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

2010 Initial Transmission Proposal

Revenue Requirement Study

TR-10-E-BPA-01

February 2009

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BONNEVILLE POWER ADMINISTRATION

TRANSMISSION SERVICES

2010 INITIAL PROPOSAL

REVENUE REQUIREMENT STUDY

TR-10-E-BPA-01

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TRANSMISSION REVENUE REQUIREMENT STUDY

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1. INTRODUCTION

The purpose of the Revenue Requirement Study (Study) is to establish the level of revenues needed from rates for Bonneville Power Administration's (BPA's) transmission and ancillary services to recover, in accordance with sound business principles, costs associated with the transmission of electric power over the Federal Columbia River Transmission System (FCRTS). The FCRTS is part of the larger Federal Columbia River Power System (FCRPS) which also includes the hydroelectric, multipurpose facilities constructed and operated by the U.S. Army Corps of Engineers and the Bureau of Reclamation in the Pacific Northwest. The FCRPS costs that are not associated with the FCRTS are funded and repaid through BPA power rates. The transmission revenue requirements herein include: recovery of the Federal investment in transmission and transmission-related assets; the operations and maintenance (O&M) and other annual expenses associated with the provision of transmission and ancillary services; the cost of generation inputs for ancillary services and other inter-business-line services necessary for the transmission of power; and all other transmission-related costs incurred by the Administrator.

The cost evaluation period for this rate proposal includes Fiscal Years (FYs) 2009 - 2011, the period extending from the last year for which historical information is available through the proposed rate approval period (rate test period). The Study includes the transmission revenue requirements for the rate test period, FYs 2010 – 2011, which incorporates the results of transmission repayment studies.

This Study outlines the policies, forecasts, assumptions, and calculations used to determine BPA's transmission revenue requirements. Legal requirements are summarized in Chapter 5 of this Study. The Documentation for the Revenue Requirement Study, TR-10-E-BPA-01A, contains key technical assumptions and calculations, the results of the transmission repayment studies, and a further explanation of the repayment inputs and its outputs.

The revenue requirements that appear in this Study are developed using a cost accounting analysis comprised of multiple steps. *See* Figure 1, Transmission Revenue Requirement Process. The primary features of the Study include repayment studies, transmission operating expenses, and risk analysis. First, repayment studies for the transmission function are prepared to determine an amortization schedule and to project the resulting annual interest expense for bonds and appropriations that fund the Federal investment in transmission and transmission-related assets. Repayment studies are conducted for each year of the rate test period, and extend over a 35-year repayment period. Second, transmission operating expenses, debt service reassignment, and minimum required net revenues (if needed) are projected for each year of the rate test approval period. Third, the necessity for including annual planned net revenues for risk is evaluated by taking into account Transmission's business risks, BPA's cost recovery goals, and risk mitigation measures. From these three steps, revenue requirements are set at the revenue level necessary to fulfill BPA's cost recovery requirements and objectives.

BPA conducts a current revenue test to determine whether revenues projected from current rates meet its cost recovery requirements and objectives for the rate test and repayment period. If the current revenue test indicates that cost recovery and risk mitigation requirements can be met, current rates could be extended. The current revenue test, discussed in Chapter 4.2, demonstrates that current revenues are insufficient to meet cost recovery requirements and objectives for the proposed rate approval period and the repayment period.

Consistent with the Treasury Payment Probability (TPP) standard that BPA adopted as a long-term policy in 1993, the revenues from the transmission and ancillary services rates in this initial rate proposal provide a greater than 95 percent probability that associated United States (U.S.) Treasury payments will be made on time and in full over the two-year rate period. *See* Chapter 2.2.

Table 1 shows projected net revenues from proposed rates and summarizes the revenue test over the two-year rate period. In combination with other risk mitigation tools, these net revenues are set at the lowest level necessary to achieve BPA's cost recovery objectives in the face of transmission-related risks.

Table 1: Projected Net Revenues From Proposed Rates

($000s)	FY 2010	FY 2011	Rate Period Average
Projected Revenues From Proposed Rates	$939,035	$990,430	$964,733
Projected Expenses	$859,596	$914,390	$886,993
Net Revenues	**$79,439**	**$76,040**	**$77,740**

The TPP for the two year rate period is greater than 95%.

Table 2 shows planned transmission amortization repayments to the U.S. Treasury for each year of the proposed rate approval period.

