

KIMBERLY A. LEATHLEY, ROY B. FOX, AND VALERIE A. LEFLER

Witnesses for Bonneville Power Administration

SUBJECT: Financial Strategy and Risk Tolerance

Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Kimberly A. Leathley and my qualifications are contained in WP-07-Q-BPA-27.

A. My name is Roy B. Fox and my qualifications are contained in WP-07-Q-BPA-12.

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

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to provide the context and background to the financial and risk policy objectives for BPA's WP-07 Initial Proposal.

Q. How is your testimony organized?

A. Our testimony contains eight sections. The first is this introduction. Section 2 provides background regarding BPA's Subscription Strategy and the Subscription contracts to which the WP-07 rates will apply. Section 3 describes the financial policy objectives considered when establishing the WP-07 rates. Section 4 describes BPA's risk profile, the risk mitigation tools used in prior rate periods, those proposed here, and additional tools under consideration for the FY 2007-2009 rate period. Section 5 describes financial policy directives and decisions that have shaped the WP-07 Initial Proposal. Section 6 describes the uncertainties of the current litigation regarding the National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion and how it is addressed in this proposal. Section 7 briefly discusses the risk mitigation package in the WP-07 Initial Proposal. Finally, Section 8 describes some liquidity tools that may be incorporated into final studies if circumstances allow.

Section 2: Background on BPA's Subscription Strategy and Existing Power Contracts

Q. Please describe the relationship between BPA's Subscription Strategy and this rate proceeding.

A. The rates established in the WP-02 proceeding expire on September 30, 2006, and must be replaced in order to comply with BPA's statutory obligations to establish rates to market the power of the FCRPS. The WP-02 rates apply to the ten-year contracts BPA signed with its power customers at the conclusion of BPA's Power Subscription Strategy that run from October 1, 2001 to September 30, 2011.

Q. Please describe BPA's Power Subscription Strategy.

A. BPA's Power Subscription Strategy and the accompanying Power Subscription Record of Decision (Subscription ROD) were issued on December 21, 1998. The Subscription Strategy and Subscription ROD were the culmination of a lengthy and thorough public process that formed a framework to equitably distribute the benefits of the electric power generated by the FCRPS among BPA's customers. The Subscription Strategy addressed the availability of power, described the power products available, laid out strategies for pricing the products, including risk management strategies, and discussed some contract elements.

BPA's principle goal in the Subscription Strategy was to spread the benefits of the FCRPS as broadly as possible, to both public and investor-owned utilities and Direct Service Industries (DSIs).

Q. Please describe the primary policy decisions and processes that shaped the WP-07 Initial Proposal.

A. Besides the Subscription Strategy described above, the primary policy decisions and public processes that shaped the Initial Proposal are: BPA's Policy for Power Supply Role for Fiscal Years 2007-2011 Administrator's Record of Decision, dated February 4, 2005 (Near-Term Policy ROD); Service to Direct Service Industrial Customers for Fiscal

Years 2007-2011 Administrator's Record of Decision (DSI ROD) signed June 30, 2005; the May 25, 2004 Administrator's Record of Decision related to the Residential Exchange Program Settlement Agreements (IOU Contract ROD) and the Power Function Review (PFR), for which the final close-out letter was dated June 24, 2005. The decisions made in these areas, along with normal rate-making directives, form the basis of the WP-07 Initial Proposal.

The Near-Term Policy contained four significant changes designed to give greater certainty to BPA's load service obligations under the existing Subscription Contracts for the upcoming rate period. First, BPA is setting the duration of this rate period to three years, from FY 2007 through FY 2009.

Second, public customers who signed five-year Subscription contracts without a guarantee of the lowest cost-based PF rates for FY 2007-2011 received that guarantee, as long as those customers signed a new contract or amendment by June 30, 2005. All customers eligible for the treatment did sign contracts or amendments to ensure they continue to receive the lowest cost-based PF guarantee. Third, nearly all of BPA's "Pre-Subscription" contracts terminate at the end of FY 2006. These Pre-Subscription contracts provide a protection against the application of any adjustment to "posted" rates during the FY 2002-2006 rate period. Those customers will now take power deliveries under their standard Subscription contracts that allow rate adjustments and they will take service under the WP-07 rates. However, there are eight Pre-Subscription customers who receive an allocation of the Hungry Horse Dam until 2011 that will continue to have rate protection.

Lastly, the Near-Term Policy ROD provided that any new or existing public customer whose contract expires at the end of FY 2006 may select from any of the existing standard products except Complex Partial (Factoring), Block with Factoring, or Slice. In addition BPA resolved not to offer contract amendments that would allow changes in the power products and services purchased under a customer's 10-year Subscription contract.

In the DSI ROD, BPA determined to offer the aluminum company DSIs power sales contracts for an aggregate 560 aMW of benefits at a capped $59 million annual cost. In addition, BPA plans to offer, through the local public utility, a 17 aMW surplus power sales contract to Port Townsend Paper Company under its FPS rate schedule (or the IP-07 rate if viable) at a price approximately equivalent to, but in no case less than, its lowest cost PF rate. BPA's assumptions about service to the DSIs are explained in the testimony of Gustafson, *et al*. WP-07-E-BPA-17.

In the IOU Contract ROD, BPA agreed to particular changes to the REP Settlement Agreements with the region's six IOUs. These amendments modified the manner and method by which BPA provides benefits to the region's IOUs. In general, these modifications included an election by BPA to provide only financial benefits to the IOUs during FY 2007-2011 period (as opposed to providing a combination of power deliveries and financial benefits) and adopted a mark-to-market methodology to calculate the level of financial benefits paid to the IOUs. In addition, the IOU Contract ROD established a floor of $100 million and a cap of $300 million for the annual benefit level. The decisions in the IOU Contract ROD shaped the assumptions regarding the level of benefits provided during the FY 2007-2009 rate period and are more fully explained in the testimony of Petty, *et al*., WP-07-E-BPA-11.

Finally, the decisions related to forecasts of program-level expenses used in the development of this proposal received thorough public review during the PFR. In January 2005, BPA initiated the PFR with BPA customers and constituents to examine the PBL's finances and determine the cost projections to be used in WP-07 Initial Proposal. The PFR focused on nine major cost areas. On June 24, 2005, after the conclusion of the public process, BPA issued a close-out letter that discussed the forecast of program level expenses and capital investments to be used in the WP-07 Initial Proposal. These forecasts, with certain limited exceptions, are the basis for the development of the WP-07 Initial Proposal revenue requirement. *See,* Homenick, *et al*., WP-07-E-BPA-10.

Section 3: Financial and Policy Objectives

Q. What are the primary financial and policy objectives that guided the development of the WP-07 Initial Proposal?

A. Six major financial and policy objectives helped shape the WP-07 Initial Proposal. Those objectives are: 1) a rate design that meets BPA financial standards, including meeting a 92.6 percent three-year Treasury Payment Probability (TPP) (which is equivalent to a 95% two-year TPP); 2) lowest possible rates, consistent with sound business principles including statutory obligations; 3) lower, but adjustable, effective rates rather than higher, but stable rates; 4) a risk package that includes only those elements BPA believes can rely upon; 5) reserve levels that are not built up to unnecessarily high levels; and 6) allocation of costs and credits to customers based upon product choice to the extent possible.

Q. Are these financial and policy objectives mutually exclusive?

A. These objectives are interdependent and require BPA to balance competing objectives against each other when developing its overall rate design strategy. This Initial Proposal reflects BPA's efforts to balance these competing objectives.

Q. Can you give an example of how these objectives need to be balanced relative to each other?

A. Yes. One example of the competition among these objectives involves balancing the goals of meeting BPA's financial standards and not building up reserves to high levels. In the past, we have relied heavily on relatively high levels of reserves to meet our Treasury Payment Probability standard. In today's volatile market environment, this would require BPA to build up a high level of reserves. In order to avoid building up reserves to high levels while still meeting BPA's financial standard, we have developed a risk package that collects revenue from customers only when we need it and returns revenue to customers when reserves reach a particular level. In this way, we have balanced the two competing goals: meeting BPA's financial standards and not building up reserves.

Section 4: Risks and Risks Mitigated in BPA's Power Rates

Q. Are there significant changes in BPA's risk exposure compared to that in prior rate periods?

A. Most of the risks BPA faces are substantively similar today to those BPA faced in previous rate cases However, the financial magnitude of these risks has increased due to the increased market price levels and volatility. The West Coast energy crisis bore witness to dramatic market price spikes that were unprecedented. Even though there are some market controls in place today that should limit a repeat of similar events, market prices today are nevertheless significantly higher and more volatile than those BPA experienced in the past. *See,* Mainzer e*t al*. During the last five years, BPA has seen wholesale prices as low as \$20/MWh and as high as over \$300/MWh. Electricity prices during 1980s and 1990s in the Pacific Northwest were relatively stable and driven largely by the availability of hydro generation. Today most new generation involves combustion turbines. As a result, gas prices have been the driving factor behind electricity prices.

Given this volatility in revenue from net secondary sales, the balance among, for example, rate levels, rate volatility, reserve levels and Treasury Payment Probability, is more challenging.

Q. Has BPA established any internal risk policies that address the financial risks BPA faces?

A. Yes. BPA established an Office of the Chief Risk Officer (CRO) and associated staff. In addition, to address the risks associated with the Agency's marketing activities, BPA established a Transaction and Credit Risk Management Committee (TRMC), which is composed of the CRO and other senior managers, to oversee BPA's commodity transaction risks within the broad limits established by the Enterprise Risk Management Committee. The TRMC developed a policy covering all power trading, non- Priority Firm marketing, and non-Treaty hydro marketing at BPA. This includes all transactions with Preference Customers not under the Priority Firm rate, including embedded power transactions in contracts that also include the Priority Firm (PF) rate with preference customers but which are non-Priority Firm products, DSI contracts, Slice contracts, Scheduling activities, voluntary water agreements with other parties accomplished for commercial reasons, and energy, capacity, ancillary services (except between BPA power and transmission business which are excluded) and reserve services marketing and trading not under the PF rate.

Q. In addition to the greater financial variability described above, does BPA face other major uncertainties?

A. Yes. In addition to increased volatility related to BPA's net secondary revenues, BPA also faces significant uncertainties related to its fish and wildlife obligations. Decisions by the courts, as well as negotiated settlements in recent years, have affected both the level of fish and wildlife program expenses as well as the operation of the hydro system. These risks are further discussed in Section 6.

Q. Please describe the tools that BPA has traditionally relied upon to mitigate risks in BPA power rate proceedings, and if these tools are still available.

A. Traditionally, BPA has relied on its cash reserves and the addition of Planned Net Revenues for Risk (PNRR) to its revenue requirement as the primary risk mitigation tools in setting rates. In some rate proposals, rate adjustment clauses (interim rate adjustment and cost recovery adjustment clauses or CRACs) have been incorporated in the rate design. In the 1996 and 2002 power rate proposals, the Fish Cost Contingency Fund (FCCF) was also available to mitigate some specific risks. While BPA may still rely on PNRR and CRACs to address the risks it faces, the FCCF was exhausted in FY 2003 and is no longer available.

While reserves are still available to mitigate risk, the forecast of reserves available to the PBL for the FY 2007-2009 rate period is lower than it was for the beginning of the FY 2002-2006 period. As a result, starting reserves will not be as effective a mitigation measure as it was when rates were set for the current rate period.

Q. How have the changes in BPA's risk profile and loss of tools affected BPA's risk mitigation?

A. Given the more volatile market environment and the lower level of forecast starting reserves, barring other risk mitigation tools, BPA would need to have a very high level of PNRR in the revenue requirement, resulting in a high "posted" rate (the rate without application of adjustment or dividend distribution clauses) for all three years of the rate period. Staff has analyzed a "PNRR-only" non-adjustable rate design which results in a rate significantly higher than the effective rate level that results from BPA's Initial Proposal, which has an adjustable rate design.

Section 5: Policies That Guide BPA in Rate-Setting

Q. Can you elaborate on some of the major policy directives and processes that provide guidance in BPA rate-setting.

A. In 1993, BPA determined that a 95 percent probability of paying the U.S. Treasury on time and in full for both years of a two-year rate period was a prudent policy. This policy was laid out and adopted in the 1993 Ten-Year Financial Plan. This policy has not been superseded, and still remains a key policy directive for rate-setting. This was listed as a financial objective in the first question. The equivalent of the TPP standard for a three-year rate period is 92.6 percent and is incorporated into this proposal.

See, WP-07-E-BPA-14.

The other financial policies that provided guidance to this initial proposal relate to assumptions about liquidity requirements, the use of reserves, the cost recovery period for new, non-augmentation conservation costs, and financing of CGS capital costs.

Q. *What assumptions regarding BPA liquidity requirements are used for this WP-07 Initial Proposal?*

A. We assume no change to the $50 million level of liquidity reserves (or "working capital") assumed in meeting the Treasury Payment Probability in the 1993 and 1996 rate proposals and the 2002 rate proposal.

Q. *Have assumptions regarding the use of BPA reserves changed?*

A. Yes. BPA accounts for reserves for each business line (Transmission and Power) separately. In TBL's recently-completed rate proceeding the TBL reserve levels, together with proposed rate levels, result in a forecast of transmission TPP that exceeds the 95 percent standard for the two-year rate period. This occurs because TPP is not driving the level of TBL rates – the need for net revenues is. As a consequence, there is a certain amount of TBL reserves that could be made available to PBL, and still allow TBL to maintain a 95 percent TPP standard. BPA will assume that any financial reserves attributed to TBL above the level required to satisfy TBL's 95 percent TPP standard for FY 2006–2007 can be considered to be available to PBL for rate-setting purposes for FY 2007. PBL will assume that any use of these reserves in FY 2007 would be completely made up for in such a way that TBL rates would be no higher than if BPA had not made this assumption. The reserves attributed to TBL for FY 2008 will not be reduced, and PBL rate-setting will not assume any availability of these reserves for FY 2008 or FY 2009. For additional details on how PBL has treated this matter see the testimony of Normandeau *et al*., WP-07-E-BPA-14.

Q. *What was the driver for reviewing the amortization period of Conservation costs?*

A. Reflecting BPA's current Energy Conservation Project Accounting Policy Including Conservation Augmentation Activities, BPA determined that a change in the emphasis of the program warranted a review of the useful life of conservation measures. The emphasis has returned to acquiring resources, similar to the "legacy program." The legacy program, or Energy Efficiency Legacy Conservation, includes conservation activities that began during BPA's major conservation acquisition efforts following the implementation of the Regional Act prior to 2002.

Q. Please give some background on BPA's ability to amortize Conservation costs.

A. BPA has been able to capitalize legacy conservation costs based solely on the recognition that BPA, as a "Rate Regulated Utility," has the ability to capitalize intangible asset costs since those costs will be recovered in future rates. Conservation assets are recognized as intangible assets on our financial statements and are treated differently than transmission assets.

Q. How have Conservation costs been treated in the past?

A. BPA's policy has been to capitalize and amortize straight-line the legacy conservation costs over a 20-year period, which represents the composite life of the conservation measures being capitalized. Because cost recovery was sought through future rates, future economic benefit was assumed, thus meeting the requirements to capitalize costs under Generally Accepted Accounting Principles (GAAP) [Financial Accounting Standard (FAS) 71 – "Accounting for the Effects of Certain Types of Regulation" which specifically address regulation created assets].

Conservation Augmentation (ConAug) is separate and distinct from legacy conservation. ConAug is the conservation component of BPA's system augmentation effort to acquire additional power needed for the FY 2002-2006 rate period due to expected Subscription contract loads in excess of the available BPA resource supply. ConAug is also a resource acquisition effort to purchase conservation measures to reduce

BPA's load obligation. Presently, costs under this program are capitalized according to the methodology established in the 2002 Power Rate Case.

This methodology differs from that used for BPA's other conservation assets, with the ConAug costs amortized over the life of the contracts, i.e., through FY 2011. Capitalization rules for ConAug Program costs, as established by the WP-02 Power Rate proposal, allowed for a maximum amortization period equal to the ten-year contract period. Therefore, the costs are amortized on a schedule not to exceed the amount of time remaining in the contract period from October 1, 2001 through September 30, 2011. Costs incurred for Energy Conservation measures in January 2006, for example, with six years remaining in the contract period, will have a six-year amortization schedule.

Q. Are you proposing to use a different amortization period in the upcoming rate period?

A. Yes. Beginning in FY 2007, non-ConAug costs related to conservation acquisition will be amortized over five years. Although the composite life approach is a reasonable method for determining the future benefit following GAAP (FAS 142, Goodwill and Other Intangible Assets), the effects of competition or other factors may be included in the determination of useful life. Based on a review of industry practices and other considerations, the five-year amortization has been deemed the most appropriate for conservation acquisition investments for the FY 2007-2009 period.

Q. What assumptions is BPA making about financing any EN capital costs?

A. Historically, these costs have been revenue-financed, but in FY 2003 in the SN-03 rate case, BPA decided to debt-finance CGS capital costs for FY 2003-2006. BPA and Energy Northwest (EN) have agreed that capital costs for CGS for FYs 2007 through 2009 will be debt-financed rather than revenue-financed. This decision is reflected in the repayment studies and revenue requirement. *See,* Revenue Requirement Study, WP-07-E-BPA-02.

Section 6: Uncertainties due to Current Biological Opinion Litigation

Q. What are the uncertainties surrounding BPA's fish and wildlife obligations?

A. BPA faces a significant level of uncertainty regarding hydro operations and direct program costs for its fish and wildlife program. The uncertainty stems from litigation challenging the adequacy of actions taken by BPA, the U.S. Army Corps of Engineers and the Bureau of Reclamation to discharge their individual and collective fish and wildlife obligations. The rules guiding system operations and/or the level of program costs could change dramatically under some concepts advanced by those involved in this litigation. Such changes could be the results of judicial decisions, settlements, or other such actions resulting from the litigation.

Q. How did BPA deal with this uncertainty in the WP-02 proceeding?

A. In the WP-02 proceeding, BPA modeled 13 alternatives that represented the potential range of possible fish and wildlife costs. The 13 alternatives arose in the development of the Fish and Wildlife Funding Principles. These principles specified, among other things, that when setting rates in the WP-02 proceeding BPA would take into account the entire range of potential fish and wildlife costs as reflected in the 13 long-term alternatives for configuration of the FCRPS, and treat each alternative as if each is equally likely to occur.

