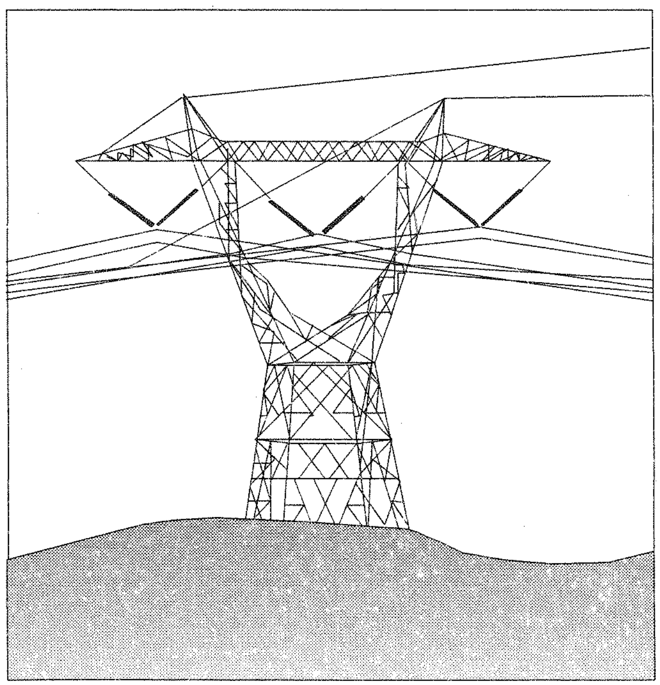
B O N N E V I L L E P O W E R A D M I N I S T R A T I O N
T R A N S M I S S I O N B U S I N E S S L I N E

2002 INITIAL TRANSMISSION PROPOSAL

DIRECT TESTIMONY

TR-02-E-BPA-05 THROUGH TR-02-E-BPA-11



BONNEVILLE
POWER ADMINISTRATION

2002 Initial Transmission Proposal
Direct Testimony

BPA Exhibit No.	Witness
TR-02-E-BPA-05	Gilman, McCollister, McReynolds
TR-02-E-BPA-06	Homenick, Jensen, Chang, Crawford
TR-02-E-BPA-07	Westman, Sapp
TR-02-E-BPA-08	Woerner, Gilman, Metcalf, Parker, Buchanan
TR-02-E-BPA-09	Stemler, Metcalf, Russell, McReynolds
TR-02-E-BPA-10	Altman, Comegys
TR-02-E-BPA-11	Anasis, Haines

March, 2000

Table of Contents
for Transmission Rate Case Testimony

INDEX

TESTIMONY OF

DAVID L. GILMAN, JOHNNY J. MCCOLLISTER AND

WARREN L. MCREYNOLDS

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: Segmentation Study – Transmission and Ancillary Services

TESTIMONY OF

DAVID L. GILMAN, JOHNNY J. MCCOLLISTER, WARREN L. MCREYNOLDS

Witnesses for the Bonneville Power Administration Transmission Business Line

SUBJECT: SEGMENTATION STUDY – TRANSMISSION & ANCILLARY SERVICES

SECTION 1 INTRODUCTION

Q. Please state your names and qualifications.

A. My name is David L. Gilman. My qualifications are at TC/TR-02-Q-BPA-08.

A. My name is Johnny J. McCollister. My qualifications are at TC/TR-02-Q-BPA-13.

A. My name is Warren L. McReynolds. My qualifications are at TC/TR-02-Q-BPA-14.

Q. Please state the purpose of your testimony.

A. The purpose of our testimony is to sponsor the Segmentation Study, TR-02-E-BPA-02.

Q. How is the testimony organized?

A. Section 1 is this introduction. Section 2 provides background on the Segmentation Study. Section 3 discusses changes in segmentation. Section 4 discusses the sale of Delivery facilities. Section 5 discusses Ancillary Service segmentation.

SECTION 2 BACKGROUND

Q. What is the purpose of the Segmentation Study?

A. The Segmentation Study classifies Transmission Business Line (TBL) facilities by the type of service they provide in order to determine their associated costs. The results of this study are the segmented investment base and O&M expense for each of the transmission segments and the ancillary services segment. The six transmission segments proposed for the Segmentation Study are the Integrated

Network, Southern Intertie, Eastern Intertie, Generation Integration, Utility Delivery, and DSI Delivery segments.

Q. What is new in the proposed Segmentation Study?

A. This study includes a new segmentation of Ancillary Services. Ancillary Services were not included in previous transmission rate proposals, as the transmission function was not expected to determine ancillary service rates. In addition this study includes a forecast of Delivery facilities expected to be sold through the end of the rate period. The study also does not include a sub-segmentation study for the Formula Power Transmission (FPT) rate or segmentation of the U.S. Army Corps of Engineer (COE) and U.S. Bureau of Reclamation (BOR) facilities.

Q. What other segmentation changes were made in the proposed Segmentation Study?

A. The facilities in the historical Fringe and Northern Intertie Segments are rolled into the Network Segment. The Delivery segments have been redefined to include facilities that deliver power at voltages below 34.5 kV.

SECTION 3 CHANGES IN SEGMENTATION

Q. Why does the Segmentation Study include a forecast of Delivery facilities to be sold through the rate period?

A. The forecast is needed to correctly determine the rate period investment and the associated O&M for the Delivery segments. A forecast was not required in previous Segmentation studies as there was no specific Bonneville Power Administration (BPA) policy to allow the sale of facilities and so no significant sales were expected. In 1996, BPA adopted a policy to allow customers to purchase Delivery substations that serve them. TBL plans to extend the sale policy through the next rate period.

Q. *Why was the FPT rate sub-segmentation excluded from the proposed Segmentation Study?*

A. The sub-segmentation for the FPT rate is no longer needed. TBL proposes to determine the 2002 FPT rate using a different method than in previous rate periods. This proposal is explained in more detail in the Transmission Rate Study (TRS), TR-02-E-BPA-03, and is addressed in TRS testimony, Woerner, et al., TR-02-E-BPA-08.

Q. *Why are the COE and BOR transmission facilities not included in the study?*

A. The segmentation of the COE and BOR facilities was included in the 2002 Power Rate Case. The annual costs of the COE and BOR Network and Delivery facilities are assigned to TBL as inter-business line costs. TBL assigned these expenses to the appropriate segments in the TBL revenue requirement. *See* Revenue Requirement Documentation, TR-02-E-BPA-01A, at Chapter 2.

Q. *What are the major changes in segmentation of TBL transmission facilities in the proposed study?*

A. The Fringe and Northern Intertie segments are eliminated with the facilities in those segments rolled into the Network segment. The Delivery segments were redefined to include only facilities that provide delivery at voltage less than 34.5 kV.

Q. Please explain why the facilities in the Fringe and Northern Intertie segments are rolled into the Network segment?

A. Prior to 1996, the segmented system included a Fringe segment. At that time, the Fringe segment was defined as facilities used only by power customers. Since then, TBL adopted open access transmission service. As a result, all of TBL's transmission facilities, except the Generation Integration segment, are now available to deliver both Federal and non-Federal power. In the 2002 transmission rate proposal, all facilities formerly in the Fringe segment that are equal to or greater than 34.5 kV are rolled into the Network. TBL also proposes to roll the facilities formerly in the Northern Intertie segment in to the Network segment. These facilities are of the same voltage and are integrated with the Network facilities in the area, they are relatively short in distance compared with the Southern and Eastern Interties, they are used by both Federal and non-Federal power, and rolling them into the Network does not significantly increase the Network costs.

Q. Has TBL proposed any different treatment for the Generation Integration segment?

A. No. In the 2002 Power Rate Case, BPA proposed to assign all Generation Integration costs to the Power Business Line (PBL). The TBL proposal assigns Generation Integration costs to the PBL. The level of the investment and O&M costs for the Generation Integration segment was not determined in the power rate case. Those costs are defined in the TBL Segmentation Study.

SECTION 4 SALE OF DELIVERY FACILITIES

Q. Please describe TBL's policy for the sale of Delivery facilities.

A. In 1996 BPA agreed to offer for sale the facilities in the Utility and DSI Delivery segments to the customers served by those facilities. TBL plans to extend this policy to include the 2002-3 rate period.

Q. How does this affect the Delivery segment?

A. The 1996 sales policy resulted in the sale of a number of Delivery segment facilities through September 30, 1998, the historical period covered by the initial proposal Segmentation Study. The investment and O&M costs associated with the facilities sold were removed from the Segmentation Study. Customer interest in purchasing additional Delivery segment facilities has continued, and increased significantly after the announcement of the proposed increase in the Utility Delivery rate. A forecast of expected sales was made for the period 1999 through the end of the rate period. The investment and O&M associated with the facilities forecast to be sold were subtracted from the Delivery segment investment and O&M base for the appropriate year based on the forecast. The forecast indicates that about a third of the remaining Utility and DSI facilities would be sold.

Q. Please describe how the forecast was made?

A. TBL staff familiar with the current sale negotiations and customer interest in buying facilities made an estimate of which facilities would be sold by the end of the rate period. The facilities projected to be sold in FY 1999 were those where the negotiations were completed or that were expected to be removed from service during FY 1999. It was assumed that all sales would be made before the beginning of the rate period (October 2001) in FY2001 for ease in calculating the rates. It is uncertain when the sales will actually become final, but TBL expects most customers would want to complete the purchases before the beginning of the rate period to avoid the proposed increase in the Delivery rates.

Q. *How are Delivery facilities that were removed from service treated?*

A. The Delivery facilities that were forecast to be removed from service were treated the same as those that were sold. The investment and O&M were subtracted from the investment and O&M bases. These were older facilities that were no longer required to serve the customer.

Q. *Are there uncertainties in the forecast?*

A. The forecast has uncertainty regarding which facilities will be sold and when each sale will be completed. The forecast is needed to provide a reasonable adjustment to the investment and O&M bases for the test years, so the timing of each sale is less important that the number of facilities expected to be sold. Based on TBL staff experience with the sale process to date, and the interest by the customers, the projected sales appear to be achievable and the overall number of stations and timing to be reasonable. The forecast will be updated in the final study.

Q. *Did TBL forecast a sales price for facilities expected to be sold?*

A. Yes. TBL staff familiar with historical sales estimated the average sales price to be 25% over book value. An average price is needed to determine total proceeds from the sale of facilities. The estimated proceeds are used in the revenue requirement study to determine cash reserves and to determine an interest credit for the Delivery segments. The revenue requirement treatment is described in

Revenue Requirement Documentation, TR-02-E-BPA-01A at chapter 5, and in testimony, Homenick, *et al.,* TR-02-E-BPA-06.

SECTION 5 ANCILLARY SERVICE SEGMENTATION

Q. *Why is TBL including Ancillary Services in the Segmentation Study?*

A. In 1996, BPA voluntarily agreed to offer open access transmission service similar to the open access service that the Federal Energy Regulatory Commission (FERC) requires Investor-Owned Utilities (IOUs) to offer. FERC's open access policy provides that ancillary services be offered under separate rates. To determine the revenue requirement for ancillary services the investment and O&M costs associated with these services must be determined.

Q. *What are Ancillary Services?*

A. Ancillary Services are those services necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of TBL's transmission system. Currently, FERC's proforma tariff defines six ancillary services: Scheduling, System Control and Dispatch, Reactive Supply and Voltage Control, Regulation and Frequency Response, Energy Imbalance, Operating Reserves – Spinning, and Operating Reserves – Supplemental.

Q. *What are the transmission assets that are used to provide Ancillary Services?*

A. The primary facilities providing these services are the control equipment located primarily at the TBL control centers and a portion of the TBL communication system. These facilities are all in general plant accounts.

Q. How was investment in TBL facilities providing these services identified?

A. The facilities providing these services are primarily in two classes, control and communications. The control facilities include much of the equipment at the Dittmer and Munro control centers. This equipment was assigned to each service based on staff estimates of its use for each service. The communications facilities were allocated to the different services based on the use associated with each service. The use of the backbone system was determined by estimating the number of circuits used for each service as a percentage of the total circuits used. The SCADA system is used to control and monitor transmission facilities, so it was primarily assigned to the Control and Dispatch function. The method is described in more detail in chapter 8 of the Segmentation Study, TR-02-E-BPA-02, at 88.

Q. How were the TBL O&M costs associated with these services identified?

A. The O&M costs associated with these services were determined by examining the budgets for control center operations, scheduling, and maintenance for equipment associated with these functions. Staff familiar with these functions estimated the amount of staff time spent in providing each of these services. The method is described in more detail in chapter 9 of the Segmentation Study, TR-E-BPA-02, at 93.

Q. Does this conclude your testimony?

A. Yes.

INDEX

TESTIMONY OF

RONALD J. HOMENICK, DANA M. JENSEN,

MARGARET A. CHANG, BRYAN V. CRAWFORD

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: Revenue Requirement Study

TESTIMONY OF

RONALD J. HOMENICK, DANA M. JENSEN, MARGARET A. CHANG,

BRYAN V. CRAWFORD

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: REVENUE REQUIREMENT STUDY

SECTION 1 INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your names and qualifications.

A. My name is Ronald J. Homenick and my qualifications are contained in TC/TR-02-Q-BPA-11.

A. My name is Dana M. Jensen and my qualifications are contained in TC/TR-02-Q-BPA-12.

A. My name is Margaret A. Chang and my qualifications are contained in TC/TR-02-Q-BPA-04.

A. My name is Bryan V. Crawford and my qualifications are contained in TC/TR-02-Q-BPA-06.

Q. Please state the purpose of your testimony.

A. The purpose of this testimony is to sponsor the development of transmission revenue requirements for the transmission function of the Federal Columbia River Transmission System (FCRTS). This testimony also sponsors the Revenue Requirement Study, TR-02-E-BPA-01, and the Documentation for the Revenue Requirement Study, TR-02-E-BPA-01A.

Q. How is your testimony organized?

A. Our testimony addresses significant changes in the projections, assumptions, and methods used to determine transmission revenue requirements and to demonstrate cost recovery from Bonneville Power Administration's (BPA's) practices in prior rate cases. First, we address changes to the transmission revenue requirement, including additional cost components, the impact of a new depreciation study, the functionalization of various expenses, and treatment of Delivery facilities sales. We also address the inclusion of new ancillary services revenue requirements, in keeping with Federal Energy Regulatory Commission (FERC) policy that transmission providers offer ancillary services necessary for reliable transmission service. In Section 3, we address technical changes to the transmission repayment study. In Section 4, we discuss potential adjustments and updates for the Final Rate Proposal.

SECTION 2 REVENUE REQUIREMENTS

Q. What changes have been made in the way BPA determines transmission revenue requirements?

A. There have been no changes in the methodology BPA uses for determining revenue requirements, but there have been changes in the composition of transmission revenue requirements. There are now entries in the Income Statement for inter-business line expenses in the Total Operating Expenses component, and for the amortization of capitalized bond premiums in the Net Interest Expense component. The Statement of Cash Flows includes a new entry for fiber optic accrual revenues in the Cash from Current Operations component.

In addition, there are also costs included in the transmission revenue requirement that were functionalized to generation in previous rate cases.

