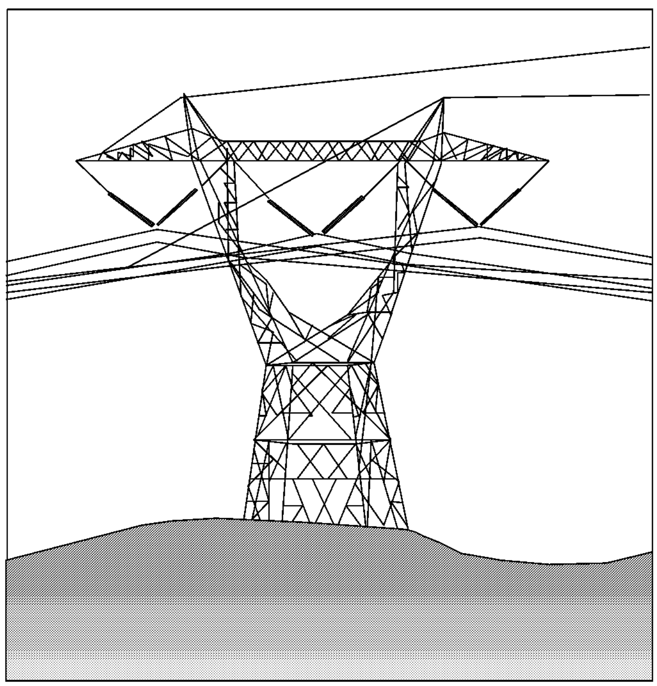
B O N N E V I L L E   P O W E R   A D M I N I S T R A T I O N
T R A N S M I S S I O N   B U S I N E S S   L I N E

2006 INITIAL TRANSMISSION PROPOSAL

DIRECT TESTIMONY & QUALIFICATION STATEMENTS

TR-06-E-BPA-03 THROUGH TR-06-E-BPA-05

TR-06-Q-BPA-01 THROUGH TR-06-Q-BPA-07



FEBRUARY 2005

Bonneville Power Administration
Transmission Business Line

2006 INITIAL TRANSMISSION PROPOSAL

DIRECT TESTIMONY AND

QUALIFICATION STATEMENTS

DIRECT TESTIMONY

BPA Exhibit No.	Subject	Witness
TR-06-E-BPA-03	Overview of Rate Proposal	Metcalf, Parker
TR-06-E-BPA-04	Revenue Forecast	Knudsen, Woerner
TR-06-E-BPA-05	Revenue Requirement Study and Risk Analysis	Homenick, Jensen, Lovell

QUALIFICATION STATEMENTS

TR-06-Q-BPA-01	Ronald J. Homenick
TR-06-Q-BPA-02	Dana M. Jensen
TR-06-Q-BPA-03	F. Steve Knudsen
TR-06-Q-BPA-04	Byrne E. Lovell
TR-06-Q-BPA-05	Dennis E. Metcalf
TR-06-Q-BPA-06	Nancy Parker
TR-06-Q-BPA-07	John R. Woerner

February 2005

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TESTIMONY OF

DENNIS E. METCALF and NANCY PARKER

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: OVERVIEW OF RATE PROPOSAL

SECTION 1. INTRODUCTION AND PURPOSE

Q. Please state your names and qualifications.

A. My name is Dennis E. Metcalf and my qualifications are stated at TR-06-Q-BPA-05.

A. My name is Nancy Parker and my qualifications are stated at TR-06-Q-BPA-06.

Q. What is the purpose of your testimony?

A. TBL is proposing transmission and ancillary service rates to be effective Fiscal Years (FY's) 2006 and 2007 (Rate Period). The purpose of this testimony is to provide an overview of the 2006 Initial Rate Proposal, which is based on the attached Settlement Agreement for the 2006 Transmission Rate Case. This testimony also sponsors the 2006 Transmission and Ancillary Service Rate Schedules, TR-06-E-BPA-02.

Q. How is your testimony organized?

A. This testimony is organized in 6 sections. Section 1 is this Introduction. Section 2 provides an overview of the Settlement Agreement and Initial Rate Proposal. Section 3 reviews the proposed revisions to the transmission and ancillary service rates including formula rates and other proposed rate schedule revisions provided for in the Settlement Agreement. Section 4 discusses the GTA Delivery Charge and section 5 discusses redispatch. Finally, section 6 addresses the equitable allocation standard in relation to the rate proposal.

SECTION 2. SETTLEMENT AGREEMENT AND INITIAL RATE PROPOSAL

Q. Please describe how the Transmission Business Line (TBL) and interested parties developed the Settlement Agreement for the 2006 Transmission Rate Case.

A. In order to establish transmission and ancillary service rates to be effective October 1, 2005, when current transmission and ancillary service rates expire, the TBL held a public workshop in July 2004 to begin discussing with interested parties issues associated with the upcoming 2006 Transmission Rate Case. TBL held three more public workshops regarding rate case issues. At the parties' suggestion, TBL and the parties met to explore the possibility of a negotiated settlement of the rate case. The resulting Settlement Agreement includes transmission and ancillary service rate levels for the Rate Period and addresses a limited set of other issues. The Settlement Agreement was sent to TBL customers and interested parties for signature. TBL signed the Settlement Agreement after receiving signed agreements from most TBL customers. TBL's initial rate proposal reflects the terms of the Settlement Agreement. The Settlement Agreement is shown in Attachment 1. Attachment 2 is a list of the entities that have signed the Settlement Agreement.

Q. Please provide an overview of the Initial Proposal.

A. TBL proposes to increase the rates as specified in the Settlement Agreement. See Settlement Agreement, pages 6-7. The Initial Proposal also includes formula rates for certain ancillary service and transmission rates. Other revisions to the transmission and ancillary services rate schedules include: a limitation on Network Integration (NT) Customer-Served Load; Advance Funding rate schedule clarifications to accommodate the implementation of Federal Energy Regulatory Commission (FERC) Order 2003-A; Failure to Comply Penalty Charge clarifications that include a requirement to curtail actual use; the conversion of billing factors for hourly nonfirm service to Reserved Capacity when systems are in place to accommodate the change; and limitation of additional charges for redirecting long-term Point-to-Point transmission service to short-term service.

Q. Are there other rate-related provisions in the Settlement Agreement that have been reflected in the Initial Proposal?

A. The Settlement Agreement also includes provisions regarding payment for redispatch service described in Attachment K of the Open Access Transmission Tariff (OATT) and the level of the GTA Delivery Charge, both of which are addressed in this testimony. The use of TBL reserves as a funding source for transmission capital programs is addressed in the testimony of Homenick, et al., TR-06-E-BPA-05.

SECTION 3. RATE PROPOSAL

Q. What is the basis of the rate increase?

A. BPA held a public process, Programs in Review (PIR), in which the TBL developed its capital and expense cost estimates for the Rate Period. *See* TR-06-E-BPA-01, Chapter 2. Based on these PIR costs and TBL's sales projections, a 12.5% rate increase, on average, is required to recover TBL's costs for the Rate Period. The primary reason for the rate increase is the major shortfall in sales and revenues during the current rate period (FY 2004-2005), when compared to the sales and revenues forecasted when the current rates were adopted. TBL sales are projected to rise only modestly during the upcoming rate period. *See* the testimony of Knudsen and Woerner, TR-06-E-BPA-04, regarding TBL sales projections. Another reason for the rate increase is capital costs of new transmission projects.

Q. Why is the FPT-06.3 rate level not increasing?

A. The FPT-06.3 rate is applicable to Formula Power Transmission (FPT) contracts that contain provisions that the rate cannot be adjusted more frequently than once every three years. Because the rate could not be adjusted until October 1, 2004 (FY 2005), the current FPT-04.3 rate schedule provides for a stepped rate: for FY 2004, the first year of the rate period, the rate level was not adjusted from the previous FPT-02.3 rate level; and for

FY 2005, the second year of the rate period, the rate was increased 3%. Since the rate cannot be adjusted more frequently than once every three years, the FPT-06.3 rate is proposed to remain at the same level as the FY 2005 FPT-04.3 rate.

SECTION 3.A. FORMULA RATES

Q. Which rate schedules are proposed as formula rates?

A. Formula rates are proposed for the following ACS-06 Ancillary Service and Control Area Service Rates:

- Reactive Supply and Voltage Control from Generation Sources (Generation-Supplied Reactive, or GSR) Service Rate
- Regulation and Frequency Response (RFR) Service Rates
- Operating Reserves – Spinning Reserve Service Rates
- Operating Reserves –Supplemental Reserve Service Rates

The following transmission rates, which include a GSR cost component, adjust to reflect changes in the GSR rate:

- FPT-06.1 Rate
- IR-06 Rate

Q. Please explain the need for formula rates.

A. Formula rates will allow TBL to pass through two types of costs as they become known during the Rate Period. The two types of costs are: 1) the generation inputs for the ancillary services of GSR Service, RFR Service, and Operating Reserves – Spinning and Supplemental Reserve Services; and 2) compensation for GSR from non-federal generation through payment of a FERC-approved rate or self-supply credits.

Q. Please explain the generation inputs.

A. "Generation inputs" refer to the costs of federal system resources allocated to the provision of the ancillary services identified above, and represent the majority of the costs recovered through these rates. In the 2002 Power Rate Case, generation inputs were determined for a five-year period (FY 2002-2006) and used to develop the 2002 and the current 2004 transmission and ancillary service rates. Thus, the generation input costs and rates are known for the first year (FY 2006) of this upcoming transmission Rate Period, but not for the second year (FY 2007). BPA will conduct a power rate case that will determine generation input costs and set power rates effective FY 2007 and beyond.

Q. *How will the disparity between the power and transmission rate periods be accommodated?*

A. The ACS-06 rate charges for Regulation and RFR Service and Operating Reserves (OR) – Spinning and Supplemental Reserve Services are specified for FY 2006, the period for which generation inputs are known. For FY 2007, the RFR and OR rate charges will be set following the conclusion of the power rate case according to the formulas in the respective rate schedules. The final proposal power rates, including generation inputs, will be available at least 60 days prior to October 1, 2006, the date that the FY 2007 RFR and OR rate charges go into effect.

The ACS-06 GSR rate will be adjusted similarly to reflect the FY 2007 GSR generation input. However, the proposed GSR formula rate also will be adjusted quarterly during the Rate Period to reflect other costs, as described below.

Q. *Please describe the formulas that determine the rates effective October 1, 2006.*

A. The RFR and OR rate formulas are designed to be straightforward and mechanical in nature. The generation input cost for FY 2007 is the only unknown item in the formula; the other forecasted costs and sales that are the basis for the rates are specified in the rate schedule. The RFR and OR rates will change to reflect a change in the generation input costs for FY 2007 only.

Q. *Please explain the GSR rate formula.*

A. The proposed GSR rate will be calculated quarterly to account for three factors. First, the rate will adjust to recover the one-time revision of the GSR generation input cost for FY 2007 from the next BPA power rate case, similar to the proposed RFR and OR rates. Second, the rate will adjust quarterly to reflect TBL's expense associated with compensating non-federal generators for GSR under a FERC-approved rate. Third, the rate will adjust quarterly to account for self-provision of GSR. Thus, the quarterly adjustment of the GSR rate allows TBL to ensure that it fully recovers its costs as they become known during the Rate Period. The GSR formula rate is designed to recover TBL's cost of GSR from federal and non-federal resources in a timely manner, while not changing the rate level dramatically each quarter.

Q. Please describe the GSR expense associated with compensating non-federal generators under a FERC-approved rate.

A. Non-federal generators may be compensated for GSR by filing a rate with FERC. At this time, one non-federal generator has filed with FERC for such a rate and TBL expects that others may file similar rates for GSR compensation. The additional cost to TBL to compensate non-federal generators for GSR will not be known until each rate filing is made and approved by FERC.

Q. *Please discuss the credit for self-provision of GSR.*

A. The GSR rate schedule permits transmission customers to apply for a reduction in the billing factor to the extent the transmission customer demonstrates it can self-provide this service. TBL is currently developing a business practice, with customer input, concerning self-provision of GSR and expects that some customers will qualify for the self-supply credit after TBL's 2006 transmission and ancillary service rates have been filed for FERC approval.