The 13 alternatives became necessary because at the time BPA was developing rates it did not have a biological opinion (BiOp) from National Marine Fisheries Service (NMFS) or an updated Fish and Wildlife Program from the Northwest Power Planning Council to use to model fish costs. After the adoption of the WP-02 rates, the 2004 BiOp was issued that dictated the operation of the FCRPS and the activities funded in the BPA Fish and Wildlife Direct Program.

Q. How have things changed since the adoption for the 2004 BiOp for the FCRPS?

A. As a consequence of pending litigation regarding the operation of the FCRPS to address fish and wildlife issues under the Endangered Species Act (ESA), an additional level of uncertainty has arisen regarding the adequacy of BPA's actions to satisfy its obligations under the ESA. The outcome of the litigation could result in additional restrictions on the operations of the dams on the FCRPS and or additional program level expenses for the fish and wildlife program.

Q. Will the proposed CRAC be sufficient to deal with the costs associated with these risks?

A. We don't know. It is possible that the CRAC would be sufficient to mitigate these risks. However, while the proposed CRAC, described below, is a fairly robust risk mitigation tool, it is designed to deal with a set of specific risks. The magnitude of the cap of the CRAC was determined without factoring in the risks associated with the pending litigation. Therefore BPA is proposing the NFB Adjustment to specifically address any cost and revenue impacts associated with specified trigger events. This adjustment will allow the maximum amount of revenues allowed to be collected through the CRAC to increase. However, while the NFB Adjustment allows the CRAC to collect additional revenues if needed, the actual rate calculation is determined based upon actual modified net revenues. As a result, BPA will not be collecting any more additional revenues than necessary.

Q. Please describe the events that would trigger the NFB Adjustment and why BPA adopted these events?

A. The trigger events are limited to a court order(s) (including court-approved agreements), an agreement related to litigation, a new NMFS FCRPS BiOp, or Recovery Plans under the ESA. The trigger events for the NFB Adjustment are tailored specifically to those circumstances associated with the litigation surrounding the FCRPS and that impact hydro operations and/or program levels for fish and wildlife.

Section 7: BPA's Risk Package

Q. Generally describe the risk package contained in the WP-07 initial proposal.

A. The risk package contained in the WP-07 Initial Proposal includes a combination of reserves, PNRR to augment reserves, a CRAC that is fashioned after the current Financial-Based CRAC, and a Dividend Distribution Clause (DDC). Both the CRAC and the DDC are available for use in setting rates for the first year of the rate period. In addition the NFB Adjustment that works in conjunction with the CRAC is also available. The various details surrounding the risk package are described in more detail in the testimony of Normandeau, *et al.,* WP-07-E-BPA-14, and the Risk Analysis Study, WP-07-E-BPA-04.

In addition, if events occur that dramatically affect BPA's finances, BPA retains the ability to initiate a new rate case to reset rates to deal with this change. The effect on any one year's rate will depend on the financial results of the year as represented in the thresholds that govern the implementation of the CRAC.

Q. Why did BPA choose this risk package for its initial proposal?

A. The combination of reserves, PNRR, a CRAC, NFB Adjustment and a DDC present BPA with a reasonable mix of fixed and flexible tools, and balances the competing policy objectives stated in Section 3. The selected package allows BPA to meet its TPP standard without setting "posted" rates at an unacceptably high level or building up significant cash reserves in the FY 2007-2009 rate period. The initial rate will be lower and more volatile than the rate resulting from a risk package that relied less on adjustable mechanisms and more on fixed ones. This is in line with our understanding of customer preferences. Additionally, this set of risk mitigation tools relies only on tools that BPA can rely on with a very high degree of certainty, reducing the risk that the mitigation itself could fail.

Q. Might other risk mitigation tools be considered during the rates proceeding?

A. As discussed below in Section 8, BPA is continuing to pursue additional liquidity tools, that, if secured, could produce lower overall rate levels – all else being equal. At the present time, BPA does not believe that it can rely on them when setting rates because they are not sufficiently certain. That does not mean that these options might not be appropriate for adoption by the Administrator if circumstances change between now and the issuance of a draft or final ROD.

Section 8: Alternative Risk Mitigation Tools

Q. In developing the WP-07 Initial Proposal, did BPA consider tools that were not adopted?

A. Yes. There are several risk mitigation tools that could specifically provide BPA with additional liquidity. These have been discussed both internally and with interested outside parties. Liquidity tools, like reserves, provided BPA with temporary access to cash. That is, while they do not provide BPA with an overall higher level of revenue, these tools change the timing or shape of BPA's cash flows. Having additional liquidity tools may allow us to be less reliant on cash reserves. BPA did not include these tools as part of its initial proposal because BPA does not yet have confidence that it they would be available when needed.

Q. Are you still exploring these liquidity tools?

A. Yes. Several of these tools show great promise in helping to lower the need for PNRR or the expected values of necessary CRAC revenues. Therefore, we are continuing to pursue some of these liquidity tools to increase the likelihood that they can be included in the rate calculations for the final rate decisions.

Q. Please describe the liquidity tools that BPA is continuing to pursue and the factors that must be established before BPA can rely on them in the final rate calculations.

A. BPA is exploring the ability to directly pay EN's annual expenses. Currently these expenses are covered through the net billing agreements. Under this option, Bonneville and EN would agree that BPA would pay EN directly, on a current basis, all net-billed project costs. This could provide up to $200 million of additional liquidity prior to September 30 of each year, depending upon the amount of the EN budget that can be paid directly by BPA. Before relying on this tool, BPA must be sure that there is no adverse tax impact on existing or future EN tax-exempt bonds from such a change and that the changes in cash flow that would result would not create unacceptable liquidity risk at other times in the year. BPA has filed a request with the Internal Revenue Service for a letter-ruling on the tax implications of this new arrangement. BPA has asked for expedited consideration so that a decision can be captured in the final rates.

Another liquidity tool being discussed is the idea to defer the pre-payment of the Federal debt associated with the Debt Optimization program (DO). Under DO, BPA refinances due EN debt, and uses the funds that would have otherwise been used to pay the EN debt to repay Federal debt of a like amount. This pre-payment is sent to the U.S. Treasury at the end of September. If BPA could defer the pre-payment until December, this would provide BPA additional cash during the first few months of the fiscal year. In order to include this assumption in final rates, BPA would have to make some assumption about the future of the debt optimization program. To date, BPA has not forecast the continuation of the debt optimization program due to the uncertainties associated with the program. For example, the resolution of outstanding litigation may make this program economically unviable. In addition, BPA does not know how the key decision makers, the Energy Northwest Executive Board, would react to such a change.

BPA is also evaluating the effects of having certain customers pre-pay a portion of their power bills either in association with a cost adjustment clause or otherwise. This option would entail modifying power sales contracts or entering into new contracts. BPA must determine if such an option, particularly used in conjunction with some of the other options, provides significant cash flow benefit.

Another possibility is to shape the IOU REP Settlement benefits out of the fall (October through December) and into other parts of the year. This tool would give BPA additional liquidity in the fall. BPA would not be able to count on this option without a contract amendment and perhaps some concessions from public power regarding the underlying agreements between BPA and the IOUs. The resolution of this matter is beyond the control of BPA and as a consequence, BPA is focusing the bulk of its efforts in trying to achieve the three options described above.

Q. Are there other options for liquidity under consideration?

A. Yes. The customers have proposed two additional ideas; changing the June billing date to May in association with a mid-year CRAC option and changing EN's and Net Billing Agreements' "Contract Year." Each of these could be a viable tool, but significant impediments exist that prevent BPA from adopting these at the present time. The June billing date change would require an amendment to the power sales agreements as well as significant billing system and process changes. BPA believes the expected cash flow improvement from this tool doesn't warrant the significant effort necessary to achieve this change. The Energy Northwest contract year change would require amending over 300 net billing contracts. However, if the impediments are overcome before final rates are adopted and the contract year change provides value when considered with all the other tools BPA and customers are working on, BPA will include the contract year change in the final rates.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY OF

JON A. HIRSCH, TIMOTHY C. MISLEY, JANET ROSS KLIPPSTEIN,
HARRY CLARK, AND ROGER SCHIEWE

Witnesses for Bonneville Power Administration

SUBJECT: LOAD RESOURCE STUDY

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TESTIMONY OF

JON A. HIRSCH, TIMOTHY C. MISLEY, JANET ROSS KLIPPSTEIN,

HARRY CLARK, AND ROGER SCHIEWE

Witnesses for Bonneville Power Administration

SUBJECT: LOAD RESOURCE STUDY

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

A. My name is Janet Ross Klippstein and my qualifications are contained in WP-07-Q-BPA-25.

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

A. My name is Roger Schiewe and my qualifications are contained in WP-07-Q-BPA-48.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to describe and answer questions concerning the Load Resources Study (Study), WP-07-E-BPA-01. Additionally this testimony sponsors the Load Resource Study (Study), WP-07-E-BPA-01, of Bonneville Power Administration's (BPA) 2007 Wholesale Power Rate Case Initial Proposal, and the 2007 Wholesale Power Rate Case Initial Proposal Load Resource Documentation, WP-07-E-BPA-01A.

Q. How is your testimony organized?

A. The Load Resource testimony comprises 10 sections, including this one. Section 2 discusses the process used to generate the total retail load forecasts for the public body and cooperative utilities and Federal agencies (Public Agencies) served by BPA. Section 3 describes BPA's Priority Firm (PF) sales forecasting process. Section 4 addresses BPA's forecast of sales to the investor-owned utilities (IOU) and direct service industries (DSI). Section 5 describes BPA's Load Resource Study process. Section 6 describes BPA's hydro regulation studies. Section 7 describes BPA's Federal generating resources. Section 8 addresses BPA's treatment of Federal system contracts. Section 9 describes BPA's treatment of Federal system transmission losses. Section 10 addresses PNW regional total hydro resources for the Market Price Forecast Study.

Section 2. Public Agencies Total Retail Load Forecasts

Q. Please describe the process used to produce the Public Agency Total Retail Load Forecasts.

A. BPA routinely produces, or obtains from its customers, forecasts of its customers' total retail loads. A description of the process or method BPA uses to produce the total retail load forecasts is contained in the Load Resource Study, WP-07-E-BPA-01, Section 2.2.2. In general, the forecasting method uses a time series approach, projecting annual total retail loads based on annual historical values. The annual projections are then shaped to months and diurnal periods using recent historical data.

Section 3. PF Sales Forecasting Process

Q. Please describe BPA's forecasting process for its power sales contract obligations.

A. BPA's forecast of Public Agency total retail loads described above was used as the basis for BPA's Priority Firm (PF) sales obligation forecast. Customer-owned generation and/or contract power purchases were subtracted from their total retail load forecast to produce a sales obligation forecast for those customers for whom BPA follows the load. For the Slice/Block and Block customers, BPA's sales obligations were those designated by contract. Details pertaining to BPA's Federal power sales contract obligation forecasting process are contained in the Load Resource Study, WP-07-E-BPA-01, Section 2.2.2.

Q. *Please summarize the growth exhibited in BPA's Public Agency sales obligation forecast.*

A. Full Service customer power sales contract obligations are projected to grow at an average annual rate of approximately 2.4 percent for fiscal year[1] (FY) 2007 through 2009. Partial Service customer power sales contract obligations are projected to grow at an average annual rate of about 1.2 percent for FY 2007 through 2009. Overall, power sales contract obligations for which BPA follows the load obligation are projected to grow at an average annual rate of about 2.0 percent over the FY 2007 through 2009 period. Block sales and Slice Block sales are fixed by contract and are projected to remain constant over the same period. BPA's total Public Agency power sales contract obligations served at PF rates are projected to grow at an average annual rate of 1.1 percent per year over the FY 2007 through 2009 period.

Q. *The growth rate for the Full Service customers of 2.4 percent seems rather high. Please explain what is causing this amount of growth?*

A. The 2.4 percent growth rate represents both expected new load and load growth of approximately 95 aMW for the Full Service customers over the rate period.

Q. *Have BPA's actual power sales tracked well in comparison to forecasts of its power sales contract obligations?*

A. Yes. For FY 2004, the projected power sales contract obligations of the load following customers, including the pre-Subscription customers, exceeded the actual sales to those customers by 1.3 percent, or 42 aMW. For the first 11 months of FY 2005, forecasted power sales contract obligations exceeded the actual BPA power sales contract purchases by 0.9 percent, or 27 aMW.

Q. *Please describe each of the specific power sales contract obligation forecasts by products purchased.*

[1] Fiscal year (FY) is the 12-month period October 1 through September 30. For example FY 2007 is October 1, 2006, through September 30, 2007.

A. Power sales contract obligation forecasts are needed for both the Full and Partial Service product customers. These obligation forecasts comprise the four billing determinants used in BPA's PF rate schedule. These billing determinants are heavy load hour energy (HLH), light load hour energy (LLH), generation system peak, and load variance. Billing determinants for Block products, whether or not in conjunction with the Slice product, are specified by contract and no forecasts are required.

Q. *How did BPA forecast Public Agency Full Service customer energy sales?*

A. A description of how BPA forecasts public agency Full Service customer power sales contract obligation is contained in the Load Resource Study, WP-07-E-BPA-01, Section 2.2.2. In general, the forecasting method uses a time series approach, projecting annual energy sales based on annual historical values.

Q. *Please describe how the HLH and LLH sales were developed for BPA's power sales contract obligation forecast.*

A. BPA developed the HLH and LLH splits based on historic relationships of HLH and LLH for each customer. These customer-specific relationships were used to split the total monthly power sales contract obligations into heavy and light load hours. Then any sales made under the Firm Power Product and Services (FPS) rate schedule, such as Pre-Subscription or the Irrigation Rate Mitigation Product were subtracted to derive sales at the PF rates. In this Study, the HLH and LLH sales for the rate period comport with the North American Electric Reliability Council (NERC) definition of HLH and LLH.

Q. *How did BPA forecast the power sales contract demand obligations for the Public Agency Full Service customers?*

A. A description of BPA's process for forecasting Full Service peak power sales contract obligations is contained in the Load Resource Study, WP-07-E-BPA-01, Section 2.2.2. Monthly load factors were calculated from historical sales data and applied to the monthly energy sales forecasts to project the power sales contract demand obligations.

Q. How does BPA use load factor in this Study?

A. Load factor, traditionally defined as the relationship between a utility's monthly energy and its monthly peak load, is defined slightly differently here. For this process, load factors are defined as the relationship between a utility's energy and its basic demand billing determinant Generation System Peak (GSP), load at the time of the BPA system peak. Load factors for Full and Partial Service customers were calculated as the monthly energy divided by the load at the time of BPA's generation system peak.

Q. Why has BPA defined load factor as the relationship between a customer's energy and its load at the time of BPA's system peak?

A. BPA requires a forecast of those elements for which its customers will be billed to project revenues. In this case, the traditional definition of load factor does not provide a forecast of the billing determinant GSP on which BPA will collect revenues. BPA, therefore, utilized a slightly different relationship, using a customer's load at the time of the BPA system peak rather than the customer's own system peak as the denominator, referred to here as load factor.

Q. How did BPA forecast power sales contract energy obligations to Public Agency Partial Service customers?

A. A description of BPA's process for forecasting public agency Partial Service customer power sales contract energy obligations is contained in the Load Resource Study, WP-07-E-BPA-01, Section 2.2.2. The Partial Service customers' energy resources are subtracted from the total retail load energy forecast to derive BPA's energy power sales contract obligations. The energy sales projections are then split into HLH and LLH forecasts using the process described above for the Full Service customers. Sales made under the Firm Power Sale (FPS) rate schedule, such as Hungry Horse Reservation Pre-Subscription sales or the Irrigation Rate Mitigation Product are subtracted to derive power sales contract obligations at the PF rates.

Q. How did BPA forecast the peak power sales contract obligations for the Public Agency Partial Service customers?

A. A description of BPA's process for forecasting Partial Service customer peak power sales contract obligations is contained in the Load Resource Study, WP-07-E-BPA-01, Section 2.2.2. Monthly load factors are applied to the power sales contract energy obligation forecasts to derive power sales contract demand obligation forecasts by month. The Partial Service customers' monthly estimated resource peaks are then subtracted to derive the demand power sales contract obligation forecast.

Q. How was the billing determinant for the Load Variance charge estimated?

A. The Load Variance charge is charged against a utility's total retail load for those utilities purchasing the Full and Partial Service products. The total retail load forecasts for customers with products subject to the Load Variance charge were summed by product.

Q. What historical time period did BPA use in the estimation of its loads and sales obligation forecast models?

A. The time period for the historical series of data which BPA's loads and sales obligation forecasts are based varies by customer. BPA used the historical data for FY 1993 through 2004, when possible, in its total retail load and power sales contract obligation forecasts. If discrete changes in a customer's historic loads or sales obligations occurred, changes in the length of the historical data streams would be incorporated.

Q. Why would the historical time period used in the estimation of its loads and sales obligation forecast models vary?

A. For some customers, the historical data reflect long- or near-term changes that could possibly skew load growth trends. For example, BPA customers may have large (relative to their system) discrete consumer loads that started or ended during the historical period. The historic data provided to the loads and sales obligation forecast models in such instances would take into account the most recent stable data.

Q. Are the historical data used in the forecast period adjusted for weather?

A. No. BPA does not weather-adjust the historical data. BPA believes the forecast period is of sufficient length to capture the variations in load caused by weather.

Q. Do your models reflect price elasticities?

A. No. BPA does not reflect the effects of price elasticities in its models. There are several reasons for not doing so. If BPA were to incorporate price elasticities in the models, we would need to be certain that, and the extent to which, the wholesale rate changes are being incorporated into retail rates. That is, consumers will only respond to changes in BPA's rates to the extent utilities reflect those changes in their retail rates. Since different consuming sectors (residential, commercial, industrial, etc.) presumably have different retail rate structures and perhaps different elasticities, trying to develop an overall price elasticity to assume is problematic. Because wholesale power costs are only a portion of a utility's total retail rates wholesale price changes are muted to a certain extent. Also, some customers may supply part of their retail load from sources other than BPA. The costs of these resources, to which BPA is not privy, would go into their retail rate calculations as well. In short, BPA is not inclined to presuppose the retail rate treatment of its individual customers.