Table 2: Planned Repayments to U.S. Treasury

Fiscal Year	Annual Amortization ($000s)
2010	$216,618
2011	$208,223
Total	$424,841

2. SPENDING LEVEL DEVELOPMENT AND FINANCIAL POLICY

2.1 Development Process for TR-10 Rate Case Spending Levels

BPA has long worked to assure its decision-making process is open and transparent to its customers and constituents. In response to interest expressed by Regional Dialogue participants, BPA developed the Integrated Business Review (IBR) to provide customers and constituents the opportunity to provide meaningful and tangible input in BPA's long-term budget setting process.

2.1.1 Integrated Business Review

The IBR entails two processes, the Integrated Program Review (IPR) and the Quarterly Business Review (QBR). The IPR was designed to create a centralized forum for addressing and reviewing power and transmission proposed program spending levels prior to inclusion in a rate case. The QBR is an on-going forum designed to update and inform customers and constituents of the current financials, cost trends, and emerging issues that could impact rates in the future.

2.1.2 Integrated Program Review

The IPR was designed to provide customers and constituents an opportunity to examine, understand, and comment on BPA's cost projections for both power and transmission rate proceedings. BPA began the IPR for FY 2010-2011 program levels on May 15, 2008 with an opening workshop containing an overview of all Power and Transmission services proposed spending levels thru FY 2011. BPA conducted five subsequent workshops on Transmission programs. At the workshops, BPA conducted detailed discussions outlining transmission capital spending levels and planned transmission system improvements, upgrades, and reinforcement projects. Additionally, while asset management plans and debt management issues are not decided in the IPR forum, BPA held workshops on these topics to better inform participants about the implications of past debt management decisions and proposed capital spending levels. Notices of the workshops were distributed widely to TS' customers and interested parties and posted on BPA's website. At the conclusion of the IPR process, BPA issued a close-out letter and report setting forth the Administrator's decision on spending levels.

Comments gathered in these forums included a request for additional information about possible alternative program levels. On July 29, 2008, BPA released a "draft report." The draft report did not propose different spending levels for the FY 2010-2011 period although it did provide two illustrative scenarios for each program, one that explored the impacts of a 10-percent increase and one that explored the impacts of a 10-percent decrease in proposed program spending levels. This material was also presented and discussed at the July 30 workshop.

The public comment period on TS' proposed FYs 2010 and 2011 program spending levels ran from May 15, 2008, to August 15, 2008. Workshop participants provided substantial oral and written comments regarding TS' planned transmission capital spending and program expenditures. Based on comments received during the IPR process and on internal reassessment, BPA changed some of its initial forecasts of program spending levels. These changes are reflected in the final IPR close-out letter. *See* Appendix A. These include reshaping the I-5 corridor project to reflect a more achievable schedule and increasing the lapse factor[1] for transmission capital from 15 percent to 17 percent. This results in an overall reduction of $10 million in FY 2010 and $1.7 million in FY 2011 in transmission capital spending from initial IPR forecasts.

The final close-out letter and report were issued on November 14, 2008. *Id.* The results of the IPR process are reflected in the revenue requirements, including repayment studies, in this rate proposal. BPA also committed to an abbreviated IPR process outside of this rate proceeding during the spring of 2009 to review and update spending forecasts for FY's 2010 and 2011.

[1] The lapse factor is an assumption that a percentage of planned capital investment will be delayed into the subsequent rate period.

After the conclusion of the IPR, the Administrator determined that a portion, $50 million over the rate period, of the projected spending levels for operations and maintenance programs would be withheld from recovery by transmission rates in the 2010-1011 rate period and would be covered by other sources of funds.

2.2 Financial Risk and Mitigation

BPA adopted a long-term policy in its 1993 Final Rate Proposal that called for setting rates that build and maintain financial reserves sufficient for the agency to achieve a 95 percent Treasury Payment Probability (TPP) of making the end-of-year U.S. Treasury payments in full and on time during the two-year rate period. *See* 1993 Final Rate Proposal, Administrator's Record of Decision, WP-93-A-02, p. 72. Beginning in the 2002 Power and Transmission rate proceedings, this standard was applied separately to both functions. The 95 percent TPP standard was reaffirmed in BPA's Financial Plan published in 2008.[2]

In this rate proposal, BPA has analyzed its transmission risks and has determined that this rate proposal achieves the 95 percent two-year probability standard for the transmission function for the two-year rate period. To achieve this level of TPP, the following risk mitigation "tools" are considered in the rate proposal.