Q. *Please describe the inter-business line expenses.*

A. The inter-business line expenses are the annual charges from the Power Business Line (PBL) to the Transmission Business Line (TBL). These consist of annual charges for the generation inputs to ancillary services, station service, remedial action schemes and Corps of Engineers (COE) and Bureau of Reclamation (BOR) Network and Delivery facilities. The specific inter-business line costs were developed in the 2002 Initial Power Rate Proposal and are included in the revenue requirements for the initial transmission rate proposal. The annual charges associated with these costs will be updated based on the final decision on these issues as determined in the Administrator's Record of Decision of the 2002 Final Power Rate Proposal and accompanying final studies.

Q. *Please describe the amortization of capitalized bond premiums.*

A. When BPA refinances Treasury bonds, it typically must pay a call premium. The amortization of capitalized bond premiums is the allocation of the annual expense of the call premiums over the term of the new bond. The cost of the call premiums are capitalized and included in the principal of the replacement bonds. The capitalized bond premiums are then amortized over the term of the respective replacement bonds and constitute a non-cash component of interest expense. Because the amortization of capitalized bond premiums exceeds $3 million per year it is now identified as a separate item in transmission revenue requirements. Previously, this item was rolled into Net Interest Expense.

Q. *What are fiber optic accrual revenues?*

A. The fiber optic accrual revenues are the annual allocation and recognition of the up-front payments received by TBL from leasing fiber optic capacity to other entities over the term of the particular contracts. The treatment is similar to the treatment of capacity ownership accrual revenues for the AC Intertie in the Statement of Cash Flows. Because the cash associated with these payments has already been received by BPA, it is necessary to adjust the Cash Provided From Operations to account for these non-cash revenues in the rate test period.

Q. *How is BPA proposing to finance new capital transmission investments during FY 2002-2003?*

A. We are not proposing to revenue finance any transmission capital investments during the FY 2002-2003 rate period. The Study assumes that new investments during the rate period are financed by bonds BPA issues to the U. S. Treasury. *See* Chapter 2 of the Revenue Requirement Study, TR-02-E-BPA-01.

Q. *Are there any other changes that are reflected in revenue requirements?*

A. A new depreciation study related to transmission and general plant investment was prepared for BPA in FY 1999. The results of that study are reflected in the calculation of depreciation expense included in the initial proposal revenue requirements. Based on the study, various service lives and net salvage factors were modified. This caused a change in the calculation of the annual expense to the remaining life technique of straight-line depreciation. The depreciation calculated for the revenue requirements in this proposal uses the annual accrual rates from the new study. *See* TR-02-E-BPA-01A, Chapter 4.

Q. What effect has the use of the new depreciation study had on transmission revenue requirements?

A. Forecasted depreciation expense has increased. This in turn has reduced Minimum Required Net Revenues to zero. It has also made cash available to apply to mitigate risk. *See* Revenue Requirement Study, TR-02-E-BPA-01, Section 4.1.2, for a description of Minimum Required Net Revenues.

Q. What are the changes in the revenue requirement related to functionalization?

A. The functionalization of both power and transmission costs was developed in the 2002 initial power rate proposal. In the power rate case, the investment in the BPA control centers and supporting communications equipment previously functionalized to generation was refunctionalized to transmission. The investment in the control centers and supporting communications equipment are needed to perform scheduling, dispatch and control operations. TBL now is the provider of ancillary services, which include transmission scheduling, dispatch and control services. What had previously been functionalized to the generation portion of these investments is now appropriately part of the transmission function. These costs have been further assigned to transmission or ancillary services based on an identification of the service they provide. This identification and assignment was determined by the TBL staff working with these services. *See* Segmentation Study, TR-02-E-BPA-02; and Gilman, *et.al.,* TR-02-E-BPA-05.

Q. Are there other areas in which changes have occurred that affect revenue requirements?

A. Yes. The sale of Delivery segment facilities resulting from the 1996 Sale of Facilities Policy have had an effect on the revenue requirement, both on an actual and forecasted basis. The proceeds from sales closed in fiscal years 1997 through 1999, totaling $22 million, were applied as additional amortization to transmission debt to reduce overall repayment obligations, consistent with the transfer of title of these assets. *See* Gilman, *et al.*, TR-02-E-BPA-05, and the Segmentation Study, TR-02-E-BPA-02.

Q. What is the treatment in revenue requirements for the forecasted sales of Delivery facilities after FY 1999?

A. TBL staff identified the facilities projected to be sold by the end of the current rate period. The gross investment in those facilities was removed from the plant-in-service forecast in 2001. The total proceeds that TBL would expect to receive for these sales was determined by calculating the book value of the facilities as a base estimate and adding an additional 25 percent, based on the judgment of TBL staff involved with the sales. *See* Gilman, *et.al.*, TR-02-E-BPA-05 and the Segmentation Study, TR-02-E-BPA-02. The book value portion of the forecasted proceeds was included in the interest credit calculation, to provide a reduction to revenue requirements comparable to the effect of using this portion of the proceeds to repay outstanding debt. The amount over depreciated book value was included in cash balances at the beginning of the rate period, and is treated as available to mitigate risk. This amount over depreciated book value was also used to calculate interest credits that were applied directly to the Delivery segments.

Q. Are there any other changes related to revenue requirements?

A. Yes. There have been modifications to the segmentation of the components of revenue requirements for O&M, general plant depreciation expense, and net interest expense.

Q. What modifications have been made to the segmentation of O&M?

A. Previously, O&M was segmented in three steps. First, research and development, leases and General Transfer Agreements (GTAs) were assigned directly to the relevant segments. Second, the remaining O&M was split between lines and substations based on the three-year averages of that split. Third, the lines and substations O&M portions were segmented pro rata based on the respective segmented three-year averages of O&M.

Q. How was O&M segmented for the initial proposal?

A. O&M was segmented in four steps. In the first step, the generation inputs to ancillary services, COE and BOR transmission costs, ancillary services O&M, leases, GTAs (non-Federal transmission arrangements) and remedial action schemes (RAS) were directly assigned to the relevant segments. Except for COE and BOR costs, these costs are assigned to segments and ancillary services as identified by staff supporting the respective areas. COE and BOR costs are segmented based on the method developed in the power rate case. In the second step, transmission system operations (less the directly-assigned amount for ancillary services) and maintenance and environmental remediation programs were divided between lines and substations according to a 3-year historical average of that split. In the third step, the lines and substations costs were separately segmented based on their respective 3-year averages of historical O&M. Station service expense was also segmented by the 3-year historical averages of substation O&M. In the final step, the previously-segmented O&M for the transmission system operations and maintenance programs and the environmental remediation program were summed in order to provide the pro rata basis for the segmentation of all other remaining O&M expenses.

Q. How was the segmentation of general plant depreciation modified?

A. As described previously, the investment in control and communications equipment was assigned to both ancillary services and transmission. The transmission depreciation for control and communications equipment was prorated to the transmission segments based on the depreciation expense calculated from the investment in those segments. The remaining general plant depreciation was prorated to the transmission segments and the individual ancillary services based on the total depreciation in those areas.

Q. How was the segmentation of interest expense modified?

A. The transmission net interest expense was prorated to the segments and ancillary services based on the average net plant investment in those areas. As in previous rate cases, the Southern Intertie net plant was adjusted to remove the balance of the unearned revenues associated with non-Federal capacity ownership. Similarly, the unearned revenue balance associated with prepaid fiber optic leases was segmented pro rata to reduce net plant based on the disposition of communications investment in each segment and ancillary service. The previously described Interest credits attributed to the sale of the Utility and DSI Delivery segments were applied directly to those segments prior to the segmentation of the remainder of net interest expense. The adjustments for capacity ownership and fiber optic revenues similarly affected the segmentation of planned net revenues.

SECTION 3 TECHNICAL CHANGES IN REPAYMENT STUDIES

Q *Does the repayment study reflect the implementation of the BPA Appropriations Refinancing Act?*

A. Yes. The 1996 Final Rate Proposal included projections of the Bonneville Refinancing Act, which was passed in April of 1996. In 1997, after audited actual financial data became available, BPA calculated the refinancing transaction and forwarded a demonstration of the calculations to the Treasury for review. Treasury approved the transaction calculations in July of 1997. The repayment study in this rate proposal reflects the actual transactions for transmission. *See* Revenue Requirement Study Documentation, Volume 1, WP-02-E-BPA-02A, Chapter 8, pp. 144-194.

Q. *What functionalization changes have been made to the repayment studies?*

A. The COE and BOR transmission-related repayment obligations, totaling $67,080,000 with a weighted average interest rate of 7.13 percent, were moved from the transmission repayment study to the generation repayment study. Likewise, the portions of construction bonds associated with the BPA transmission asset allocation previously functionalized to generation were refunctionalized to transmission. As a result, a total of $32,065,000 with a weighted average interest rate of 7.3 percent, was moved from the generation repayment study to the transmission repayment study. The changes have been reflected in generation revenue requirements for the wholesale power rate proposal.

Q. *What other changes have been made to the repayment studies?*

A. The repayment period of transmission repayment studies has been changed. In the 1996 rate filing transmission repayment studies were run with 45-year repayment periods. *See* Revenue Requirement Study, WP-96-FS-BPA-02(R), page 30. In this rate proposal transmission studies are being run with 35-year repayment periods. The results of the 1999 depreciation study indicated that the weighted average service life for BPA transmission/general plant was 40 years. The repayment policy applicable to BPA requires that the repayment period be assigned due (maturity) dates that are no longer than 50 years or the average service lives of the assets, whichever is less. Thus, the horizon of the repayment period must be no longer than 40 years. Since no current transmission obligations have due dates later than 35 years from the last year of the rate period, the horizon has been shortened to 35 years. *See* the Revenue Requirement Study, TR-02-E-BPA-01.

Q. *Why do transmission bonds have due dates that do not exceed 35 years?*

A. Projected new transmission debt is assigned a maximum maturity of 35 years, reflecting BPA's actual bond issuances. Debt that has already been issued reflects the particular maturities of the individual bonds. The repayment studies for the initial proposal reflect actual borrowings and amortization through FY 1999. *See* Revenue Requirement Study, TR-02-E-BPA-01, Section 5.2.

Q. Are there any other changes or adjustments to data in the repayment studies?

A. Yes. We have not recalculated the annual funding requirements for transmission replacements during the repayment periods. Repayment study results for the initial proposal reflect the use of replacements calculated for 2002 and 2003 transmission repayment studies used in the 7(b)(2) Rate Test from the 1996 Final Rate Proposal. However, the interest rates assigned to the replacements have been updated. Due to technical problems, we were not able to produce replacement forecasts for the repayment periods based on the current plant data and the results of the new depreciation study.

Q. Is reliance on the 1996 replacement data reasonable?

A. Yes. We made a number of comparisons that are included as Attachment 1 to this testimony. The total projected transmission plant from which the 1996 replacements were calculated was $162 million higher on average for 2002-2003 than the forecast in the initial proposal. Also, projected outstanding repayment obligations in the same period were $44 million higher on average than in the initial proposal. However, the resulting amortization is $10 million higher on average in the initial proposal studies than what was scheduled in the same years in the 1996 rate case studies. Also, the average rate period amortization in this proposal is $21 million higher than the average annual amortization for the 1997-2001 rate period. Based on these comparisons, we believe that the initial proposal amortization is consistent with the shortening of the average service life from 45 years to 40 years in the new depreciation study.

SECTION 4 ANTICIPATED CHANGES FOR THE FINAL RATE PROPOSAL

Q *What changes are anticipated in program spending levels as a result of public comments?*

A. BPA, in consultation with its customers and constituents, determines program spending levels separate from the rate case. As outlined in chapter 2 of the Revenue Requirements Study (TR-02-E-BPA-01), the capital and expense levels incorporated in the revenue requirement reflect preliminary program levels presented to TBL's customers and constituents in the recent public involvement process, "Reliability and the Future of Transmission Costs." Customer and constituent views expressed during the public process, and any comments made outside the rate case subsequent to that process, have not been incorporated in the revenue requirements of this initial transmission rate proposal. TBL remains open to discussions of spending plans outside the formal rate proceedings. The Administrator will make decisions outside the rate case on transmission capital and expense levels that will consider comments received during the public process. The Administrator's decisions, and consideration of subsequent comments, will be reflected in the revenue requirements, including repayment studies, for the final rate proposal.

Q. *What other changes in the Revenue Requirement are anticipated for the Final Rate Proposal?*

A. In addition to any potential program level adjustments mentioned above, we will update the cost of non-Federal transmission arrangements and inter-business line expenses as necessary to reflect final decisions in the power rate case.

Additionally, we expect that there will be an updated reserves forecast and other updates as actual financial results become available.

Q. Does that conclude your testimony?

A. Yes

Attachment 1

Changes in Transmission Repayment Study Input Data and Results
($000)

Transmission Plant Investment

		2002	2003
1996 Rate Case		5,613,297	5,810,131
2002 Rate Case		5,422,665	5,676,343
	Difference	(190,632)	(133,788)
	average change		***(162,210)***

Outstanding Repayment Obligations

		2002	2003
1996 Rate Case		3,314,826	3,349,427
2002 Rate Case		3,238,368	3,338,634
	Difference	(76,458)	(10,793)
	average change		***(43,626)***

Amortization

		2002	2003
1996 Rate Case		135,833	142,872
2002 Rate Case		148,139	150,480
	Difference	12,306	7,608
	average change		***9,957***

Annual Average Amortization

1997-2001 1996 Rate Case		127,932
2002-2003 2002 Rate Case		149,310
	average change	***21,378***

INDEX

TESTIMONY OF

ERIK D.WESTMAN AND JAMES C. SAPP

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: Risk Analysis and Mitigation

TESTIMONY OF

ERIK D. WESTMAN AND JAMES C. SAPP

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: RISK ANALYSIS AND MITIGATION

SECTION 1 INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Please state your names and qualifications.

A. My name is Erik D. Westman and my qualifications are contained in TC/TR-02-Q-BPA-20.

A. My name is James C. Sapp and my qualifications are contained in TC/TR-02-Q-BPA-18.

Q. Please state the purpose of your testimony.

A. The purpose of our testimony is to sponsor the Financial Risk and Mitigation sections of the Revenue Requirement Study, TR-02-E-BPA-01, and Documentation for the Revenue Requirement Study, TR-02-E-BPA-01A; and describe the risk analysis and risk mitigation tools used to calculate the probability of making U.S. Treasury (Treasury) payments on time and in full during the two-year rate period for this rate proceeding.

Q. How is your testimony organized?

A. This testimony contains six sections including this introductory section. Section 2 summarizes the methodology for calculating the probability of making all Treasury payments in full and on time. Section 3 discusses the risk analysis methodology. Section 4 discusses mitigation tools. Lastly, in

Section 5, we describe possible adjustments that could occur prior to the final rate proposal.

SECTION 2 TREASURY PAYMENT PROBABILITY METHODOLOGY

Q. Why has the Bonneville Power Administration (BPA) performed a risk analysis for the transmission rate case?

A. In this rate proposal, BPA has identified and quantified transmission risks and designed risk mitigation tools to ensure that the transmission function has sufficient end-of-year cash reserves to meet its share of BPA's U.S. Treasury payment obligations. In prior rate cases, the risk analysis was performed at the agency level, and focused on power-related risks. BPA has functionally separated its transmission and power business lines and is setting transmission and ancillary service rates in a separate rate proceeding from power rates. BPA must determine revenue requirements and demonstrate cost recovery to the Federal Energy Regulatory Commission (FERC) separately for each function. Accordingly, risks must be identified and quantified, and risk mitigation portfolios must be designed, separately for the generation and transmission functions. Doing so ensures that rates in each function will achieve a high probability of recovery of their respective costs, including Treasury payments. If the transmission function did not evaluate and mitigate its risks, it would not meet BPA's commitment to manage power and transmission as functionally separated businesses.