Q. Please describe the changes to the FPT-06.1 and IR-06 transmission rates.

A. The proposed FPT-06.1 and IR-06 rates are based on the cost of TBL's Integrated Network plus the two required ancillary services, Scheduling, System Control, and Dispatch Service and GSR Service. To the extent that the ACS-06 GSR rate changes quarterly, as discussed above, that change will be factored into the FPT-06.1 and IR-06 rates quarterly according to the formulas in those rate schedules. The two other cost components are not adjusted and so remain constant over the Rate Period.

SECTION 3.B. ADVANCE FUNDING RATE

Q. Please explain the changes to the Advance Funding rate.

A. In the Settlement Agreement, BPA agreed to begin immediately applying the pricing methodologies of FERC Order 2003-A. Under these methodologies, new generators that interconnect with the BPA transmission system fund the costs of the network upgrades required for the interconnection. As the generator makes payment for transmission services with respect to the generation facility, it receives a repayment of these costs, on a dollar-for-dollar basis as credits against the non-usage sensitive portion of the transmission charges. Under Order 2003-A, BPA and the generator may agree on an alternative repayment schedule. However, full reimbursement of the advanced funds must be made within 20 years of the commercial operation date of the generating facility.

The Advance Funding (AF) Rate Schedule applies to customers that execute an agreement under which BPA collects the capital and related costs of new transmission facilities through advance funding or other financial arrangements. The AF rate was intended to allow for a wide array of financial arrangements under which the transmission customer pays for or advances the costs of new facilities. The proposed amendment to the AF Rate Schedule clarifies that the AF rate applies to cases in which the customer is reimbursed for all or part of its advance payment in the form of credits against transmission service. Therefore, this amendment makes clear that the AF Rate Schedule applies to the advance funding and repayment of the costs of network upgrades constructed for a new generation interconnection. See TR-06-E-BPA-02, AF-06 Rate Schedule.

SECTION 3.C. FAILURE TO COMPLY PENALTY CHARGE

Q. What is the Failure to Comply Penalty (FTC) charge?

A. The FTC charge is assessed to transmission customers who jeopardize Federal Columbia River Transmission System (FCRTS) reliability by failing to comply with TBL operational orders to curtail, redispatch or shed load. The penalty is the highest of: 100 mills per kilowatthour; costs incurred by TBL due to a party's failure to comply; or 110% of an hourly market price. *See* TR-06-E-BPA-02, GRSPs, Section II.B. The purpose of the FTC charge is to maintain system reliability, discourage improper behavior and penalize parties who ignore or fail to comply with TBL operating orders.

Q. What change are you proposing?

A. TBL is proposing to revise section 2.c. of the FTC charge to clarify that the transmission customer must curtail or redispatch actual use of the transmission contract when TBL directs them to do so. Although the total use of a transmission path is known at any given time, TBL does not always know the use of a transmission path by individual customers. For example, dynamic and memo schedules represent an estimated hourly use of the transmission system that is not trued-up to actual usage until after the hour. When directing customers to curtail use of the transmission system, it is necessary that customers curtail the actual transmission use. However, if the schedule is only an estimate of expected use, the curtailment order may have little or no effect when actual use differs, sometimes substantially. This revision will help to ensure that appropriate actions are taken, regardless of whether the schedule accurately reflects use of the transmission system. In addition, the specification of a market index was updated to change from a defunct CAISO index to one that is active.

SECTION 3.D. OTHER RATE SCHEDULE REVISIONS

Q. What other revisions are proposed to the rates?

A. TBL is proposing to revise the Hourly Nonfirm Billing Factor; the billing for redirected service; and the Customer-Served Load provisions in the Network Integration rate schedule.

Q. Please describe the revision to the Hourly Nonfirm Billing Factor.

A. Currently, the rate for hourly nonfirm (HNF) Point-to-Point transmission service (in the PTP, IS, and IM rate schedules) is assessed based on the scheduled kilowatthours. TBL proposes to change the billing factor to the Reserved Capacity. Currently, HNF service is not reserved on the OASIS. When a customer schedules HNF service, TBL decrements Available Transmission Capability in the amount of the schedule. However, the customer may reduce or cancel the schedule up to 20 minutes before the scheduling hour and is charged the HNF rate only for the transmission capacity that is actually scheduled and used. Overall, changing HNF service to a reserved product, which includes changing the HNF billing factor to Reserved Capacity, will encourage more efficient use of the FCRTS.

Q. When will the HNF billing factor change occur?

A. The HNF billing factor change will not take place until TBL gives a 60-day notice of the change to all customers. TBL will give this notice only when necessary changes have been made to the applicable TBL systems and Business Practices. Associated with this HNF billing factor change, the proposed PTP rate schedules are revised to charge for actual use of HNF, and not Reserved Capacity, when service is curtailed or interrupted.

Q. Please describe the rate schedule revision for redirected service.

A. Pursuant to the Settlement Agreement, the proposed PTP, IS and IM rate schedules are revised to state that no additional charge will be assessed when the customer redirects long-term service to short-term service pursuant to OATT section 22.2.

Q. Please describe the proposed revision to the Customer-Served Load provisions in the Network Integration NT rate schedule.

A. The NT Customer-Served Load (CSL) definition is revised to limit Declared CSL to the annual amounts, resources and contracts specified in the NT Service Agreement on October 1, 2005. An NT customer with Declared CSL serves Network Load on a firm basis from sources internal to its system, over non-federal transmission or pursuant to contracts other than the NT service agreement. TBL intends to eliminate CSL effective October 1, 2011. CSL provisions were first implemented in FY 1997 as a way to mitigate possible inequities caused by customers moving from legacy contracts to open-access NT service. However, the FERC pro forma tariff does not provide for CSL, and the CSL provisions themselves make contract administration complex. This proposed revision is the first step in phasing out CSL.

Q. Are there other revisions to the rate schedules?

A. The ACS Operating Reserve rates updates the billing factor to reflect the current Northwest Power Pool Reserve Sharing Procedure that the Reserve Requirement for wind generation is 5%, split equally between Spinning and Supplemental Reserve Service.

SECTION 4. GTA DELIVERY CHARGE

Q. What is the GTA Delivery Charge and to whom does it apply?

A. The GTA Delivery Charge is a Power Business Line (PBL) rate for low voltage delivery over third party transmission systems, and it is charged to PBL power customers that take delivery on low voltage facilities when PBL is paying for the transfer service over the third party transmission system.

Q. Please explain the settlement provisions concerning the GTA Delivery Charge.

A. PBL agrees to charge its GTA Delivery Charge customers the same rate as the TBL Utility Delivery charge, agreed to in the Settlement Agreement, for the period October 1, 2005 until September 30, 2007. The GTA Delivery Charge for post-September 30, 2007, will be determined in the 2007 power rate case and PBL agreed to address the post-September 30, 2007, GTA Delivery Charge rate in a rates workshop or other public forum prior to the commencement of the 2007 power rate case.

SECTION 5. REDISPATCH

Q. Please explain the settlement provisions concerning redispatch service.

A. TBL agrees to submit to FERC a revised Attachment K to the OATT defining the redispatch services to be provided by PBL in fiscal years 2006 and 2007. The revised Attachment K (Settlement Agreement, pp. 8-9) is identical to the current Attachment K with the applicability extended through the Rate Period. TBL agrees to pay PBL $1.5 million per year for redispatch services described in Attachment K. TBL, PBL and parties to the Settlement agreed to this fixed annual payment for redispatch services as part of the broader rate settlement. During the Rate Period, BPA will continue to develop a methodology for determining the costs of redispatch. Any information developed by BPA relating to redispatch provided by PBL will be provided to any party requesting it.

Q. How is the $1.5 million per year recovered?

A. The Settlement Agreement specifies that the $1.5 million per year is recovered solely through the NT Load Shaping Charge. Except for redispatch that occurs within the hour of delivery, redispatch under Attachment K is provided only when needed to maintain NT service.

SECTION 6. EQUITABLE ALLOCATION

Q. Do the proposed transmission and ancillary services rates represent an equitable allocation of costs between Federal and non-Federal power?

A. Yes. TBL is not presenting segmentation and cost allocation studies to support the proposed rates; the rates are a product of the Settlement Agreement. Nevertheless, equitable allocation is demonstrated in two important ways. First, equitable allocation between Federal and non-Federal power is achieved through adherence to the principle of comparability. Prior to 1996, when most transmission for Federal power was provided for in bundled power sales contracts, an allocation of costs in the rate case was needed to demonstrate equitable allocation of transmission costs between Federal and non-Federal power. Under BPA's OATT, purchasers of transmission for Federal power, including both BPA's PBL and PBL's customers, receive the same service and pay the same rates as purchasers of transmission for non-Federal power. BPA draws no distinction between Federal and non-Federal power using the system. An equitable allocation of transmission costs between Federal and non-Federal power is achieved through application of the same rates to the two classes of service. A separate rate case allocation is unnecessary.

Second, equitable allocation is demonstrated by the breadth of the settlement and the diversity among the settling parties. The settling parties include the PBL and PBL full requirements customers; large partial requirements customers that both buy Federal power and wheel large amounts of non-Federal power; large wheeling customers, such as the region's Investor Owned Utilities, which purchase little Federal power; and power marketers and resource developers. The TBL would not have been able to obtain the agreement of such a large group of customers with such diverse interests unless the proposed allocation of costs was equitable.

Q. Does this conclude your testimony?

A. Yes.

SETTLEMENT AGREEMENT
Bonneville Power Administration 2006 Transmission Rate Case

The undersigned signatories to this Settlement Agreement hereby agree to the following:

1. In the Bonneville Power Administration (BPA) 2006 Transmission Rate Case (Rate Case), the Transmission Business Line (TBL) will submit a proposal (Initial Proposal) commencing the rate process for the period FYs 2006-2007 (Rate Period) that reflects the Transmission and Ancillary Service rates shown in Attachment 1.

2. Redispatch

   a. The signatories recognize and agree that there is value associated with the redispatch of hydro-electric resources and other generation. BPA will develop information during the Rate Period regarding the amount of and reason for redispatch requested by TBL and the amounts and locations of redispatch provided by the Power Business Line (PBL). BPA will provide all such information developed to any party requesting it. During the Rate Period, BPA will also work to develop a method or methods to appropriately value redispatch associated with hydro-electric resources. BPA will discuss the proposed methods with and take comments from customers in rate case workshops or other public policy forums.

   b. The revised Open Access Transmission Tariff (OATT) Attachment K (shown in Attachment 2 to this Settlement Agreement) will replace the existing Attachment K. The TBL will compensate the PBL for redispatch services associated with Attachment K by paying PBL $1.5 million per year in FY 2006 and FY 2007 for all such services provided during such period. This payment by TBL to PBL is recovered solely through the NT Load Shaping charge. In the interest of reaching a settlement the signatories have agreed to this amount of compensation to the BPA PBL for providing redispatch during the Rate Period. However, nothing in this Settlement Agreement nor actions taken pursuant to section 2.a, above, will serve as a precedent for any methodology for implementing or valuing redispatch for future rate periods, or for the purpose of determining the rights of an RTO or any other regional transmission provider to require redispatch.

   c. TBL will submit the revised Attachment K (Attachment 2 to this Settlement Agreement) to the Federal Energy Regulatory Commission (FERC) as a proposed amendment to BPA's Open Access Transmission Tariff, and will request that it be effective as of October 1, 2005. The signatories agree not to challenge the approval of the revised Attachment K by FERC, and, if FERC approves the revised Attachment K without change, the signatories agree not to challenge such approval in any judicial forum.

3. NT Customer-Served Load

   The Initial Proposal will add the following language to the end of the definition of Declared Customer-Served Load in the NT rate schedule: "Declared Customer-Served Load shall not exceed the annual amounts and shall be limited to the resources and contracts specified in the Service Agreement on October 1, 2005."

   TBL currently intends to eliminate Customer-Served Load effective on October 1, 2011. Prior to that time, TBL agrees to work with interested customers to determine the most appropriate mechanism, if any, to recognize the contribution that local Network Resources make to the need for an adequate transmission system, and to determine whether a transition mechanism is appropriate for NT customers that currently serve Customer Served Load with such resources.

4. Effective on the date that TBL signs this Settlement Agreement, BPA will apply the pricing methodologies contained in FERC Order 2003-A for determining, funding, and allocating the costs of: Network Upgrades; Distribution Upgrades, if any; and Interconnection Facilities. TBL's Initial Proposal will include the revised AF rate schedule in Attachment 3. The AF rate schedule revisions clarify the availability of the AF rate to implement Order 2003-A.