In addition, when considering elasticities for other analyses in the past, BPA concluded there are rather small price elasticity effects. To try to incorporate a rather complex adjustment for an insignificant effect was deemed inefficient and impractical. Given that BPA is proposing fairly small changes to its wholesale power rate design, any expected elasticity effects would be insignificant. Finally, the sales to which price elasticities would apply (those for whom BPA follows their load) is about 3,000 aMW, while the sales that would not be influenced by price elasticities accounts for about 4,000 aMW. This, too, makes the impact of including a price elasticity adjustment relatively insignificant.

Q. *Are any adjustments made to the aggregate power sales contract obligation forecast?*

A. Yes, the aggregate sum of the individual utility forecast of power sales contract obligations is adjusted by a reduction of 20 aMW per year for the rate period to reflect projected savings from bilateral conservation acquisition agreements.

Q. *Are individual customer sales data adjusted by accounting for historical conservation before producing your forecasts?*

A. No, individual customer sales data are not adjusted to account for the effects of historical conservation savings.

Q. *Does reducing the aggregate forecast by 20 aMW per year produce a forecast that is too low?*

A. BPA does not believe so. Conservation and energy efficiency measures such as building codes will continue to save an increasing amount of energy over time as houses built to those codes become an ever-increasing share of the housing stock. Items like compact fluorescent lights and more efficient appliances will continue and perhaps increase in use as technology improves and costs come down. BPA believes a lower growth in energy consumption was realized in areas where such measures had already been incorporated is a reasonable outcome. However, when bilateral agreements are negotiated to provide conservation savings it is reasonable and appropriate to reflect those savings in the sales forecast.

Q. *Are the power sales contract obligation forecasts reduced for savings achieved through BPA's conservation rate credit programs?*

A. No. The sales forecasts are produced using historic consumption. These forecasts reflect the savings impact from customer activities taken pursuant to BPA rate credit programs. However, because the rate credit programs are not directed at specifically acquiring conservation savings, BPA is not forecasting conservation savings that may be achieved through such programs.

Q. *Will the individual customer power sales contract obligation forecast data and models be made available?*

A. No. BPA considers customer specific data, both historical and forecast, to be proprietary and business sensitive and so will not release such data to third parties. In addition, some customers have requested that the data regarding their specific utility be kept confidential.

Section 4. IOU and DSI Sales Forecasts

Q. What does BPA forecast for IOU power sales contract obligations during the rate period?

A. BPA forecasts no power sales to regional IOUs for FY 2007 through 2009. This is consistent with the Residential Exchange Program (REP) Settlement Agreements that provide monetary benefits equivalent to 2196.8481 aMW of power to the six regional IOUs. *See,* Load Resource Study, WP-07-E-BPA-01, Section 2.2.3.

Q What is BPA's forecast for DSI sales during the rate period?

A. BPA forecasts actual physical sales of power to the DSIs will be 17 aMW per year over the FY 2007 through 2009 period. This will be a sale of surplus power for each year of the rate period to a local preference customer for delivery to Port Townsend Paper Corporation. In addition, BPA will assume for the purposes of this Study that it will provide benefits to DSI smelters, for up to 560 aMW per year, through local preference customers for market purchases such that the DSI's resultant power costs are not less than the PF rate. *See,* Load Resource Study, WP-07-E-BPA-01, Section 2.2.4 and Gustafson, *et al.*, WP-07-E–BPA-17.

Section 5. Load Resource Study Process

Q. How are the Federal system loads, sales, and contract obligations treated in the Study?

A. The Study treats all Federal system loads, sales, and contract obligations as firm obligations that are served regardless of weather, water, or economic conditions. The

Federal system sales and contract obligations are summarized monthly, for energy in aMW, in the Load Resource Documentation, WP-07-E-BPA-01A, Section 2.3, Tables 2.3.1 through 2.3.3, *Loads and Resources-Federal System, (2002 PSC Sales)*, *(Slice Sales)*, *(Exports)* and *(Intra-Regional Transfers (Out))*. These obligations are detailed monthly, for energy in aMW, HLH MWh, and LLH MWh in the Load Resource Documentation, WP-07-E-BPA-01A, Sections 2.4 through 2.6, Table A-2, *Exports*, Table A-16, *Intra-Regional Transfers*, and Table A-22, *BPA Power Sales Contracts*. These obligations are used as input to the Risk Analysis Study, WP-07-E-BPA-04.

Q. How are the Federal resources and contract purchases treated in the Study?

A. The Study's hydro regulation analysis sets the hydro project generating characteristics for the Federal system. The firm energy capability of Federal hydro resources is estimated using 1937 water conditions. This low flow water condition approximates one of the lowest water years of the 50 water years of record (August 1928 through July 1978) in the Columbia River Basin. The energy, in aMW, of the Federal system hydro under 1937 water conditions, is summarized in the Load Resource Documentation, WP-07-E-BPA-01A, Section 2.3, Tables 2.3.1 through 2.3.3, *Loads and Resources-Federal System*, *(Regulated Hydro)* and *(Independent Hydro)*. The hydro energy is detailed in the Load Resource Documentation, WP-07-E-BPA-01A, Section 2.4, Table A-3, *Federal Regulated Hydro Projects* and Table A-4, *Federal Independent Hydro Projects*. The monthly output of the hydro system varies greatly, depending on the season and water conditions. The hydro regulation study provides 50-water year Federal hydro generation estimates for FY 2007 through 2009. This 50-water year data is used in the Risk Analysis Study, WP-07-E-BPA-04, and presented in the Risk Analysis Documentation, WP-07-E-BPA-04A, Tables 3 through 6.

The Study assumes that all Federal system non-hydro resources and contract purchases are firm resources available to meet Federal obligations, regardless of weather, water, or economic conditions. The expected generation from non-hydro resources and contract purchases are summarized monthly, for energy in aMW, in the Load Resource Documentation, WP-07-E-BPA-01A, Section 2.3, Tables 2.3.1 through 2.3.3, *Loads and Resources-Federal System*, *(Imports)*, *(Renewables)*, *(Large Thermal)*, *(Non-Federal Canadian Entitlement Return for Canada)*, *(Intra-Regional Transfers (In))*, and *(Non-Utility Generation)*. This data is detailed monthly for energy in aMW, HLH MWh and LLH MWh in the Load Resource Documentation, WP-07-E-BPA-01A, Sections 2.4 through 2.6, Table A-5, *Federal Imports*, Table A-8, *Federal Renewable Resources*, Table A-10, *Federal Large Thermal*, Table A-15, *Canadian Entitlement Return for Canada*, Table A-16, *Intra-Regional Transfers (In)*, and Table A-24, *Federal Non-Utility Generating Resources by Project*. This data is provided for the Risk Analysis Study, WP-07-E-BPA-04.

Section 6. Hydro Regulation Studies

Q. Please describe the primary drivers of reservoir operations in the hydro regulation studies.

A. Hydro plant operating requirements are used to regulate plant operations. Operating requirements and project operating characteristics are based on data submittals taken from the Pacific Northwest Coordination Agreement (PNCA). Operating requirements include, but are not limited to, storage content limits determined by rule curves, maximum project draft rates determined by each project, and flow and spill objectives determined by the National Oceanographic and Atmospheric Administration Fisheries (NOAA Fisheries) Biological Opinion (BiOp) published November 2004, and the United States Fish and Wildlife Service (USFWS) 2000 Biological Opinions for the Snake River and Columbia River projects.

Q. Does this Study reflect the current method of reservoir operation in the PNCA planning process?

A. Yes, however, some deviations from the PNCA data submittals occurred when specific operating decisions were made subsequent to the time of submission in order to more accurately implement the BiOp for the rate period.

Q. Please describe the steps in the hydro regulation study.

A. First, an Actual Energy Regulation (AER) study is run to determine the operation of the Federal (U.S.) hydro projects under each of the 50-historic water conditions while meeting the Firm Energy Load Carrying Capability (FELCC) produced in the PNCA final regulation. In this step, the Canadian operation is fixed to that specified in the assured operating plan (AOP). The U.S. projects draft to meet the Coordinated System FELCC while still meeting their operating requirements. If possible, all projects draft to their Energy Content Curve (ECC) to produce secondary energy. The project operation from the AER study determines the drafting rights of each of the projects for use in the Operational study.

Second, an Operational 50-year study is run with estimated regional firm loads developed for this Study. The operation of the non-Federal projects is limited by the proportional draft points (PDP) developed in the 50-year AER study.

Q. What are the differences between the FY 2007, 2008, and 2009 hydroregulation studies?

A. There are two major differences in the hydro regulation studies for FY 2007, 2008, and 2009, respectively. First, there are yearly differences in the hydro regulation studies that are based on modeling assumptions regarding the BiOp implementation. These modeling assumptions relate to the yearly spill for juvenile bypass operations during the April through August period. As Removable Spillway Weirs (RSW) are added at some of the projects at various times during the FY 2007 through 2009 rate period, the amounts of spill required for juvenile bypass is expected to change. Second, the amount of anticipated hydro generation increases due to the implementation of hydro improvement programs vary with each year of the Study. These improvements are part of BPA's capital improvements programs.

Q. Please explain the difference between two modes of hydro regulation studies: refill and continuous.

A. There are two modes for hydro-regulation studies: refill and continuous. Both are used to estimate the energy production of the hydro system. However, each mode is different in how it treats initial reservoir conditions. Continuous hydro studies operate from one water year to another, using the previous water year's final reservoir elevations as the initial reservoir elevations for the next water year. Refill studies operate each water year independent of all other water years, using the same initial reservoir elevations for each water year. Continuous studies are typically used when there is little or no information on initial reservoir elevations such as when considering operations for a future year. For the FY 2007 through 2009 studies, each was run in the continuous mode.

Q. In the Load Resource Study, why is the hydro regulation study called a "50-year study?"

A. The hydro system operation under current operating requirements is simulated over the 50-historic water conditions from August 1928 through July 1978 using the hydro regulation simulation model HydroSim. HydroSim produces a monthly estimate of hydro energy production that could reasonably be expected from the hydropower system over a wide range of runoff conditions. The Federal hydro generation estimates under 50-water conditions are used as inputs to the Risk Analysis Study, WP-07-E-BPA-04, that estimates revenues and risks associated with various load, resources, and rate scenarios. The Federal hydro generation estimates under 50-water conditions are presented in the Risk Analysis Documentation, Tables 4 through 6, WP-07-E-BPA-04A.

Q. Please explain why BPA uses a 50-year hydro regulation study in the Study.

A. BPA uses the 50-year hydro regulation study because it is a historically prudent and reasonable way to forecast the expected operations of the regulated hydro projects for varying hydro conditions. BPA's Federal system resource stack is comprised of about 80 percent of hydro generation that can vary annually by up to 5,000 aMW. Depending on water conditions, Federal hydro generation estimates for FY 2007 annually range from 6,800 aMW to 11,800 aMW. BPA uses the HydroSim regulation simulation model to estimate regulated hydro project generation for varying water conditions, which takes into account specific flows, volumes of water, elevations at dams, biological opinions, and many other aspects of the hydro system.

One such input to the HydroSim model is the January through July runoff volume forecast. This Study incorporates the January through July volume runoff forecast estimates for 50-historical water conditions, August 1929 through July 1978. These volume runoff forecasts were produced using methods provided by the Kuehl/Moffitt analysis that developed synthetic hydro flows that were based on water conditions and forecasted volume runoffs for the Columbia River Basin. This allowed HydroSim to utilize the relationship between the January through July volume runoff forecast and monthly shape changes throughout the operating year. By using the volume runoff forecast, HydroSim provides regulated hydro generation estimates that reflect the actual operation characteristics of the mainstem Columbia River Basin system. The U.S. Army Corps of Engineers (COE) and River Forecast Center (RFC), not BPA, have oversight over the production of the volume runoff forecast which currently uses 50-water years (August 1928 through July 1978).

Additionally, BPA has generation estimates for other hydro projects that are based on 50-historical water conditions, 1929 through 1978. These projects are called "independent hydro" projects because their operations are not regulated in the HydroSim model and they have much less storage capability than those hydro projects in the Columbia River Basin. The independent hydro projects usually have generation estimates for each of the 50-water years of record. Most of the hydro projects are not

Federally-owned and must be updated with the cooperation of each project owner. Some independent hydro project data was expanded to include the project's median generation for additional water conditions. However, not all projects have updates; hence, BPA is unable to include additional water conditions for those projects.

Section 7. Federal System Generating Resources

Q. What Federal regulated and independent hydro generation is included in the Study?

A. The generation from the Federal system regulated and independent hydro projects is set by the hydro regulation study using the HydroSim model. HydroSim produces monthly energy generation estimates by project, incorporating August 1928 through July 1978 water years. Due to the monthly span of an operating year[2] (OY), it is termed as 1929 through 1978 water years and is called the 50 water years of record. The Federal system regulated hydro generation includes estimated generation increases due to capital improvements at specific Federal system projects. Both the Federal regulated and independent hydro resources are presented in FY format to be consistent within this Study. The detailed monthly energy, in aMW for each hydro project, is shown in the Load Resource Documentation, WP-07-E-BPA-01A, Section 2.4, Table A-3, *Federal Regulated Hydro Projects,* and Table A-4, *Federal Independent Hydro Projects*. The summarized HLH/LLH split of the regulated and independent hydro is presented in the Risk Analysis Study, WP-07-E-BPA-04.

Q. What other Federal generation besides regulated and independent hydro are included in the Study?

A. In addition to the generation from the Federal system regulated and independent hydro projects, this Study includes the output of several generation projects contracted for or assigned to BPA. These resources are inputs to the Risk Analysis Study, WP-07-E-BPA-

[2] Operating Year (OY) is the 12-month period August 1 through July 31. For example OY 2007 is August 1, 2006, through July 31, 2007.

04, and are presented as monthly energy in aMW as well as HLH MWh and LLH MWh. These projects include the following resources:

1) Small hydro (Elwah and Glines Hydro through September 30, 2009, and Dworshak/Clearwater Small Hydropower), wind (shares of Foote Creek 1, 2, and 4 wind projects; Stateline wind project; Condon wind project; Nine Canyon wind project; and Klondike Phase 1 wind project), geothermal (100 percent of Fourmile Hill Geothermal Project expected to begin October 1, 2008), and a small amount of solar resources (Ashland solar project and White Bluffs solar). *See* Load Resource Documentation, WP-07-E-BPA-01A, Sections 2.4.through 2.6, Table A-23, *Federal Non-Utility Generating Resources by Project*;
2) The gas-fired Georgia-Pacific (Wauna) (formally James River Wauna) project. *See,* Load Resource Documentation, WP-07-E-BPA-01A, Sections 2.4.through 2.6, Table A-8, *Federal Renewable Resources*; and
3) The generation from the Columbia Generating Station. *See* Load Resource Documentation, WP-07-E-BPA-01A, Sections 2.4 through 2.6, Table A-10, *Federal Large Thermal*.

The Non-Utility Generation and Renewable Resources generation estimates are provided by BPA, using actual project output data or estimates provided by the project owner. The generation estimates for the Columbia Generating Station nuclear power plant are provided by Energy Northwest, Inc.

Q. How are improvements to the Federal system hydro resource generation treated in the Study?

A. The Study includes expected increases in hydro generation for specific Federal regulated hydro projects resulting from BPA's capital improvements programs. These improvements are expected to increase and preserve Federal hydro generation by: (1) replacing turbine runners to preserve and increase hydro generation and to make the turbine operation more fish friendly; (2) providing increased reliability by decreasing forced and planned outages; and (3) implementing hydro system optimization and operational planning tools to increase generation efficiency. These improvements are estimated by regulated hydro project and vary by FY and water conditions; and are included in that project's generation estimate. Using 1937 water conditions, generation increases are expected to yield as much as 79 aMW in FY 2007, increasing to 98 aMW by FY 2009. *See,* Documentation of the WP-07-E-BPA-01A, Section 2.3, Table A-3 *Federal Regulated Hydro Projects*.

Section 8. Treatment of Federal System Contracts

Q. Please describe how BPA treats Federal system contract obligations and contract purchases in the Study.

A. BPA's power sales contract obligations, other signed contract obligations, and contract purchases are considered firm and are assumed to be met regardless of weather, water, or economic conditions. These contracts are categorized as: (1) power sales contract obligations; (2) power or exchange contracts; (3) capacity or capacity-for-energy exchange contracts; (4) power payments for services; and (5) power commitments under international treaty.

BPA's power sales contract and other contract obligations are summarized monthly, for energy in aMW in the Load Resource Documentation, WP-07-E-BPA-01A, Section 2.3, Tables 2.3.1 through 2.3.3, *Loads and Resources-Federal System, (2002 PSC Sales)*, *(Slice Sales)*, *(Exports)*, and *(Intra-Regional Transfers (Out))*. These contracts are detailed monthly, for energy in aMW, HLH MWh, and LLH MWh in the Load Resource Documentation, WP-07-E-BPA-01A, Sections 2.4 through 2.6, Table A-2, *Exports*, Table A-16, *Intra-Regional Transfers (Out)*, and Table A-22, *BPA Power Sales Contracts* for the rate period.

BPA's expected contract purchases are summarized monthly, for energy in aMW, in the Load Resource Documentation, WP-07-E-BPA-01A, Section 2.3, Tables 2.3.1 through 2.3.3, *Loads and Resources-Federal System*., (*Imports)*, *(Non-Federal Canadian Entitlement Return for Canada)*, and *(Intra-Regional Transfers (In))*. The monthly energy in aMW, HLH MWh, and LLH MWh is detailed in the Load Resource Documentation, WP-07-E-BPA-01A, Sections 2.4 through 2.6, Table A-5, *Imports*, Table A-15, *Canadian Entitlement for Canada*, and Table A-16, *Intra-Regional Transfers (In)*. In addition, the Study assumes additional power purchases for the Federal system to meet forecasted firm annual energy deficits in FY 2008 and FY 2009. Under the Inventory Solution outlined in the Slice costing table in the Slice Contract, these additional purchases are considered firm Federal resources to augment the resource stack in order to meet deficits under 1937 water conditions. These augmentation purchases are shown in the Load Resource Documentation, WP-07-E-BPA-01A, Section 2.3, Tables 2.3.1 through 2.3.3, *Loads and Resources-Federal System*, *(Augmentation Purchases)*. The power sales contract obligations, other signed contract obligations, and contract purchases data is provided to the Risk Analysis Study, WP-07-E-BPA-04.