Q. Why does BPA use a Treasury Payment Probability (TPP) standard as an indicator for cost recovery?

A. BPA estimates its potential for recovering costs, given all its risks and risk management tools, using TPP. Payments to Treasury, in particular principal payments to Treasury, are the lowest priority in BPA's priority of payments. If BPA meets its Treasury repayment obligations, it will have met all its other financial obligations as well. For this reason, TPP serves as the key measure of the potential to recover all costs.

Q. What level of Treasury Payment Probability is BPA targeting for the transmission function?

A. BPA has identified and quantified transmission risks, and designed risk mitigation tools to set transmission and ancillary services rates to achieve a 95 percent probability that payments to Treasury be made on time and in full over the two-year rate period.

Q. Are the Treasury payment probability standards the same for the BPA power and transmission functions?

A. Yes. The Treasury payment standard that is being applied to BPA's transmission function is the long-standing TPP standard that comes directly out of the 1993 Administrator's Record of Decision, which is defined in terms of a two year rate period. In the power rate case, the standard was defined in terms relevant to a five year rate period instead of a two year rate period. Otherwise, they are identical.

Q. How has the probability of the transmission function making its share of Treasury payments in full and on time been calculated?

A. Treasury Payment Probability calculations are performed by using the Transmission Risk Analysis Processor (TRAP)--an Excel spreadsheet with the @RISK add-in to enable BPA to simulate the effects of uncertainty in costs and revenues on the annual cash flows and therefore cash reserves of the transmission function. This is described further in Chapter 9 of the Documentation for the Revenue Requirement Study, TR-02-E-BPA-01A.

Q. Has this model been used by BPA before?

A. No. BPA has never before incorporated a risk analysis in determining its transmission rates. BPA's transmission function only recently developed a risk management capability, including risk analysis processes and tools. The TRAP functions much like the models used in the power rate case for risk analysis, particularly the Non-Operating Risk Model (NORM), that rely on the technique of Monte Carlo simulation.

Q. Are all risks that may affect BPA's ability to recover its transmission and ancillary service costs quantified in the Transmission Risk Analysis Processor?

A. No. The risks quantified are those that reasonably bear on estimating the amount of required planned net revenues for risk for the transmission function during the next rate period and those that influence the amount of beginning cash reserves at the start of the next rate period. These risks can be called normal operating risks and mainly affect short-run variability in transmission function cash flows between fiscal year 2000 and fiscal year 2003. Long run risks such as changes in capital spending patterns, environmental protection and mitigation effects on generation and load patterns that may change transmission longer term costs and potential changes in transmission industry structure due to formation of a Regional Transmission Organization are not included in the analysis. These long-term risks are mitigated by the transmission function's ability to change rate levels in response to such fundamental changes in the business environment.

SECTION 3 RISK ANALYSIS MODELING

Q. Please describe the Transmission Risk Analysis Processor (TRAP).

A. The Transmission Risk Analysis Processor, or TRAP, is a model that was developed to analyze risks that affect the transmission function in the rate-setting process. It, like the models used in the power rate case, uses a Monte Carlo simulation methodology to estimate a distribution of outcomes. The frequency distributions of cost and revenue inputs reflect BPA's best current outlook about the probabilities of future events that affect the Transmission Business Line's (TBL's) financial reserves and its ability to recover its costs and repay Treasury. The output from the TRAP is an estimate of the frequency of continuous successful Treasury payment during the two-year rate period simulated over 3000 games.

Q. Please describe the risks that were analyzed.

A. The transmission risk analysis methodology is simpler than the method used in the power rate case. The variables that were analyzed with uncertainty are referred to as normal operating risks, and include the following: (1) annual firm Network revenues; (2) annual hourly nonfirm Network revenues; (3) annual firm Southern Intertie revenues; (4) annual hourly nonfirm Southern Intertie revenues; (5) scheduling, system control, and dispatch ancillary services revenues; (6) reactive supply and voltage control ancillary services revenues; (7) regulation and frequency response ancillary services revenues; (8) Delivery segment revenues; (9) revenue from the sale of dark fiber capacity; (10) total annual transmission expenses excluding Corporate expense; (11) BPA Corporate expenses paid by transmission; (12) effects of interest rates on interest expense associated with new borrowing; and, (13) retained net proceeds from the sale of facilities.

Q *Why were these particular risks chosen?*

A. In a projection of net revenues that extends into the future there is some uncertainty surrounding most revenues and costs. TBL chose to model the uncertainties in the transmission risk analysis based on those that: (1) have the largest range of uncertainty in the short run (less than 5 years); (2) have specific uncertainties that are readily quantifiable from prior risk analysis work, such as interest rate uncertainty; or (3) are specific cost review recommendations for which there is some uncertainty of BPA's ability to achieve full savings within the rate period. Long run risks, i.e. effects mainly beyond the next rate period, were not evaluated based on the assumption that their effects can be mitigated by the transmission function's ability to change rate levels to ensure that success in meeting

BPA's Treasury Payment Probability standard. Such risks include potential changes in capital budgets related to changes in future generation facility development and the effects of fish and wildlife programs and policies on transmission capital budgets and operating constraints.

Q. Please describe how TRAP works.

A. TRAP is a financial spreadsheet model that uses transmission revenue and expense accruals to estimate net transmission revenue on a fiscal year basis. The net revenues are then converted into annual changes in cash flows and end of year cash reserves as reported in a statement of cash flows. Net revenues and expenses not requiring cash are used to estimate the cash provided by current operations. Capital spending is captured as a cash flow out that is covered by cash obtained from long-term borrowing. Repayment of old appropriations and repayment of long term debt also is captured in estimating the annual change in cash balance. With the start of year cash balance as an input, the model estimates the end of year cash balance, which is used to determine whether Treasury payment is made on time and in full for the fiscal year. This estimate is captured by binary variables that test whether the end of year cash balance, or cash reserves, are $20 million or greater. These tests are performed for each fiscal year of the rate period individually as well as jointly for both years of the rate period. If the result shows that sufficient end of year cash reserves were achieved for both years of the rate period in a simulation game, the transmission function is assumed to have successfully paid Treasury during the rate period. If at least one year fails to achieve the minimum end of year cash balance, Treasury payment is determined not to be successful for the rate period. Using TRAP to simulate TBL cash flows over the rate period estimates the frequency that successful Treasury payment occurs, resulting in an estimate of future TPP.

Q. What time frame is captured in the transmission risk analysis?

A. The TRAP analyzes the annual changes in cash flows and end of year cash reserves for FYs 1999-2003. This time frame permits analysis of the change in revenues, costs, and accrual to cash adjustments that are expected to occur between the time the initial rate proposal is developed and the end of the next rate period (FY 2002-2003). The FY 1999 information reflects actual data from BPA's 1999 4th Quarter Review, FYs 2000-2001 are transition years, and FYs 2002 and 2003 reflect the next rate period. The transition year of 2001 is analyzed with uncertainty in revenues and costs so that uncertainty in cash reserves at the beginning of the next rate period (FYs 2002-2003) may be accounted for in the risk analysis.

Q. What are the sources for cost and revenue information for the transition years, FYs 2000 and 2001?

A. FY 2000 and 2001 costs come from TBL and Corporate start of year forecasts of expenses for FY 2000 and OMB budget projections for FY 2001. Transmission point estimate revenue forecasts are from TBL's June 1999 FY

2000 and FY 2001 Revenue Forecast. See Appendix K, Documentation for Transmission Rates Study, TR-02-E-BPA-03.

Q. How are fiscal year 2000 revenues and costs treated in the risk analysis?

A. FY 2000 revenues and costs are expected to be known with relative certainty by the time the final transmission rate studies are prepared, so that it is not necessary to account for uncertainty in those inputs to the risk analysis model.

Q. Please explain the distributions relating to Network Revenues and Southern Intertie Revenues.

A. Distributions for four categories of wheeling revenues were developed. They include annual firm Network revenue, annual hourly nonfirm Network revenue, annual firm Southern Intertie revenue, and annual hourly nonfirm Southern Intertie revenue. The distributions rely on Transmission Rate Study (TRS) total segmented cost minus planned net revenues for risk (PNRR) allocated to each of these products to set the mean or most likely value for the distribution. The variation around the most likely value was estimated based on historical monthly revenues for these products from fiscal year 1998 and fiscal year 1999. A technique called the bootstrap was used to simulate the variation that could be expected on an annual basis from the variation present in the patterns of monthly revenues from these products. *See* Revenue Requirement Study Documentation, TR-02-E-BPA-01A.

Q. Please explain the distributions relating to transmission expenses?

A. The distribution for transmission expenses was based on historical annual expense variations from FY 1978 through FY 1998. Data were not available for expense categories more detailed than total transmission operation and maintenance (O&M) expense due to organizational and accounting changes that have occurred over that time period. Like the transmission revenue distributions, the most likely value for the distribution was calibrated to TBL forecasts of transmission expense budgets for FYs 2001-2003 used in the Revenue Requirement Study and Transmission Rate Study. The historical expense data was de-trended and short run variation in total expense was estimated from expense deviations from the long run trend. Corporate overheads and inter-business line expenses were not historically captured in total O&M expense figures. These expense categories are treated separately in the risk analysis. *See* Revenue Requirement Study Documentation, TR-02-E-BPA-01A, Chapter 9.

SECTION 4 RISK MITIGATION TOOLS

Q. Please describe the risk tools the transmission function relies on to achieve the 95 percent probability goal.

A. The transmission function is relying on three basic tools to mitigate the effects of uncertainty in costs and revenues on transmission cash flows. First, BPA will rely on expected cash reserves available to the transmission function at the end of the current rate period and cash reserves, not including required planned net revenues for risk, during the next rate period (FYs

2002–2003). Second, BPA is including in its expenses sufficient required planned net revenues for risk to cover normal operating risks during the rate period not otherwise mitigated by cash reserves. Finally, long run risks or extraordinary changes in business conditions are covered by the transmission function's ability to change rate levels.

Q. *What is meant by the term "reserves?"*

A. The term "reserves," as used in this testimony and the accompanying studies refers to financial reserves functionalized to transmission.

Q. *Please explain how financial reserves are modeled as a risk mitigation tool.*

A. Financial reserves are BPA's central risk mitigation tool. Financial reserves comprise cash in the BPA Fund and cash equivalents in the form of a deferred borrowing balance. The first step in modeling financial reserves is to project the level of reserves for the beginning of the rate period. Projected reserves for the transmission function at the end of FY 1999 total -\$6.8 million. Reserves for the start of the next rate period (October 2001) are forecast to be about \$26.9. Financial reserves at the start of the rate period are estimated by simulating cash flows through time from the historical FY 1999 through FY 2001.

Q. *How did the transmission risk analysis deal with the proposed fish and wildlife recovery alternatives?*

A. The Transmission Risk Analysis Processor does not quantify the effects of the fish and wildlife recovery alternatives. Instead transmission relies on its ability to change rate levels to accommodate the impacts of fish and wildlife recovery alternatives on long term transmission costs and revenues. Such changes in operating environments are not considered normal operating risks and are not mitigated by cash reserves or planned net revenues for risk. This is not an exclusion of fish and wildlife recovery alternatives from consideration, but rather an assumption that such changes are best mitigated by the transmission function's ability to change rate levels in response to fundamental changes in business environments and the costs of transmission service.

Q. *Why are additional planned net revenues needed for risk?*

A. Planned Net Revenues for Risk (PNRR) is a component of revenue requirements that is added to annual expenses to bolster reserves and mitigate normal operating risks. *See* Revenue Requirement Documentation, TR-02-E-BPA-01A. PNRR is included when the projections of revenues, expenses, financial risks, and cash reserves fail to meet the 95 percent TPP goal. Increasing the PNRR component of revenue requirements increases the rate level: generating additional revenue and higher reserves which improves the TBL's ability to make Treasury payments in years when costs and revenue patterns depress TBL financial performance.

Q. *What is the relationship between PNRR and other risk mitigation tools BPA will be using?*

A. The amount of PNRR included in revenue requirements is determined after the impacts of starting reserves have first been assessed. PNRR fills the gap between financial reserves available at the beginning of the next rate period and the ability to increase net revenues through a rate increase at the end of the next rate period.

Q. Why do reserve levels grow over the rate period?

A. PNRR is determined by the normal operating risks that are expected during the rate period and the effects of normal operating risks and cash flows expected to occur during the transition fiscal years 2000 - 2001. Lower than required cash reserves during the transition years puts upward pressure on PNRR. That upward pressure on PNRR is carried into FY 2003 expenses and therefore into revenue requirements, leading to a somewhat higher expected cash reserve by the end of FY 2003.

Q. What amount of Planned Net Revenues for Risk would be required to achieve a two-year TPP of 95 percent?

A. BPA has estimated that PNRR in the amounts of $10.8 million in FY 2002 and $9.8 million in FY 2003 are required to achieve a 95 percent TPP for the two-year rate period.

Q. If BPA did not have PNRR in its prior transmission rates why has it included in this rate proposal?

A. During the 1996 Rate Case, BPA did not consider the need for a risk analysis to support its transmission rate setting or PNRR to cover normal transmission operating risks. In retrospect this oversight contributed to the deteriorating financial position of the transmission function and the lack of financial reserves which otherwise might have been available to mitigate normal operating risks during FYs 2002–2003. Although the transmission function faces less risk than the power function, it still faces operating risk associated with transmission costs and revenues. Continuing to ignore this risk is not a prudent business practice.

Q. *Is a transmission surcharge included as a risk to be covered by cash reserves or PNRR in the FY 2000–2003 rate period?*

A. No. TBL has not included a transmission surcharge for any stranded power cost recovery in its proposal. BPA expects that in the event a transmission surcharge becomes necessary a new and separate transmission rate proceeding will occur to establish the surcharge. In essence, TBL is relying on its ability to change rate levels as the risk mitigation tool to cover a stranded cost surcharge.

SECTION 5 POSSIBLE ADJUSTMENTS

Q. *What changes might be made in the final rate proposal with respect to the risk analysis?*

A. The most significant areas of change in analytic assumptions are expected to come from updated revenue forecasts and expense forecasts for the transition FYs 2000-2001. New revenue forecasts will be made between the initial proposal and final proposal. Updated expense projections for the remainder of FY 2000 and FY 2001 may be made before the final proposal. In addition, BPA Corporate is expected to update current financial reserves functionalized to the TBL prior to the final proposal. This will play an important role in determining the start of year financial reserves for the next rate period; one of the three risk mitigation tools available to the transmission function. An increase in 1999 end of year financial reserves attributable to the TBL can be expected to reduce the amount of PNRR required by transmission to achieve the 95 percent TPP level, all other things held constant. A reduction in current or projected financial reserves would have the opposite effect on required PNRR.

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

A. Any changes to the proposed rate schedule, revenue requirement expense levels, or to the revenue forecasts during the rate period could affect the amount of cash for risk that is anticipated, potentially changing the probability results.

Q. *Do you anticipate any other changes?*

A. Should additional data become available for updating the estimated distributions for revenues and expenses between the initial proposal and the final proposal, the distribution assumptions for these inputs could change as well. This is not considered as likely as changes in transition year (current rate period) or next rate period point forecasts of revenues and expenses. If a significant uncertainty effecting short run net revenue volatility was uncovered prior to the development of the final rate proposal, it may be added to the transmission rate case risk analysis. An updated PNRR could be required if there are major shifts in the risk factors used in TRAP.