5. For the period October 1, 2005 until September 30, 2007, PBL agrees to charge its GTA Delivery Charge customers the same rate as the TBL Delivery Charge agreed to in this Settlement Agreement. BPA will include the proposal for such PBL charge in the Initial Proposal. The GTA Delivery Charge for post-September 30, 2007 will be determined in the 2007 PBL rate case. PBL commits to address the GTA Delivery Charge either in a PBL rates workshop or other policy forum prior to commencement of the 2007 PBL rate case.

6. Reactive Supply and Voltage Control from Generation Sources Service (Generation Supplied Reactive): BPA agrees to work with customers through its Business Practice Technical Forum process to establish criteria for BPA Transmission Customers to receive credits for self-supplying Generation Supplied Reactive from qualifying non-federal generators, and draft a business practice incorporating the criteria. BPA reserves the right to determine what terms will be contained in the draft Generation Supplied Reactive business practice, and in any final business practice. BPA will use best efforts to post a final Generation Supplied Reactive self-supply business practice by April 1, 2005, for implementation on or before October 1, 2005.

7. TBL's Initial Proposal will include the Failure to Comply Penalty Charge in Attachment 4.

8. Financial Reserves

    a. BPA expects to use, and the signatories will not object to or otherwise challenge the agency's use of, $15 million recorded as TBL reserves in each year of the rate period (for a total of $30 million) as a funding source for transmission capital programs. The foregoing does not prohibit any signatory from objecting to or otherwise challenging the level of TBL capital programs, the specific projects included therein, or the level of expenditures for such project(s);

    b. The use of TBL reserves as a funding source for transmission capital programs as described in 8.a., above, will be modeled in the calculation and presentation of the revenue requirement in the Rate Case; and

    c. $15 million of transmission reserves described in 8.a., above, may be treated by the agency as dedicated to the funding of transmission capital programs and therefore unavailable for use as reserves for any purpose in the determination of the level of the SNCRAC for FY 2006.

9. Hourly Nonfirm

    TBL's Initial Proposal will include the language in Attachment 5.

10. Conditional Firm

BPA will work to develop a "conditional firm product" that includes long term duration and seasonal firm service in months as may be available. The product would also address elements such as curtailment priority during the months that firm ATC is not available, and how much new long-term and short-term firm service can be sold on BPA's system. BPA also commits to running an expedited 7(i) process to price this product should one be necessary for implementation, as well as any necessary filings or approvals.

11. Formula Rates for Generation Inputs

TBL's Initial Proposal will include formula rates consistent with the methodology described in Attachment 6 to recover the FY 2007 generation input costs adopted in the 2007 PBL rate case.

12. Formula Rates for Reactive Supply and Voltage Control from Generation Sources Service

TBL's Initial Proposal will include formula rates to: (a) recover the generation input costs of Reactive Supply and Voltage Control from Generation Sources Service adopted in the 2007 PBL rate case; (b) recover the costs of Reactive Supply and Voltage Control from Generation Sources Service charged TBL by generators according to FERC approved rates; and (c) reflect the self-supply of Reactive Supply and Voltage Control from Generation Sources Service by transmission customers. The rates will adjust quarterly to include known changes in the above three items as well as any underrecovery or overrecovery from the previous quarter. Formula rates will be proposed for the ACS Reactive Supply and Voltage Control from Generation Sources Service rate, the IR rate and the FPT-06.1 rate.

13. Redirected Service

Due to the per unit rate differences between Long-Term and Short-Term services, the PTP, IS and IM rate schedules in the Initial Proposal will be modified to include the following language:

Section III.C. Redirect Service

> Redirecting Long-Term Firm PTP to Short-Term Firm PTP service will not result in an additional charge if the capacity reservation does not exceed the amount reserved in the existing service agreement.

14. The signatories agree not to contest any aspect of the TBL's Initial Proposal, including but not limited to the level of any transmission or ancillary or control area services rate or any of the elements thereof, the methodologies and principles used to derive such rates, or any aspect of the rate schedules, or any general rate schedule provision, and agree to waive their rights to cross-examination and discovery with respect thereto. If, however, the TBL does not submit an Initial Proposal consistent with the terms of this Settlement Agreement, the signatories may contest any aspect of the TBL's proposal.

15. If no party in the Rate Case contests any aspect of the TBL Initial Proposal, the TBL will propose to the Administrator that he adopt the TBL's Initial Proposal and establish rates consistent therewith.

16. The signatories will move the Hearing Officer to specify a date within a reasonable time of the prehearing conference by which any party to the Rate Case that has not executed this Settlement Agreement (a) must object to the settlement proposed in this Settlement Agreement and identify each issue such party chooses to preserve for hearing; or (b) be deemed to have waived any right to object to the settlement proposal or preserve issues for hearing. If no party objects to the settlement proposal and preserves issues for hearing, the TBL shall propose to the Administrator that he adopt the Initial Proposal in its entirety. In the event that any party does so object, the TBL may, but shall not be required to, revise the Initial Proposal as it believes appropriate, either after such party states its objection or after parties file their direct testimony. If the TBL decides not to revise its Initial Proposal, the TBL will propose to the Administrator that he adopt the Initial Proposal in its entirety. If the TBL decides to revise, or otherwise departs from, its Initial Proposal, the TBL and the parties will meet promptly to discuss a new procedural schedule that they will propose to the Hearing Officer, allowing the TBL a reasonable time in which to present a revised proposal and the parties a reasonable time to respond to such revised proposal. In that event, the signatories may contest any aspect of TBL's proposal or position.

17. If the TBL submits an Initial Proposal consistent with the terms of this Settlement Agreement, and does not submit a revised proposal pursuant to section 16, the signatories agree not to enter any evidence into the Rate Case or make any argument in the Rate Case contesting any provision of section 36 of BPA's current OATT. If the Administrator establishes transmission rates consistent with the TBL's Initial Proposal and submits such rates to FERC for confirmation and approval, the signatories agree not to make any such argument before the FERC or any judicial forum during the Rate Period.

18. Nothing in this Settlement Agreement is intended in any way to alter the Administrator's authority and responsibility to periodically review and revise the Administrator's transmission rates or the signatories' rights to challenge such revisions.

19. If the Administrator establishes transmission rates consistent with the Initial Proposal and submits such rates to FERC for confirmation and approval only under the applicable standards of the Northwest Power Act and as part of a reciprocity filing, the signatories agree not to challenge such confirmation and approval of such rates or any element thereof, including the methodologies and principles used to establish such rates, or support or join any such challenge, and agree not to challenge such rates or any element thereof, including the methodologies and principles used to establish such rates, in any judicial forum. In addition, BPA's commitment in sections 2, 5, 6 and 10 of this Settlement Agreement shall apply only if the Administrator establishes rates consistent with the Initial Proposal and submits such rates to FERC for confirmation and approval.

20. The signatories agree that they will not assert in any forum that anything in this Settlement Agreement or any action with regard to this Settlement Agreement taken or not taken by any signatory, the Hearing Officer, the Administrator, FERC, or a court, creates or implies any procedural or substantive precedent or creates or implies agreement to any underlying principle or methodology, or creates any precedent under any contract between BPA and any signatory.

21. By executing this Settlement Agreement, no signatory waives any right to pursue BPA OATT dispute resolution procedures consistent with BPA's OATT (including without limitation any

complaint concerning implementation of BPA's OATT) or any claim that a particular charge, methodology, practice or rate schedule has been improperly applied.

22. Nothing in this Settlement Agreement amends any contract or modifies rights or obligations or limits the remedies available thereunder.

This Settlement Agreement may be executed in counterparts.

____________________________for

____________________________ Date ___________

Party

Attachment 1
Summary of Rate Level Changes

		Units	(A)	(B)	(C)	(D)
						Percent
					Settlement	Change
		Units	Current 2004 Rates		2006 Rates	(C)/(A)
				FPT-04.3		(percent)
	FPT-06.1 and FPT-06.3		**FPT-04.1**	**FY 2005**	**FPT-06.1**	
1	M-G Distance............................	$/kW-mi-yr	0.0511	0.0518	0.0581	13.7%
2	M-G Miscellaneous Facilities............	$/kW-yr	2.91	2.96	3.31	13.7%
3	M-G Terminal............................	$/kW-yr	0.59	0.60	0.67	13.6%
4	M-G Interconnection Terminal............	$/kW-yr	0.53	0.54	0.60	13.2%
5	S-S Transformation......................	$/kW-yr	5.49	5.57	6.24	13.7%
6	S-S Interconnection Terminal............	$/kW-yr	1.50	1.52	1.71	14.0%
7	S-S Intermediate Terminal...............	$/kW-yr	2.12	2.15	2.41	13.7%
8	S-S Distance............................	$/kW-mi-yr	0.5021	0.5095	0.5709	13.7%
9	Overall FPT Rate......................	$/kW-yr	13.30	8.73	15.13	13.8%
10	Overall FPT Rate......................	$/kW-mo	1.109	0.728	1.261	13.7%
	IR-06					
11	Demand..................................	$/kW-mo	1.261		1.484	17.7%
	NT-06					
12	Base Rate ($/kW-mo).....................	$/kW-mo	1.028		1.216	18.3%
13	Load Shaping ($/kW-mo)..................	$/kW-mo	0.425		0.367	-13.6%
14	Base plus Load Shaping................	$/kW-mo	1.453		1.583	8.9%
	PTP-06					
15	Demand..................................	$/kW-mo	1.028		1.216	18.3%
16	Daily Block 1 (day 1 thru 5)............	$/kW-day	0.047		0.056	19.1%
17	Daily Block 2 (day 6 and beyond)........	$/kW-day	0.035		0.043	22.9%
18	Hourly..................................	mills/kWh	2.96		3.50	18.2%
	Utility Delivery					
19	Demand..................................	$/kW-mo	0.946		1.119	18.3%
	IS-06					
20	Demand..................................	$/kW-mo	1.176		1.211	3.0%
21	Daily Block 1 (day 1 thru 5)............	$/kW-day	0.054		0.056	3.7%
22	Daily Block 2 (day 6 and beyond)........	$/kW-day	0.040		0.042	5.0%
23	Hourly..................................	mills/kWh	3.39		3.48	2.7%
	IM-06					
24	Demand..................................	$/kW-mo	1.258		1.230	-2.2%
25	Daily Block 1 (day 1 thru 5)............	$/kW-day	0.058		0.057	-1.7%
26	Daily Block 2 (day 6 and beyond)........	$/kW-day	0.042		0.040	-4.8%
27	Hourly..................................	mills/kWh	3.61		3.54	-1.9%

Attachment 1
Summary of Rate Level Changes

			(A)	(B)	(C)	(D)
		Units	Current 2004 Rates		Settlement 2006 Rates	Percent Change (C)/(A)
	Intertie East					
28	IE-06................................	mills/kWh	1.38		1.13	-18.1%
	Power Factor Penalty Charge					
29	Demand -- Lagging....................	$/kVAr-mo	0.28		0.28	0.0%
30	Demand -- Leading....................	$/kVAr-mo	0.24		0.24	0.0%
	Scheduling Control and Dispatch					
31	Demand...............................	$/kW-mo	0.166		0.203	22.3%
32	Daily Block 1 (day 1 thru 5)..........	$/kW-day	0.008		0.010	25.0%
33	Daily Block 2 (day 6 and beyond)......	$/kW-day	0.005		0.006	20.0%
34	Hourly...............................	mills/kWh	0.48		0.59	22.9%
	Generation Supplied Reactive					
35	Demand...............................	$/kW-mo	0.067		0.068	1.5%
36	Daily Block 1 (day 1 thru 5)..........	$/kW-day	0.003		0.003	0.0%
37	Daily Block 2 (day 6 and beyond)......	$/kW-day	0.002		0.002	0.0%
38	Hourly...............................	mills/kWh	0.19		0.19	0.0%
	Regulation and Frequency Response					
39	Hourly...............................	mills/kWh	0.30		0.32	6.7%
	Energy Imbalance					
40	Hourly...............................	mills/kWh	100.00		100.00	
	Operating Reserves					
41	Spinning.............................	mills/kWh	8.39		7.93	-5.5%
42	Supplemental.........................	mills/kWh	8.39		7.93	-5.5%
	GTA Delivery					
43	Demand...............................	$/kW-mo	0.946		1.119	18.3%

Attachment 2

Open Access Transmission Tariff
Revised Attachment K

For the period October 1, 2005, through September 30, 2007, to the extent the Transmission Provider determines that redispatch of Network Resources is necessary to maintain Network Integration Transmission (NT) Service, the Transmission Provider shall implement redispatch in accordance with the provisions of this Attachment K. Attachment K addresses only circumstances in which the Tariff requires NT and Point-to-Point (PTP) uses on a constraint be reduced on a comparable basis.