Q. Please describe how BPA's surplus firm power contracts with Pacific Southwest (PSW) utilities were treated in the Study.

A. This analysis includes several contracts with the PSW utilities that contain power sales and capacity-for-energy exchange agreements. This Study assumes the contracts with the cities of Burbank, Glendale, and Pasadena are capacity-for-energy exchange agreements throughout the study horizon. The power sale and capacity-for-energy exchange agreement with Southern California Edison (SCE) were terminated January 10, 2002, and is not included in the Study. *See,* Load Resource Documentation, WP-07-E-BPA-01A, Sections 2.4 through 2.6, Table A-2, *Exports*.

Q. Please describe how BPA treats augmentation purchase contracts in the Study.

A. This analysis includes both signed and projected augmentation purchases to meet annual firm Federal system energy needs. BPA has executed some augmentation purchase contracts with various customers that extend through December 31, 2006, and are included in FY 2007 of this Study. For FY 2007, these proprietary contracts total 106 annual aMW and are included in the Load Resource Documentation, WP-07-E-BPA-01A, Sections 2.4 through 2.6. Table A-16, I*ntra-Regional Transfers (In)*, *Other Entities to BPA*. The projected annual Federal system load resource balance for FY 2008 and 2009 requires augmentation purchases to meet forecasted annual firm energy deficits. For FY 2008, the annual augmentation purchase is estimated to be 38 aMW and 92 aMW for FY 2009. These purchase projections are considered firm Federal system resources to augment the Federal resource stack under the Inventory Solution to meet Federal system firm deficits, under 1937 water conditions, as outlined in the Slice costing table under the Slice Contract. These augmentation purchase projections are assumed to be purchased flat and are summarized below in Table 8-1. The augmentation purchases are shown monthly, for energy in aMW in the Load Resource Documentation, WP-07-E-BPA-01A, Section 2.3, Tables 2.3.1 through 2.3.3, *Loads and Resources-Federal System*, *(Augmentation Purchases)*.

Table 8-1

Projected Federal System Augmentation Purchase
FY Annual Energy in Average Megawatts

Energy in aMW	2007	2008	2009
Augmentation Purchase	106	38	92

The monthly energy of these contracts for energy in aMW, HLH MWh, and LLH MWh, are inputs to the Risk Analysis Study, WP-07-E-BPA-04.

Section 9. Federal System Transmission Losses

Q. Please describe BPA's treatment of Federal system transmission losses in the Study.

A. Federal system transmission loss estimates are treated as generation reductions in the Study. The transmission losses are calculated as 2.82 percent of the energy output of all Federal system hydro, small and large thermal, renewable, non-utility generation resources, and contract purchases. This reduction allows transmission losses to be calculated monthly and to vary by water conditions. BPA's Transmission Business Line (TBL) provided the analysis of expected Federal system transmission loss factors for energy and peak load conditions. The Federal system transmission loss factors used in this Study were developed in 1992 and reaffirmed by TBL in 1994. These studies concluded the Federal system loss factors for BPA's transmission system are 2.82 percent for energy and 3.35 percent peak when averaged over the year.

The loss factors have several components that combine to give the estimate of losses typically associated with Federal system generation, step-up transformers to the high voltage transmission network, high voltage network distribution, transfers through adjacent networks, and step-down transformers to BPA customer meters. The estimated magnitude of those loss factor components for energy is as follows:

1) Step-up transformers between the Federal generation and the transmission network of 0.31 percent;
2) Network loss factor of 1.90 percent;
3) Some loads are transfer customers, which have additional losses crossing other transmission networks averaging 0.34 percent; and
4) Some loads have step-down transformer losses of 0.27 percent.

These assumed loss factors for load delivery to BPA customer have not changed since 1992.

The Federal system surplus energy availability reflects Federal system transmission losses that vary by water conditions and is consistent with the Risk Analysis Study, WP-07-E-BPA-04. *See,* Load Resource Documentation, WP-07-E-BPA-01A, Section 2.3, Tables 2.3.1 through 2.3.3, *Loads and Resources-Federal System*, *(Federal Transmission Losses)*.

Section 10. PNW Total Regional Hydro Resources for the Market Price Forecast Study

Q. Please describe the treatment of the regional hydro resources used in the Study.

A. To provide an additional input for the secondary revenue analysis used in the Market Price Forecast Study, WP-07-E-BPA-03A, the Load Resource Study also developed a PNW total regional hydro resource stack for FY 2007 through 2009. The regional hydro resources include all regional regulated and independent hydro projects, plus regional non-utility generation (NUG) hydro projects. BPA estimates the regional hydro generation energy by month for each of the 50 water years of record (August 1929 through July 1978) using the hydro regulation study developed for this Study. The hydro data is then formatted to FY format to be consistent with the Study. The generation estimates for the set of NUG hydro projects are not produced in the hydro regulation study; the individual NUG project owners provide these estimates. The total regulated, independent, and NUG regional hydro projections are summarized for 50 water years for FY 2007 through 2009 in the Load Resource Documentation, WP-07-E-BPA-01A, Section 2.7, Tables 2.7.1 through 2.7.3, *Pacific Northwest Regional Hydro Resources*. These estimates are provided to the Market Price Forecast Study, WP-07-E-BPA-03.

Q. Does this conclude your testimony?

A. Yes.

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TESTIMONY OF

RONALD J. HOMENICK, DANA M. JENSEN, AND DAVID M. STEELE

Witnesses for Bonneville Power Administration

SUBJECT: REVENUE REQUIREMENT STUDY

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TESTIMONY OF

RONALD J. HOMENICK, DANA M. JENSEN, DAVID M. STEELE

Witnesses for Bonneville Power Administration

SUBJECT: REVENUE REQUIREMENT STUDY

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

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

A. My name is Dana M. Jensen and my qualifications are contained in WP-07-Q-BPA-19.

A. My name is David M. Steele and my qualifications are contained in WP-07-Q-BPA-49.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor the development of the generation revenue requirement study used to establish power rates for fiscal years (FY) 2007-2009 (Rate Test Period). This testimony also sponsors the Revenue Requirement Study, WP-07-E-BPA-02, and the Revenue Requirement Study Documentation, Volume1, WP-07-E-BPA-02A and Volume 2, WP-07-E-BPA-02B.

Q. How is your testimony organized?

A. Our testimony is organized in five sections. Section 1 is the introduction and purpose of the testimony. Section 2 addresses changes to program spending levels used in the revenue requirement. Section 3 describes the Debt Optimization (DO) program and its impact on Federal and non-Federal debt service. Section 4 outlines technical changes in the repayment study. Section 5 identifies modifications and adjustments that may be included in the final proposal.

Section 2. Generation Revenue Requirement

Q. Have any changes been made to the way Bonneville Power Administration (BPA) determines the generation revenue requirements since the WP-02 rate proceeding?

A. No. BPA is using the same methodology to determine the generation revenue requirements as it used in the WP-02 rate proceeding and prior proceedings since 1987. The basis for the revenue requirements is the total accrued expenses projected for each year of the rate period, displayed in an income statement. In addition, a cash flow statement is used to determine whether additional net revenues are required to cover the amortization payments scheduled by the repayment study and the cash required for risk mitigation. *See,* Study, Chapter 1.1, WP-07-E-BPA-02. The only change that has occurred is to the categories by which the expenses are displayed. The line items in the operating expenses on the income statement have been reconstituted to reflect BPA's current standard financial report format. *See,* Study, Chapter 4.1, WP-07-E-BPA-02 for descriptions of the contents in the line items.

Q: Are there any new cost components in this reconstituted display?

A: No. However, there were two changes pertaining to the investments in the FCRPS since the WP-02 rate proceeding that effect certain categories. In 2001, Reclamation's Green Springs (Rogue River Irrigation Project) project in southern Oregon, with investment of $11.2 million, was added to the FCRPS. BPA's total irrigation assistance obligation was increased by $9.9 million for this project. Also in that year, Reclamation completed an examination of project purposes at the Columbia Basin project that resulted in a reallocation to power of plant previously associated with irrigation (directly as irrigation or indirectly as common plant). As a result, the investments at the project for which power rates are responsible and BPA's irrigation assistance obligation were adjusted in accordance with the reallocation report. These investment changes are incorporated in the depreciation calculations for revenue requirements and in the outstanding repayable obligations and irrigation assistance in the generation repayment study. This analysis also changed the allocation of the power purpose of the Columbia Basin project operations and maintenance costs from 69.9 percent to 92.1 percent. *See,* Documentation, Chapter 9, WP-07-E-BPA-02A for a description of BPA's current irrigation assistance obligations.

Q. How did BPA develop the forecast of program spending levels and capital investments used in the generation revenue requirement?

A. BPA developed the program spending levels in the generation revenue requirement during the Power Function Review (PFR). In January 2005, BPA initiated the PFR with BPA customers and constituents to examine the Power Business Line's (PBL) finances and determine the cost projections to be used in the WP-07 rate case. The PFR focused on nine major cost areas including Army Corps of Engineers and Bureau of Reclamation operation and maintenance costs and capital investments, Columbia Generating Station operation and maintenance costs and capital investments, transmission acquisition costs, fish and wildlife program expenses and capital investments, internal operations costs charged to power rates, conservation program costs, renewable program costs, Federal and Non-Federal debt service and debt management, and risk mitigation packages and tools.

On June 24, 2005, after the close of the public process, BPA issued a final report that spelled out the forecast of program level expenses and capital investments to be used in the WP-07 Initial Proposal.

Q. Has BPA's forecast of program spending levels changed since the end of the PFR?

A. Yes. In the PFR Final Report, BPA identified specific cost categories that would likely change prior to the initial proposal. *See,* Study, Appendix A, WP-07-E-BPA-02. Program spending levels for these cost categories have changed. However, most of the categories described in the PFR Final Report have not changed and the estimates contained in the PFR Final Report are reflected in the generation revenue requirement.

Q. Please describe the changes to the program spending levels.

A. A change was made in the category entitled "Other Income, Expenses, and Adjustments," which includes the forecast of benefits paid to the Direct Service Industrial customers (DSIs). In the PFR, BPA included a forecast of $40 million annually in service benefits to the DSIs. During that process, BPA informed parties that the $40 million forecast would be revised to reflect the decision in an upcoming record of decision (ROD) on the level of DSI benefits. On June 30, 2005, BPA issued the *Bonneville Power Administration's Service to Direct Service Industrial (DSI) Customers for Fiscal Years 2007-2011 Administrator's Record of Decision* that established that service benefits to the aluminum DSIs would be capped at a maximum of $59 million annually. *See,* Gustafson, *et al.,* WP-07-E-BPA-17, for additional details on the DSI ROD. The forecast in this proposal is $59 million annually which reflects that decision.

BPA also modified the IOU REP Settlement benefits forecast to properly reflect the different components of that cost category. This modification re-categorizes $23 million of the PFR total of $323 million as augmentation costs rather than IOU REP Settlement benefits. This change reflects the *Proposed Contracts or Amendments to Existing Contracts with the Regional Investor-Owned Utilities Regarding the Payment of Residential and Small-Farm Consumer Benefits under the Residential Exchange Program Settlement Agreements FY 2007-2011 Administrator's Record of Decision* (May 25, 2004) in which the proposed contracts with Puget Sound Energy and PacifiCorp modified the $200 million reduction-of–risk discount contained in their Conditional Deferral Agreements. *See,* Petty, *et al*., WP-07-E-BPA-11. BPA added $1 million, which had been inadvertently left out of the PFR final report, to the remaining IOU Settlement balance to reflect the interest expense on deferred settlement costs.

Two other categories, short-term power purchases and transmission acquisition/ancillary services, have been updated, and will potentially change again for the final proposal, because they are based on the load/resource balance and secondary sales forecast used in the initial proposal. These items are dynamic variables that are an outcome from loads and sales and change accordingly during the rate development process if those assumptions change.

Q. *Has BPA's forecast of capital investments changed since the end of the PFR?*

A. No. The forecast of capital investments has not changed since the PFR. However, as was explained in the PFR final report, depreciation and amortization have been recalculated and repayment studies have been rerun to produce the planned amortization payments and resulting gross Federal interest expense using the projected capital spending levels decided on in the PFR. The repayment studies and the revenue requirement also reflect other decisions BPA has made related to Federal and non-Federal debt and debt management.

Q. *What other decisions has BPA made regarding capital investments?*

A. BPA and Energy Northwest (EN) decided to use debt financing for new Columbia Generating Station (CGS) capital investments during the rate period. This decision is reflected in the Energy Northwest debt service. In addition, the revenue requirement reflects a decision to amortize conservation acquisition investments beginning in 2007 over a five-year period. *See,* Leathley, *et al.*, WP-07-E-BPA-08.

Section 3. Debt Optimization Program

Q. *Please describe the Debt Optimization Program.*

A. In FY 2001, BPA initiated the Debt Optimization (DO) Program in conjunction with EN as a means for BPA to replenish its limited Treasury borrowing authority. At the agency level, BPA manages its debt requirements -- Federal Treasury bonds and Congressional appropriations as well as non-Federal debt service payment requirements -- as a single portfolio. The basic mechanism of the DO program is that shortly before the principal of qualifying outstanding EN debt reaches its final maturity (due date), it is repaid with the proceeds of new EN debt that has a final maturity at a later date. The final maturity of the new EN principal is in the FY 2013-2018 period, which is currently the maximum allowable maturity of these particular obligations. The cash flows that otherwise would have been used to pay the principal of the refunded EN debt is used to repay an equivalent amount of Federal repayment obligations (bonds issued to the U.S. Treasury or Congressional appropriations), thereby restoring Treasury borrowing authority or providing opportunities for future restoration of borrowing authority for the agency.

Q. How has BPA applied cash flows made available by DO?

A. Since the maturing EN debt service was incurred contractually by BPA as a purchased power obligation that is recovered by power revenues, initially BPA used the cash flows made available by DO to repay an equivalent amount of generation-related Treasury obligations. This was done in a manner that would not increase the combined levelized Federal and non-Federal debt service in the generation repayment study. Essentially, DO repays Federal generation obligations in the current period in amounts that, absent DO, have been scheduled to be repaid during the FY 2013-2018 period, where the maturities of the refinanced EN debt have been set. To expand the capability to restore Treasury borrowing authority, BPA instituted the Debt Service Reassignment (DSR) concept.

Q. What is Debt Service Reassignment?

A. Beginning in FY 2003, annual cash flows from DO have been used to repay Treasury obligations associated with BPA's transmission function in addition to those associated with the generation function. The funds to repay the transmission Treasury obligations have been made available by cash flows resulting from the recognition that power rates have satisfied the cost recovery obligation for the extended EN principal payments. This relieves power rates from any further obligation to recover any annual EN debt service associated with a corresponding amount of extended EN principal. The recovery of that portion of the debt service for the refinanced EN debt is assigned to transmission to be recovered from transmission revenues.

Q. Has BPA reassigned the exact actual EN debt service to transmission for cost recovery?

A. No. The annual debt service assigned to transmission is derived from the actual EN debt service, but it also incorporates any additional costs associated with the EN bond refinancings such as issuance costs. Under BPA's DSR concept, the transmission function is responsible for the recovery of any and all relevant costs associated with the exchange of EN debt service for Federal obligations associated with transmission. As a result, BPA's generation function is held harmless. For BPA's PBL, it is as if the refinancing transactions related to DSR never took place. That is, power rates were set to recover the maturing EN principal payment as it came due and actual power revenues were available to do so. Therefore, the PBL's obligation to recover the maturing EN principal has been satisfied, which is reflected in actual PBL expenses as EN Debt Retirement.

Q. How is DO reflected in the initial proposal's generation revenue requirement?

A. The initial proposal revenue requirements and repayment studies do not include forecasts of debt optimization actions during the rate test period. However, a probabilistic estimate of the cash flow effect of DO actions in FY 2007 has been included in the risk analysis. *See,* Wagner, *et al.*, WP-07-E-BPA-13. The repayment studies do assume additional Federal amortization equivalent to the amounts of EN principal that have been extended through advance refundings of EN debt. BPA will update its revenue requirement assumptions regarding DO actions to reflect any changes that occur between the initial proposal and the final proposal.

Q. What is the impact of DO on the initial proposal revenue requirement?

A. Federal gross interest expense is lower than it otherwise would be as a result of the Federal obligations that have been repaid under DO. Conversely, EN debt service includes higher annual interest expense from the extended debt.

Q. What are these advance refundings mentioned above?

A. As part of BPA's DO program, in addition to refunding maturing EN bonds that come due on July 1 of each year, there are times when EN and BPA have refunded bonds in advance of the maturity or first call date by more than 90 days, and, in many cases by many years in advance of the first call. These actions are called "advance refundings." For example, when BPA and EN completed a refunding in FY 2002 (Series 2002-A), certain bonds were refunded that had original maturities falling in the years 2003-2011. When the advance refunding was completed in FY 2002, the maturities established for the new refinancing bonds were between FY 2013 and FY 2018 and the original bonds were "escrowed to maturity." This means that the proceeds of the refunding issue were deposited in an escrow account for investment in an amount sufficient to pay the principal and interest on the bonds being refunded until those bonds were legally able to be called.

Q. How are these advanced refundings reflected in the WP-07 Initial Proposal repayment studies?

A. A two-step process for conducting repayment studies was created to reflect the effects of DO actions involving advanced refunding of EN bonds. It demonstrates that BPA is repaying Federal principal dollar-for-dollar for the principal of the EN debt that has been extended through advance refundings, and that this is in addition to an amortization base that is the lowest level of amortization that satisfies repayment requirements. In the first step, BPA identifies a base level of Federal amortization that is determined as if the advanced refundings had not occurred. In this step, EN debt service that is reflected in the total non-Federal debt service in the study is restored to its level prior to the advanced refundings. The repayment model is then run to establish a base level Federal amortization schedule. In the second step, the advanced refunding actions are included in the total non-Federal debt service. The additional Federal amortization payments equivalent to the advance-refunded EN principal are added to the base level of Federal amortization identified in step one. The results of this study are incorporated in the revenue requirements for the rate test period.