Q. *Does this conclude your testimony?*

A. Yes.

INDEX

TESTIMONY OF

JOHN R. WOERNER, DAVID L. GILMAN, DENNIS E. METCALF,

NANCY PARKER AND SHEPARD C. BUCHANAN

Witnesses for the Bonneville Power Administration Transmission Business Line

SUBJECT: Transmission Rate Study and Transmission Rate Schedules

TESTIMONY OF

JOHN R. WOERNER, DAVID L. GILMAN, DENNIS E. METCALF,

NANCY PARKER AND SHEPARD C. BUCHANAN

Witnesses for the Bonneville Power Administration Transmission Business Line

SUBJECT: TRANSMISSION RATE STUDY AND TRANSMISSION RATE SCHEDULES

SECTION 1 INTRODUCTION AND PURPOSE

Q. Please state you name and qualifications.

A. My name is John R. Woerner and my qualifications are stated at TC/TR-02-Q-BPA-21.

A. My name is David L. Gilman and my qualifications are stated at TC/TR-02-Q-BPA-08.

A. My name is Dennis E. Metcalf and my qualifications are stated at TC/TR-02-Q-BPA-15.

A. My name is Nancy Parker and my qualifications are stated at TC/TR-02-Q-BPA-16.

A. My name is Shepard C. Buchanan and my qualifications are stated at TC/TR-02-Q-BPA-03.

Q. Please state the purpose of your testimony.

A. The purpose of our testimony is to sponsor the Transmission Rate Study, TR-02-E-BPA-03, and the Transmission and Ancillary Service Rate Schedules and General Rate Schedule Provisions (GRSP), TR-02-E-BPA-04, with the exception of the Power Factor Penalty Charge and the Ancillary

Service and Control Area Service (ACS) rate. The Power Factor Penalty Charge is addressed in Altman and Comegys,TR-02-E-BPA-10. ACS rate development, and the ACS-02 rate schedule and associated GRSPs are addressed in Stemler, et al., TR-02-E-BPA-09.

Q. *How is your testimony organized?*

A. This testimony is organized in 7 sections. Section 1 is this Introduction. Section 2 discusses transmission load forecasting. Section 3 discusses calculation of the Formula Power Transmission (FPT) rates. Section 4 discusses calculation of the Network rates. Section 5 discusses the seasonal rates charged for Southern Intertie (IS) service. Section 6 discusses the Unauthorized Increase Charge (UIC). Section 7 discusses the DSI Delivery Charge.

SECTION 2 LOAD FORECAST

Section 2a Long-Term Sales

Q. *Please describe the approach used in forecasting long-term sales.*

A. For customers with current contract demand service on the Network and Southern Intertie billed on a Transmission Demand (contract demand) basis and whose current contracts extend into the FY 2002 and 2003 rate period, the Transmission Demands found in those contacts are used for the FY 2002-2003 long-term sales forecast. "Contract demand service" refers to those transmission services billed on the basis of Transmission Demands which are reserved capacity amounts specified in contracts.

Q. *How are long-term sales forecasted for customers not covered by current long-term contracts?*

A. For customers not covered by such contracts, TBL must forecast which transmission service on the Network it expects the customer to select during the rate period, and then forecast the corresponding billing determinants. In order to forecast which type of service each customer will choose, TBL utilizes a load forecast for each customer to forecast the Transmission Demand the customer would need assuming a contract demand service, and to forecast the billing determinants assuming the customer selected the Network Integration (NT) load-based service. TBL then determines the cost of each service for each customer. Generally, TBL assumes that the customer will select the least expensive transmission service. *See* TR-02-E-BPA-03, Table 4, for the forecasted long-term Network and Southern Intertie sales.

Q. *Why is the choice of transmission service important for rate development?*

A. For rate development, it is important only whether the service is a contract demand service (Integration of Resources (IR), Point-to-Point (PTP), Network Contract Demand (NCD)) or a load-based service (NT). Contract demand services and load-based service are treated differently when allocating transmission costs and developing transmission rates. *See* Section 3, Calculation of Transmission Rates.

Q. *How are the loads forecasted for the non-generating and generating public utilities?*

A. TBL develops a point of delivery load forecast for the non-generating public utilities. The forecasts for the generating public utilities are developed from data published in the Northwest Power Pool Operating Program or the Northwest Regional Loads and Resources Study.

Q. How do you estimate revenue assuming the customer selects NT service?

A. The NT rate includes a Base and Load Shaping Charge. Both charges are billed on contributions to TBL's monthly transmission system peak. Estimated Load Shaping revenue is based on the customer's total retail load. To estimate Base Charge revenue, the Base Charge billing determinants exclude Customer-Served Load (CSL), which is forecasted as service under IR, FPT, Columbia Storage Power Exchange (CSPE), and PTP agreements. For the generating publics, internal generation—another source of CSL--is also subtracted from the customer's Base Charge load.

Q. How do you estimate revenue assuming the customer selects a contract demand (NCD) service?

A. NCD loads are estimated as the maximum monthly customer load over an annual cycle in FY 2002 and FY 2003 excluding any existing long-term service.

Q. What rates are assumed in determining NT and NCD revenues in the Network choice analysis?

A. TBL used an iterative process to determine the choice of NT or NCD service and calculate the rates so that the rate levels finally used to determine Network service choice are similar to the proposed rates.

Q. Do you make any specific assignments of Network transmission service?

A. Yes. In some instances, a transmission service on the Network was assumed for a customer based on discussions with transmission account executives or utility representatives.

Section 2.b Short-Term Sales

Q. How is the forecast of Network and Southern Intertie short-term sales developed?

A. The Network and Southern Intertie short-term sales forecasts are based on the average of TBL's FY 1998 and FY 1999 short-term business. *See* TR-02-E-BPA-03, Table 5, for the forecasted short-term Network and Southern Intertie sales.

Q. Are any adjustments made to the historical sales?

A. Yes. For the Southern Intertie forecast an amount equal to 44% of the increase in long-term contract demands between historical and forecast periods is subtracted from historical (FY 1998/1999) short-term sales as an adjustment to the forecast.

Q. Why is this adjustment made to the Southern Intertie forecast?

A. Long-term transmission sales are a substitute for short-term sales. This is particularly intuitive over constrained paths. The 44% estimate of the sensitivity between long-term and short-term business on the Southern Intertie is based on a study of the BPA Power Business Line for FY 1998. This study affirms an inverse relation between long-term and short-term sales. *See* TR-02-E-BPA-03, Appendix D, Table 3.

SECTION 3 CALCULATION OF TRANSMISSION RATES

Section 3a Prior Formula Power Transmission Rate Calculation Method

Q. How was the Formula Power Transmission (FPT) rate calculated in previous rate cases?

A. In previous rate cases, the FPT rate was calculated by subsegmenting the Network revenue requirement into cost categories for the facility components of the FPT rates. Peak usage on each facility type was determined from a power flow analysis, and then unit costs were calculated by dividing the cost of each facility type by the peak usage. Finally, these unit costs were scaled to achieve the FPT class revenue requirement.

Q. Why are you not proposing to use this method to calculate the FPT-02 rate?

A. This method was very complex and time consuming. The segmentation/power flow analysis only determines the relationship between the individual FPT components. The TBL ordinarily would not perform an analysis of cost subsegmentation and power flow over individual facility types for any other purpose. Furthermore, the BPA Corporate office and TBL have reduced staff in the parts of the organization where this work would be performed. Staff would have to taken off other higher priority projects in order to perform these analyses for this rate case.

Furthermore, with the offering of the Integration of Resources (IR) service in the early 1980's, and the advent of Open Access Transmission Tariffs (Tariff) in 1996, FPT revenues have made up a steadily declining share of the Network revenue requirement. With the advent of the Tariffs in October 1996, TBL stopped offering new FPT agreements. TBL expects the FPT share of total Network revenues to continue to decline as FPT contracts expire, FPT customers choose to convert to Tariff service, and FPT resources are sold by their historical owners to marketers.

Before the 1996 rate case, BPA used a scaling methodology based on an allocation of costs between Federal use, on one hand, and combined IR use and FPT use, on the other hand. The FPT and IR rates were designed to recover the allocated costs to the combined class. That methodology is antiquated because transmission for Federal use is acquired under the Tariff, either by PBL or PBL's customers, and transmission service for non-Federal power is now also purchased under the Tariff. This was also true to a lesser extent in the 1996 rate case, so the proper scaling factor for FPT was much debated, with a number of different proposals being made. In the settlement, it was agreed that the scaling factor would be calculated so that the overall percentage in the FPT rate would not exceed 13.5%, the same agreed increase as the IR rate.

Section 3b FPT-02 Rate Calculation

Q. How do you propose to calculate the FPT-02 rate?

A. TBL proposes to scale up the FPT-96 component charges by the overall increase in unit Network costs. Unit Network costs are calculated by adding the Network component of the two required Ancillary Services to Network costs and dividing the total by annual peak usage, as determined in a power flow analysis. See TR-02-E-BPA-03, at 17-19.

Q. Why do you add a Network component of required Ancillary Services to Network costs?

A. There is some question as to whether all the FPT contracts would allow a separate charge for these ancillary services. However, FPT service could not be provided without the services provided by Scheduling, System Control and Dispatch Service and the Reactive Supply and Voltage Control from Generation Sources Service. By adding a Network component of these Ancillary Services costs to Network costs, TBL assures that required Ancillary Service costs are reflected in the FPT rate level.

Q. Why did you use annual peak usage from a power flow analysis in the denominator?

A. Annual peak use from a power flow analysis provides a relatively easy way of making an "apples to apples" comparison of forecasted Network use in the upcoming rate period to Network use levels forecasted in the 1996 rate case. In addition, the calculation of FPT component costs in the past was based on power flows of the annual peak hour. This method is also consistent with the one coincidental peak method of calculating the PTP rate. *See* section 4a, Network Cost Allocation.

SECTION 4 CALCULATION OF NETWORK RATES

Section 4a Network Cost Allocation

Q. How did you calculate the PTP, IR, NCD, and NT Base rates?

A. Rates for service on the Network are calculated by dividing Network costs, net of FPT revenues, by the total transmission system peak load, net of FPT loads. The

PTP, IR, and NCD rates are all annual contract demand rates, so they are treated as one class for the purpose of setting rates. The peak load used in the divisor for these contract demand services is equal to the forecasted contract demands. For NT service, the peak load used in the divisor is the NT load on the hour of the annual transmission system peak, the one coincidental peak (1CP) method.

Q. Did you consider using a 12CP divisor?

A. Yes. TBL understands the methodology used by FERC to determine when it is appropriate to use a 12 coincidental peak (12CP) divisor is to compare the lowest monthly peak to the annual peak, and to compare the average of the 12 monthly peaks to the annual peak. Using either approach, TBL's transmission loading pattern would support the use of a 12CP divisor to calculate the PTP, IR, NCD, and NT Base rates.

Q. Why didn't TBL use a 12CP methodology for Network cost allocation?

A. TBL was concerned about the level of cost shifts that would result if a 12CP divisor was used to calculate the Network rates. In the 1996 rate case we used a one non-coincidental demand (1NCD) divisor for the load-based services. That is, we used the sum of the NT and NTP customers' individual forecasted annual peak demands. (The NTP-96 rate is a load-based rate applicable to transmission service under BPA's 1981 Power Sales Contracts.) Because there is considerable diversity among the NT customers' annual peak demands, using a 1CP rather than 1NCD divisor results in a smaller denominator, and thus a higher PTP rate. Because the NT Load Shaping rate is set to recover the remaining revenue requirement after the IR/PTP/NCD/NT Base rate is determined, the use of a 1CP rather than 1NCD divisor results in a lower NT rate. Using the 1CP methodology, the proposed PTP and IR rates are increasing by 13.2% and the proposed NT rate is decreasing by 5.3%. *See* TR-02-E-BPA-03, Table 13. The use of 12CP would produce an even larger disparity between the percentage rate changes for these customer classes, which we seek to avoid by using a 1CP divisor.

Section 4b Calculation of Short-Term Firm and Nonfirm PTP Service Rates

Q. How are the short term firm and nonfirm PTP service rates normally calculated?

A. In the 1996 rate case TBL proposed to set the short-term firm and nonfirm PTP service rates as follows: the monthly rate was set at 1/12th of the annual rate, the weekly rate was set at 1/52nd of the annual rate, the daily rate was set at 1/5th of the weekly rate, and the hourly rate was set at 1/16th of the daily rate. The daily and hourly rates are calculated by dividing by 5 and 16, rather than 7 and 24, to reflect the fact that the 5 weekdays tend to be more heavily loaded than the weekends and that the peak load period during the day lasts about 16 hours.

Q. Do you propose to modify this formula to calculate short-term firm and nonfirm PTP and IS rates?

A. Yes. TBL does not propose to sell weekly or monthly products. Instead, TBL proposes to sell short-term service in any number of daily increments of less than one year. This is a considerably more flexible product than that offered by the *pro forma* tariff. In order to reflect the higher cost of providing less than 5-day service, and the additional flexibility associated with longer term daily service, TBL proposes to set the price for the first 5 days of service equal to the annual rate/(52*5). All remaining days after the first 5 days of service will be priced at the annual rate/(52*7).

Q. *Does this result in a higher rate than a customer would pay under the 1996 formula if it purchased in exact weekly or monthly increments?*

A. Yes, slightly. However, to avoid such an outcome, TBL would have had to either reduce the price for the first 5 days or have discontinuities in the rate. TBL was reluctant to reduce the rate for the first 5 days because some customers depend on short-term transmission to serve firm loads, because of the cost savings. TBL is concerned about the implications of this practice on reliability and transmission system planning and does not want to encourage it by reducing the short-term rates relative to the long-term rates.

Q. *Do higher short-term rates result in TBL over recovering from PTP customers as a whole?*

A. No. The higher rates for short-term service are factored into the calculation of the annual PTP rates by artificially increasing the sales, or megawatts (MWs), of short-term service in the divisor. *See* TR-02-E-BPA-03, Table 7 and Table 8. For example, the forecasted MWs of daily sales in Block one, the first 5 days of any daily sale, are increased by 7/5 to reflect that the rate is 7/5 higher than it would be if the annual rate were divided by 52*7.

Section 4c NT Rate Calculation

Q. *How is the NT rate calculated?*

A. The NT Base Charge is set equal to the PTP/NCD/IR rate. However, this Base Charge alone does not recover the whole NT revenue requirement. In developing the Base Charge, NT loads are included in the denominator on a 1CP basis, as described above. However, the NT billing determinant is the customer's load on the hour of TBL's *monthly* peak, not annual peak. Since the average contribution to the monthly peak is significantly less than the contribution to the annual peak, the application of the Base Charge does not recover sufficient revenue. Therefore, the Load Shaping Charge is calculated to recover the remaining revenue requirement.

Q. Why is the billing determinant for the NT Load Shaping Charge the total Network Load even when the customer may have some Customer Served Load?

A. As explained above, the need for the Load Shaping Charge derives from the requirement that the NT service imposes on TBL to serve the customer's load, including load variations, rather than a designated annual contract demand. These load variations will not be covered by the Customer-Served Load, which will normally be a flat amount off the bottom of the load. Therefore, the load variation will be related to the total Network Load rather the load net of Customer Served Load.