1. The Transmission Provider shall not issue redispatch instructions under this Attachment K to increase ATC.

2. The BPA Power Business Line (PBL) will inform the Transmission Provider of all non-power constraints that limit the PBL's ability to redispatch generation resources. The Transmission Provider will not violate these non-power constraints unless an emergency situation leaves no other alternative for maintaining system reliability or providing safety to individuals or property. Notwithstanding any other provision of Attachment K, the protection of transmission system reliability and the safety of people and property will be the primary criteria the Transmission Provider will use in an emergency situation.

3. PBL will provide the Transmission Provider federal hydroelectric generation resource set points. The Transmission Provider may request changes to such set points. Not all changes to set points are redispatch.

4. For redispatch that occurs within the hour of delivery:

   If the Transmission Provider determines that a redispatch of federal hydro-electric projects is necessary to maintain the reliability of the FCRTS in real-time and the Transmission Provider is unable to calculate the portion of the constraint attributable to NT schedules, the Transmission Provider may redispatch the federal hydro-electric projects as necessary to relieve the constraint for the remainder of the hour and, if the event occurs twenty minutes past the hour, for the next hour also. However, the Transmission Provider must make the determination described in section 5 as soon as possible, not to exceed 100 minutes after the need for redispatch arises, and adjust the redispatch instructions accordingly.

5. For Day-ahead and Hour-ahead redispatch:

   a. The Transmission Provider will use redispatch only to manage congestion on the FCRTS that would impact NT schedules. The Transmission Provider will redispatch the system only to the extent necessary to maintain the NT schedules.

   b. The Transmission Provider will not issue any redispatch instructions until it has curtailed all non-firm schedules across the constrained path.

   c. If the Transmission Provider determines that a constraint can be relieved by redispatching federal hydro-electric projects, the Transmission Provider will determine what portion of the constraint is caused by NT schedules and what portion is caused by PTP schedules. Then the Transmission Provider will issue a redispatch instruction in an amount that will relieve the NT portion of the constraint and will curtail the PTP schedules in an amount necessary to relieve the PTP portion of the constraint.

   d. If the Transmission Provider determines that the portion of the constraint caused by NT schedules cannot be relieved by only redispatching federal hydro-electric projects, the Transmission Provider will contact the PBL schedulers and inform the PBL schedulers of the amount of NT schedules associated with the constraint. The PBL schedulers will attempt to relieve the constraint by the least cost means, including, but not limited to, purchasing alternative transmission from a third party, purchasing replacement generation from a third-party and redispatching federal generation accordingly, or requesting third party generation to decrease and using federal generation to replace the third-party generation. In making these arrangements the PBL will act as a purchasing agent for the Transmission Provider.

6. The Transmission Provider will not request redispatch for any purpose under the Tariff other than that stated herein or otherwise required by the Tariff.

Attachment 3

Schedule AF-06
Advance Funding Rate

SECTION I. AVAILABILITY

This schedule supersedes Schedule AF-04 and is available to customers who execute an agreement that provides for BPA-TBL to collect capital and related costs through advance funding or other financial arrangement for specified BPA-owned Federal Columbia River Transmission System (FCRTS) facilities used for:

A. Interconnection or integration of resources and loads to the FCRTS;

B. Upgrades, replacements, or reinforcements of the FCRTS for transmission service; or

C. Other transmission service arrangements, as determined by BPA-TBL.

Service under this schedule is subject to BPA-TBL's General Rate Schedule Provisions (GRSPs).

SECTION II. RATE

The charge is:

A. The sum of the actual capital and related costs for specified FCRTS facilities, as provided in the agreement. Such actual capital and related costs include, but are not limited to, costs of design, materials, construction, overhead, spare parts, and all incidental costs necessary to provide service as identified in the agreement; or

B. An advance payment equal to the sum of the capital and related costs for specified FCRTS facilities, as provided in an agreement. A credit for some or all of the amount advanced will be applied against charges for transmission service, as provided in the agreement. The charges for transmission service shall be at the rate for the applicable transmission service.

SECTION III. PAYMENT

A. ADVANCE PAYMENT

Payment to BPA-TBL shall be specified in the agreement as either:

1. A lump sum advance payment;
2. Advance payments pursuant to a schedule of progress payments; or
3. Other payment arrangement, as determined by BPA-TBL.

Such advance payment or payments shall be based on an estimate of the capital and related costs for the specified FCRTS facilities as provided in the agreement.

B. ADJUSTMENT TO ADVANCE PAYMENT

For rates under II.A., BPA-TBL shall determine the actual capital and related costs of the specified FCRTS facilities as soon as practicable after the date of commercial operation, as determined by BPA-TBL. The customer will either receive a refund from BPA-TBL or be billed for additional payment for the difference between the advance payment and the actual capital and related costs.

Attachment 4

FAILURE TO COMPLY PENALTY CHARGE

If a party fails to comply with the BPA-TBL's curtailment, redispatch, or load shedding orders, the party will be assessed the Failure to Comply Penalty Charge.

Parties who are unable to comply with a curtailment, load shedding, or redispatch order due to a force majeure on their system will not be subject to this penalty provided that they immediately notify the BPA-TBL of the situation upon occurrence of the force majeure.

1. RATE

The rate shall be the highest of:

a. 100 mills per kilowatthour;

b. any costs incurred by the BPA-TBL in order to manage the reliability of the FCRTS due to the failure to comply;

c. an hourly market price index plus 10%.

The hourly market price index will be the larger of the California ISO Real-Time Hourly Average Energy Price or the Dow Jones Mid-Columbia Firm Index Price for the hour(s) when the failure to comply occurred.

2. BILLING FACTORS

The Billing Factor shall be the kilowatthours that were not curtailed or redispatched in any of the following situations:

a. Failure to shed load when directed to do so by BPA-TBL in accordance with the Load Shedding provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to shed load pursuant to such orders within the time period specified by the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), or Northwest Power Pool (NWPP) criteria.

b. Failure of a generator in the BPA Control Area or which directly interconnects to the FCRTS to change generation levels when directed to do so by the BPA-TBL. This includes failure to change generation levels pursuant to such orders within the time period specified by NERC, WECC, or NWPP criteria.

c. Failure to curtail or redispatch a reservation or schedule or failure to curtail or redispatch actual transmission use of the Contract or Service Agreement when directed to do so by the BPA-TBL in accordance with the curtailment or redispatch provisions of the Open Access Transmission Tariff or any other applicable agreement between the parties. This includes failure to curtail or redispatch pursuant to such scheduling protocols or orders within the time period specified by NERC, WECC, or NWPP criteria.

Attachment 5

Rate Schedule Language: Hourly Nonfirm Service [1]

The language in quotation marks will be included in the following rate schedules in the Initial Proposal: PTP; IS; IM; ACS Scheduling, System Control and Dispatch; ACS Reactive Supply and Voltage Control from Generation Sources.

I. Billing Factor

"The Billing Factor for the rate specified in section ___[2] for Hourly Non-Firm Service shall be the scheduled kilowatthours."

"Upon 60 day's notice by TBL, the Billing Factor for the rate specified in section ___[3] for Hourly Non-Firm Service shall become the Reserved Capacity."[4]

II. Interruption/Curtailment

"If Hourly Non-Firm PTP Transmission Service is Curtailed or Interrupted, the Transmission Customer will be charged for actual use during the hour, and not Reserved Capacity. If the Curtailment originates from conditions on another Transmission Provider's Transmission System, no adjustment will be made to the Reserved Capacity billing factor."

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[1] The proposed changes to the billing determinants for Hourly Non-firm service would not affect customers' contractual rights to use secondary delivery and receipt points.
[2] In the PTP rate schedule, the section number will be II.B.2; in the IS rate schedule, the section number will be II.B.2; in the IM rate schedule, the section number will be II.B.2; in the ACS Scheduling, System Control and Dispatch, the section number will be 1.b.(2); and in the ACS Reactive Supply and Voltage Control from Generation Sources rate schedule, the section number will be 1.b.(2).
[3] The appropriate section number for this blank correlate with the section numbers as listed in FN 2 above.
[4] Notice will not be given until TBL determines that the necessary changes have been made to TBL's applicable Business Practices and systems to accommodate the Billing Factor becoming Reserved Capacity.

Attachment 6

I. Regulation and Frequency Response (RFR) Service

<u>Parameters</u>
Known values:
t = Average FY 2006 and 2007 transmission cost allocated to RFR = $2,128,000
bd = Average FY 2006 and 2007 RFR billing determinant = 43,598,520 MWh

Determined in next power rate case:
P = FY 2007 PBL Generation Input cost for RFR

RFR Rates

FY2006 Rate = 0.32 mills/kWh

FY2007 Rate (calculated prior to FY2007, following power rate case)

$$\frac{t + P}{bd} = \frac{\$2{,}128{,}000 + P}{43{,}598{,}520\ \text{MWh}}$$

II. Operating Reserves Services (Spinning and Supplemental)

Parameters
Known values:
t = Average FY 2006 and 2007 transmission cost allocated to OR = $379,000
bd = Average FY 2006 and 2007 OR billing determinant = 1,787,040 MWh
r = Amount of reserves to be acquired from PBL during 2007 = 204.5 MWyr

Determined in next power rate case:
P = FY 2007 PBL Generation Input unit cost for reserves ($/MWyr)

OR Rates

FY2006 Rate = 7.93 mills/kWh

FY2007 Rate (calculated prior to FY2007, following power rate case)

$$\frac{t + (P \times r)}{bd} = \frac{\$379{,}000 + (P \times 204.5\ \text{MWyr})}{1{,}787{,}040\ \text{MWh}}$$

Attachment 2

ENTITIES THAT HAVE SIGNED
THE 2006 TRANSMISSION RATE CASE SETTLEMENT AGREEMENT
AS OF JANUARY 12, 2005

Alcoa, Inc.
Avista Corp.
Benton County PUD
BPA Power Business Line
Cheney, City of
Columbia Falls Aluminum Co.
Cowlitz County PUD No. 1
Emerald PUD
Franklin PUD
Grant County PUD
Idaho Energy Authority
  Representing:
  Burley, City of
  Declo, City of
  East End Mutual Electric Co.
  Farmer's Electric Cooperative
  Heyburn, City of
  Idaho County Light & Power Cooperative
  Idaho Falls Power
  Lower Valley Energy
  Minidoka, City of
  Riverside Electric Cooperative
  Rupert, City of
  Soda Springs, City of
  South Side Electric
  United Electric Cooperative
Kaiser Aluminum
Northwest Independent Power Producers Coalition (NIPPC)
Northwest Requirements Utilities
  Representing:
  Ashland, City of
  Benton REA
  Big Bend Electric Cooperative
  Bonners Ferry, City of
  Burley, City of
  Cascade Locks, City of
  Central Lincoln PUD
  Columbia Basin Electric Cooperative
  Columbia Power Cooperative
  Columbia River PUD

Columbia REA
East End Mutual Electric
Ferry County PUD 1
Flathead Electric Cooperative
Forest Grove, City of
Glacier Electric Cooperative
Harney Electric Cooperative
Hermiston Energy Services
Hood River Electric Cooperative
Idaho County Light & Power
Inland Power & Light
Klickitat County PUD
Kootenai Electric Cooperative
Lincoln Electric Cooperative
Lower Valley
McMinnville, City of
Midstate Electric Cooperative
Mission Valley Power
Missoula Electric Cooperative
Modern Electric Water Co.
Monmouth, City of
Nespelem Valley Electric Cooperative
Northern Wasco County PUD
Orcas Power & Light Cooperative
Oregon Trail Electric Cooperative
Ravalli County Electric Cooperative
Rupert
Salem Electric
Skamania County PUD
Surprise Valley
Tanner Electric Cooperative
Tillamook County PUD
United Electric Cooperative
Vera Water & Power
Vigilante Electric Cooperative
Wasco Electric Cooperative
Wells Rural Electric Cooperative

NorthWestern Energy
PacifiCorp
Pend Oreille County PUD No. 1
PNGC

Representing:
Blachly-Lane Electric Cooperative
Central Electric Cooperative
Clearwater Power Company
Consumers Power Inc.
Coos-Curry Electric Cooperative

Douglas Electric Cooperative
Fall River Rural Electric
Lane Electric Cooperative
Lost River Electric Cooperative
Northern Lights, Inc.
Okanogan County Electric Cooperative
Raft River Rural Electric Cooperative
Salmon River Electric Cooperative
Umatilla Electric Cooperative
West Oregon Electric Cooperative

Port Townsend Paper Corp
Portland General Electric
POWEREX Corp.
Public Power Council
Puget Sound Energy, Inc.
Renewable Northwest Project
Seattle City Light
Springfield Utility Board
Sumas, City of
Tacoma Power
Tractebel Electricity & Gas International
Wahkiakum County PUD #1
WPAG

Representing:
Alder Mutual Light
Benton REA
Clallam County PUD #1
Clark County PUD #1
Eatonville, Town of
Ellensburg, City of
Elmhurst Mutual Power & Light
Grays Harbor County PUD #1
Kittitas County PUD #1
Lakeview Light & Power
Lewis County PUD #1
Mason County PUD #1
Mason County PUD #3
Milton, City of
Ohop Mutual Light
Pacific County PUD #2
Parkland Light & Water
Peninsula Light
Port Angeles, City of
Snohomish County PUD
Steilacoom, Town of

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TESTIMONY OF F. STEVEN KNUDSEN AND JOHN R. WOERNER

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: REVENUE FORECAST

TESTIMONY OF

F. STEVEN KNUDSEN AND JOHN R. WOERNER

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: REVENUE FORECAST

SECTION 1. INTRODUCTION AND PURPOSE

Q. Please state your name and qualifications.

A. My name is F. Steven Knudsen. My qualifications are stated in TR-06-Q-BPA-03.

A. My name is John R. Woerner. My qualifications are stated in TR-06-Q-BPA-07.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor and describe Bonneville Power Administration (BPA) Transmission Business Line's (TBL) revenue forecast for Fiscal Years (FYs) 2005-2007.