Section 4. Technical Changes in Repayment Studies

Q. Have there been any changes affecting the repayment study model?

A. Yes. There have been two changes to the repayment model: a Bond Rollover feature has been added so that the model can better reflect actual debt management practices and the calculation of interest expense on forecasted appropriations has been modified to better reflect the timing of new appropriated repayment obligations.

Section 4.1 Bond Rollover Feature

Q. What is the Bond Rollover feature?

A. The Bond Rollover feature is a new capability associated with BPA's repayment model pertaining to actual short-term bond issuances. It allows the study to mirror BPA's actual practice of rolling over (refinancing) short-term bonds if BPA determines that it is impractical to pay such bonds when due or BPA determines, consistent with sound business practices, that market conditions justify refinancing the bonds within the allowable repayment period of the associated assets.

Q. Why was the Bond Rollover feature developed?

A. In conformance with Department of Energy repayment policy (RA 6120.2), BPA's repayment model determines the minimum revenue levels necessary to ensure repayment of all Federal investments in full and on time within the average service life of such investments or 50 years, whichever is less. In recent years, BPA has issued many short-term Treasury bonds in anticipation of their retirement with DO cash flows and to take advantage of the low interest rates available at the time of issue. The maturities of these bonds are considerably shorter than the average service lives of the associated assets. The normal operation of the repayment model would only recognize that these short-term bonds must be paid in full by their issued due dates. As a result, the repayment program would most likely establish repayment schedules that are artificially higher than if those bonds had repayment periods that were closer to the average service lives of the associated assets. The Bond Rollover feature was developed to respond to this situation.

Q. How does the Bond Rollover feature work?

A. The Bond Rollover feature allows the repayment program to recognize the original short-term bond and to reflect the interest expense associated with it until its maturity. Then the program recognizes that a replacement bond with an interest rate based on a new maturity date determined by the model operator has taken its place. The short-term bonds ultimately will be shown to be repaid by the repayment study, but at the optimum schedule determined by the program based on the longer repayment periods provided by the replacement bonds.

Section 4.2 Appropriations Interest

Q. What modification has been made to the calculation of interest on forecasted appropriations?

A. Previously, in accordance with RA 6120.2, the repayment model calculated six months of interest on projected bonds and appropriations in the year the bonds are projected to be issued and the appropriations are projected to be placed in service. In actual practice, appropriated plant for the FCRPS is not transferred to plant-in-service in the accounting records until the very end of the fiscal year. As such, interest does not begin to accrue on the repayment obligation on appropriations until the following fiscal year. To accurately reflect this practice, the model now begins interest calculations in the year after appropriated plant is projected to be placed in service.

Q. Have there been other changes to interest rate forecasts?

A. BPA's interest rate forecasts are based on the Global Insight CY 2005 First Quarter Long-Term Economic Outlook. The forecast now includes interest rate projections for tax-free municipal bonds and for Federal appropriations. The municipal bond forecast is used for non-Federal debt service calculations. The change to the calculation of appropriations interest described above uses the appropriations forecast. *See,* Documentation, Chapter 6, WP-07-E-BPA-02A.

Section 5. Final Proposal Modifications and Adjustments

Q. Are there changes that will affect the Revenue Requirement Study in the final rate proposal?

A. Yes. In the transmittal letter for the PFR Final Report, BPA committed to conducting a public process to review a few outstanding program cost changes. *See,* Study, Appendix A, WP-07-E-BPA-02. This process will be conducted in early 2006. Any program spending level changes resulting from this process will be incorporated in the final proposal. Capitalized contract debt service streams in repayment studies will be updated to reflect any new refinancings that are initiated in FY 2006. Federal amortization for FY 2006 will be adjusted to reflect DO actions initiated in that year. The repayment study database will be updated for all FY 2005 bond issuances and debt repayments and any FY 2006 actions completed prior to the Final Proposal. Depreciation forecasts will be updated to reflect all FY 2005 actual investments. FY 2006 ending reserve estimates will be updated for the Final Rate Proposal, which could affect such things as interest credit amounts, key risk modeling data assumptions, and probability results. The repayment study will also reflect any changes in non-Federal debt management assumptions. Any program cost changes due to additional cost reductions or increases, mandatory expenditures due to law or regulation, or policy initiatives will be updated in the final proposal.

Q. Are other changes possible in the final proposal?

A. Yes. Several actions may occur which could affect the revenue requirement. The plant-in-service forecast for the Columbia River Fish Mitigation project will be revised if the Corps of Engineers provides an updated forecast, although we do not anticipate other changes to capital investments. The irrigation assistance repayment schedule will be updated if the Bureau of Reclamation provides a revised schedule. If legislation including a settlement agreement with the Spokane Tribe is ratified by Congress, the associated costs will be incorporated into the revenue requirement. If BPA enters into a public exchange agreement or public exchange settlement with any public utilities, any associated costs will be incorporated. In addition, if the results of a judgment related to pending litigation or any agreement settling such litigation results in a financial impact on BPA, those revenue or cost changes will be included. Each of these changes could result in higher costs. In addition, BPA may update its interest rate forecasts which might raise or lower debt service costs.

BPA is also exploring several potential changes regarding Energy Northwest debt service, including extending existing debt to 2024, and/or issuing new debt for new capital with maturities out to 2024. Should BPA and EN make a decision to do this, EN capital financing forecasts will be revised to reflect this.

Q. Have any corrections been identified that should be made for the final proposal?

A. Yes. While finalizing the documentation, we discovered that the total debt service for the three EN projects is misstated. The total debt service includes outdated estimates of contingency fund costs that will be updated for the final proposal. Debt service also includes expenses for treasury service fees that average $2.6 million per year although a more recent projection is approximately $5 million. At the same time, $9.5 million per year had been added to the non-Federal debt service total in the revenue requirement on the belief that the total debt service did not include treasury service fees. The net effect on total EN debt service is estimated to be a decrease of less than $5 million per year. Staff will continue to research these issues. Corrections to EN debt service will be incorporated in the repayment study for the final proposal.

Q. What effect would these changes have in the Revenue Requirement Study?

A. These changes would be reflected in the income statements for the revenue requirements, statement of cash flows, the current revenue test, and the revised revenue test. It is anticipated that all of these changes should have a minimal effect on the revenue requirement for the rate period.

Q. Does that conclude your testimony?

A. Yes.

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TESTIMONY OF

ROBERT J. PETTY, ROBERT W. ANDERSON, ARNOLD L. WAGNER, AND RODNEY E. BOLING

Witnesses for Bonneville Power Administration

SUBJECT: MARKET PRICE FORECAST STUDY

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TESTIMONY OF

ROBERT J. PETTY, ROBERT W. ANDERSON, RODNEY E BOLING,

AND ARNOLD L. WAGNER

Witnesses for Bonneville Power Administration

SUBJECT: MARKET PRICE FORECAST STUDY

Section 1. Introduction and Purpose of Testimony

Q. Please state your name(s) and qualifications.

A. My name is Robert Petty and my qualifications are contained in WP-07-Q-BPA-44.

A. My name is Robert Anderson and my qualifications are contained in WP-07-Q-BPA-01.

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

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

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor the Market Price Forecast Study, (WP-07-E-BPA-03) and documentation (WP-07-E-BPA-03A) included in BPA's 2007 Initial Rate Proposal.

Q. How is your testimony organized?

A. This testimony contains six sections including this introductory section. Section 2 defines market prices and describes their relevance to BPA. Section 3 explains how and why the market price forecasts are used in the rate case. Section 4 describes the methodology used to estimate market prices. Section 5 describes the development of the market prices for the secondary revenue forecast and the risk analysis. Section 6 describes the IOU REP Settlement flat block price.

Section 2. Definition of Market prices

Q. What are market prices?

A. For the purposes of this testimony, market prices, market-clearing prices, and marginal cost are synonymous. Marginal cost is the additional cost of producing or acquiring an extra unit of a product or service. In economic theory, when supply and demand are in equilibrium the market price will equal the variable cost of the marginal unit of production. This is because producers will find it in their interest to add production as long as the price they can receive exceeds the marginal cost of production. For the electric energy market, this definition translates to the variable cost of the marginal generating unit, where the marginal generating unit is the last unit dispatched in least cost order to meet energy demand.

Q. Please define the specific quantities that you use to represent the marginal costs.

A. The market price, for purposes of this testimony, is equal to the hourly variable cost of the marginal resource for energy available at the Mid-Columbia trading hub. Equivalently, this value may also be referred to as the market-clearing price.

Q. Why is the market-clearing price relevant to BPA?

A. The marginal cost is used as an indication of a market-clearing price for hourly secondary energy transactions. Therefore, it is related to the cost that BPA could experience to purchase additional energy, or the price that BPA could realize in selling secondary energy. The actual cost BPA experiences for secondary power transactions may not be exactly equal to the hourly market-clearing price because BPA may buy or sell a different product than what is traded in an hourly market. In addition, BPA's secondary energy transactions may occur at a price not exactly set by the marginal resource in a particular hour. In either case, the hourly marginal cost is related to the market-clearing price for secondary energy and is therefore used as a starting point for the price that BPA will experience for hourly secondary energy transactions. Another use of the market price forecast is as a basis for sending price signals through BPA's rate design.

Section 3. Uses in the Rate Case

Q. Has BPA used AURORA in previous rate cases?

A. Yes. BPA used AURORA in the WP-02 and SN-03 rate proceedings.

Q. How is the Market Price Forecast used in the rate case analysis?

A. The market price forecasts are used for six purposes in the rate case. First, it is used in the calculation of Demand Rate. Second, it is used for shaping the base energy rates. Third it is used as a proxy for the IOU REP Settlement payments for fiscal years 2008 and 2009. Fourth, AURORA prices are also used for calculating the uncertainty around the IOU REP Settlement payments and the financial payments to the DSIs. Fifth, it is used to inform, but not to directly set, the price level at which BPA buys and sells in the secondary energy market (secondary revenue forecast). Sixth, it is used as a price input for the risk analysis. For a complete description of how the Demand Rate was calculated and how the base energy rates were shaped, *see* BPA's Wholesale Power Rate Development Study, WP-07-E-BPA-05. A description of the IOU REP Settlement Forward Block Price Forecast follows later in this testimony. For a complete description of the uncertainty surrounding payments to the DSIs and IOU REP Settlement payments, secondary revenue forecast, and the risk analysis *see,* the Risk Analysis Study WP-07-E-BPA-04, Sections 2.4.7 and 2.4.8.

Section 4. Estimation Methodology

Q. What technique is BPA using to forecast market prices?

A. BPA uses an electrical energy market model called AURORA which as been used in previous rate proceedings.

Q. Please briefly describe the theory behind AURORA's modeling technique.

A. AURORA models wholesale energy transactions in a competitive pricing system using an approach based on economic fundamentals. AURORA uses a demand forecast and supply cost information to find an hourly market clearing price, or equivalently, the marginal cost. To determine the market-clearing price in a given hour, AURORA models the dispatch of electric generating resources in a least-cost order to meet the load (demand) forecast. The price in the given hour is equal to the variable cost of the marginal resource. Over time, AURORA will add new resources and retire old resources based on the net present value of the resource. In this way, AURORA models the functioning of a perfectly competitive economic market system.

Q. *When was the natural gas forecast for the Initial Proposal prepared?*

A. The natural gas forecast was developed in early June of 2005. It is fully described in Section 3.3 in the Market Price Forecast Study, WP-07-E-BPA-03.

Q. *Will you update the natural gas forecast?*

A. BPA will review the forecast and assess the need for updating. If market conditions have changed significantly or if other factors argue persuasively for an update, BPA will update the forecast.

Q. *What do you assume regarding the values of this forecast relative to the distribution of expected future prices?*

A. BPA assumes this is a median forecast, meaning that there is a 50% probability that future gas prices may be either higher or lower than this forecast.

Section 5. Development of Price Forecasts for the Secondary Revenue Forecast and Risk Analysis.

Q. *Please explain the underlying assumptions used in the AURORA model.*

A. AURORA is a production cost model that uses the variable cost of the last marginal generating unit required to equalize supply and demand as a proxy for the future spot market price in a future hour. This price proxy is used as the single price for all power sold or purchased in a given hour. The assumptions underlying AURORA are that all power is marketed on an hourly basis, all sellers receive the same price, and the price is equal to the cost of the last kilowatt sold. This theoretical construct envisions a perfectly competitive hourly spot market with perfect price transparency.

Q. *Does BPA sell and purchase power in a perfectly competitive, transparent market with an hourly marginal clearing price?*

A. No. The market into which BPA sells secondary power and from which it purchases power is not a single-price, perfectly competitive market. It is a bilateral market without a single central exchange or central market-clearing mechanism. Prices are not perfectly transparent and buyers and sellers are not guaranteed the marginal price on every hour. Instead, prices are negotiated based on current or future expectations, marketing needs, and risk preferences as well as factors other than the production cost of the most expensive generation unit on line at the time. Rather than realizing the hourly marginal price during each hour, BPA's experience is that it receives prices for its secondary sales that more closely reflect the average value associated with the amount of energy BPA is displacing from the market through its surplus sales.

Q. *Has BPA taken any steps to reconcile the disparity between AURORA's theoretical construct and the market faced by BPA?*

A. Yes. As a result of the fundamental difference between the theoretical world of AURORA and the actual market in which BPA sells and purchases power, BPA concluded it was not appropriate to simply apply the output of AURORA without considering some adjustments. BPA therefore used a broader marginal band to approximate prices that BPA would receive for its secondary revenue.

Q. *What methodology was used to adjust the initial results of the AURORA model?*

A. In order to reflect the fact that BPA sells and purchases power in a bilateral market, BPA ran the AURORA model in a mode that decremented Pacific Northwest (PNW) loads by 2,500 aMW.

Q. *Why is decrementing PNW loads by 2,500 aMW a reasonable proxy for the type of prices BPA can be expected to earn in a bilateral market, as opposed to a single marginal price market?*

A. Under average water conditions, 2,500 aMW is approximately the amount of surplus energy that comes off the Federal Columbia River Power System (FCRPS) in a year. This surplus energy will be marketed in wide-ranging quantities from month-to-month and hour-to-hour. The production of this 2,500 aMW of surplus energy is transparent to the market because market participants observe publicly available hydroelectric forecasts, reservoir elevations, and fish-related operational decisions. Due to this transparency, seller and buyer expectations about the amount of surplus hydroelectric generation available for sale may alter the range of prices achieved in the market for the participants. As a result, BPA concluded that prices at the 2,500 aMW decrement point provide a good proxy for the prices BPA would receive for its surplus energy.

Q. Does decrementing load undermine the fundamental concept of marginal pricing?

A. No. The range of prices BPA receives in the market is still associated with marginal costs. The actual price BPA receives, however, cannot precisely be estimated by the variable cost of generating the last kWh sold. For example, the average generation in the Western Electric Coordinating Council (WECC) is about 90,000 aMW. A party selling approximately 2,500 aMW into this market would be doing well to receive prices reflecting the marginal 3 percent of generation it might displace in such a market.

Q. Is this the first time BPA has adjusted the AURORA output to develop its secondary revenue forecast?

A. No. In BPA's WP-02 rate case, BPA adjusted the AURORA prices in certain instances during the April, May, and June (Q2) timeframes.

Q. Why were these prices adjusted?

A. BPA observed that during periods of heavy Q2 surplus, the market will adjust its pricing behavior as it observes large volumes of hydro supply being produced that must be run through the system in response to spring flood control or other non-power requirements. Under these conditions, any party marketing "must run resources" likely would not receive the prices reflected in the AURORA marginal price output. In essence, buyers understand that parties marketing FCRPS output are in a condition where they must generate and sell surplus power, and such buyers are therefore likely to pay less for excess supply.

Q. Is the modification to the AURORA output proposed by BPA consistent with past rate-making practices?

A. Yes. In BPA's WP-02 rate case, AURORA was used to determine the price forecast for flat block forward markets as a means of determining the financial benefits BPA was proposing to offer regional IOUs on behalf of their residential and small farm loads. AURORA was run in much the same manner as it has been run for the current secondary revenue forecast. Loads were decremented by 1,800 aMW to derive a price at which either BPA or the IOUs could purchase a block of energy to serve the IOUs' residential loads. *See,* Oliver, *et al*., WP-02-E-BPA-20. Modifications were also made in the 2002 Supplemental Proposal, but in a somewhat different manner.

Q. Could you explain how AURORA was used in developing BPA's 2002 Supplemental Proposal?

A. Yes. In winter 2000/2001, the WECC market was experiencing a well documented, sustained price spike. The AURORA model was not able to produce the high prices that were being experienced in the market at that time. In order to more accurately reflect market realities, BPA had to use market prices derived from actual purchases and price quotes for fiscal years 2002 and 2003, and then revert to AURORA prices for fiscal years 2004-2006.

Q. Do you believe such modifications, including the one proposed in the current rate case, are appropriate for establishing BPA's rates now and in the future?

A. Yes. BPA has always applied professional judgment and experience to AURORA when estimating secondary revenues. As the market in the PNW and WECC changes, so does the market in which BPA sells and purchases power. BPA will continue to use AURORA or another production cost model as a starting point to estimate marginal prices. From that point, depending on current market design and BPA's experience marketing power at that time, BPA will apply its best judgment to evaluate how realistic it is to achieve the results produced by the model.

Section 6. IOU REP Settlement Forward Flat-Block Price Forecast

Q. What is the IOU REP Settlement Forward Flat-Block Price Forecast (FBPF)?

A. The FBPF is a contractually prescribed method to forecast forward price data for a flat block of firm power that currently would meet the requirements of Western Systems Power Pool Agreement Service Schedule C firm energy. The FBPF methodology is described in Exhibit C, "Determination of Forward Flat-Block Price Forecast for Contract Years 2007 through 2011," to the contracts and contract amendments between BPA and the six regional IOUs signed in May 2004 regarding payment of Residential Exchange Program (REP) settlement benefits for the fiscal years 2007 through 2011.

Q. What is the purpose of the FBPF?

A. The FBPF is an integral part of the formula that will be used to determined IOU Monetary Benefit payments during fiscal years 2007 through 2011. It establishes a procedure to determine the FBPF for each fiscal year.