In addition, this rate design reduces the possibility for gaming between the PTP and NT rates. NT customers can use a power supplier's PTP contract as Customer-Served Load. The proposed rate structure insures that cost saved by the NT customer (the Base Charge) in this scenario is equal to TBL's PTP revenues from the supplier's PTP service.

Q. Is there any relationship between the NT Load Shaping Charge and the charges for the Load Regulation or Energy Imbalance ancillary services?

A. No. As described above, the NT Load Shaping Charge is necessary to recover the total transmission costs associated with NT service. No costs for Ancillary Services are included in the Load Shaping Charge.

SECTION 5 SEASONAL DIFFERENTIATION OF THE SOUTHERN INTERTIE (IS) RATE

Section 5a Seasonal Differentiation for North to South Sales

Q. Please describe your IS rate proposal.

A. TBL is proposing that the IS rates for North to South long-term and short-term firm and nonfirm service be seasonally differentiated.

Q. What is the reason for developing seasonal rates?

A. The demand for North to South service on the Southern Intertie is greater in the summer than it is in the winter. By developing seasonal rates, the price signal will more accurately reflect the demand for service, resulting in more economically efficient use of the intertie.

Q. Will seasonal rates be applied to all transmission on the Southern Intertie?

A. Seasonal rates apply only to North to South sales, which constitute the bulk of TBL's transmission sales on the Southern Intertie. The demand for South to North capacity has a less clear seasonal differentiation pattern so seasonal rates are not proposed for these sales.

Q. *How are the seasons defined for purposes of setting the seasonal IS rates?*

A. "Winter" is defined as October 1 through March 31. "Summer" is April 1 through September 30.

Q. *What evidence does TBL have that there are different demands in the winter versus the summer?*

A. More than 60% of Southern Intertie sales occur in summer and less than 40% of Southern Intertie sales occur in winter.

Q. *How did TBL determine what the seasons would be?*

A. TBL's initial analysis indicated that April through September are the contiguous six months having the highest sales. For administrative ease and efficiency, two seasons of equal duration are optimal.

Q. *Has subsequent analysis changed your opinion of the appropriate definition of the seasons?*

A. Yes. Further analysis of sales during FY 1998 and FY 1999 indicate that November through April would be the appropriate winter period, while May through October would be the appropriate summer period. Sales in October are slightly higher than those in April. However, TBL did not have time to make the change prior to the initial proposal.

Q. *What is the starting point for deriving the seasonal rates for service on the Southern Intertie?*

A. Currently, one rate is applied over the course of the year. At that rate, the quantity of transmission capacity demanded in the winter is 75% of the quantity demanded in the summer, which is shown by comparing the average proportion of

Total Transmission Capacity (TTC) sold in winter to that sold in the summer. *See* Attachment 1, Total Transmission Capacity Sold vs. Price Differentials.

Q. Does TBL know what the demand functions are in the summer and winter?

A. No. Essentially, there are two observations in which summer sales average one-third higher than winter sales. Until now, only one rate has been applied throughout the year. Therefore, there is a point on the winter demand curve where the quantity demanded is 75% of the quantity demanded on the summer demand curve at the same price. *See* TR-02-E-BPA-03 *at* I1, graph of Illustrative Seasonal Demand for the Southern Intertie, which depicts this situation. This graph shows illustrative demands for transmission capacity in the summer and in the winter. "IS96" represents the current IS-96 rate. "Qw" represents the quantity of transmission demanded in the winter and "Qs" represents the quantity of transmission demanded in the summer, each at the IS-96 rate.

If the demand functions have unitary price elasticity, which is assumed, raising the summer rate by about 12% would reduce the quantity demanded in the summer by 12%. Reducing the winter rate by an offsetting proportion would increase the quantity demanded in the winter by the same percentage. In theory, a price can be established for each time period, summer and winter, where existing transmission capacity would just meet the demand. Although TBL does not precisely know the demand functions, nor the corresponding price elasticities, the assumption of unitary elasticity is reasonable, and we already know that winter demand is 75% of summer demand. Therefore, it is reasonable to infer that the rate for winter sales should be 75% of the summer rate.

Section 5b Calculation of the Southern Intertie Rate

Q. How is the IS rate developed?

A. First, the average IS rate is determined by dividing the net revenue requirements by forecast sales. The average IS rate is the rate to be applied to South to North IS sales, for which seasonal rates are not proposed. *See* TR-02-E-BPA-03 for a description and supporting documentation of the development of the IS rate.

Q. How did TBL derive the seasonal rates?

A. Southern Intertie sales forecasts are distributed throughout the year based on expected sales distributions. Because rates are set to recover costs, the revenue from sales are equal to costs; i.e., total revenue requirement (net costs) equal total net revenues. Mathematically, this is demonstrated as follows:

(1) Total IS Revenue = ISs * Summer Sales + ISw * Winter Sales

Where ISs is the summer IS rate and ISw is the winter IS rate.

Since the winter rate is 75% of the summer rate, equation (1) can be expressed as follows:

(2) Total IS Revenue = ISs * Summer Sales + ISs * 0.75 * Winter Sales

Thus, for rate design purposes, 75% of the forecasted winter sales are added to the summer sales. Solving Equation (2) produces:

(3) Total IS Revenue ÷ (Summer Sales + 0.75 * Winter Sales) = ISs

Once the summer transmission rate is determined, the last step is to compute the winter rate by setting it equal to 75% of the summer rate.

As a final check, the two rates are multiplied by expected North to South sales. That total is added to the average rate applied to expected South to North sales. The resulting forecast is compared to the overall revenue requirement to ensure that the two match.

Q. *Did TBL investigate alternative methods of seasonally differentiating the IS rate?*

A. Yes. One would expect that as power prices increase in California relative to the Northwest, the demand for Southern Intertie capacity would increase. Therefore, TBL analyzed daily prices at the California-Oregon Border (COB) and Mid-Columbia (Mid-C) hubs to see if price differentials there could explain sales or usage of the Southern Intertie. *See* Attachment 1. TBL averaged the daily price differentials to compute monthly price differentials. We found that the difference in prices averaged 3 mills/kWh for the 30 months of observations from May 1997 through October 1999. The average price difference in summer was 3.6 mills/kWh while in winter it was just over 2 mills/kWh. This is consistent with the observation of a higher demand in the summer. However, when we tried to correlate the price differentials with sales on the intertie there was no statistically significant correlation. For example, the correlation coefficient between price differentials and the monthly percent of TTC sold was 0.17.

Q. *Does applying different seasonal rates mean that the Southern Intertie rate would no longer be cost-based?*

A. No. The rates are set to recover required revenues.

Section 5c Potential Pricing Alternative for Southern Intertie Sales

Q. Did you consider another approach for selling transmission services on the Southern Intertie?

A. Yes, although TBL did not have sufficient time to develop a comprehensive alternative prior to issuing the Initial Proposal.

Q. Can you provide a brief description of the potential alternative approach?

A. Yes. Some customers suggested that TBL conduct an auction to sell Southern Intertie transmission service rights. Since an auction is market-based, it could, in theory, lead to a more economically efficient allocation of Southern Intertie capacity.

Q. Could TBL have a limited auction?

A. Yes, in theory. Instead of auctioning the entire capacity of the Southern Intertie, which would be almost impossible because of existing customer contract rights, the auction could be limited to sell only incremental Available Transmission Capacity (ATC) when it becomes available.

Currently, when incremental ATC becomes available TBL announces it on the Open Access Same-Time Information System (OASIS). The first transmission customer to make a firm request for the transmission capacity receives it. Using an auction, in which all interested customers would have a period of time, say, up to the next hour, to bid on ATC would potentially be fairer. All customers, not just those who continually monitor the OASIS, would have an opportunity to bid on the ATC. This may result in allocating the scarce resource more efficiently.

Q. Could an auction result in TBL collecting revenue greater than the Southern Intertie segment revenue requirement?

A. That would depend on how the auction is structured. As long as the auction resulted in a price less than or equal to the cost based price cap, it could operate the same way as the downwardly flexible rates. However, for an auction to achieve the goal of allocating scarce resources efficiently, the price would need to be allowed to exceed the cap. Even in that situation, it may be possible to implement a mechanism so that the additional revenues would be credited to the path users or segment users, either on a forecasted or real time basis. That would be one of many complicating factors in developing an auction system.

Q. Are there other issues raised by an auction?

A. Yes. Although TBL did not have time to fully explore the implementation issues or the advantages and disadvantages of an auction, we can identify several potential issues which may include:

- When and how often would the auction be conducted?
- Would the auction be conducted one time, annually, monthly, or whenever additional transmission capacity becomes available?
- What would be the minimum or maximum purchase period?
- Would there be a requirement to purchase transmission services for a minimum of one month's duration or some other period?
- How would TBL differentiate between North to South and South to North transmission?
- How would TBL handle re-assignment of transmission rights to third parties?

There likely are other issues, but this illustrates the potential complexity of an auction approach. It would be helpful to hear from the parties regarding their views and suggestions relating to the potential auction approach.

SECTION 6 UNAUTHORIZED INCREASE CHARGE

Q. What level of Unauthorized Increase Charge (UIC) did you propose in the 1996 rate case?

A. TBL proposed to set the UIC equal to 12 times the monthly charge for transmission service. This was designed to have a similar impact as an annual ratchet, which we have in a number of older contracts.

Q. Why does TBL propose to set the charge equal to only 6 times the monthly charge?

A. TBL has received many complaints from customers over the level of this charge. Simple mistakes in reservations and scheduling could result in the assessment of large Unauthorized Increase Charges.

Q. Why then has TBL not reduced the charge even further?

A. A number of transmission customers try to minimize the amount of transmission they purchase by depending on the availability of short-term transmission to serve their annual peak loads. TBL is concerned that, in the situation where short-term service is not available, some customers may take service above reserved amounts. A significant penalty charge is needed to deter this kind of behavior.

SECTION 7 DSI DELIVERY CHARGE

Q. Please describe the DSI Delivery Charge.

A. The DSI Delivery Charge is a UFT charge, calculated consistent with the UFT-02 rate schedule, increased by a factor of 1.197. *See* TR-02-E-BPA-04, at 56, and TR-02-E-BPA-03, at Section 3.11.1. The UFT charge recovers the cost of the DSI Delivery facilities used to deliver power to the DSI. The factor allows TBL to recover the entire cost of the DSI Delivery segment from the DSI customers.

Q. Why does TBL propose to change the design of the DSI Delivery Charge?

A. TBL is trying to insure that the DSI Delivery Charge fully recovers the cost of the segment. In order to do so, we needed to address two problems. The first problem, which TBL has encountered during this FY 1997-2001 rate period was that the UFT rates were calculated using forecasted plant loads or plant capacities. Actual loads at some plants were much less than the load used to calculate the UFT rate. This caused a significant underrecovery of the costs of the Delivery Segment. In order to avoid this problem in the future, if a DSI Delivery facility serves only the DSI customer, then the UFT charge will be a sole use charge that recovers the cost of the facility and does not depend on the DSI load.

If the DSI Delivery facilities serve more than one customer, the UFT charge will be based on the total annual cost associated with the facilities prorated between or among the customers using the delivery facilities in accordance with section III.B.2 of the UFT-02 rate schedule. This prorated cost will be the UFT basis for the DSI Delivery Charge and will not depend on the DSI load, similar to the sole-use UFT charge.

The second problem is that the standard UFT methodology, if applied to the DSI Delivery facilities, would not collect the full annual cost of the segment, as determined in the Revenue Requirement Study. Therefore, we have included a factor in the UFT formula so that it will fully recover the costs.

Q. *Does this conclude your testimony?*

A. Yes.

ATTACHMENT 1

Total Transmission Capacity Sold vs. Price Differentials

Month	Ave Percent TTC Sold	Ave COB - MidC Delta	
May-97	78%	4.7	
Jun-97	86%	4.8	
Jul-97	98%	4.9	
Aug-97	101%	4.5	
Sep-97	81%	4.7	
Oct-97	95%	3.2	
Nov-97	69%	4.3	
Dec-97	67%	2.4	
Jan-98	68%	0.8	
Feb-98	71%	2.3	
Mar-98	83%	1.5	
Apr-98	79%	1.0	
May-98	109%	1.0	
Jun-98	95%	2.0	
Jul-98	97%	5.1	
Aug-98	108%	0.0	
Sep-98	114%	0.9	
Oct-98	112%	0.9	
Nov-98	71%	1.2	
Dec-98	53%	-0.9	
Jan-99	56%	3.6	
Feb-99	70%	2.1	
Mar-99	90%	2.4	
Apr-99	93%	1.7	
May-99	104%	0.2	
Jun-99	107%	4.6	
Jul-99	101%	12.0	
Aug-99	101%	5.1	
Sep-99	99%	4.6	
Oct-99	114%	4.2	
		3.0	**Average**
	0.17	**Correlation Coefficient**	

	Delta	%TTC sold
ave. oct98-sep99	3.1	88%
ave oct98-mar99	1.5	75%
ave apr99-sep99	4.7	101%
ave oct97-sep99	2.6	88%
ave winters 97,98	2.0	75%
ave summer 98,99	3.2	101%
ave. all summer months	3.6	97%
ave all winter months	2.2	78%

INDEX

TESTIMONY OF

GARY E. STEMLER, DENNIS E. METCALF, GLENN A. RUSSELL, AND

WARREN L. MCREYNOLDS

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: Ancillary Services and Control Area Services

TESTIMONY OF

GARY E. STEMLER, DENNIS E. METCALF, GLENN A. RUSSELL, AND

WARREN L. MCREYNOLDS

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: ANCILLARY SERVICES AND CONTROL AREA SERVICES

SECTION 1 INTRODUCTION

Q. Please state your name and qualifications.

A. My name is Gary E. Stemler. My qualifications are stated at TC/TR-02-Q-BPA-19.

A. My name is Dennis E. Metcalf. My qualifications are stated at TC/TR-02-Q-BPA-15.

A. My name is Glenn A. Russell. My qualifications are stated at TC/TR-02-Q-BPA-17.

A. My name is Warren L. McReynolds. My qualifications are stated at TC/TR-02-Q-BPA-14.

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor the Ancillary Services and Control Area Services Rate Schedule, relevant portions of the General Rate Schedule Provisions, and calculation of the ACS-02 rates. TR-02-E-BPA-04; TR-02-E-BPA-03.

Q. How is this testimony organized?

A. This testimony is organized into nine sections starting with an Introduction, then moving to an Overview of Ancillary Services and Control Area Services. Following that is a section on each of the six Ancillary Services Bonneville Power Administration's (BPA's) Transmission Business Line (TBL) is offering, with a description of when certain of those services may be purchased as Control Area Services. Finally, there is the section on Generation Imbalance Service, which is offered only as a Control Area Service.

SECTION 2 OVERVIEW OF ANCILLARY SERVICES AND CONTROL AREA SERVICES

Q. What are Ancillary Services?

A. Ancillary Services are the six services that the Federal Energy Regulatory Commission (FERC) identified in Order 888 as required to provide basic transmission service to a customer. These services range from actions taken to effect the transaction (such as scheduling and dispatching services) to services that are necessary to maintain the integrity of the transmission system during a transaction (such as load following and reactive power support). Another Ancillary Service is needed to correct for the effects associated with undertaking a transaction (energy imbalance service). Operating reserve services are needed to help assure reliability of energy delivery to loads in the event of resource failure.