Q. How is your testimony organized?

A. This testimony is organized in three sections. Section 1 is this introduction. Section 2 describes the derivation of the sales forecasts and presents a summary of it shown as Attachment 1. Section 3 describes the revenue forecast and presents a summary of revenues under current and proposed rates. Revenues under current rates are shown for FY 2005 through FY 2007 in Attachment 2. Revenues under proposed rates for FYs 2006 and FY 2007 appear as Attachment 3.

SECTION 2. SALES FORECAST

Q. What are the requirements of the sales forecast?

A. Sales are forecasted for each transmission service TBL offers. Sales over the Network segment of the federal transmission system are distinguished from those over the Southern Intertie segment. Different methodologies are used for forecasting long-term versus short-term business; and within long-term, between contract demand and load-based sales.

Q. Has use of the transmission system changed since the revenue forecast of the 2004 transmission rate case?

A. Yes. Transmission sales and revenues have declined significantly for a number of reasons. Customers are making increasing use of the secondary market for transmission capacity by entering into bilateral arrangements to share existing transmission contract capacity. Customers are also making more frequent use of Section 22.2 of the Open Access Transmission Tariff (Tariff) to redirect existing firm transmission to alternate points of receipt and delivery on a firm basis. Both of these activities tend to reduce the demand for revenue producing long-term and short-term transmission service from TBL. In addition, contracts for long-term south-to-north Southern Intertie business and the large base of aluminum direct service industry customers have all but disappeared.

Q. What categories of sales are forecast?

A. The categories of sales forecast for services provided under the Tariff are load-based Network Integration (NT) service and contract demand Point-to-Point (PTP) service. PTP sales can be long term, for a year or more of service, or short term, for less than one year. PTP service is offered on the Network, Southern Intertie, and Montana Intertie segments of the federal transmission system. Sales are also forecast for long-term service on the Network segment of the transmission system that is provided under legacy, contract-demand based Formula Power Transmission (FPT) and Integration of Resources (IR) contracts that we expect will convert to Tariff service when they expire. Utility Delivery Charge and ancillary services sales are also forecasted.

Q. How are NT sales forecast?

A. For non-generating customers served entirely with federal power, NT sales are forecast from point of delivery (POD) load forecasts. These POD forecasts are straight-line extrapolations, which means they incorporate a simple growth trend based on observed growth over 5 years of history, adjusted on a case-specific basis for known events such as the addition or loss of a large local load. For generating customers served with a mix of federal and non-federal power, NT sales are developed from BPA White Book forecasts, NW Power Pool Operating Program load forecasts, or from billing history. Forecasts of NT sales based on published system load or area load forecasts are first converted to sales units of the NT billing determinant, which is Network Load on the hour of the monthly transmission peak load, and then spread across PODs contained in NT agreements. The POD level forecasts are summed and shown as the NT Load Shaping forecast in Attachment 1, line 19. Customer-Served Load (CSL) declared in NT contracts is subtracted from Load Shaping to produce the NT Base billing determinant shown on Attachment 1, line 3.

Q. *How are the Utility Delivery Charge sales forecast?*

A. Utility Delivery Charge sales are the amounts from the NT Load Shaping forecast served through the low voltage PODs that are assessed the Utility Delivery Charge. Low voltage PODs are those in which TBL owns the transformer and the low side voltage is less than 34.5kV. The forecast is shown on Attachment 1, line 20.

Q. *What long-term contract demand products does TBL sell on the Network segment?*

A. Long-term service over the TBL Network billed on transmission demand is provided under the Formula Power Transmission (FPT), Integration of Resources (IR), and Point-to-Point (PTP) contracts.

Q. *How is the forecast of long-term transmission demand for these products developed?*

A. First, a base forecast of executed contracts is established by summing the contract amounts from each PTP, FPT and IR agreement that is in effect at the start of the forecast period. These contract amounts are summed for each month of the forecast period extending through the end of the rate period. Any contract with an expiration date prior to the end of the rate period is specified as zero beginning the month after expiration. Thus, the forecast of executed contracts is the base level of future sales secured by contract, assuming no expiring contract is renewed.

Second, to this base forecast, all expiring FPT and IR contract amounts are continued through FY 2007 to reflect a preliminary determination that these contracts will all be converted to PTP service. *See* Attachment 1, line 5. Third, we identify any FPT or IR contracts that we forecast will not be converted to PTP and subtract them from the forecast. *See* Attachment 1, "Exceptions to Conversion," line 6. Fourth, for each expiring PTP contract that is eligible to renew its service, we evaluate the likelihood that the party will exercise that right. Those contracts forecasted to exercise renewal rights are summed and added to the forecast. Fifth, we forecast the expected new PTP sales. These forecasted new PTP sales are assumed to start at various monthly points over the forecast period, and continue thereafter through the end of the rate period.

Q. What assumptions were used to determine which terminating PTP contracts would renew service?

A. We evaluated each terminating PTP contract to determine if it had renewal rights under section 2.2 of the Tariff. If rights to renew were excluded in the contract provisions, the contract was not extended beyond its termination date. Otherwise, the transmission demand was extended through the rate period if the contract facilitated power deliveries to the customer's system or to the head of the Southern Intertie. Projected contract renewals are shown on Attachment 1, line 7.

Q. On what basis do you project new long-term PTP sales from the long-term queue?

A. The projections of new PTP sales shown on line 8 of Attachment 1 are based on analyst judgment, taking into account available transmission capacity (ATC), regional economic activity, load resource balance, and an examination of individual requests in TBL's generation interconnection queue and long-term transmission queue. New business from the long-term queue is the most speculative of all categories of sales incorporated in the network sales forecast. The number and size of requests in the queue are poor predictors of new sales. The outlook for any significant level of new incremental sales during the forecast period is low. Because of the current generation surplus in the region and the limited amount of actual generation construction activity, only a minimal level of new PTP sales is included in the forecast.

Q. How is the forecast of long-term transmission demand for the Southern Intertie (IS) developed?

A. First, a tally of the amount of existing long-term transmission demand determines the base level of future sales secured by contract, assuming no expiring contract is renewed. *See* Attachment 1, lines 12 and 13. Second, we prepare a forecast of contract renewals by parties whose contracts expire during the forecast period with Section 2.2 renewal rights. Approximately 50% and 70% of the expiring contracts in FY 2006 and FY 2007, respectively, are assumed to be renewed. The forecast of contract renewals is shown on Attachment 1, line 14. Lastly, contract demands expected to be in place during FY 2005 that are in excess of FY 2004 levels are shown as new business on Attachment 1, line 15.

Q. What risk is associated with the forecast of contract renewals on the Southern Intertie?

A. Fully 76% of the existing contracted capacity on the Southern Intertie expires prior to the end of the rate period. There is a significant level of risk that some of these contracts will not be renewed. Unlike long-term network PTP contracts that are used to meet load in the Pacific Northwest (PNW), the predominant use of the Southern Intertie is to conduct economic energy trade between the PNW and California and the Pacific Southwest. The value underlying this inter-regional trade is a function of a multitude of structural market variables, many of them highly volatile over time. These variables include, but are not limited to, load growth, generation additions and retirements, electric and natural gas infrastructure expansion and regional differences in the delivered price of gas, and regulatory actions. A number of these variables have led us to perceive significant risk associated with expiring long-term Southern Intertie sales, including the large amounts of highly efficient competitive generation additions in California and the Southwest, the completion of Path 15 transmission upgrades expanding competitive supplies into Northern California, significant gas transmission expansions into the Southwest lowering gas prices relative to the Northwest, and proposed LNG import facilities in Baja California that will likely depress gas prices further relative to the Northwest.

Q. How is the forecast of long-term transmission demand for the Montana Intertie (IM) developed?

A. One reservation for 6 megawatts for PTP service on the Montana Intertie is included in the PTP Network sales. *See* Attachment 1, line 4. No other IM service is forecasted.

Q. What are short-term sales and how are they forecast?

A. Short-term sales are sales of less than one year's duration. They consist of monthly, weekly, and daily firm service as well as hourly firm and non-firm service. Short-term sales are forecast from a statistical model of recent history covering January 2001 through June 2004. Daily observations of quantitative and qualitative variables were correlated with sales. Quantitative variables included trend (time), long-term contract demand, contract demand use factors, shares of short-term sales which are hourly, Southern Intertie capacities, average forebay elevations, and bulk hub electricity prices. Qualitative variables included the Southern Intertie line (AC versus DC), redirects (before or after implementation), and seasons.

Q. *How was the forecast produced from historical relations?*

A. First, we forecast contract demand, contract use factors, and hourly shares based on their relation to time, prices, line, redirects, and seasons. These forecasts combined with a forecast of bulk hub prices were used to produce a forecast of short-term sales through FY 2007.

Q. *How were short-term Network sales distinguished from short-term Southern Intertie sales?*

A. Four forecasts of short-term sales were developed in order to more accurately model our business. Sales were grouped into four categories: Southern Intertie north to south; Southern Intertie south to north; Network headed to the Southern Intertie; and all other Network. Forecasts of the first two categories result in the short-term Southern Intertie forecast shown on Attachment 1, line 17; and forecasts of the latter two categories result in the short-term PTP forecast shown on Attachment 1, line 10.

SECTION 3. REVENUE FORECAST

Q. *Please describe the revenue forecast.*

A. A summary of the revenue forecast by product by year is shown on Attachments 2 and 3. The revenue forecast is shown assuming current rates (Attachment 2) and proposed rates (Attachment 3). The revenues from FPT, IR, PTP, NT, IS, IM and Utility Delivery sales are calculated by applying the current and proposed rates to the forecasted sales shown on Attachment 1. The rates used are shown in the Settlement Agreement. *See the testimony of* Metcalf and Parker, TR-06-E-BPA-03, Attachment 1.

Q. *How were revenues for Ancillary and Control Area Services estimated?*

A. The billing factors for the two required Ancillary Services, Scheduling, System Control, and Dispatch Service and Reactive Supply and Voltage Control from Generation Sources Service, are the same as the billing factors for transmission service. Thus, the sales forecast generated for the Network, Southern Intertie, and Montana Intertie transmission sales were also used for the revenue forecast of the two required Ancillary Services.

Sales of Operating Reserves services were forecast to remain at FY 2004 levels, with an adjustment for an expected FY 2005 increase in the amount of self-supply. Any additional increases in self-supply and new generation in the control area were assumed to cancel, warranting no change from these levels. Regulation and Frequency Response Service was assumed to grow at 1.5% per year. No net revenue was assumed from Energy and Generation Imbalance Services.