Q. Please summarize the FBPF procedures.

A. One of the "big four" accounting firms, KPMG , LLP, has been retained as a Qualified Third Party (QTP). The QTP must have extensive expertise in the electric power industry, including auditing FAS 133 compliance and risk accounting. The QTP solicits, on a quarterly basis, forward price forecasts from Eligible Data Providers (EDP). An EDP "means an entity that (1) routinely buys and sells bulk power for resale in the Pacific Northwest; (2) routinely produces Forward Price Data for use in risk accounting in the normal course of business; (3) is regularly audited by an outside accounting firm; and (4) has been selected by an affirmative vote by each representative on the Committee "(See Exhibit C). The Committee is composed of one representative each from BPA, a participating IOU, and a PNW Public utility.

For each calendar quarter the QTP will randomly select six to eight EDPs to provide forward price forecasts for the quarter beginning 21 months hence. Forward price data are requested from each EDP for a date during the forecast quarter that is randomly selected by the QTP. The first quarter begins 21 months prior to fiscal year start, i.e., January 1 of the prior calendar year. The fourth quarter forecast ends nine months prior to fiscal year start. For the WP-07 rate period, each fiscal year FBPF will be known not later than January 1.

Q. How is the FBPF calculated?

A. Each quarterly forecast is the simple average of the six to eight forecasts provided by the selected EDPs after the high and low forecasts have been excluded. The fiscal year FBPF is the simple average of the four quarterly forecasts.

Q. How is forecasted FBPF, or related data, used in this WP-07 filing?

A. For fiscal year 2007, the price quotes from the EDPs for the first two quarters were averaged to determine the price which resulted in a price of $52.07/MWh. For fiscal years 2008 and 2009, the same AURORA price forecast in the calculation of the Demand Rate and shaping the base energy rates was used. These prices are $49.85/MWh for fiscal year 2008 and $45.84/MWh for fiscal year 2009.

Q. Will the REP IOU Settlement FBPF be updated for the final proposal?

A. Yes. By the time of the final proposal, the FBPF for fiscal year 2007 will be set and, if needed, the estimates for fiscal years 2008 and 2009 will be updated.

Q. Does this conclude your testimony?

A. Yes.

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SID CONGER, JR., RANDY B. RUSSELL, KENNETH J. MARKS, AND STEVE KERNS

Witnesses for Bonneville Power Administration

SUBJECT: RISK ANALYSIS

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Witnesses for Bonneville Power Administration

SUBJECT: RISK ANALYSIS

Section 1. Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

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

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

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

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

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

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

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

Q. What is the purpose of your testimony?

A: The purpose of this testimony is to describe BPA's assumptions used, and the analysis performed, to complete the risk analysis and subsequent risk mitigation package for the Initial Proposal for the FY 2007-2009 rate period, and to sponsor the Risk Analysis Study, WP-07-E-BPA-04, and Documentation, WP-07-E-BPA-04A.

Q. How is your testimony organized?

A. This testimony is organized into six sections including this introductory section. The second section discusses the Operational Risk Model. In Section 3, the testimony addresses Modeling Operating Risks. In Section 4, we discuss the development of the secondary energy revenue forecast. Section 5 addresses the Non-Operating Risks and the Non-Operating Risk Model (NORM). Section 6 addresses the Accrual-to-Cash (ATC) Adjustments.

Section 2. Operational Risk Model (RiskMod)

Q. Please briefly describe RiskMod.

A. RiskMod is an operational risk analysis model that estimates PBL net revenues under varying load, resource, natural gas price, forward market electricity price, transmission expense, and aluminum smelter benefit payment conditions. RiskMod is comprised of a set of risk simulation models, collectively referred to as RiskSim; a set of computer programs that manages data referred to as Data Manage; and RevSim, a model that calculates net revenues (revenues less expenses). *See,* Risk Analysis Study and Documentation, WP-07-E-BPA-04 and WP-07-E-BPA-04A.

Q. What risks are reflected in RiskMod?

A. Operating risks reflected in RiskMod are the following:

- Federal Hydro Generation
- PNW Hydro Generation
- PNW Loads
- BPA Loads
- California Hydro Generation
- California Loads
- Natural Gas Prices
- Columbia Generation Station (CGS) Nuclear Plant Generation
- DSI Benefits
- Wind Project Generation
- PBL Transmission and Ancillary Services Expense
- Forward Market Electricity Prices
- 4(h)(10)(C) credit

Also, while not quantified in RiskMod, RiskMod supports the quantification of the following operating risks:

- IOU Benefits
- Spot Market Electricity Prices

Q. What are the risk simulation models (RiskSim) used in this Risk Analysis Study?

A. The risk simulation models are the following:

- PNW Load Risk Model
- California Load Risk Model
- Natural Gas Price Risk Model
- CGS Nuclear Plant Risk Model
- DSI Benefit Risk Model
- Wind Generation Risk Models
- Transmission Expense Risk Model
- Forward Market Price Risk Model

Q. With which studies, processes, and models does the Risk Analysis Study interact?

A. The Risk Analysis Study interacts with the Rate Analysis Model (RAM 2007), ToolKit Model, AURORA, the Revenue Forecast Study, and the Revenue Requirement Study.

Q. There is an iterative process between the RAM, RiskMod, and ToolKit when developing rates. Please describe this process.

A. In order to calculate Treasury Payment Probability (TPP) there is an iterative loop that must take place between the RAM, RiskMod and ToolKit. This process involves providing average annual surplus revenues, power purchase expenses, and 4(h)10(C) credits from the RiskMod to the RAM. The RAM, in turn, provides RiskMod with a set rates and expenses. Based on the information from the RAM, RiskMod estimates net revenue risk. These results are provided to the ToolKit, which then calculates Planned Net Revenues for Risk (PNRR) for a specific TPP. *See,* WP-07-E-BPA-14 for a discussion regarding TPP. The PNRR from the ToolKit is included in the Revenue Requirement used to calculate rates in the RAM. This process is iteratively performed until the specified TPP is reached. *See,* Graph 1, Risk Analysis Study, WP-07-E-BPA-04.

Section 3. Risk Modeling

Federal Hydro Generation

Q. What does Federal hydro generation risk account for in the Risk Analysis Study?

A. Federal hydro generation risk is incorporated into RiskMod to account for the impact that various Federal hydro generation levels and Heavy Load Hour (HLH) and Light Load Hour (LLH) hydro generation shaping capability have on the quantity of energy that BPA has to buy and sell during HLH and LLH periods. This risk, coupled with price risk, is the largest risk PBL faces.

Q. Please briefly describe how this risk is modeled.

A. BPA randomly selects, by water year, monthly Federal hydro generation data and the associated HLH hydro generation ratios reported in output tables for the 50 historical water years. *See,* Tables 4-9 in the Risk Analysis Study Documentation, WP-07-E-BPA-04A. These output data are from a "continuous study" performed by the HydroSim model and the Hourly Operating and Scheduling Simulator (HOSS) model where hydro generation is calculated sequentially over all 600 months of the 50 water year period. *See,* Load Resource Study, WP-07-E-BPA-01, regarding a continuous study by HydroSim. After an initial water year is selected for the first year of the rate period (FY 2007) for a given simulation, hydro generation data for a sequential set of three water years, starting with the water year selected for FY 2007, are selected from water years 1929-1978. When the end of the 50 water years is reached (at the end of water year 1978), monthly hydro generation data for water year 1929 is subsequently used. Additional hydro generation adjustments were made to each year of the 50 water year data from the continuous study for FYs 2007-2009 to reflect the refilling of non-treaty storage in Canada and to reconcile differences between the HydroSim study for FY 2006 and the HydroSim study for FY 2007.

Q. *Why did BPA select Federal hydro generation data in a continuous manner?*

A. Selecting hydro generation data in such a continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 50 water year period.

Q. *When BPA randomly selects the water year for the first year of the rate period for Federal hydro generation, it does so based on values sampled from a uniform probability distribution. Why did BPA sample from this probability distribution?*

A. The uniform probability distribution was selected for modeling hydro generation risk because it appropriately assigns equal probability to each of the 50 water years being sampled.

Q. *When the end of the 50 water years is reached (at the end of water year 1978), why did BPA sequentially use monthly Federal hydro generation data for water year 1929?*

A. BPA starts over with water year 1929 so that all water years are equally represented in the 3 year water sequences.

Q. *In the May 2000 Power Rate Proposal, a single 50 water year hydro generation table was used for each of the fiscal years in the rate period. Why is a separate table used for each fiscal year in this Initial Proposal?*

A. Since the May 2000 Power Rate Proposal, RiskMod has been modified to accommodate a separate hydro generation table for each fiscal year in the study. This added capability allows RiskMod to consider changes in hydro system operating requirements between fiscal years.

Q. *Are there any adjustments to the 50 water year tables to account for refilling non-treaty storage and if so, what is non-treaty storage?*

A. Yes. Under the Columbia River Treaty, Canada was required to construct 15.5 million acre-feet (MAF) of storage at the Mica, Arrow, and Duncan projects. The United States was allowed to construct 5 MAF of storage at Libby Dam. BC Hydro also built storage on the Columbia River system beyond what was required by the Treaty (termed non-treaty storage), including storage behind Revelstoke Dam and an additional 5 MAF of usable storage at Mica. On occasion, BC Hydro has also made available 2 feet (0.26 MAF) of storage in Arrow above the normal full elevation of the Arrow reservoir.

Q. What is the Non-Treaty Storage Agreement (NTSA)?

A. In order to operate existing non-treaty space in Canada and to change the flows into the United States, additional agreements were required. A long-term agreement to operate non-treaty storage in Canada was signed in 1990, along with companion agreements with some mid-Columbia project participants. The 1990 Non-Treaty Storage Agreement (NTSA) is an agreement between BPA and BC Hydro that allows operation of some non-treaty storage in Canada, the most significant of which is 4.5 MAF of space in Mica (2.25 MAF for BPA [U.S. parties] and 2.25 MAF for BC Hydro) known as "Active Storage Space."

Q. What circumstances brought about the need for the U.S. to refill non-treaty storage?

A. The NTSA had an initial termination date of June 30, 2003. A one-year extension of that agreement resulted in initial termination on June 30, 2004. The initial termination date is the date when parties are no longer able to release water from non-treaty storage space and the 7-year refill period is initiated. When agreements were first negotiated for operation of non-treaty storage space, the Active Storage Space was full. Under terms of the agreement, the space must be refilled no later than 7 years after the initial termination date (June 30, 2011).

Q. How does BPA reconcile the difference between FY 2006 and FY 2007 hydro regulation studies?

A. To reconcile the difference between the September ending storage content in the FY 2006 study and the October beginning storage content in the FY 2007 study, generation adjustments were applied to the hydro generation table for FY 2007. These generation adjustments for FY 2007 represent expected changes in hydro generation that would occur if the starting content of the FY 2007 study were consistent with the ending content of the FY 2006 study for the above mentioned Canadian projects. A separate adjustment was made for each water year in the 50 water year historical record used in this study. The FY 2006 study includes assumptions regarding Canadian operations in August and September of 2006, which are different than what was assumed in the 2007 study. The result is that the ending storage contents for the Canadian projects, specifically Mica, Arrow, Duncan, and Kootenay, are different at the end of September 2006 than what was assumed in the FY 2007 study. The FY 2006 study was done after the FY 2007 study was completed. BPA made these adjustments rather than redoing the FY 2007 study.

Pacific Northwest (PNW) Hydro Generation

Q. What does PNW hydro generation risk cover in the Risk Analysis Study?

A. PNW hydro generation risk accounts for the impact that various PNW hydro generation levels have on monthly HLH and LLH spot market electricity prices estimated by AURORA.

Q. Please briefly describe how this risk is modeled.

A. BPA randomly selects, by water year, monthly PNW hydro generation data reported in output tables for the 50 water years. *See,* Tables 1-3 in the Risk Analysis Study Documentation, WP-07-E-BPA-04A. These output data are from a "continuous study" performed by the HydroSim model where hydro generation is calculated sequentially over all 600 months of the 50 water year period. *See,* Load Resource Study, WP-07-E-BPA-01, regarding a continuous study by HydroSim. After an initial water year is selected for the first year of the rate period (FY 2007) for a given simulation, hydro generation data for a sequential set of three water years, starting with the water year selected for FY 2007, are selected from water years 1929-1978. When the end of the 50 water years is reached (at the end of water year 1978), monthly hydro generation data for water year 1929 is subsequently used.

Q. Why did BPA select PNW hydro generation data in a continuous manner?

A. Selecting hydro generation data in such a continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 50 water year period.

Q. How does BPA align Federal and PNW hydro generation simulations?

A. When BPA selects the water year for the first year of the rate period for PNW hydro generation, it uses the same value sampled from a uniform probability distribution for Federal hydro generation.

Q. When the end of the 50 water years is reached (at the end of water year 1978), why did BPA sequentially use monthly PNW hydro generation data for water year 1929?

A. BPA starts over with water year 1929 so that all water years are equally represented in the 3 year water sequences.

PNW and BPA Load

Q. What does PNW and BPA load risk account for in the Risk Analysis Study?

A. PNW load risk is incorporated into the Risk Analysis Study because PNW load variability affects monthly HLH and LLH spot market electricity prices. These price impacts in turn affect PBL's surplus energy revenues and power purchase expenses. BPA load risk is incorporated into the Risk Analysis Study to account for the impact that monthly PF load variability has on Priority Firm Power (PF) revenues, surplus energy revenues, and power purchase expenses.

Q. Please describe how PNW and BPA load risk are modeled.

A. PNW (and indirectly BPA) load variability is modeled in the PNW Load Risk Model such that annual load growth variability and monthly load swings due to weather conditions are both accounted for in one PNW load variability factor. BPA monthly load variability is derived such that the same percentage changes in PNW loads are used to quantify BPA load variability. Annual PNW (and indirectly BPA) load growth risk is modeled to simulate various load patterns through time using a mean-reverting, random-walk technique.

Q. Please describe the mean-reverting, random-walk technique used in this analysis.

A. The random-walk technique simulates various annual average load levels through time with the starting point for simulating annual average load in a given year being the annual average load level from the previous year. The mean-reverting technique causes simulated annual loads to tend to revert to the forecasted loads as loads move further from forecasted loads (either higher or lower). *See,* Risk Analysis Study Documentation, WP-07-E-BPA-04A.

Q. What load data did BPA use to calculate the annual load growth deviations for the PNW?

A. BPA used Western Electricity Coordinating Council (WECC) load data for the Northwest Power Pool Area from 1982-2004 to calculate the annual load growth deviations for the PNW. *See,* Table 14, Risk Analysis Documentation, WP 07-E-BPA-04A. BPA used the WECC data because it is the recognized source of load data for the western United States for load data.

Q. Please describe how the variability in monthly loads due to weather conditions was derived.

A. PNW (and indirectly BPA) monthly load swings due to weather conditions were derived from estimates of daily load standard deviation values for each of the 12 months. The source of these estimates was the 1996 Rate Case Marginal Cost Analysis Study Documentation, WP-96-FS-BPA-04A.

Q. *How are monthly load standard deviations for weather conditions derived from daily load standard deviations in the Risk Analysis Study?*

A. Calculating monthly load standard deviations from historical load data by sorting historical load data for the same month (over a period of years) yields load standard deviations that include both the impact of load growth and weather conditions. In the Risk Analysis Study, BPA is explicitly modeling load growth. Accordingly, BPA developed this methodology to estimate monthly load variability due to weather that excludes the impact of load growth. Thus, BPA avoids double counting the impact of load growth when it calculates monthly load standard deviations for weather conditions from daily load standard deviations.

Q. *Why were daily load standard deviations from the 1996 Rate Case Marginal Cost Analysis (MCA) used in the Risk Analysis Study?*

A. BPA used the 1996 MCA because it is not aware of an alternative source of load information from which daily load standard deviations can be computed for both the PNW and California.

Q. *Why did BPA estimate PF load variability using the forecasted PF loads that are subject to the load variance charge?*

A. BPA estimated PF load variability using the forecasted PF loads that are subject to the load variance charge because BPA is responsible for meeting all incremental changes in loads due to both weather conditions and load growth. *See,* Load Resource Study Documentation, WP-07-E-BPA-01A, Section 2.2.1, regarding the forecasted amount of PF loads that are subject to the load variance charge.

California Hydro Generation

Q. *Why does BPA include California hydro generation risk in the Risk Analysis Study?*

A. California hydro generation risk is incorporated into the Risk Analysis Study because it affects monthly HLH and LLH spot market electricity prices. These in turn impact BPA's surplus energy revenues and power purchase expenses.

Q. Please describe how California hydro generation risk is quantified.

A. BPA randomly selects from eighteen years of historical monthly California hydro generation data. Once one of the years is selected for the first year of the rate period, then the following two years of data are referenced in a continuous manner.

Q. Why did BPA select California hydro generation data in a continuous manner?

A. Selecting hydro generation data in a continuous manner captures the risk associated with various dry, normal, and wet weather patterns over time that are reflected in the 18 years of historical data.

Q. When the end of the 18 years of historical data is reached, why does BPA sequentially use monthly California hydro generation data for year one?

A. BPA sequentially uses monthly California hydro generation data for year one when the end of the 18 years of historical data is reached so that all 18 years of the data are equally represented in the 3 year water sequences. For example, if hydro generation data for year 18 is selected for FY 2007, then data for years one and two would be used for FY 2008 and FY 2009, respectively.

California Load

Q. Why is California load risk included in the Risk Analysis Study?

A. California load risk is included into the Risk Analysis Study because California load variability affects monthly HLH and LLH spot market electricity prices. These price impacts in turn affect PBL's surplus energy revenues and power purchase expenses.

Q. Please describe how the California load risk is modeled.

A. California load variability is modeled in the California Load Risk Model such that annual load growth variability and monthly load swings due to weather conditions are both accounted for in one California load variability factor. Annual California load growth risk is modeled to simulate various load patterns through time using a mean-reverting, random-walk technique in which load growth variability for the PNW and California are interdependent. See discussion of mean-reverting, random-walk technique under the PNW Load section above.

Q. Why did BPA model load growth variability for the PNW and California as interdependent?

A. Load growth variability for the PNW and California is modeled as interdependent because there is a strong interrelationship between regional economies and the national economy. This is reflected in the high correlation 0.8943 between annual PNW and California loads. *See,* Table 14, Risk Analysis Study Documentation, WP-07-E-BPA-04A.