Q. Please provide an overview of the Ancillary Services.

A. BPA is offering the following six Ancillary Services:

1) **Scheduling, System Control, and Dispatch Service**

This service is required to schedule and secure the movement of power through, out of, within, or into a Control Area (this service includes scheduling and dispatch of generation to maintain generation/load balance and maintain reliability of the transaction).

2) **Reactive Supply and Voltage Control from Generation Sources Service**

This service provides generation-supplied reactive support to the transmission system, and is required to provide transmission system stability and to maintain transmission system voltages within acceptable limits.

3) **Regulation and Frequency Response Service**

This service provides the continuous balancing of resources (generation and interchange) with load and maintains frequency at 60 Hz. This service is accomplished by committing on-line generation (predominantly through the use of automatic generation control equipment), the output of which is raised or lowered to follow the moment to moment changes in load.

4) **Energy Imbalance Service**

Energy Imbalance is provided when a difference occurs over a single hour between the scheduled and actual delivery of energy to a *load* in the Control Area. This service does not apply to generation in the Control Area. Service for mismatch of generation will be handled separately through Control Area Services.

5) **Operating Reserve --Spinning Reserve Service**

Spinning Reserve Service is needed to continuously and reliably serve load in the event of a system contingency. Generating units that are on-line and loaded at less than maximum output and immediately available to pick up load provides this service. Regional criteria establish the minimum reserve requirement to meet broadly accepted technical standards for power system (delivery) performance.

6) **Operating Reserve -- Supplemental Reserve Service**

Supplemental Reserve Service is needed to serve load in the event of a contingency. Unlike spinning reserve, supplemental reserve is not necessarily available immediately to serve load, but is available within a short period of time. This service may be provided by units that are on-line but unloaded, by quick start generation, by interruptible load, or by on-demand rights from others.

Q. What are Control Area Services?

A. Control Area Services are available to meet the reliability obligations of generation or loads in the BPA Control Area. Control Area Services are provided to generation or loads in the BPA Control Area that may not be taking service from BPA's TBL, but do impose reliability obligations on the BPA Control Area that are not otherwise met. TBL is proposing to offer the following Control Area Services: Regulation and Frequency Response; Generation Imbalance; Operating Reserve-Spinning; and Operating Reserve-Supplemental.

Q. What is the difference between Ancillary Services and Control Area Services?

A. Ancillary Services are provided or offered to Customers taking related Transmission Service. Control Area Services are offered to loads or generators in the BPA Control Area that may not be taking Transmission Service from TBL, but do impose reliability obligations on the BPA Control Area that are not otherwise met.

Q. *How do the proposed Ancillary Services differ from BPA's currently offered Ancillary Services?*

A. Under the current 1996 rates, Scheduling, System Control and Dispatch Service is not separated from basic transmission service. In this proposal, it is unbundled and offered as a separate Ancillary Service.

Under the current 1996 rates, the Reactive Supply and Voltage Control from Generation Sources Service is included in BPA's power rates. In this proposal, it is unbundled and offered as a separate Ancillary Service..

Regulation and Frequency Response Service replaces what was previously called Load Regulation. The proposed service recognizes the Control Area's obligation to follow load and maintain the frequency at 60 Hz, and includes capacity for between-hour load changes (ramps).

The proposed Energy Imbalance Service applies only to *loads* in the Control Area. The corresponding service for generators in the Control Area is now offered as the Control Area Service called Generation Imbalance Service.

Operating Reserve -- Spinning Reserve Service, as proposed, is always purchased as a separate unbundled service. Under current 1996 rates, this service can be purchased separately as the Ancillary Service "Control Area Reserves for Resources (Partial Service)," but is most often sold as part of a bundled service called "Control Area Reserves for Resources (Full Service)." The proposed service is offered as an Ancillary Service to Transmission Customers. For generators in the BPA Control Area not using BPA Transmission Service, Operating Reserve -- Spinning Reserve Service is offered as a Control Area Service to allow those generators to meet their Western Systems Coordinating Council (WSCC) reliability obligations for reserves.

Operating Reserve -- Supplemental Reserve Service provides the non-spinning operating reserve service portion of a customer's contingency reserve requirement. For Transmission Customers, this service is offered as an Ancillary Service. Under the current 1996 rates it is included as part of the Ancillary Service "Control Area Reserves for Resources (Full Service)," or may be purchased as a separate item under "Control Area Reserves for Resources (Partial Service)."

For generators in the BPA Control Area not using BPA Transmission Service, Operating Reserve -- Supplemental Reserve Service is offered as a Control Area Service to allow those generators to meet their WSCC reliability obligations for reserves.

Q. Which Ancillary Services must be purchased?

A. Transmission Customers are required to purchase: 1) Scheduling, System Control and Dispatch Service; and 2) Reactive Supply and Voltage Control from Generation Sources Service.

Transmission Customers may not decline TBL's offer of the other four Ancillary Services unless the Transmission Customer can demonstrate to TBL's satisfaction that it has made alternative comparable arrangements that are technically feasible.

Q. Who must purchase Ancillary and Control Area Services?

A. All Transmission Contract Holders must purchase the two required Ancillary Services and have the right to purchase the other four Ancillary Services from the TBL. Generators or loads in the BPA Control Area that impose reliability obligations on the BPA Control Area which are not otherwise provided for under a TBL transmission agreement may purchase Control Area Services to satisfy their obligations.

Q. How are a customer's Ancillary Service requirements determined?

A. Ancillary Service requirements are determined through application of FERC, North American Electric Reliability Council (NERC), WSCC, and Northwest Power Pool (NWPP) standards.

Q. How are a customer's Control Area Services requirements determined?

A. Loads and resources in the BPA Control Area each impose certain reliability obligations on the BPA Control Area. These obligations are determined through application of NERC, WSCC, and NWPP reliability standards for Control Areas. To the extent that the reliability obligations associated with a load or resource in BPA's Control Area are not met through the purchase of Ancillary Services or through some other appropriate arrangement, the obligations must be met with the purchase of Control Area Services.

Q. Does BPA propose flexible rates for Ancillary Services and Control Area Services?

A. Yes. All of the proposed Ancillary Services and Control Area Services rates are downwardly flexible rates and allow discounting.

SECTION 3 SCHEDULING, SYSTEM CONTROL, AND DISPATCH SERVICE

Q. Please briefly describe Scheduling, System Control, and Dispatch Service.

A. This service includes all the activities associated with scheduling energy transactions, verifying available transmission capacity for the schedule period, controlling generation to ensure adequate generation to meet firm load and interchange schedules, meeting reliability standards, and evaluating performance adequacy.

Q. What facilities and costs have been assigned to Scheduling, System Control, and Dispatch Service?

A. The facilities and costs associated with Scheduling, System Control, and Dispatch Service are described in the Segmentation Study (TR-02-E-BPA-02).

Q. Who will be charged for Scheduling, System Control and Dispatch Service?

A. Each customer taking Transmission Service is charged for Scheduling, System Control and Dispatch Service for both firm and non-firm transactions. Transmission on the Network, on the Southern Intertie, and on the Montana Intertie are each charged separately. However, FPT customers will not pay an unbundled charge for Scheduling, System Control and Dispatch Service; instead, the cost of this service is embedded in the FPT rate. *See* Woerner, et al., TR-02-E-BPA-08, for discussion of the FPT rate.

Q. Why are the Interties charged separately?

A. Each transaction category requires activities and facilities to accomplish the Scheduling, System Control and Dispatch Service. The Interties contribute to a significant portion of the costs associated with the Scheduling, System Control and Dispatch Service.

Q. *Why isn't there a separate, unique rate for each Intertie and the Network?*

A. Because of the interdependence of the three categories of transactions on the Scheduling, System Control and Dispatch Service, it is not clear how an equitable attribution of cost exclusive to each transaction category could be made. Consequently, the total cost for the service has been identified in the Revenue Requirement Study (TR-02-E-BPA-01), and the rate for the service has been determined from the forecasted use of the service. *See* TR-02-E-BPA-03, Table 11. Each transaction category (Network, Southern Intertie, and Montana Intertie) will then be charged the Scheduling, System Control and Dispatch rate for each use.

Q. *Why aren't FPT customers charged separately for Scheduling, System Control, and Dispatch Service?*

A. Some FPT contracts may not allow a separate charge for this service. *See* Metcalf, et al., TR-02-E-BPA-08, for discussion of FPT rate development.

Q. *What is the Billing Factor for Scheduling, System Control and Dispatch Service?*

A. For Transmission Customers taking Point-to-Point service (PTP, IS, and IM rates), Network Contract Demand service (NCD rate), and Integration of Resources service (IR rate), the Billing Factor is Transmission Demand. For Transmission Customers taking Network Integration service, the Billing Factor shall equal the NT Base Charge Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-02).

Q. Why are you proposing to use the transmission service billing factor for Scheduling, System Control and Dispatch Service?

A. This Ancillary Service includes not only transmission schedule reservation and confirmation, but also operational studies to verify adequate transmission capacity, dispatch and automatic control of generation to match system loading requirements, coordination of interchange schedules with the 14 other Control Areas adjacent to TBL, security monitoring and dispatch action in the delivery hour to maintain reliable delivery to load, and generation dispatch to accomplish between-hour load changes. Many of the activities and costs associated with this service are a function of transmission loading levels and patterns rather than the number of schedules. In addition, the use of a billing factor other than that proposed would greatly increase the complexity of billing for this service. For example, billing on the number of schedules would require making a host of judgments as to how to count schedules, would require the development of an additional system to keep track, and would likely create many disputes with customers.

SECTION 4 REACTIVE SUPPLY AND VOLTAGE CONTROL FROM GENERATION SOURCES SERVICE

Q. Please briefly describe Reactive Supply and Voltage Control from Generation Sources Service.

A. In addition to supplying real power, Federal Columbia River Power System (FCRPS) generation facilities provide reactive power and voltage control to the

Federal Columbia River Transmission System (FCRTS). Reactive power and voltage control from FCRPS generation sources is critical to the reliable operation of the FCRTS, because these generation facilities provide the high speed dynamic reactive power and voltage control response necessary during moment to moment voltage deviations, especially during system outages. To the extent possible, the reactive power capability of FCRPS generation facilities is held in reserve as a reactive margin to prevent voltage collapse when outages occur on the system.

Q. Are costs associated with FCRPS generation facilities assigned to TBL?

A. Yes. Reactive supply and voltage control from generators is separate and distinct from reactive power supplied by transmission facilities such as capacitors. Reactive Supply and Voltage Control from Generation Sources is an Ancillary Service and must be unbundled. BPA therefore developed a methodology in its 2002 Power Rate Case to determine the appropriate FCRPS generation related costs to allocate to the unbundled service. In short, the methodology allocates to Reactive Supply and Voltage Control from Generation Sources Service a portion of the cost of generation electrical equipment, plus related real power losses caused by supplying reactive power. These costs are assigned to TBL as a generation input for the Ancillary Service Reactive Supply and Voltage Control from Generation Sources. For a detailed description of the costing methodology used and the costs assigned to TBL for FCRPS generation facilities, refer to testimony from BPA's 2002 Power Rate Case. *See* DeClerck, et al., WP-02-E-BPA-26, section 2.

Q. *Will the costs assigned to TBL for generation inputs for Reactive Supply and Voltage Control from Generation Sources Service be revised in TBL's transmission rate case?*

A. No. The cost of generation inputs for Reactive Supply and Voltage Control from Generation Sources Service is determined in BPA's 2002 Power Rate Case. The proposed rates are based on BPA's initial proposal in the 2002 Power Rate Case. TBL's final proposal will reflect the Administrator's decision in the 2002 Power Rate Case final Record of Decision on this issue.

Q. *Are there costs in addition to the cost of generation inputs?*

A. Yes. In addition to the cost of generation inputs, TBL is allocating to Reactive Supply and Voltage Control from Generation Sources Service a portion of those costs of transmission facilities and O&M attributable to providing the service, primarily communications and control equipment. This equipment is used to control and monitor generation-supplied reactive power on the transmission system. *See* Segmentation Study, TR-02-E-BPA-02, Table 8.1.

Q. *Who will be charged for Reactive Supply and Voltage Control from Generation Sources?*

A. Each Transmission Customer is charged for Reactive Supply and Voltage Control from Generation Sources Service, for both firm and non-firm transmission transactions. Transmission on the Network, on the Southern Intertie, and on the Montana Intertie are each charged separately.

Q. Why are the Interties charged separately?

A. Reactive Supply and Voltage Control from Generation Sources Service is needed to maintain the stability and the ratings of Network and Intertie facilities. FCRPS generation facilities provide reactive support necessary to maintain ratings on the Interties, particularly the Southern Intertie. For example, hydro units at The Dalles and John Day plants were modified to allow synchronous condenser operation of selected units. These modifications support both the Network and the Southern Intertie by enabling certain units to provide reactive power even when the units are not used for real power production. In addition, parties that have access to the Intertie without purchasing transmission on the Network could avoid the Reactive Supply and Voltage Control from Generation Sources Service charge if TBL were to charge only Network users.

Q. What is the Billing Factor for Reactive Supply and Voltage Control from Generation Sources Service?

A. For Transmission Customers taking Point-to-Point service (PTP, IS, and IM rates), Network Contract Demand service (NCD rate), and Integration of Resources service (IR rate), the Billing Factor is Transmission Demand. For Transmission Customers taking Network Integration service, the Billing Factor shall equal the NT Base Charge Billing Factor determined pursuant to section III.A. of the Network Integration Rate Schedule (NT-02).

Q. Why is the Billing Factor the Transmission Demand, rather than the reactive power used by the customer?

A. All users of the FCRTS benefit from a stable transmission system. FCRPS generation facilities provide the dynamic reactive response and dynamic reactive reserve necessary to ensure that real power transactions can be completed. Billing a customer based on actual use of generation reactive output, as well as the customer's share of the generation reactive reserve would be unduly complicated. Charging all customers based on Transmission Demand is an equitable means of recovering the cost of Reactive Supply and Voltage Control from Generation Sources Service.

Q. Will customers be allowed to self-supply Reactive Supply and Voltage Control from Generation Sources Service?

A. Yes, in certain cases, to the extent that a customer can demonstrate the ability to meet TBL's requirements for self-supply for integrating a specific resource. In such cases, TBL will negotiate an adjustment to the Transmission Customer's Billing Factor for Reactive Supply and Voltage Control from Generation Sources Service. Such adjustment shall be specified in the Transmission Customer's Service Agreement. The requirements for self-supply include a location criteria such that self-supply is limited to those generation resources which are directly connected to the FCRTS, and which are located either west of the Cascade Mountains or near the head of the Southern Intertie. The requirement for self-supply will be posted on the OASIS, and may be adapted over time as system operations and/or conditions warrant. Table 11 of the Transmission Rate Study, TR-02-E-BPA-03, shows the calculation of the rate for this service, which includes an adjustment for the forecasted self-supply.

Q. Why does the proposed location criteria limit self-supply to resources located west of the Cascade Mountains or near the head of the Southern Intertie?