Q. Are all sources of revenue affected by the proposed rate increase?

A. No. Certain monies come into the business line from sources other than the general transmission rates. These are referred to here as revenue credits because in rate setting they are used to credit costs prior to calculating the general rates. They include revenue from certain rates such as the Townsend Garrison Transmission (TGT) and Southern Intertie Annual Cost (AC) rates, as well as revenue from various services that TBL provides such as Operation and Maintenance.

Q. How are these revenue credits forecast?

A. Revenue credits are forecast at FY 2004 levels with adjustments for known changes. These revenues, accounting for less that 10% of TBL revenues, are shown at on Attachments 2 and 3, lines 18-33.

Q. Will any changes be made to the revenue forecasts for the final rate proposal?

A. We expect to update the revenue forecast for FY 2005 for actual sales to-date. TBL does not expect to revise the revenue forecasts for the FY 2006 and FY 2007 rate period.

Q. Does this conclude your testimony?

A. Yes.

Attachment 1
Transmission Sales Forecast
FY 2005 - FY 2007
(Megawatts)

	Rate Schedule	(A) FY 2005 1/	(B) FY 2006 2/	(C) FY 2007 2/
	Network			
1	Formula Power Transmission (FPT)........	3,168	2,707	2,346
2	Integration of Resources (IR)...........	4,397	4,393	4,292
3	Network (NT) Base......................	5,780	5,915	6,008
	Long-term Point to Point (PTP)			
4	Executed Agreements (including IM).....	12,879	11,547	11,416
5	Conversions from FPT/IR................	105	587	1,049
6	Exceptions to Conversion...............	-53	-178	-187
7	Contract Renewals......................	291	1,279	1,514
8	New Sales of Long-term Service.........	403	1,103	1,138
9	Subtotal Long-term PTP...............	13,625	14,337	14,931
10	PTP Short Term.........................	604	644	740
11	**Subtotal Network.....................**	**27,573**	**27,996**	**28,316**
	Southern Intertie			
	Long-term Intertie South (IS)			
12	Executed Agreements, North to South....	3,836	3,670	3,057
13	Executed Agreements, South to North....	471	271	271
14	Contract Renewals......................	263	740	1,348
15	New Sales of Long-term IS Service......	360	0	0
16	Subtotal Long-term IS................	4,929	4,681	4,676
17	IS Short Term..........................	383	392	406
18	**Subtotal Intertie....................**	**5,312**	**5,073**	**5,082**
19	NT Load Shaping........................	6,093	6,257	6,350
20	Utility Delivery Charge................	264	194	197

1/ Forecast developed 08/07/2004.

2/ Developed 10/27/2004.

Attachment 2
TBL Revenues, Current Rates
FY 2005 - FY 2007
($000)

		(A) FY2005	(B) FY2006	(C) FY2007
	Long-Term			
	Network			
1	Formula Power Transmission	28,628	25,896	24,825
2	Formula Power Transmission	6,863	6,066	4,767
3	Integration of Resources	66,531	66,474	64,942
4	Point to Point	168,166	176,952	184,276
5	Network Integration Transmission, Base Charge	71,297	72,962	74,117
6	Network Integration Transmission, Load Shaping	31,076	31,909	32,386
	Southern Intertie			
7	Intertie South Assured Delivery	5,179	5,179	5,179
8	Intertie South	64,380	61,538	60,145
	Short-Term			
9	Network	9,104	10,772	12,550
10	Southern Intertie	8,204	8,371	8,668
	Delivery			
11	Utility	3,000	2,208	2,240
12	Industry	1,715	1,715	1,715
	Ancillary			
13	Scheduling Control & Dispatch	50,973	52,567	54,058
14	Generation Supplied Reactive	20,554	21,193	21,792
15	Operating Reserves	30,046	30,046	30,046
16	Regulation and Frequency Response	12,790	12,982	13,177
17	Generation and Load Imbalances	0	0	0
	Revenue Credits			
18	Aircraft	373	373	373
19	Annual Cost Rate and NFP Depreciation	5,557	4,243	4,243
21	Direct Corp and Bureau	1,354	954	954
22	Fiber	6,974	6,974	6,974
23	Generation Integration Costs	7,235	8,454	8,469
24	Operation and Maintenance Srvcs	882	898	898
25	Other Revenue	2,129	2,129	2,129
26	Power Factor Penalty	4,550	3,640	3,413
27	Remedial Action Scheme	51	51	51
28	Reservation Fees	318	200	200
29	Townsend Garrison Transmission	9,796	9,796	9,796
30	Unauthorized Increase Charge	0	0	0
31	Use of Facilities	6,465	6,921	6,921
33	Wireless Personal Communications	3,620	3,795	3,795
34	**Subtotal Network**	**381,663**	**391,032**	**397,863**
35	**Subtotal Southern Intertie**	**77,763**	**75,088**	**73,992**
36	**Subtotal Delivery**	**4,714**	**3,922**	**3,955**
37	**Subtotal Ancillary**	**114,362**	**116,788**	**119,073**
38	**Subtotal Revenue Credits**	**49,304**	**48,428**	**48,216**
39	**Total TBL**	**627,806**	**635,258**	**643,100**

Attachment 3
TBL Revenues, Proposed Rates
FY 2006 - FY 2007
($000)

		(A) FY2006	(B) FY2007
	Long-Term		
	Network		
1	Formula Power Transmission	29,446	28,228
2	Formula Power Transmission	6,066	4,767
3	Integration of Resources	78,230	76,427
4	Point to Point	209,313	217,977
5	Network Integration Transmission, Base Charge	86,305	87,671
6	Network Integration Transmission, Load Shaping	27,554	27,967
	Southern Intertie		
7	Intertie South Assured Delivery	5,333	5,333
8	Intertie South	63,369	61,935
	Short-Term		
9	Network	12,941	15,072
10	Southern Intertie	8,684	8,991
	Delivery		
11	Utility	2,611	2,650
12	Industry	1,715	1,715
	Ancillary		
13	Scheduling Control & Dispatch	64,276	66,099
14	Generation Supplied Reactive	21,493	22,099
15	Operating Reserves	28,398	28,398
16	Regulation and Frequency Response	13,847	14,055
17	Generation and Load Imbalances	0	0
	Revenue Credits		
18	Aircraft	373	373
19	Annual Cost Rate and NFP Depreciation	4,243	4,243
21	Direct Corp and Bureau	954	954
22	Fiber	6,974	6,974
23	Generation Integration Costs	8,454	8,469
24	Operation and Maintenance Srvcs	898	898
25	Other Revenue	2,129	2,129
26	Power Factor Penalty	3,640	3,413
27	Remedial Action Scheme	51	51
28	Reservation Fees	200	200
29	Townsend Garrison Transmission	9,796	9,796
30	Unauthorized Increase Charge	0	0
31	Use of Facilities	6,921	6,921
33	Wireless Personal Communications	3,795	3,795
34	**Subtotal Network**	**449,856**	**458,108**
35	**Subtotal Southern Intertie**	**77,386**	**76,260**
36	**Subtotal Delivery**	**4,326**	**4,365**
37	**Subtotal Ancillary**	**128,014**	**130,652**
38	**Subtotal Revenue Credits**	**48,428**	**48,216**
39	**Total TBL**	**708,011**	**717,600**

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TESTIMONY OF

RONALD J. HOMENICK, DANA M. JENSEN, AND BYRNE E. LOVELL

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: REVENUE REQUIREMENT STUDY AND RISK ANALYSIS

TESTIMONY OF

RONALD J. HOMENICK, DANA M. JENSEN, AND BYRNE E. LOVELL

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: REVENUE REQUIREMENT STUDY AND RISK ANALYSIS

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 TR-06-Q-BPA-01.

A. My name is Dana M. Jensen and my qualifications are contained in TR-06-Q-BPA-02.

A. My name is Byrne E. Lovell and my qualifications are contained in TR-06-Q-BPA-04.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to sponsor the development of the transmission revenue requirements for fiscal years 2006 and 2007 (Rate Period) used to establish the rates for transmission and ancillary services provided on the Federal Columbia River Transmission System (FCRTS). This testimony also sponsors the Revenue Requirement Study (Study), TR-06-E-BPA-01, and the Documentation for the Revenue Requirement Study (Documentation), TR-06-E-BPA-01A.

Q. How is your testimony organized?

A. Our testimony addresses changes from BPA's practices in prior rate cases in the payment obligations and assumptions used to develop the transmission revenue requirements for the Rate Period and to demonstrate cost recovery and repayment of the Federal investment. First, in Section 2, we identify certain new payment obligations and capital funding assumptions reflected in the transmission revenue requirement study, including the use of cash reserves to fund capital expenditures and two forms of non-Federal payment obligations. In Section 3, we describe technical changes related to the treatment of data in the transmission repayment study. In Section 4, we address the risk of Treasury payment probability. In Section 5, we discuss the potential for adjustments and updates that may be made in the Final Rate Proposal.

SECTION 2. REVENUE REQUIREMENTS

Q. *Have any changes been made to the way Bonneville Power Administration (BPA) determines the transmission revenue requirements?*

A. No. There have been no changes in the methodology BPA uses for determining transmission revenue requirements.

Q. Are there any changes to BPA's cost obligations or assumptions that affect the determination of transmission revenue requirements?

A. Yes. The transmission revenue requirements for the Rate Period reflect the assumption that BPA will use $15 million per year of transmission cash reserves as a funding source for transmission capital programs and incorporate two forms of non-Federal long-term payment obligations.

Q. What non-Federal payment obligations have been incorporated in the rate proposal?

A. Recently, BPA undertook two financial obligations involving non-Federal sources that benefit the transmission system during the Rate Period and beyond. These are the obligation for annual payments associated with a third-party lease-purchase arrangement for a long-term capitalized transmission asset purchase (lease-purchase), and the reassignment to transmission of a portion of refinanced Energy Northwest (EN) non-Federal bond debt service obligations under BPA's Debt Optimization Program (Debt Service Reassignment).

SECTION 2A. Use of Cash Reserves

Q. Why is BPA proposing to use cash reserves to fund capital expenditures during the rate period?

A. As part of the Settlement Agreement, BPA is using $15 million per year of transmission-generated cash reserves to fund transmission capital programs. *See* section 8 of the Settlement Agreement in the testimony of Metcalf and Parker, TR-06-E-BPA-03, Attachment 1.

Q. Were cash reserves used in this way in prior rate cases?

A. No. In prior transmission rate cases, BPA specifically included a cash requirement for funding a portion of new transmission capital expenditures in the development of revenue requirements. As part of the Settlement Agreement for the current rate case, BPA is changing the source of funds from a cash requirement in revenue requirement development to a draw-down of existing cash reserves in the same amount.

Q. Why is the amount proposed to be $15 million?

A. BPA has used this amount in the past three transmission rate filings. Some utilities do not debt finance their short-lived capital investments. For the current rate case, BPA determined that capital investments with an average service life of five years, information technology (IT), were appropriate for revenue financing. The projected new IT capital investments for the rate period average about $15 million per year. *See* Documentation, TR-06-E-BPA-01A, Chapter 3, "BPA Transmission General Plant, Projected Plant Additions."

Q. How is the proposed use of cash reserves reflected in the revenue requirement for the Rate Period?

A. In the Statement of Cash Flows, the projected Treasury borrowing is $15 million less than the cash used for capital investments each year. The draw-down of cash reserves is included as a source of funds in cash from current operations to cover that difference. Study, TR-06-E-BPA-01, Table 4. As a direct result, the interest income calculation reflects this draw-down, showing the decrease in available cash reserves during the rate period. Documentation, TR-06-E-BPA-01A, Chapter 4.

SECTION 2B. Third-Party Lease-Purchase Model

Q: Please describe the lease-purchase model.

A. The lease-purchase model allows BPA to make long-term capitalized asset purchases of transmission infrastructure without using BPA's Treasury borrowing authority.

Q. *How has BPA used the lease-purchase model?*

A: In March 2004, BPA entered into a 30-year lease-purchase agreement with the Northwest Infrastructure Financing Corporation (NIFC), a subsidiary of JH Management, for the construction of the Schultz-Wautoma 500 kilovolt transmission line. BPA expects that the Schultz-Wautoma line will be energized during the rate period in November 2005.

Q: *What are the features of the lease-purchase agreement?*

A: Under the terms of the lease-purchase agreement, BPA will make lease rental payments to NIFC for the next 30 years, with the right to prepay the present value of the lease payments at any point in the 30-year period. At the end of the lease, BPA has the option to enter into another lease with NIFC or purchase the Shultz-Wautoma line for $10. Under the lease-purchase arrangement, BPA will operate the Shultz-Wautoma line as part of the FCRTS and provide transmission service over the facilities for the term of the lease.