Q. Why was additional annual load variability adjustment factors developed for years one through five (CY 2005-2009) in the California Load Risk Model?

A. BPA developed additional annual load variability adjustment factors to more closely match the simulated load growth standard deviations for California to the load growth standard deviations in the historical data.

Q. Why did BPA use Western Electricity Coordinating Council (WECC) load data for the California/Mexico Power Area from 1987-2004 to calculate the annual load growth deviations for California?

A. BPA used WECC load data from 1987-2004 to calculate annual load growth deviations for California because a footnote in the WECC publication states that the California/Mexico Power Area data prior to 1987 includes loads in Southern Nevada which are not included in the California/Mexico Power Area data from 1987-2004. *See,* Table 14, Risk Analysis Study Documentation, WP-07-E-BPA-04A.

Q. *Please describe how the variability in monthly loads due to weather conditions was derived.*

A. California monthly load swings due to weather conditions were derived from estimates of daily load standard deviation values for each of the 12 months. The source of these estimates was the 1996 Rate Case Marginal Cost Analysis Study Documentation, WP-96-FS-BPA-04A.

Q. *Why are monthly load standard deviations for weather conditions derived from daily load standard deviations in the Risk Analysis Study?*

A. Calculating monthly load standard deviations from historical load data by sorting historical load data for the same month (over a period of years) yields load standard deviations that include both the impact of load growth and weather conditions. In the Risk Analysis Study, BPA is explicitly modeling load growth. Accordingly, BPA developed this methodology to estimate monthly load variability due to weather that excludes the impact of load growth. Thus, BPA avoids double counting the impact of load growth when it calculates monthly load standard deviations for weather conditions from daily load standard deviations.

Q. *Why were daily load standard deviations from the 1996 Rate Case Marginal Cost Analysis used in the Risk Analysis Study?*

A. BPA is not aware of an alternative source of data from which updated daily information of this type is available.

Q. *Why was load variability due to weather conditions in the PNW and California modeled as perfectly dependent within the two California regions (southern and northern California) and the three PNW regions (Oregon/Washington, Idaho, and Montana) in AURORA, but independent between the California and PNW regions?*

A. This modeling approach represents a reasonable trade-off, since one would expect a relatively high positive correlation between load swings due to weather within a region and a relatively modest positive correlation between PNW and California load variability.

Natural Gas Price

Q. *Why is natural gas price risk included in the Risk Analysis Study?*

A. Natural gas price risk is incorporated into the Risk Analysis Study because natural gas price variability affects monthly HLH and LLH spot market electricity prices. These price impacts in turn affect PBL's surplus energy revenues and power purchase expenses.

Q. *Please describe how natural gas price risk is modeled.*

A. Natural gas price variability is modeled in the Natural Gas Price Risk Model using a mean-reverting, random-walk technique. The random-walk technique simulates monthly natural gas prices through time where the starting point for simulating the natural gas price in a given month is the monthly natural gas price from the prior month. The mean-reverting technique causes simulated natural gas prices to tend to revert to the forecasted natural gas prices as simulated prices move further from forecast prices (either higher or lower). *See,* Section 2.4.5, Risk Analysis Study, WP-07-E-BPA-04A.

Q. *Why is a mean-reverting random-walk methodology used for modeling monthly price risk?*

A. This methodology provides the flexibility to simulate natural gas prices that can be more volatile in some months than others and that can rise and fall at different rates during the year and across years. This is accomplished through the use of monthly and annual decay parameters, coupled with each month having different month-to-month gas price volatilities. Thus, the flexibility associated with the methodology utilized in the Natural Gas Price Risk Model allows the model to closely calibrate to the attributes of gas price movements in the historical data.

Q. *What does BPA mean when it uses the terms "returns" and "volatility" when quantifying natural gas price risk? How are these computed?*

A. BPA derived monthly and annual price volatilities for natural gas prices by computing the standard deviations of all the natural log (ln) price ratio changes from one time period to another. These natural log price ratio changes [ln(price at time t/price at time t-1)] are commonly referred to as "returns" and the standard deviation of these returns is referred to as "volatility" in the technical literature.

Q. *BPA uses both the terms "volatility" and "variability" in regard to natural gas price risk. Please explain the differences between these two terms.*

A. Volatility has a very specific meaning in the technical literature with these standard deviation values being specified in terms of percentages. For instance, a volatility of 30% means that a one standard deviation swing in price is 30% of the forecast price. Price variability, as measured by standard deviation, is reflected in dollars and accounts for both the volatility and price level with price variability increasing the higher the volatility and/or the price level.

Q. *Why were returns and volatilities computed in this manner?*

A. Monthly and annual price volatilities were estimated in this manner so that price movements through time could be modeled using the mean-reverting, random-walk technique.

Q. *Why were lognormal probability distributions used for natural gas price risk?*

A. BPA compared the average and median prices for the monthly and annual historical Ignacio, Colorado, price data and found that all the average prices are greater than the median prices. *See,* Table 21, Risk Analysis Study Documentation, WP-07-E-BPA-04A. Additional comparisons indicate that the differences between the maximum prices and the median prices are greater than the differences between the minimum prices and the median prices. Asymmetrical differences with these attributes exhibit the shape of lognormal probability distributions with longer tails at higher prices that differ in skewness depending on the size of the differences. Also, the use of lognormal probability distributions for quantifying price risk is well supported in the technical literature (it forms the basis for the Black and Black-Scholes formulas for valuing options). This distribution also reflects that prices can not go below $0, but that no comparable price limits on the upside exist.

Q. *What are the results from the natural gas price risk model?*

A. Results from this Natural Gas Price Risk Model on a monthly basis over time are shown in Graph 6 in the Risk Analysis Study Documentation, WP-07-E-BPA-04A, for the 5th, 50th, and 95th percentiles. The monthly natural gas price variability patterns shown in this graph for CY 2006-2009 indicate that gas price variability is highest in CY 2006-2007 and lowest in CY 2008-2009.

Q. *What is the reason for this outcome?*

A. The reason that gas price variability is highest in CY 2006-2007 and lowest in CY 2008-2009 is due to Calendar Year (CY) 2006-2007 having both higher forecast prices and higher cumulative annual price volatilities. Such results are consistent with computations shown in Table 22 in the Risk Analysis Study Documentation, WP-07-E-BPA-04A, where the cumulative annual price volatilities for one to four years duration after the current year (CY 2005) were calculated to be 31.7 percent for one year, 39.9 percent for two years, 27.3 percent for three years, and 31.6 percent for four years.

Q. *What do cumulative annual price volatilities for one to four years duration after the current year (CY 2005) of 31.7 percent, 39.9 percent, 27.3 percent, and 31.6 percent imply?*

A. These results imply that cumulative annual price volatilities over various annual time durations are large and exhibit cyclical behavior.

Q. When using these cumulative annual price volatilities for one to four years duration after the current year (CY 2005), is BPA making an assumption regarding where natural gas prices are in the natural gas price cycle?

A. No. The cumulative annual price returns for one to four years duration (after the current calendar year) were derived by computing from the historical data all the annual price returns over one, two, three, and four year increments and calculating the associated standard deviations to get the volatilities. *See,* Tables 21-22, Risk Analysis Study Documentation, WP-07-E-BPA-04A. These cumulative annual price returns and volatilities were computed from a series of annual prices that each represents various stages in the natural gas price cycle. For this reason, the cumulative annual price return and volatilities indicate that, regardless of where natural gas prices are in the cycle, cumulative annual price return and volatilities will generally exhibit the cyclical behavior already described.

Q. Did BPA make any price level adjustments to the simulated natural gas price?

A. BPA made month-specific price level adjustments to the simulated natural gas prices for FY 2007-2009 in order to perfectly align the median monthly simulated gas prices to the monthly prices in the natural gas price forecast.

Q. Why did BPA make these adjustments based on median prices rather than average simulated prices?

A. BPA based these adjustments on median prices because BPA assumes that its natural gas price forecast is a median forecast, where there is a 50 percent probability that natural gas prices could go higher or lower than its forecast. *See,* WP-07-E-BPA-11.

Q. Do the month-specific price level adjustments made to the simulated natural gas prices for FY 2007-2009 alter the price variability?

A. No. These price level adjustments do not alter the price variability because each of these month specific price level adjustments is applied to all simulated prices for that month.

Q. Why did BPA begin simulating natural gas price risk in June 2005?

A. For BPA's Third Quarter Financial Review, the forecast for the remainder of the year started with June 2005. Natural gas price variability was turned off in the Natural Gas Price Risk Model, because BPA had actual historical data for January through May of 2005.

Q. BPA set minimum and maximum real delivered gas price constraints in the Natural Gas Risk Model at $1.50/MMBTU (Million British Thermal Units) and $50.00/MMBTU On what basis did BPA set values at these levels?

A. The minimum price constraint was set based on reviewing the historical real 2005 dollar prices at Ignacio, Colorado (*See,* Table 21, Risk Analysis Study Documentation, WP-07-E-BPA-04A) and adding an additional charge for delivery from Ignacio to Southern California and the maximum price constraint was set such that no simulated prices would be constrained.

CGS Nuclear Plant Generation

Q. Why is CGS nuclear plant generation risk included in the Risk Analysis Study?

A. Nuclear plant generation risk is included in the Risk Analysis Study because CGS generation has an impact on the amount of energy that BPA has to buy and sell. This in turn affects BPA's surplus energy revenues and power purchase expenses.

Q. Please describe how the CGS nuclear plant generation risk is modeled.

A. Nuclear plant generation risk is modeled in the CGS Nuclear Plant Risk Model through a process that involves sampling values from uniform probability distributions, substituting the sampled values into a mathematical equation, and simulating variability in CGS output.

Q. Why did BPA model this risk in this manner?

A. This methodology allows BPA to calibrate the results from the mathematical equation such that, when all the simulations are run, the expected simulated nuclear plant output is the same as the expected plant output shown in the Load Resource Study (WP-07-E-BPA-01). Also, BPA selected this methodology because the frequency distribution of CGS output produced from the equation is negatively skewed with the median value (the value at the 50th percentile) being higher than average. The shape of the simulated frequency distribution of nuclear plant output appropriately reflects that thermal plants (including CGS) typically operate at output levels higher than average output levels, but the average output is driven down by occasional forced outages in which monthly output can be substantially lower than the typical monthly output.

Q. When modeling the operational risk of CGS, BPA does not model the risk of expensive repairs or premature decommissioning. Why?

A. BPA does not need to model these risks in the Risk Analysis because BPA carries both business interruption and property insurance and pays into a decommissioning fund. The cost for this insurance is included in BPA's revenue requirement. The insurance covers many of the costs associated with prolonged closures due to accidents or expensive repairs. Though not all costs would be covered, the insurance is sufficient to justify not modeling these risks. Therefore, since the premiums for the insurance are in the revenue requirement, BPA would be double-counting the costs of such outages if it also modeled these risks.

DSI Benefits

Q. Why is DSI benefit risk included in the Risk Analysis Study?

A. This risk factor is incorporated into the Risk Analysis Study because there is uncertainty in the amount of DSI benefits that will be paid in FY 2007-2009.

Q. Please describe how DSI benefit risk is modeled.

A. The quantification of this risk reflects the service terms set forth in the BPA Service to DSI Customers for FY 2007-2011, Administrator's Record of Decision (DSI ROD) signed June 30, 2005. *See,* WP-07-E-BPA-17. The DSI ROD includes a provision for

560 aMW of financial benefits to be paid to the aluminum company DSIs based on the difference between forward market electricity prices and the lowest cost-based flat PF rate up to a maximum of $12.00/MWh or $58.9 million/year. The quantification of this risk also includes an FPS sale of 17 aMW to the Port Townsend Paper Company via its local utility at a PF-equivalent flat rate. The forward market electricity price risk for a 12-month strip of power was simulated by the Forward Market Price Risk Model. The benefits paid to the aluminum DSI were computed in the DSI Benefit Risk Model, and the service to Port Townsend was accounted for in RevSim.

In the DSI Benefit Risk Model it is assumed that the benefits to the aluminum DSIs (560 aMW) are monetized and that the aluminum DSIs will maximize their benefits and adjust their energy used to as low as 280 aMW to minimize their per aMW effective (after BPA payments) electricity prices. It is also assumed that there will be no uncertainty in the amount of DSI benefits paid in FY 2007, relative to the benefits included in the Revenue Requirement when setting rates, since by the Final Rate Proposal the actual benefit payments for FY 2007 will be known. Benefit computations reflect the following: (1) reallocation of unused service benefits to more efficient DSIs, to the extent that a less efficient smelter cannot operate economically; (2) complete shutdown of all DSIs at forward market electricity prices of $70.00/MWh or more (i.e., no benefit payments); and (3) no benefit payments for prices below the lowest cost-based flat PF rates.

The reasoning behind the assumptions that are being made regarding DSI benefits in the Initial Proposal is explained in WP-07-E-BPA-17.

Q. Why are results from the DSI Benefit Risk Model based on the lowest cost-based flat PF rates from a preliminary run of ToolKit?

A. The results from the DSI Benefit Risk Model are computed at the beginning of the iterative rate calculation process, whereas the results from the ToolKit are at the end.

Accordingly, is not possible for the results from the DSI Benefit Risk Model to be based on the final ToolKit run. *See,* Graph 1, Risk Analysis Study Documentation, WP-07-E-BPA-04A, regarding the RiskMod risk analysis information flow.

Wind Project Generation

Q. Why is wind project generation risk included in the Risk Analysis Study?

A. This risk factor is incorporated into the Risk Analysis Study because changes in the amounts and values of the energy generated by PBL's portion of Condon, Klondike, Stateline, and Foote Creek I, II, and IV wind projects affect surplus energy revenues and power purchase expenses.

Q. Please briefly describe how this risk is modeled.

A. Wind generation risk is modeled in four risk simulation models, one each for Condon, Klondike, Stateline, and Foote Creek (Foote Creek I, II, and IV wind projects were combined) based on historical daily wind generation. The risk of the value of the wind generation is based on the difference between the purchase prices specified in each output contract and the spot market electricity prices received for the amount of energy produced, since BPA only pays for the actual energy produced. This financial risk is computed in RevSim.

Q. Why did BPA combine all Foote Creek wind projects when modeling wind generation risk?

A. The three Foote Creek projects can be treated as one because they are all on the same ridgeline, contiguously located, and electrically connected at the same substation. Wind currents that affect the generation at one of these wind projects will affect the generation at the other wind projects similarly.

Q. Why did BPA model wind generation risk at Condon, Klondike, and Stateline separately?

A. Each of these wind projects are located at different sites and typically experience different daily wind conditions.

Q. How did BPA derive monthly wind generation risk?

A. BPA derived monthly wind generation risk by sampling from cumulative probability distributions of historical daily wind generation for each project.

Q. What is the basis for deriving monthly wind generation in this manner?

A. The daily wind generation from one day to the next day was modeled independently based on the erratic daily generation amounts from one day to the next exhibited in the historical data. Given this phenomenon, monthly wind generation was derived in the following manner: (1) sample the daily wind generation values from the cumulative probability distributions for each day in a given month (i.e., 31 days for January); (2) sum the daily wind generation values for all days in a given month; and (3) divide the monthly sum by the number of days in that particular month.

Q. Why did BPA model the daily wind generation risk using cumulative probability distributions?

A. There are three reasons for using the cumulative probability distribution. First, there was adequate historical data to develop many data points on these probability distributions, since the probability distributions were developed from three years of daily data (on average, about 90 observations) with generation values varying over a wide range of output levels. Second the cumulative probability distribution allows the modeler to replicate the risk represented in the historical data, with the additional benefit that the expected/average simulated monthly generation values equal the generation values in the Load Resource Study. *See,* Load Resource Study, WP-07-E-BPA-01. Finally, using this probability distribution obviates the need for the modeler to specify what functional form (such as a Weibull probability distribution) best represents the phenomena being modeled. *See,* Section 1.13, Risk Analysis Study Documentation, WP-07-E-BPA-04A.

PBL Transmission and Ancillary Services Expense

Q. Why is the PBL transmission and ancillary services expense risk included in the Risk Analysis Study?

A. The PBL transmission and ancillary services expense risk is incorporated into the Risk Analysis Study because changes in PBL transmission and ancillary services expenses affect PBL expense levels directly.

Q. Please describe how this risk is modeled.

A. The PBL transmission and ancillary services expense risk is modeled in the Transmission Expense Risk Model and is based on comparisons between monthly firm transmission capacity that PBL has under contract, firm contract sales, and variability in surplus energy sales estimated by RevSim. Expense risk computations reflect how transmission and ancillary services expenses vary from the cost of the fixed, take-or-pay, firm transmission capacity that the PBL has under contract, which must be paid regardless of whether or not it is used. The methodology used in the Transmission Expense Model is consistent with the methodology documented in BPA's Power Function Review February 1, 2005 Technical Workshop on the Transmission Acquisition Program.

Q. Why is there $85 million in transmission expenses when there are no surplus energy sales?

A. PBL transmission and ancillary services expenses do not fall below $85 million/year, regardless of the amount of surplus energy sales, because the PBL must pay for the take-or-pay firm transmission capacity it has under contract. This $85 million/year figure does not include the cost of ancillary services for any surplus energy sales, since these charges are assessed depending on the actual amount of transmission used.

Q. Why do PBL transmission and ancillary services expenses increase at varying rates as the amount of surplus energy sold increases?

A. PBL's firm transmission capacity can accommodate approximately 1000 aMW of surplus energy sales. Only ancillary services expenses vary on the first increment of secondary energy sales (up to about 1000 aMW) while both transmission line capacity and ancillary service expenses vary for surplus energy sales above this amount.

Forward Market Electricity Price

Q. Why is forward market electricity price risk included in the Risk Analysis Study?

A. Forward market electricity price risk is included into the Risk Analysis Study because changes in forward market prices affect the amount of DSI and IOU Benefits. These benefits in turn affect PBL's expense levels.

Q. Please describe what forward market electricity price curves are.

A. Forward market electricity price curves are estimates at a point in time of what electricity prices will be over a period of time in the future.