A. In the Pacific Northwest, large load centers are located west of the Cascade Mountains, while large quantities of generation are located east of the Cascades. Therefore, cross-Cascade transmission lines are heavily loaded. Power integrated east of the Cascades increases flows on these lines, thereby increasing the reactive power requirements on these facilities, exacerbating reactive problems. Power integrated west of the Cascades generally alleviates such problems. Generation located near the head of the Southern Intertie lends reactive support, inertia, and stability to the Intertie. For these reasons, self-supply of Reactive Supply and Voltage Control from Generation Sources Service is limited to the locations specified. However, as mentioned above, the location criteria may be adapted over time.

SECTION 5 REGULATION AND FREQUENCY RESPONSE SERVICE

Q. Who will be charged for Regulation and Frequency Response Service?

A. Transmission Customers serving load in the BPA Control Area will be charged for the Ancillary Service Regulation and Frequency Response Service. Loads in the BPA Control Area that are not served over TBL transmission will be charged for the Control Area Service of Regulation and Frequency Response, unless the customer can demonstrate to TBL's satisfaction that this obligation is met through other arrangements.

Q. What is the Billing Factor for Regulation and Frequency Response Service?

A. The Billing Factor is the customer's total load in the BPA Control Area. This is because the Control Area must carry regulating reserves sufficient to provide for the variations in all load in the Control Area, to meet NERC and WSCC reliability criteria. Credit will not be given for load served by customers' own generation unless it can be demonstrated to TBL's satisfaction that the customer's resource meets criteria for supply of Regulation and Frequency Response equivalent to that which TBL uses for its own supply of the service.

SECTION 6 ENERGY IMBALANCE SERVICE

Q. Please explain Energy Imbalance Service.

A. Energy Imbalance Service is delivered when a load in the BPA Control Area receives an amount of energy different from the amount scheduled for delivery during the (schedule) hour. To the extent that the BPA Control Area absorbs or delivers the amount of energy different from that scheduled to the load, Energy Imbalance service is provided. There is an energy imbalance deviation band that allows for minor deviations from schedule to be balanced during subsequent hours over a period of time. TBL is adopting a deviation band of plus or minus 1.5% with a 2 MW minimum error from schedule before a penalty rate applies.

Q. Who will be charged for Energy Imbalance Service?

A. Transmission Customers serving load in the BPA Control Area will be charged.

Q. Will customers purchasing a power requirements service be charged for Energy Imbalance?

A. Customers with certain types of power requirements contracts may possibly avoid Energy Imbalance Service, if their power sales agreement is structured such that the conditions for imbalance cannot occur.

Q. What is the Billing Factor for Energy Imbalance Service?

A. The Billing Factor for Energy Imbalance Service is the deviation outside the imbalance deviation band in a schedule hour, in kilowatthours.

Q. What is the rate for Energy Imbalance Service?

A. For deviations above the deviation band, (i.e., energy taken in excess of schedule limits), a customer will be charged the higher of: (1) a penalty rate of 100 mills per kilowatthour, or (2) 110% of a market index representative of the NW market.

For an energy imbalance that delivers energy in excess of the deviation band limit, a credit may be given equal to 90% of the market index at the time of occurrence of the imbalance, provided it is not an Intentional Deviation and the Federal System is not in Spill Condition at any time during the month.

Q. What about Imbalance Energy within the Deviation Band?

A. For deviations within the energy imbalance band, a deviation account will be tabulated. The net deviation must be brought to zero each month through energy returns.

Q. When is energy from the deviation account returned?

A. TBL will designate the quantities and the hours that deviation account energy shall be returned. The customer will then make the necessary arrangements and schedule the transaction(s).

Q. Why is TBL using a market index to determine TBL's incremental or decremental cost?

A. A market index best reflects the cost to BPA if additional purchases or sales must be made or forgone because of the imbalance.

Q. Why will TBL provide no credit if the Federal System is in Spill Condition at any time during the month?

A. If there is a Spill Condition during the month, then an imbalance that delivers excess energy is of little or no value.

SECTION 7 OPERATING RESERVE -- SPINNING RESERVE SERVICE

Q. Please describe Operating Reserves.

A. Operating reserves consist of contingency reserves, both spinning and supplemental, and regulating reserve. Contingency reserves are interruptible loads, or resources held in reserve and available to restore the balance of generation to load when a contingency occurs.

Regulating reserve is generation on AGC used to follow load variations within the hour. NERC, WSCC, and the NWPP have established standards that TBL adheres to in determining the amount of operating reserves that the Control Area must carry.

Q. How are the rates for Operating reserves being established?

A. For contingency reserves, both spinning and supplemental, the rates are established by determining the revenue requirement for the service. TR-02-E-BPA-01. These costs are then divided by the projected use of the service to establish the rate. TR-02-E-BPA-03, Table 11.

Q. How were the revenue requirements established?

A. Cost elements include: (1) generation input cost, taken from the 2002 Power Rate Case Initial Proposal, WP-02-E-BPA-05, Section 4.1; (2) an allocation of plant investment cost and a budget forecast of additional investment through 2003; and (3) an expense forecast of O&M costs through 2003. Details are described in the Segmentation Study. TR-02-E-BPA-02.

Q. How is the forecasted use of the service established?

A. PBL must purchase its operating reserves from TBL. The assumptions for the amount of generation and the reserves required in the BPA Control Area are taken from the Power Rate Case Initial Proposal. WP-02-E-BPA-05, section 4.1.2, pages 72-73.

Q. Please describe Operating Reserve -- Spinning Reserve Service.

A. Spinning Reserve Service is provided by generating units that are on-line and loaded at less than maximum output. This service provides immediate initial response to serve loads in the event that a scheduled energy supply is interrupted.

Spinning Reserve Service must be provided for all firm load served by generation in the BPA Control Area.

Q. *Who will be charged for Operating Reserve -- Spinning Reserve Service?*

A. Transmission Customers serving firm load from generation in the BPA Control Area must acquire this Ancillary Service. Generation in the BPA Control Area that is delivering energy without the use of a TBL Transmission Contract may purchase this service as a Control Area Service.

Q. *How is a customer's requirement for Operating Reserve -- Spinning Reserve Service determined?*

A. A customer's requirement for this service is established by determining the obligation that the customer's transaction imposes on the BPA Control Area each hour. The Control Area obligation is determined based upon the reliability standards of NERC, WSCC, and NWPP. Currently, the WSCC Minimum Operating Reliability Criteria (MORC) establishes a minimum contingency reserve-spinning as at least one half of the sum of: five percent of the firm load responsibility served by hydro generation in the BPA Control Area; and seven percent of the firm load responsibility served by non-hydro generation in the BPA Control Area.

Q. *Please explain the concept of firm load responsibility?*

A. Firm load responsibility for the Control Area is equal to the firm loads in the Control Area, plus firm exports minus firm imports for which reserves are provided. Normally, this results in a firm load responsibility equal to the generation in the Control Area serving firm load.

Q. What is the Billing Factor for Operating Reserve – Spinning Reserve Service?

A. The Billing Factor for Operating Reserve – Spinning Reserve Service is 2.5% of hydro generation dedicated to the Transmission Customer's firm load responsibility; plus 3.5% of non-hydro generation dedicated to the Transmission Customer's firm load responsibility, each determined on an hourly basis.

When reserves are actually delivered during a contingency, the customer must pay for or return the energy delivered.

Q. Why is the billing factor for Contingency Reserves determined and applied on an hourly energy basis?

A. The Control Area reserve requirement is determined every five minutes and totaled as an hourly average based on the generation in the Control Area that is serving firm loads. Therefore, charging on the basis of hourly energy is consistent with the Control Area reserve requirement determination. In addition, TBL is concerned that a peak billing determinant could cause inefficiencies in the power market. For example, consider a Transmission Customer that has a long term PTP agreement to wheel generation from outside the Control Area. If that customer wished to purchase energy from generation in the BPA Control Area to displace one or more of its resources and shelter the transmission under its PTP agreement, it would be subject to a demand charge for the month for its largest hourly purchase. With the proposed energy billing factor, purchasers can evaluate purchases from generation in the BPA Control Area knowing that there is a uniform adder per kWh for operating reserves.

Q. Given that the reserve requirement is based on generation in the BPA Control Area, did you consider directly charging generators in the Control Area rather than charging Transmission Contract Holders?

A. Yes. That is how our current charge works and we considered continuing that design. TBL anticipates that it will be very difficult to set up a system for identifying on an hourly basis whether power being transmitted originated in the BPA Control Area and thus requires contingency reserves (or self supply).

However, our understanding is that FERC requires transmission providers to offer Ancillary Services to *Transmission Customers* and provide *Transmission Customers* with the alternative of self supply or third party supply. TBL anticipates that, in many cases the Transmission Customer will be a different entity than the generation owner or operator, particularly with respect to PBL sales. At customer workshops, a number of customers have expressed an interest in self-supplying contingency reserves associated with their purchase of PBL power.

SECTION 8 OPERATING RESERVE -- SUPPLEMENTAL RESERVE SERVICE

Q. Please briefly describe Operating Reserve -- Supplemental Reserve Service.

A. Supplemental Reserve Service is provided by any combination of spinning reserves in excess of spinning reserve requirements, interruptible load, off-line generation that can be fully activated within ten minutes, or on-demand rights from other entities or Control Areas. This service helps restore resource and load balance within a short time after contingencies occur.

Q. *Who will be charged for Operating Reserve -- Supplemental Reserve Service?*

A. Transmission Customers serving firm load from generation in the BPA Control Area must pay for this Ancillary Service. Generating entities in the BPA Control Area that are delivering energy without using TBL transmission must purchase this service as a Control Area Service.

Q. *How is a customer's requirement for Operating Reserve -- Supplemental Reserve Service determined?*

A. A customer's requirement for this service is established by determining the obligation that the customer's energy transaction imposes on the BPA Control Area. The Control Area obligation is determined from the reliability standards of NERC, WSCC, and NWPP. Currently, application of WSCC MORC to a customer's energy transactions establishes minimum contingency reserve-supplemental as at least one half of the sum of: five percent of the firm load responsibility served by hydro generation in the BPA Control Area; and seven percent of the firm load responsibility served by non-hydro generation in the BPA Control Area. Load responsibility is firm loads plus firm exports minus firm imports for which reserve capacity is provided by the supplier. If a customer is purchasing interruptible power, reserves equal to 100% of the interruptible purchase must be purchased or otherwise provided.

Q. *What is the Billing Factor for Operating Reserve -- Supplemental Reserve Service?*

A. The Billing Factor for *Operating Reserve -- Supplemental Reserve Service* is determined consistent with WSCC and NWPP guidelines, which are currently:

- 2.5% of hydro generation dedicated to the Transmission Customer's firm load responsibility; plus
- 3.5% of non-hydro generation dedicated to the Transmission Customer's firm load responsibility; plus
- 100% of interruptible purchases.

The billing factor for energy delivered is the amount of energy delivered, in kilowatthours.

Q. How does Spinning Reserve Service differ from Supplemental Reserve Service?

A. Spinning Reserve Service starts responding immediately to contingency events, and must be fully available and loaded within ten minutes. Supplemental Reserve Service does not provide for immediate response to a contingency, but still must be fully available and loaded within ten minutes. Spinning Reserve Service can be provided from generators that are on-line and loaded to less than full capacity. Supplemental Reserves can be provided from interruptible load, or from generation (off-line or on-line) which is fully available within ten minutes.

SECTION 9 GENERATION IMBALANCE SERVICE

Q. Please briefly describe Generation Imbalance Service.

A. Generation Imbalance Service is not an Ancillary Service, but rather a Control Area Service which must be acquired for all generation in the BPA Control Area. This service is delivered when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area

Q. How does Generation Imbalance Service differ from Energy Imbalance Service?

A. Energy Imbalance Service is an Ancillary Service which applies only to loads in the BPA Control Area. Generation Imbalance Service is a Control Area Service which must be taken to ensure that the Control Area maintains load-resource balance. If generators in the BPA Control Area do not schedule accurately and reliably, the Control Area incurs extra costs to maintain reserves available to meet the scheduling error. Arrangements for generation imbalance will be specified in the generator's Interconnection Agreement

Q. Who will be charged for Generation Imbalance Service?

A. Entities representing generation resources operating in the BPA Control Area will be charged for Generation Imbalance Service. For customers taking transmission service from TBL, arrangements for Generation Imbalance Service can be specified in the Service Agreement. Other generators in the Control Area can arrange for this service through their Generation Interconnection Agreement, Interconnected Operation Agreement, or a separate agreement.

Q. Is there a deviation band for Generation Imbalance Service?

A. Yes. The Deviation Band for Generation Imbalance Service is the greater of 2 MW or 1.5% of schedule during a schedule hour.

Q. What is the Billing Factor for Generation Imbalance Service?

A. The Billing Factor for Generation Imbalance Service is the amount of energy that the generator under-generates, in kilowatthours, outside the Generation Imbalance Deviation Band. For over-generated energy outside the Generation Imbalance Deviation Band, a credit will be allowed to the extent that the over-generation is not an Intentional Deviation and occurs during a month in which the Federal System is not in Spill Condition at any time

Q. How will BPA treat generation imbalances within the Generation Imbalance Deviation Band?

A. For deviations within the Generation Imbalance Deviation Band, a deviation account will be tabulated. The net deviation must be brought to zero each month through energy returns.

Q. When is energy from the Generation Imbalance Deviation account returned?

A. TBL will designate the quantities and the hours that deviation account energy shall be returned. The customer will then make the necessary arrangements and schedule the transaction(s).

Q. What is the rate for Generation Imbalance Service associated with under-generation?

A. The rate for under-delivery of energy by the generator is the higher of 100 mills per kWh or 110% of the market price at the time of occurrence of the imbalance. The market to be referenced for the fiscal year will be posted on the OASIS by September 30th preceding the fiscal year for which the rate applies, and will remain posted until superseded.

Q. What rate will be used in determining the credit associated with Generation Imbalance energy for over-generation?

A. The rate for qualifying energy shall be 90 percent of the market rate cited above.

Q. Why is a market index used to determine BPA's incremental or decremental cost of Generation Imbalance energy?

A. A market index best reflects the cost to BPA if additional purchases or sales must be made or forgone because of the imbalance.

Q. Please explain why BPA will not provide a credit for imbalance energy outside the Generation Imbalance Deviation Band if the Federal System is in Spill Condition at any time during the month.

A. If the Federal System is in Spill Condition at any time during the month, the excess energy has little or no value.

Q. Does this conclude your testimony?

A. Yes.

INDEX

TESTIMONY OF

BRIAN D. ALTMAN AND GORDON L. COMEGYS

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: Power Factor Penalty Charge

TESTIMONY OF

BRIAN D. ALTMAN AND GORDON L. COMEGYS

Witnesses for Bonneville Power Administration Transmission Business Line

SUBJECT: POWER FACTOR PENALTY CHARGE

SECTION 1 INTRODUCTION AND PURPOSE

Q. *Please state your names and qualifications.*

A. My name is Brian D. Altman. My qualifications are contained in TC/TR-02-Q-BPA-01.

A. My name is Gordon L. Comegys. My qualifications are contained in TC/TR-02-Q-BPA-05.

Q. *What is the purpose of your testimony?*

A. The purpose of this testimony is to sponsor the Power Factor Penalty Charge contained in the General Rate Schedule Provisions for Transmission Rates. See TR-02-E-BPA-04, at 58-61.

Q. *How is your testimony organized?*

A. Our testimony includes an Introduction, a description of the proposed Power Factor Penalty Charge, and a description of the application of the charge.