Q: *How is this obligation reflected in the initial rate proposal?*

A: In revenue requirements, the annual lease payment appears as an operating expense and is a component of TBL's total lease payments. In the transmission repayment study, the annual debt service stream over the life of the lease-purchase agreement is included as a fixed obligation. This obligation is treated in the repayment study the same way that generation studies have incorporated non-Federal debt service, which is consistent with the priority of revenue application in BPA statutes and Department of Energy repayment policy, RA 6120.2. Because these types of obligations have a higher priority of annual revenue application, the repayment study schedules repayment of Federal obligations to accommodate the non-Federal payment obligations during the repayment period.

Q. *Does BPA expect to use lease-purchase models in the future?*

A. Because BPA's access to Treasury borrowing is limited, it is important for BPA to consider alternative arrangements to keep up with demands on its transmission infrastructure. If the right business conditions exist, it is likely BPA would use a similar approach in other circumstances. BPA, however, forecasts no other lease-purchase commitments during the Rate Period.

SECTION 2C. Debt Optimization Program

Q: *Please describe the Debt Optimization Program.*

A: As previously stated, BPA's access to Treasury borrowing is limited. In FY 2001 BPA began carrying out a Debt Optimization (DO) Program in conjunction with Energy Northwest (EN) as a means for BPA to replenish its 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 2013 to 2018 period, which is the maximum allowable maturity of these particular obligations. The revenue that otherwise would have been used to pay the principal of the refunded EN debt is used to repay an equivalent amount of Federal obligations, thereby restoring Treasury borrowing authority or providing opportunities for future restoration of borrowing authority for the agency.

Q. *How has BPA applied revenues made available by DO?*

A. Since the maturing EN debt service was contractually incurred by BPA as a purchased power obligation, initially BPA used the revenue made available by DO to repay an equivalent amount of generation-related Treasury obligations. This was done in a manner that did not increase the combined levelized Federal and non-Federal debt service in the generation repayment study. Essentially, DO repays Federal obligations in the current period in amounts that, absent DO, would have been scheduled to be repaid during the period in which 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 concept.

Q: *What is Debt Service Reassignment?*

A: In 2003, BPA applied DO proceeds to repay Treasury obligations associated with the transmission function. The funds to repay the transmission Treasury obligations were raised from power revenues that were made available after the maturing EN debt obligation was retired by the proceeds of the new EN debt. Therefore, BPA has reassigned to the transmission function the repayment obligation for debt service associated with new EN debt that is equivalent to the amount of power revenue used to amortize transmission Treasury obligations. The recovery of that portion of the debt service for the refinanced EN debt that is assigned to transmission is no longer reflected in the costs of BPA's generation function.

Q: Has BPA reassigned the 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 incorporates additional costs associated with the EN bond refinancings such as issuance costs. Under BPA's debt service reassignment concept, the transmission function is responsible for the recovery of any and all relevant costs associated with the swap of EN debt service for Federal obligations associated with transmission, and BPA's generation function is held harmless. For BPA's Power Business Line, it is as if the refinancing transactions related to debt service reassignment 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 Power Business Line's obligation to recover the maturing EN principal cost has been satisfied. *See* Documentation, TR-06-E-BPA-01A, Chapter 7.

Q: Does Debt Service Reassignment extend the allowable repayment period as defined by RA 6120.2 for the cost obligations associated with Federal transmission assets?

A: No. The transmission-related Treasury obligations that were repaid early had remaining allowable repayment periods that extended beyond the 2013-2018 timeframe in which the new EN debt is retired.

Q: How is this treated in the repayment study?

A: The payment obligation under Debt Service Reassignment is incorporated in the repayment study as a fixed stream of annual debt service in the same way and for the same reasons as the Schultz-Wautoma lease-purchase arrangement previously described. Similar to the DO effect in BPA's generation repayment study described above, the new EN debt maturities assigned to transmission were selected so that BPA's transmission repayment study would reflect no increase in the combined levelized annual debt service over what would have occurred without DO.

Q: How is Debt Service Reassignment treated in revenue requirements?

A: In BPA's business line accounting and ratemaking, the reassigned debt service becomes associated with Federal transmission assets that have their capital investment recovered through annual depreciation expense. Essentially, a debt swap was transacted. As such, the reassigned debt service components are treated the same as their Federal debt counterparts. The interest component is included in the determination of transmission net interest expense. While there are no scheduled principal payments in the Rate Period, the principal payment will appear as a cash requirement on the cash flow table in future studies for years when principal payments are due.

SECTION 3. TECHNICAL CHANGES IN REPAYMENT STUDIES

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

A. Yes. During FY 2004, BPA implemented a new Bond Rollover feature in the Munex software associated with the repayment study model.

Q. What is the Bond Rollover feature?

A. The Bond Rollover feature is a new data manipulation capability associated with BPA's repayment model. It allows the study to mirror BPA's actual practice of rolling over (refinancing) short-term bonds if BPA determines that revenues are insufficient 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, 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 proceeds 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 will ultimately 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. RISK ANALYSIS

Q. Has TBL made any changes to its risk analysis methodology?

A. No. BPA used the same method and spreadsheet model for the risk analysis used in the 2002 Final Transmission Proposal and the 2004 Final Transmission Proposal. See 2002 Final Revenue Requirement Study, TR-02-FS-BPA-01, Section 2.2; 2002 Final Revenue Requirement Documentation, TR-02-FS-BPA-01A, Chapter 9; Westman and Sapp, TR-02-E-BPA-07; 2004 Final Revenue Requirement Study, TR-04-FS-BPA-01; 2004 Final Revenue Requirement Documentation, TR-02-FS-BPA-01A, Chapter 9.

Q. What are the results of the risk analysis for this rate period?

A. In this rate proposal, TBL has identified and quantified transmission risks and designed risk mitigation tools that achieve BPA's policy standard of a 95 percent U.S. Treasury payment probability. Simulations of BPA's financial reserves attributable to the transmission function have a most-likely value of $179 million at the beginning of FY 2006. These reserves and the cash flow anticipated from the proposed rates for FY 2006 and FY 2007 meet the TPP standard without the need to include any planned net revenue for risk in the revenue requirement. Study, TR-06-E-BPA-01, Section 2.2.

SECTION 5. ADDITIONAL MODIFICATIONS AND ADJUSTMENTS

Q. Were any modifications made to the schedule of planned amortization payments of the Federal debt that were included in the FY 2006 and 2007 revenue requirements?

A. Yes. To demonstrate full cost recovery by year in the Rate Period under the revenues from proposed rates, it was necessary to shift $10 million of planned amortization of Federal debt from FY 2007 to FY 2006. Study, TR-06-E-BPA-01, Chapter 4.3. This action was taken because expected revenues were insufficient to cover all cash requirements in FY 2007, but were more than sufficient in FY 2006. Consequently, the planned amortization was reshaped to accommodate the revenue forecast. In total in the rate period, there is the same amount of amortization as was included in revenue requirements. Study, TR-06-E-BPA-01, Table 2. This procedure of reshaping planned amortization has been a long-standing practice in BPA rate filings, including the 2004 transmission rate filing, to ensure adequate cash flows from proposed rates to meet annual cash requirements. *See, for example* 2004 Final Revenue Requirement Study, TR-04-FS-BPA-01, Table 2.

Q. *What additional changes could affect the Revenue Requirement Study in the Final Rate Proposal?*

A. We do not expect any changes to the expense and capital program levels reflected in revenue requirements for the Rate Period. However, revenue and expense forecasts and resulting cash flows for FY 2005 likely will be updated when the final studies are prepared.

Q. *What effect would these changes have on the risk analysis?*

A. Any changes to FY 2005 revenues and expenses will be run through the risk analysis and could affect the amount of cash for risk that is anticipated. While these changes could affect the final TPP, it is quite unlikely that such changes would cause the final rate proposal to fail the TPP standard and therefore require the addition of Planned Net Revenue for Risk to the revenue requirement.

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

A. The interest credit on cash reserves would change according to any increase or decrease in projected cash reserves available at the start of the rate period. This would be reflected in the income statements for the revenue requirements, the current revenue test and the revised revenue test.

Q. *Does that conclude your testimony?*

A. Yes.

QUALIFICATION STATEMENT OF

RONALD J. HOMENICK

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Ronald J. Homenick. I am employed by the Bonneville Power Administration (BPA), 905 NE. 11th Avenue, Portland, Oregon, 97232.

Q. In what capacity are you employed?

A. I am a financial analyst in the Financial Analysis and Requirements group of Corporate Finance.

Q. Please state your educational background.

A. I received a Bachelor of Arts degree in English from Kent State University in 1973.

Q. Please summarize your professional experience.

A. From 1982 to 1985, I was employed as a Computer Programmer/Analyst for Electronic Data Systems under contract with BPA. In that capacity, I worked with the group that is now part of Financial Analysis & Requirements, designing and implementing numerous BPA revenue requirement/cost of service computer applications and performing various financial analyses related to BPA's 1983 and 1985 rate cases.

In 1984, I researched historical costs and performed various financial analyses that formed the financial basis of BPA's compliance report to the Federal Energy Regulatory Commission on separate accounting for power and transmission functions.

In 1985, I became a BPA employee and worked for the group that is now the Financial Analysis & Requirements section. I have been employed as a financial analyst since 1986. In this capacity, I have been responsible for various financial analyses related to revenue requirement development, such as preparation of the projected Federal Columbia River Power System investment base, depreciation forecasts, functionalization, and segmentation of the transmission revenue requirements.

I have been the primary analyst in Financial Services responsible for the annual preparation of the separate accounting analysis. I am also one of BPA's primary analysts in the area of repayment policy.

Q. Please state your experience as a witness in previous proceedings.

A. I have appeared as a witness on Revenue Requirement issues in BPA's 1991, 1993, 1995, and 1996 general rate proceedings, BPA's 3rd AC Intertie Non-Federal Participation rate case, BPA's 2002 wholesale power rate proceeding and the 2002 and 2004 transmission rate proceedings.

QUALIFICATION STATEMENT OF

DANA M. JENSEN

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Dana M. Jensen. I am employed by the Bonneville Power Administration (BPA), 905 NE. 11th Avenue, Portland, Oregon, 97232.

Q. In what capacity are you employed?

A. I am a financial analyst in the Financial Analysis and Requirements group in Corporate Finance.

Q. Please state your educational background.

A. I received an Associates degree in Humanities and General Studies from Lane Community College, Eugene, Oregon in 1987; a B.S. degree in Finance and Management from the University of Oregon in 1989; and a MBA from Portland State University in 1995. My field of concentration was public finance.

Q. Please summarize your professional experience.

A. I am currently employed as a financial analyst at BPA. I provide economic and financial analytical support for rate case and regulatory proceedings. I serve as a senior technical analyst in developing cost, revenue, and financial forecasts and related analyses with the financial and operating condition of BPA, its business lines, customers, and competitors. I participate in preparing and implementing BPA's financial business strategy; measure financial performance against strategic goals; analyze industry and marketplace developments including potential State and Federal legislation that may affect BPA's future financial integrity; and develop and maintain financial data, forecast systems, and analytical tools.

In my previous position here at BPA, I (with one other person), developed a credit review function to assess creditworthiness and determine credit limits for new customers (wholesale). I developed the procedures and a procedure manual, programmed rating criteria into our model, and developed a model to pull records from a data base program into Excel for manipulation and calculation and then to compile a user report. I performed credit analysis and review for our Environmental department on potential hazardous waste contractors. I conducted ad hoc analysis for customer account executives consisting of things such as financial profiles, ratio analysis, net present value project analysis, revenue and profit forecasts, cost-effectiveness, buy vs. lease, etc. I developed current and pro forma business line financial statements and developed and used financial models (using Excel) to identify and assess the financial effects of alternative capital spending and expense levels and financing alternatives. I served as an in-house management consultant, performing studies on efficiency, cost analysis, and feasibility. I also assisted staff end-users in computer troubleshooting and loading software.

Prior to BPA, I worked for two years as a residential mortgage loan processor and substitute loan officer at a savings bank. I conducted extensive credit and financial analysis of the borrowers and builders, reviewing private and corporate (mainly sub S) financial statements and other records. I compiled summary reports based on my analyses for the underwriters and loan committee.