Q. Please describe how this risk is modeled.

A. Forward market electricity price curves change as time progresses, often in response to whether actual spot market prices are higher or lower than the forward market price at the beginning of the spot month for that month. Based on this interrelationship, BPA designed the Forward Market Price Risk Model to estimate forward market electricity price curve movements through time that are consistent with the spot market electricity price movements estimated by AURORA. *See,* Market Price Forecast Study, WP-07-E-BPA-03, regarding AURORA. This task was accomplished in the following steps: (1) derive, through regression analysis on historical daily Mid-C price data, a series of regression equations that quantifies the relationships between the changes in spot market prices and forward market prices over a 35-month period; and (2) use these regression equations to simulate, on a monthly basis, how the forward market price curve changes from the forward market price curve for the prior month based on the difference between the actual spot market price (estimated by AURORA) and the forward market price at the beginning of the spot month for the spot month.

Q. *What assumption is BPA making in the Forward Market Price Risk Model regarding the relationship between the expected monthly spot market price and the forward market price for the spot month at the beginning of the month?*

A. BPA is assuming the forward market price at the beginning of the spot month for that month is the same as the expected spot market price for that month. Otherwise, arbitrage opportunities would exist that would likely be exploited.

Q. *Why did BPA design the Forward Market Price Risk Model to estimate forward market electricity price curve movements through time that are consistent with the spot market electricity price movements estimated by AURORA?*

A. This approach accounts for the dependency between the spot market electricity prices used to calculate surplus energy revenues and power purchase expenses and the forward market electricity prices for a 12-month strip of power used to calculate IOU and DSI benefits.

Q. *Why did BPA specify a minimum monthly forward market price for the Forward Market Price Risk Model?*

A BPA specified a minimum monthly forward market price in the Forward Market Price Risk Model so that no simulated monthly forward market price would fall below $5.00/MWh.

Q. *Why did BPA make this decision?*

A. BPA made this decision based on observing that AURORA monthly spot market prices seldom go below $5.00/MWh.

4(h)(10)(C) Credit

Q. *Why is the 4(h)(10)(C) risk included in the Risk Analysis Study?*

A. The 4(h)(10)(C) risk is incorporated into the Risk Analysis Study because there is variability in the amount of 4(h)(10)(C) credits that BPA is allowed to credit against its annual Treasury payment. *See,* Section 5.2, Revenue Requirement Study, WP-07-E-BPA-10, for a discussion of 4(h)(10)(C) credits.

Q. Please briefly describe how this risk is modeled.

A. The costs of the operational impacts are calculated for each of the 50 water years in RevSim for FY 2007-2009 by multiplying spot market electricity prices from AURORA by the amount of power purchases (aMW) that qualifies for 4(h)(10)(C) credits. These variable operational credits are combined with deterministic expenses and capital costs associated with fish and wildlife mitigation measures. *See,* Section 1.5.5, of the Risk Analysis Study Documentation, WP-07-E-BPA-04A.

IOU Benefits

Q. Why is IOU Benefit risk included in the Risk Analysis Study?

A. IOU Benefit risk is incorporated into the Risk Analysis Study because there is variability in the payments to the IOUs under Residential Exchange Settlement Agreements in FY 2008-2009 (IOU REP Settlement Agreements) due to market price volatility. *See,* WP-07-E-BPA-11.

Q. Please briefly describe how this risk is modeled.

A. The quantification of this risk reflects the contract terms set forth in the IOU REP Settlement Agreements. The forward market price risk for a 12-month strip of power was simulated by the Forward Market Price Risk Model and the lowest cost-based flat PF rates and IOU Benefits (subject to $100 million floor and $300 million cap per year) were estimated in the ToolKit Model, which are all components of the Risk Analysis Study. *See,* Section 1.11, Risk Analysis Study Documentation, WP-07-E-BPA-04A.

Section 4. Development of the Net Secondary Energy Revenue Forecast

Q. What is a net secondary energy revenue forecast?

A. A secondary energy revenue forecast consists of a forecast of surplus energy sales revenues and short term power purchase expenses. BPA uses RiskMod to calculate the secondary revenue forecast. Results are shown in Section 2.4.12, Risk Analysis Study, WP-07-E-BPA-04.

BPA obtains its primary revenues from the sale of hydroelectric power and other resources to meet firm customer loads. BPA plans its resources to meet firm load obligations under *critical* water conditions on an annual average basis. Critical water conditions are characteristic of the nearly worst water supply conditions in the existing 50-water year historical record (October 1928 through September 1978). Secondary revenues are derived from the sale of power in excess of BPA's firm load obligations. Even though BPA plans to meet its firm loads on an annual average basis, variations in loads and resources between months and between heavy and light load hour periods may require short-term purchases to meet firm loads. These short-term purchases (also known as balancing purchases) are included in the net secondary revenue forecast.

Q. Does BPA plan to make any power purchases to meet its firm load obligations under critical water conditions for this rate period?

A. Yes. BPA expects to purchase 38 aMW in FY 2008 and 92 aMW in FY 2009 in order to meet firm loads. *See,* WP-07-E-BPA-09.

Q. What is the forecast price for these projected purchases in FY 2008 and FY 2009?

A. Because BPA expects to purchase relatively small amounts, we forecast these purchases to be made on the spot market. Therefore, the forecast annual average purchase price for critical water (1937) for FY 2008 and FY 2009 are used to estimate the cost of these purchases. For FY 2008, this price was $55.85/MWh and for FY 2009, this price was $54.32/MWh.

Q. How is the net secondary revenue forecast for the FY 2007-2009 rate proposal used?

A. The calculation used to set rates to recover costs subtracts the forecast of secondary revenues (net of short-term purchase expenses) from forecast PBL expenses. The estimate of net secondary revenue has a direct impact on the magnitude of the rate.

Q. Please describe the general approach used in developing BPA's secondary revenue forecast.

A. BPA's net secondary revenue forecast is a product of two components: (1) a forecast of surplus market sales and purchase amounts, and (2) a forecast of expected prices for those sales or purchases. Secondary market sales are made when generation exceeds BPA's firm load obligations. For the current rate proposal, these sales are broken out by month and by LLH and HLH periods. In addition, BPA purchases power when it does not have enough energy to meet its firm load obligations.

The forecast of prices at which BPA would be selling surplus energy and purchasing to meet short-term deficits is provided by AURORA. AURORA is used to develop monthly LLH and HLH spot market prices. The prices are applied to the corresponding monthly LLH and HLH sales and purchase amounts to calculate sales revenues and purchase expenses. For additional information on how AURORA is used to develop price forecasts. *See,* Market Price Forecast Study, WP-07-E-BPA-03.

Q. How did BPA estimate its secondary market surpluses and deficits?

A. Secondary market surpluses and deficits were generated through a simulation process. To represent the uncertainty in forecasting surplus market sales and purchase amounts due to the variability in hydro generation, BPA forecasts generation from the Federal Columbia River Power System using the 50-water year historical water record. For each monthly LLH and HLH period, Federal firm loads are subtracted from total Federal resources. Positive values indicate an amount of surplus energy that can be sold and negative values indicate a deficit (i.e., an amount of power the needs to be purchased).

Using the 50-water year historical record provides a distribution of surplus and deficit values. This distribution is comprised of a separate value for LLH and HLH for each month under 50 different water conditions. Information about BPA's firm load obligations, hydro generation derived from the 50-water year historical record and other Federal resources can be found in the Load Resource Study, WP-07-E-BPA-01.

Q. How are net secondary revenues estimated?

A. Revenues from the secondary market sales were estimated for LLH and HLH for each month and water condition by multiplying the surplus energy forecast by the spot market electricity price generated by AURORA. The resulting LLH and HLH revenues were summed to get a monthly total. Monthly totals were summed to get an annual total. The resulting surplus energy sales revenues along with monthly energy sales and prices can be found in the Wholesale Power Rate Development Study Documentation, WP-07-E-BPA-05A, Table 3.8.1.

Q. How did BPA estimate its power purchase amounts?

A. Power purchase amounts are equal to the deficits calculated in the above discussion about calculating surpluses and deficits.

Q. How did BPA estimate its purchased power expenses?

A. Purchased power expenses were estimated using the same process used to estimate surplus energy revenues. Purchased power expenses were estimated by multiplying the LLH or HLH spot market electricity price in a particular month and a particular water condition by the corresponding purchased power quantity. The same process was followed for all water conditions and months where purchases were necessary. The LLH and HLH purchases for each month were summed to provide the monthly totals, and summed again to provide the annual total. The expected value of the distribution of annual values is reported as the total purchased power expense estimate. The resulting power purchase expenses along with monthly purchase amounts and prices can be found in the Wholesale Power Rate Development Study Documentation, WP-07-E-BPA-05A, Table 3.8.2.

Q. *Which model calculates the net secondary revenue forecast?*

A. The net secondary revenue forecast is calculated by RiskMod. *See,* Section 2.4.12 of the Risk Analysis Study, WP-07-E-BPA-04.

Q. *How much secondary power is BPA projecting to market in FY 2007 through 2009?*

A. In FYs 2007-2009, BPA expects to market approximately 1,770 aMW of secondary hydroelectric generation net of power purchases, i.e., total secondary sales less power purchases.

Q. *Are these 1,770 aMW of forecasted sales net of Slice?*

A. Yes. Secondary energy marketed by Slice customers is not included in this figure.

Section 5. Non-Operating Risk Model (NORM)

Q. *What is the Non-Operating Risk Model (NORM)?*

A. NORM is a model that was developed to quantify risks other than operational risks in the rate-setting process. Like RiskMod, NORM uses a simulation methodology to create a set of alternative outcomes. The frequency distribution of the output data reflect BPA's current estimate of the probabilities of future events that could affect BPA's non-operating expense levels. The outputs from NORM and RiskMod are used in the ToolKit model. NORM is written in Excel, with the @RISK add-in program. The output is saved as a standard Excel file.

Q. *What are operational risks?*

A. In general, operating risks include variations in prices, loads, and generation resource capability related to operating the hydro system. Most of these risks are modeled in RiskMod. NORM models the non-operating risks for the Risk Analysis Study.

Q. *What risks are reflected in NORM?*

NORM models the risks around certain components of the revenue requirement. These include non-operating costs which are the responsibility of the generation function.

Specifically, NORM models uncertainties in the following cost categories:

- Columbia Generating Station O&M
- Corp & Bureau O&M
- Colville & Spokane Settlement
- Energy Efficiency Capital
- PBL - Transmission & Ancillary Services
- Corporate G&A
- PBL internal Operations
- Fish & Wildlife O&M
- Lower Snake Hatcheries
- Fish & Wildlife Capital Expenditures
- Corps & Bureau Capital
- Public Residential Exchange
- Columbia River Fish Mitigation Project
- Capital Equipment

In addition, the following key economic risk drivers are modeled:

- Interest Rates
- Inflation

Only the risks that affect PBL associated with the transmission function are modeled in NORM or RiskMod for the WP-07 initial proposal. For a description of how transmission risks are modeled, *see* section 2.5.3.5 of the Risk Analysis Study, WP-07-E-BPA-04.

Q. Why was this particular set of non-operating risks chosen?

A. BPA chose to model NORM uncertainties that met one or more of the following three criteria: the component (1) has a large range of uncertainty; (2) has a specific uncertainties that are readily quantifiable, such as interest rate uncertainty; or (3) is a specific Power Function Review (PFR) cost saving recommendation and there is some uncertainty whether it can be achieved.

Q. Why is there a need to address non-operating risks in this rate case?

A. As BPA was preparing for the Power Function Review and looking ahead to this rate case, it was clear that there were important non-operating risks that were not being modeled. As a result, BPA determined it would understate the total financial uncertainty if these risks were not modeled. The inclusion of the PFR recommendations in the revenue requirement presented additional risk. To meet its fiduciary responsibility to the Treasury and others, it was prudent for BPA to acknowledge that it may not be able to meet these cost targets. BPA developed NORM to incorporate these uncertainties for this rate case

Q. How does NORM work?

A. For the significant non-operating risks BPA identified above, BPA developed a distribution of possible outcomes and associated probabilities. Developing the distribution required that BPA estimate the probability that the costs or revenues would deviate from what was included in the revenue requirement, and by how much.

Q. How was the information regarding non-operating risk gathered?

A. To obtain the data used to develop the probability distributions, BPA interviewed the subject matter experts (SME) for each capital and expense item modeled. Prior to each interview, the SME was sent a set of questions to think about regarding the risks surrounding the cost estimates included in the final PFR. During each interview, the SME was asked for his or her assessment of the risks concerning the cost estimates including the possible range of outcomes and the associated probabilities of occurrence. Each of the subject matter experts were interviewed regarding the following:

- Purpose and function of the cost category
- Budget level and key drivers

- Expected value
- Most likely value if it differed from the expected value
- Factors that could influence the expected value and distribution

Q. How were the risk parameters and distributions developed?

A. Based on the results of the interviews, BPA developed the probabilities and deviations for NORM.

Q. What factors contributed to the type and shape of the cost distributions used in NORM?

A. The type and shape of the cost distribution depended on two key factors:

(1) Identifying the drivers that influence the cost category, and

(2) BPA's ability to quantify the uncertainty associated with these drivers.

Given the diversity of the cost categories and risk factors, BPA utilized a number of different risk approaches. *See,* Section 2.5.2, Risk Analysis Study, WP-07-E-BPA-04.

Q. How will NORM be updated for the final rate studies?

A. Since BPA intends to review PFR cost levels prior to the completion of the final studies, it may be necessary to reassess the risks associated with any revision to the cost levels. In addition, prior to the final studies, BPA anticipates decisions on how much of Columbia River Fish Mitigation (CRFM) construction work in progress will be put in service.

Q. Was NORM used in the WP-02 rate case?

A. Yes. However, NORM has been modified and expanded to more comprehensively reflect PBL's non-operating risks.

Section 6. Accrual-to-Cash

Q. What is the purpose of the Accrual- to-Cash (ATC) adjustment?

A. The ATC adjustment makes the necessary changes to convert the net revenue scenarios (accruals) provided by RiskMod and NORM into the equivalent reserves (cash) value needed by ToolKit to calculate TPP.

Q. *Is this adjustment new for this rate case?*

A. No. PBL's WP-02 rate case included a similar adjustment in the ToolKit called the Internal Cash Flow and the SN-03 rate case included the current ATC adjustment.

Q. *Why do net revenues and cash differ?*

A. For ToolKit and TPP purposes, there are four major factors that cause cash and net revenues to differ. First, some revenues and expenses accrued and included in net revenues do not affect cash. These include the depreciation and amortization of PBL's physical and non-physical assets and the interest adjustments shown on lines 1 and 2 of the ATC Table, Table 4, Risk Analysis Study, Section 2.5.3.11, WP-07-E-PBL-04. Second, there are timing differences between when certain accrued revenue and expense items are included in the income statement, and when the associated cash is received or paid. These items include the EN net billing prepaid expense adjustments and any net-billed cash receipts lagging into or out of the current fiscal year, IOU Residential Exchange Deferral payments, the Slice True-Up, and various terminated purchase and sales contract amounts and other miscellaneous items included in the "All Other" category on line 4 of the ATC Table. Third, there are various sources and uses of cash associated with BPA's capital spending program that do not flow through the income statement, including both Planned Advanced Amortization of Federal Debt and Scheduled Federal Debt Amortization, lines 8 and 10 of the ATC Table. Fourth, there are other items of cash flow that also do not affect income. These include customer advances for work to be performed, such as the Energy Efficiency projects; funds held by BPA for other agencies pending termination of certain agreements; and customer credit deposits held in lieu of other credit enhancement instruments. These are also included on line 4 of the ATC Table.

Q. *What are the interest adjustments on Line 2 of the ATC Table?*

A. These reflect the amortization of the Capitalization Adjustment which resulted from the restructuring of Bonneville's Federal appropriated debt in The Bonneville Appropriations Refinancing Act, implemented October 1, 1997. *See,* Section 5.1.3, Revenue Requirement Study, WP-07-E-BPA-02. For PBL's portion of the refinanced debt, part of the Capitalization Adjustment is amortized (written off) annually and recognized on the income statement as a non-cash reduction in interest expense each year. Because this transaction has no cash impact, PBL's actual cash obligation to Treasury is not reduced. Therefore, PBL's actual interest payment is higher than its accrued interest expense by the amortized amount of the Capitalization Adjustment. The interest adjustments also include amortization of capitalized bond premiums.

Q. Please describe the results of the ATC calculations.

A. Lines 1 through 4, 6 through 8, and 10 and 11, of the ATC Table sum to the amounts shown on lines 5, 9 and 12, respectively. Lines 5, 9 and 12 are then added to get the ATC adjustment shown on line 13. For FY 2005 and 2006, the IOU Deferral Payment amounts (line 14), which have been included in the "All Other" category, are subtracted from this sum because they are a direct input into the ToolKit. This was done because in the ToolKit, the IOU deferral payment varied as the SN CRAC revenue varied for each RiskMod revenue scenario. For FY 2007 through 2009, the IOU deferral payments are determined by contract so they are no longer impacted by the RiskMod revenue scenarios and are therefore included in the ATC adjustment.

Q. What transmission data, if any, are included in the ATC and TPP calculations?

A. None.

Q. What changes might be made in the final rate proposal with respect to the accrual to cash adjustments?

A. The most likely adjustments include incorporating a new EN budget for EN's FY 2007, which starts July 1, 2006, and which would also include any refinancing of EN debt service. There could be some updates to EN's forecasted budgets for its fiscal years

2008 through 2010. There could also be some change to PBL non-cash expense estimates based on changes to its expected capital spending. Finally, adjustments will also be made to capture changes in expenses, revenues, and cash resulting from transactions entered into between the time of the Initial Proposal and the time of the Final Proposal where the associated stream of accrued revenues and/or expenses would differ from the stream of cash payments or receipts, such as the settlement or termination of any power purchase or sales contracts.

Q. How is the uncertainty in the ATC modeled in the risk study?

A. Not all changes in expense result in a similar change in cash. As a result, ATC is being modeled probabilistically in NORM for this rate case. NORM uses the deterministic ATC Table referred to above as its starting point, but replaces the deterministic value with the new value for each scenario. *See,* Section 2.5.3.11, Risk Analysis, WP-07-E-BPA-04.

Q. Does this conclude your testimony?

A. Yes.