SECTION 2 DESCRIPTION OF THE POWER FACTOR PENALTY CHARGE

Q. *Does the Power Factor Penalty Charge replace the existing Reactive Power Charge?*

A. Yes.

Q. *Why is TBL changing the name from the Reactive Power Charge to the Power Factor Penalty Charge?*

A. The name change is for clarity and to avoid confusion with the ancillary service "Reactive Supply and Voltage Control from Generation Sources" service (also referred to as Generation Supplied Reactive), and is in keeping with the Federal Energy Regulatory Commission's (FERC's) description in Order 888.

Q. *Is the Power Factor Penalty Charge an Ancillary Service?*

A. No. The Power Factor Penalty Charge is not an Ancillary Service as identified in the *pro forma* tariff or the Transmission Business Line's (TBL's) Open Access Transmission Tariff. The purpose of the Power Factor Penalty Charge is to provide an incentive to minimize preventable reactive power flows at parties' interconnections with the Federal Columbia River Transmission System (FCRTS). The costs of investments made in capacitors and reactors forms the basis for quantifying this penalty rate. The Ancillary Service Reactive Supply and Voltage Control from Generation Sources is for generation-related facilities. See Stemler, et al., TR-02-E-BPA-09.

Q. *How are the costs of investments to supply and manage reactive power recovered?*

A. The costs for capacitors and reactors are recovered through the rates for network transmission service. TBL has estimated the annual cost of these facilities at approximately $33 million per year.

Q. *How did the TBL develop a revenue forecast for the Power Factor Penalty Charge?*

A. The revenue forecast of $5 million per year is based on several items including: historical billing from FY 1997 through FY 1999 based on the current Reactive

Power Charge; the impact of a deadband based on a 0.97 power factor compared to the previous deadband based on a 0.95 power factor; the new rates; the change in rate design to a demand-only charge; and the expected response and actions that parties will take when faced with the proposed penalty charge. See TR-02-E-BPA-03, Appendix K, Revenue Forecast for the Power Factor Penalty Charge.

Q. *Will the forecasted revenue from the Power Factor Penalty Charge impact TBL's other rates?*

A. Yes. The Power Factor Penalty Charge forecasted revenue of $5 million per year is treated as a revenue credit against the cost of the Network segment. *See* TR-02-E-BPA-03, Table 2, lines 2.36 and 2.50.

SECTION 3 APPLICATION OF THE POWER FACTOR PENALTY CHARGE

Q. *Are there any rate design changes in the proposed Power Factor Penalty Charge from the existing Reactive Power Charge?*

A. Yes. There are two major changes in the design. The first major change is the Ratchet Period. The Ratchet Period under the current Reactive Power Charge is 35 months. The Ratchet Period under the proposed Power Factor Penalty Charge is 11 months. The reduction in the period is due to customer input over the past few years. It is our belief that an 11 month ratchet will provide an appropriate incentive to those parties interconnected with the FCRTS that have a seasonal reactive power problem that puts excess reactive power requirements on the FCRTS. The second major change is the elimination of the Reactive Energy charge. In the current Reactive Power Charge, the charge was intended to provide an incentive for customers to manage their reactive power requirements even after a ratchet charge had been imposed. We do not believe that it has performed the intended function. Furthermore, the removal of the Reactive Energy charge will simplify the proposed Power Factor Penalty Charge for both the customers and TBL.

Q. *How will customers with a current 35 month ratchet be transitioned to the 11 month ratchet?*

A. The maximum ratchet period any party will face under the proposed Power Factor Penalty Charge is 11 months. Beginning with the new rate period, the amount in excess of the deadband for the current month is compared with the equivalent amount for the 11 prior months, and the party is charged the highest of the 12 amounts. Thus, no party will be charged for reactive demands older than one year.

Q. *How did TBL determine the rates for the Power Factor Penalty Charge?*

A. The determination of the rate is similar to the determination of the current Reactive Power Charge, with the exception of (1) the elimination of the energy component, and (2) the addition of the proposed penalty factor of two. For the current charge, TBL allocated half of the cost for reactors and capacitors to capacity (demand) and the other half to energy. With the elimination of the energy charge, the full amount is allocated to the capacity charge. The proposed rate is the per unit cost of reactors and capacitors, and is calculated by dividing the annual cost of the respective facilities by the installed capacity to get cost per kVAr. This is then multiplied by the penalty factor of two to determine the Power

Factor Penalty rates. *See* TR-02-E-BPA-03, Appendix K, Calculation of the Power Factor Penalty Charge.

Q. *Does the Power Factor Penalty Charge apply strictly to Transmission Contract Holders?*

A. No. As with the current Reactive Power Charge, the Power Factor Penalty Charge applies to any party interconnected to the FCRTS that places an excessive reactive burden on the FCRTS.

Q. *Does the Power Factor Penalty Charge apply to transfer customers under General Transfer Agreements?*

A. Maybe. Customers served through a General Transfer Agreement with the BPA Power Business Line (PBL) may be subject to the Power Factor Penalty Charge. Such charges would occur only if there are significant TBL Network facilities located between the transferring utility and the point of delivery, and where reactive power is actively managed by TBL. The applicability of TBL's Power Factor Penalty Charge will not depend on whether the transferring utility imposes a charge for reactive power on PBL.

Q. *Under the proposed Power Factor Penalty Charge, must a party maintain a 0.97 power factor on all hours of the month?*

A. No. A 0.97 power factor is simply used to determine the Reactive Deadband each month, based on the peak real power demand at the point. Once the deadband is calculated, the reactive demands for each hour at that particular point are compared with it. Conceivably, there could be numerous hours within the month when the power factor could be far worse than 0.97 with no charge being incurred as long as the kVAr demand stays within the deadband.

Q. Does this conclude your testimony?

A. Yes.

INDEX

TESTIMONY OF

JOHN G. ANASIS AND RICHARD L. HAINES

Witnesses for the Bonneville Power Administration Transmission Business Line

SUBJECT: Redispatch Charge, Redispatch Adjustment for Accepted Bids, and Failure to Comply Penalty Charge

TESTIMONY OF

JOHN G. ANASIS AND RICHARD L. HAINES

Witnesses For The Bonneville Power Administration Transmission Business Line

SUBJECT: REDISPATCH CHARGE, REDISPATCH ADJUSTMENT FOR ACCEPTED BIDS, AND FAILURE TO COMPLY PENALTY CHARGE

SECTION 1 INTRODUCTION AND PURPOSE OF TESTIMONY

Q. State your name and qualifications.

A. My name is John G. Anasis. My qualifications are contained in TC/TR-02-Q-BPA-02.

A. My name is Richard L. Haines. My qualifications are contained in TC/TR-02-Q-BPA-09

Q. What is the purpose of your testimony?

A. The purpose of this testimony is to sponsor the proposed Redispatch Charge, Redispatch Adjustment for Accepted Bids, and Failure to Comply Penalty Charge in the General Rate Schedule Provisions. TR-02-E-BPA-04, GRSP, Section II.

Q. How is your testimony organized?

A. Section 1 introduces and describes the purpose of this testimony. Section 2 discusses Redispatch Charge and the Redispatch Adjustment for Accepted Bids. Section 3 explains the Failure to Comply Penalty Charge.

SECTION 2 REDISPATCH CHARGE AND REDISPATCH ADJUSTMENT FOR ACCEPTED BIDS

Q. *What is the purpose of the Redispatch Charge?*

A. The purpose of the Redispatch Charge is to recover from Network Integration (NT) and Network Contract Demand (NCD) transmission customers costs the Transmission Business Line (TBL) incurs when implementing the proposed redispatch mechanism. *See* TR-02-E-BPA-04, at 63.

Q. *What is the proposed redispatch mechanism?*

A. The proposed redispatch mechanism is a methodology for addressing congestion on constrained transmission paths that arise during preschedule. *See* Anasis and Haines, TC-02-E-BPA-03. That testimony is incorporated herein to the extent it explains the operational aspects of the redispatch mechanism.

Q. *Describe the methodology used to determine the redispatch charge and recover redispatch costs.*

A. For each constrained path where redispatch is needed, the TBL will determine during prescheduling the amount of redispatch required to relieve congestion at the constraint at the least cost. The difference between the incremental bids paid by TBL and the decremental bids paid to TBL, which represents the cost of redispatching the particular path to relieve the congestion, comprises the redispatch cost applicable to that path. Once the redispatch cost is determined, it will be assessed on a pro-rata basis to the NT and NCD customers, based upon the schedules they submitted, who were using the path during the hours when the redispatch was required.

Q. Why will only NT and NCD customers be charged redispatch costs?

A. Only NT and NCD customers will be charged redispatch costs because they selected transmission services which provide for flexible use of the transmission system without paying based on maximum possible use of a resource at a Point of Receipt (POR). Other customers, such as Point-to-Point (PTP) customers, will not be charged redispatch costs because they do not have such flexibility and have contracted for path-specific service.

Q. Although the pro forma tariff requires all NT customers to pay for redispatch costs, why do you propose to charge only the users of the constrained path for redispatch costs?

A. Charging the users of the constrained path recovers the redispatch costs only from those entities that caused or contributed to the congestion which led to the redispatch costs. NT and NCD customers who do not use a constrained path do not contribute to congestion along the path and should not be assessed the redispatch charge.

Q. Please describe the Redispatch Adjustment for Accepted Bids.

A. The Redispatch Adjustment for Accepted Bids in section II.E of the General Rate Schedule Provisions (TR-02-E-BPA-04, at 62), recognizes that parties who submit bids for redispatch will be charged for decremental bids and be paid for incremental bids when such bids are accepted for redispatch by the TBL. Parties who have their decremental bids accepted will be billed on their monthly transmission bill. Transmission customers who have their incremental bids accepted will receive a credit on their monthly transmission bills. Parties who are not transmission customers will be paid within 30 days following the end of the month that the redispatch occurred.

SECTION 3 FAILURE TO COMPLY PENALTY CHARGE

Q. What is the Failure to Comply Penalty Charge?

A. It is a penalty assessed to customers who jeopardize FCRTS reliability by failing to comply with TBL operational orders to curtail, redispatch or shed load. *See* TR-02-E-BPA-04, at 57-58.

Q. Why is TBL proposing the Failure to Comply Penalty?

A. The purpose of the Failure to Comply Penalty is to deter parties from ignoring curtailment, redispatch, or load shedding orders from TBL dispatchers or transmission schedulers. With the advent of a deregulated electricity market and the entrance of many new market participants, more parties are using the transmission system in greater and more complex ways. Consequently, the failure of any market participant to comply with TBL operating orders to shed load, redispatch generation, curtail generation or curtail schedules could significantly affect other market participants' rights to use the transmission system. Failure to comply with TBL operating orders also places the reliability of the integrated transmission system at serious risk. Therefore, TBL will assess a Failure to Comply Penalty to maintain system reliability, discourage improper behavior and penalize parties who ignore TBL operating orders.

Q. Are there other reasons to propose the Failure to Comply Penalty?

A. A Failure to Comply Penalty also will encourage parties to develop and maintain necessary systems in place to respond to TBL curtailment, redispatch, and load shedding orders in the time frames called for in reliability standards developed by the North American Electric Reliability Council (NERC), the Western Systems Coordinating Council (WSCC), and the Northwest Power Pool (NWPP). Such standards are currently in place and subject to modification by NERC, WSCC, and NWPP. Having reliable response systems in place is very important, as a customer's failure to rapidly respond to TBL operation orders to curtail, redispatch or shed load can be as detrimental to system reliability as their failure to respond at all.

Q. *Please describe the rationale behind the design of the Failure to Comply Penalty Charge.*

A. The Failure to Comply Penalty Charge is designed to remove economic incentives a party may have to ignore TBL curtailment, redispatch, and load shedding orders due to high energy prices in the market place. It is also designed to give parties an incentive to maintain appropriate systems in place in order to respond to TBL operating orders in the necessary time frames.

Q. *How will TBL assess the Failure to Comply Penalty?*

A. The penalty will be the highest of:

a. 100 mills per kWh;

b. actual costs TBL incurs in order to maintain the reliability of the FCRTS due to the failure of any party to comply with a curtailment, redispatch, or load shedding order; or

c. an hourly market index with a 10% adder.

Q. Why do you propose alternative rates for the Failure to Comply Penalty?

A. Use of a flat-rate penalty may not recover all costs incurred by TBL, or other transmission customers, caused by a customer's failure to comply with TBL operating orders.

Q. Why was the 100 mills per kWh rate selected as the baseline penalty?

A. The 100 mills per kWh rate was chosen as a reasonable floor for the penalty since BPA has previously used this rate in assessing other similar charges, including the 1993 Unauthorized Increase Charge (PF-93), the 1995 Unauthorized Increase Charge (PF-95), the 1996 Unauthorized Increase Charge (Section II.R of the 1996 GRSP's), and the 1996 Energy Imbalance Charge (APS-96).

Q. What is the basis for the alternative penalty to recover costs TBL may incur to maintain system reliability due to a failure to comply with operating orders?

A. A key aspect of the Failure to Comply Penalty is that neither TBL, nor any of TBL's other customers, should have to absorb any additional costs incurred by TBL in order to maintain reliability as a result of a transmission customer's failure to comply with TBL operating orders. Additional costs should be passed on to the customer who failed to comply with TBL's orders. The "actual cost" rate is necessary because the use of either the market index penalty or the 100 mills per kWh minimum penalty may not ensure that TBL recovers all costs caused by the failure to comply, as TBL may be forced to redispatch other generation at a cost that exceeds the index price or the 100 mill baseline.

Q. Provide representative examples of circumstances in which TBL may incur additional costs as a result of a customer's failure to comply with operating orders?

A. TBL might incur additional costs due to a customer's failure to comply where a successful incremental redispatch bidder fails to raise generation. This may require TBL to redispatch power from another source to maintain system reliability. For example, suppose the index price for energy is 200 mills per kWh on a particular hour and TBL determines it must increase generation in a particular area to relieve congestion on a specific path during that hour. If a successful incremental bidder for the redispatch fails to bring the resource up on that hour, TBL may be forced to order additional generation to redispatch at, say, 250 mills per kWh, to maintain system reliability. The bidder who failed to bring up the resource should pay the additional expense imposed upon TBL.

Q. Can you provide another example of circumstances in which TBL may incur additional costs as a result of a customer's failure to comply with operating orders?

A. Another example of a situation in which a customer's failure to comply would cause TBL to incur additional costs is where the customer fails to reduce load upon request, thereby forcing TBL to drop another customer's load to maintain system reliability. The other customer(s) affected by the failure to comply may seek reimbursement from TBL for equipment or economic damages related to their loss of load. The customer who caused the loss of load should pay the additional cost imposed upon TBL.

Q. How will the index-dependent penalty be determined?

A. In order to capture the highest market price for electricity on the West Coast, the index used to determine the index rate will be the higher of the Dow Jones Mid-Columbia Firm Index price or the California ISO Ex-Post Supplemental Energy Price. An additional 10% will be added to the applicable index price.

Q. Is TBL forecasting any revenue from this penalty?

A. No, TBL is not forecasting any revenue from this penalty. The purpose of this penalty is to deter improper behavior, promote system reliability and to encourage compliance with TBL orders to curtail, redispatch, or shed load. It is TBL's hope that this charge never has to be invoked.

Q. Does this conclude your testimony?

A. Yes.

Bonneville Power Administration

PO Box 3621 Portland, Oregon 97208-3621

DOE/BP-3251 MARCH 2000 500