From September 1994 to October 1996, I was a Reserve Police Officer for the City of Hillsboro.

Q. Have you ever been a witness in a rate case?

A. Yes. I was on the Revenue Requirements Panel in the 2002 Generation Rate Case and on the same panel in the 2004 Transmission Rate Case.

QUALIFICATION STATEMENT OF

F. STEVEN KNUDSEN

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is F. Steven Knudsen. I am employed by the Bonneville Power Administration (BPA), 5411 N.E. Highway 99, Vancouver, Washington.

Q. In what capacity are you employed?

A. I am a senior strategy analyst in the Transmission Contracts, Business Strategy, and Assessment section of the Transmission Marketing and Sales group. *Q. Please state your educational background.*

A. I graduated from University of Oregon in 1976 with a Bachelor of Science degree in Economics. I earned an MBA from the Northwestern University Kellogg School in 1979.

Q. Please summarize your professional experience.

A. I have been employed at BPA for approximately 15 out of the last 22 years. I first came to BPA in 1983 after five years with the US General Accounting Office as a management analyst. From 1983 to 1986, I was Section Chief of the Utility Load Section in the Office of Financial Management where I was responsible for financial modeling and analysis, financial policy development, and official agency projections as well as assessments of future financial position and revenue requirements. From 1986 to 1988, I was Branch Chief of the Revenue Requirements Branch where I supervised the development of Treasury repayment policies and preparation of the Revenue Requirement Study and associated Functionalization and Segmentation Studies for BPA's 1987 Rate Case.

From 1988 to 1990, I was Section Chief of the Utility Load Section in the Office of Energy Resources where I was responsible for developing monthly and hourly load forecasts for specific utilities to support BPA system planning, hydro-system operations, revenue forecasting and power marketing. In that capacity, I supervised the development of load forecasts used in developing BPA's 1990 Rate Case.

From 1990 until 1994, I was both a Section Chief and Branch Chief in BPA's Resource Planning Division where I developed and implemented resource planning and demand or supply side acquisition policies and strategies, risk management policies, and financial hedging strategies.

From 1994 through 1995, I was a BPA Account Executive responsible for sales of electric power and transmission products to electric power marketers and independent power producers.

From 1996 through 1999, I was employed by Pacific Gas Transmission Company as an Account Manager. In that position, I conducted gas transmission market development and account management activity focusing primarily on utilities in the Pacific Northwest and Independent Power Producers. I formulated market and regulatory strategies to support pipeline capacity marketing and the development and pricing of new products and services.

From 2000 through 2002, I was employed by PG&E Energy Trading as Director of Market Development where I was responsible for gas and power marketing and long-term commodity sales and purchases transactions throughout the western United States. I also was responsible for generating resource development in the Rocky Mountain West and was lead developer for the 113 MW Plains End Generating Project currently operating in Arvada, Colorado. In my capacity developing generating resources, I responded to utility

Requests For Proposals for power supply and negotiated subsequent agreements, such as Power Purchase Agreements. To successfully develop generating projects, I negotiated Engineering, Procurement, Construction and powerplant Operation and Maintenance contracts as well as Interconnection Agreements with the local Transmission Service Provider.

Since January of 2003, I have been employed by BPA in my current position where I work primarily on revenue forecasting, policy development, and tariff implementation. In this capacity, I direct a staff of revenue forecasters and revenue analysts responsible for developing the revenue forecast used to develop rates. I am responsible for revenue analysis and forecast performance reporting to senior management, and for directing the evaluation and development of enhancements to agency revenue forecasting methodologies and models.

Q. Please state your experience as a witness in previous proceedings.

A. I have helped prepare material for previous rate cases back to 1983, but to the best of my recollection, I was never a witness.

QUALIFICATION STATEMENT OF

BYRNE E. LOVELL

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Byrne Lovell. I am employed by the Bonneville Power Administration (BPA), 905 NE. 11th Avenue, Portland, Oregon.

Q. In what capacity are you employed?

A. I am employed as a Risk Analyst in BPA's Enterprise Risk Management group.

Q. Please state your educational background and professional qualifications.

A. I hold a Bachelor of Arts degree in Mathematics, which I received from Pomona College in 1974; a Master of Science degree in Counseling, which I received from the University of Oregon in 1980; and a Doctor of Philosophy degree in Systems Science, which I received from Portland State University in 1995.

Q. Please summarize your professional experience.

A. In 1984, I began working for BPA through a cooperative student program in the Resource Planning section of what was to become the Office of Energy Resources. I worked as an analyst and supervisor to develop and maintain mathematical models and perform analytical studies, (e.g., studies of the demand curve for Pacific Southwest market for nonfirm energy) for ten years. In June of 1994, I was appointed to a Financial Analyst position in the Finance group. In that position I was responsible for several aspects of financial risk management, including serving as the lead in the Financial Services Group for financial risk management activities in BPA's current general rate proceedings. In that position, I became responsible for the ToolKit, BPA's tool for calculating Treasury Payment Probability. In May 1997 I moved to a Policy Strategist job in BPA's Strategic Planning group. Along with the strategic planning work, my duties included continued support of BPA's risk analysis work, especially continuing to develop and run the ToolKit. I served as the senior staff analyst for BPA's probabilistic approach to analyzing fish funding, and for the non-operating risks in BPA's 1999 Power Rate Case. I am the author of the current version of The ToolKit and NORM (the Non-Operating Risk Model). My current duties involve helping design BPA's first Enterprise Risk Management program and implement it in conjunction with the Enterprise Risk Management Committee, and helping strengthen BPA's risk management programs across the Agency. My work continues to include supporting both the conceptual framework of BPA's TPP standard and work on developing the ToolKit and running TPP studies.

Q. Please state your experience as a witness in previous proceedings.

A. I appeared as a witness in BPA's 1995 and 1996 general rate proceedings, where I co-sponsored direct and rebuttal testimony on Revenue Requirement and Risk Analysis, as well as the Revenue Requirement Study and supporting documentation. I appeared again as a witness in the 2002 PBL rate case, in both the original ("May 2000" proposal) and the modified proposal finally submitted to FERC (the "Supplemental Proposal"), and in the Safety-Net CRAC 7(i) process in early 2003.

QUALIFICATION STATEMENT OF

DENNIS E. METCALF

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Dennis E. Metcalf. I am employed by the Bonneville Power Administration (BPA), 5411 NE. Highway 99, Vancouver, Washington, 98663.

Q. In what capacity are you employed?

A. I am the Manager of Business Process and Assessment in the Transmission Business Line (TBL). I have lead responsibility for the development and implementation of BPA's Transmission Rates and Tariffs.

Q. Please state your educational background.

A. I received a B.S. degree in Economics from Portland State University in 1973.

Q. Please summarize your professional experience.

A. I was initially employed at BPA in 1977 in the Division of Rates as an Industry Economist. For over 13 years I worked in the Division of Rates and the Division of Contracts and Rates. During this period, I worked on all aspects of BPA ratemaking, including retail rate review, transmission rates, cost allocation, nonfirm energy rates, power rate design, and rate case planning. I held several positions including Chief of the Rate Design Section, Chief of the Wholesale Rates Branch, and Deputy Director of the Divisions of Rates and of the Division of Contracts and Rates.

From 1991 to 1994 I was the Lower Columbia Area Power Manager. In that position I managed BPA's Power Sales business with its customers in Western Oregon and

Southwest Washington. My management functions included primarily load forecasting and contract negotiation and administration.

In 1994, I briefly served as a Direct Service Industry Account Executive.

From 1995 to 1996 I worked in Pricing, Marginal Cost and Ratemaking in a position similar to my current position. During that time I managed the development of BPA's 1995 and 1996 Transmission Rates and Transmission Terms and Conditions cases. In my current position, I managed development of BPA's 1995 and 1996 Transmission Rates and Transmission Terms and Conditions cases. In addition, I was BPA's lead representative on the IndeGo pricing team during 1996-1998. I was also been a member of BPA's core team to work on the formation of RTO West, focusing on pricing issues.

Q. *Please state your experience as a witness in previous proceedings.*

A. I filed written testimony and appeared as a witness in BPA's 1981, 1982, 1983, 1985, and 1987, 1995, 1996, 2002 and 2004 rate cases. In 1984, I testified before the Federal Energy Regulatory Commission on BPA's 1981 nonfirm energy rates. In 1986, I testified in BPA's Variable Industrial Rate Case.

QUALIFICATION STATEMENT OF

NANCY PARKER

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is Nancy Parker. I am employed by the Bonneville Power Administration (BPA), 5411 NE. Highway 99, Vancouver, Washington, 98663.

Q. In what capacity are you employed?

A. I am a Public Utilities Specialist in the Transmission Business Line (TBL).

Q. Please state your educational background.

A. I received a B.S. degree in microbiology from the University of Michigan in 1975. I have completed a portion of the Master's degree program in Business Administration at Portland State University.

Q. Please summarize your professional experience at BPA.

A. Since September 1979 I have been a Public Utilities Specialist specializing in rate development. For BPA's 1981 rate filing, I prepared studies in support of BPA's wholesale power rates, particularly the Nonfirm Energy rate.

For BPA's 1982 and 1983 rate filings, I was responsible for preparing BPA's Wholesale Power Rate Design Study. I also prepared studies in support of BPA's Surplus Firm Power and Nonfirm Energy rates. I prepared major portions of testimony on rate design issues for each of these rate filings as well as for the Federal Energy Regulatory Commission's Section 7(k) hearings on BPA's NF-1 and NF-2 Nonfirm Energy rates.

In 1986 I prepared testimony for BPA's rate hearing on the Southern California Edison Contract (SC-86) rate, and in 1988 I was in charge of the Modified SC-86 rate process.

I was responsible for the implementation of the Section 7(b)(2) methodology in BPA's 1987 rate case and supervised the development of wholesale power rate projections.

From 1990 through the beginning of 1991, I oversaw the process in which BPA decided to continue the Variable Industrial (VI) rate after the first 5 years of implementation, and to extend the rate for an additional 3 years.

During 8 months of 1991, I was temporarily assigned to the Power Management staff of the Lower Columbia Area office.

In 1992 I joined the transmission rates staff. I have worked on transmission rate and terms and conditions issues since that time.

Q. Please state your experience as a witness in previous proceedings.

A. I appeared as a witness in the following BPA rate cases: the 1985 and 1987 general rate cases, testifying on power rate issues; the Modified SC-86 rate case; the 1990 VI rate case; and the 1993, 1996, 2002 and 2004 rate cases, testifying on transmission rate issues.

QUALIFICATION STATEMENT OF

JOHN R. WOERNER

Witness for the Bonneville Power Administration

Q. Please state your name, employer, and business address.

A. My name is John R. Woerner. I am employed by the Bonneville Power Administration (BPA), 5411 NE. Highway 99, Vancouver, Washington, 98663.

Q. In what capacity are you employed?

A. I am an Industry Economist in BPA's Transmission Business Line (TBL), Transmission Contracts and Business Strategy and Assessment group.

Q. Please state your educational background.

A. I received a B.A. and M.A. degrees in Economics from the University of Montana in 1970 and 1975, respectively. I minored in philosophy and math as an undergraduate and emphasized econometrics during graduate school. Following this, I worked for 1 year in a Ph.D. program in geography at the University of Washington, where I studied regional economics and quantitative methods.

Q. Please state your professional experience.

A. I was employed as a research assistant for the Bureau of Business and Economic Research, University of Montana in 1974-1975. Since March 1980, I have worked for BPA specializing in rate development and forecasting. In BPA's 1981 and 1982 rate cases, I worked on the time-differentiation of power rates. I ran the Wholesale Power Rate Design computer program in BPA's 1983 rate case. From 1984 to 1993, I was responsible for the Transmission Rate Design model. I developed a statistical wheeling energy forecast model for BPA's 1987 transmission rate case as a front-end model to the Transmission Rate Design Study (TRDS). This model was used to forecast energy sales for rate-setting purposes through the 1993 case. I designed and populated the 1996 Transmission Rate Design Study, with similar responsibilities in the 2002 Transmission Rate Case. My current responsibilities include forecasting TBL revenue.

Q. Please state your experience as a witness in previous proceedings.

A. In BPA's 1987 rate case, I sponsored the above-mentioned statistical wheeling forecasting model as an exhibit to the TRDS. I was a member of the transmission rates panel sponsoring the TRDS in the 1993, 1996, 2002 and 2004 rate cases.

Bonneville Power Administration

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