(1) <u>Starting financial reserves available for risk attributed to Transmission</u>

Starting financial reserves available for risk include cash and the deferred borrowing balance attributed to the transmission function as of the beginning of the rate period. Approximately $157 million of reserves attributed to Transmission at the start of FY 2009 are considered to be encumbered and therefore not available for risk, and are not considered in the risk analysis. These monies include customer deposits for

[2] BPA's Financial Plan can be found at www.bpa.gov/corporate/Finance/financial_plan/

capital projects such things as Large Generator Interconnection Agreement (LGIA), Network Open Season, and Southern Intertie capital program deposits as well as Master Lease funds. They are either deposits from third parties to pay for specific facilities or advances through BPA's Master Lease program that are required by the lease agreement terms to be used only for specified projects. BPA's risk analysis uses a Monte Carlo model to simulate changes in reserves for each year, FY 2009 – 2011, for each of 3,000 games (iterations). The expected value (mean) from the resultant distribution for the ending FY 2011 reserves is $298.9 million.

(2) Planned Net Revenue for Risk (PNRR)

PNRR is a component of the revenue requirement that is added to annual expenses if reserves are not sufficient for risk mitigation purposes. PNRR adds to cash flows so that financial reserves are sufficient to mitigate short-run volatility in expenses and revenues and achieve the TPP goal. No PNRR is required to meet the TPP standard in this rate proposal.

(3) Two-Year Rate Period

BPA is proposing to set rates for a two-year rate period. The ability to revise rates after two years, or more frequently if need be, serves as an important risk mitigation tool for BPA's transmission function. By using a two-year rate period, BPA limits the amount of risk that must be covered by financial reserves and PNRR.

2.2.1 Transmission Risk Analysis

To quantify the effects of risk on the finances of BPA's transmission function, BPA analyzes the effects of uncertainty in expenses and revenues on transmission cash flows using a Monte Carlo simulation method. *See* Figure 2. The analysis is used to estimate the probability of successful Treasury payment (on time and in full) for both years of the rate period. Successful Treasury payment is deemed to occur when the end-of-year financial reserves for the transmission function, after Treasury payments are made, are sufficient to cover the transmission function's liquidity reserves (formerly termed "working capital") requirement of $20 million. The liquidity reserves threshold in the amount of $20 million is based on the historical monthly net cash flow patterns and monthly cash requirements for the transmission function.

The risk analysis covers the period FYs 2009 through 2011. Using this time frame permits analysis of the change in revenues, expenses, and accrual-to-cash adjustments that are expected to occur between now and the end of the rate period. The advantage to this approach is that financial reserves at the start of the next rate period (FYs 2010-2011) may be simulated, including the effects of uncertainty in current rate period (FY 2009) cash flows, thus helping define the starting conditions for the next rate period.

The risk analysis model starts from a known level of financial reserves at the beginning of FY2009, and simulates risks that can affect the level of reserves throughout FY 2009 and the FY 2010 - 2011 rate period, and can be used to calculate the required amount of PNRR if reserves are not sufficient to meet BPA's TPP standard. Initial input values for point estimates of expenses come from the Study and the revenue inputs are from the revenue forecast and, when combined with inputs describing uncertainty in expenses and revenues, provide the basis for the initial estimate of PNRR. The PNRR, in turn, is provided as an input to the Study, raising the transmission revenue requirement and transmission rates if needed to raise TPP. This iterative process is continued until successive estimates of PNRR converge. *See* Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, Chapter 9.

2.2.2 Transmission Risk Analysis Model

The foundation of the risk analysis is a transmission financial spreadsheet model. *Id.* This model was developed to estimate the effects of risk and risk mitigation tools on end-of-year financial reserves and the likelihood of successful Treasury end-of-year payment for each year during the rate period. Financial reserve levels at the end of each fiscal year determine whether BPA is able to meet its Treasury payment obligation. The model contains individual work sheets including an input matrix of revenues and expenses, an income statement, a cash flow statement, accrual-to-cash adjustments, and individual work sheets for variables specified with uncertainty in the model. Parameters for the probability distributions were developed from historical data when available. When historical data were not available, or when the future is expected to be different from the past, BPA relied on the judgment of technical staff familiar with specific areas of transmission risk as the basis for forecasting the uncertainty in those risks.

2.3 Capital Funding

BPA transmission capital outlay projections for this proposal, based on Appendix B, are $830.5 million for the FY 2010-2011 rate period. These investments are:

- transmission programs ($756.4 million);
- environmental program ($11.0 million);
- information technology projects ($63.1 million).

2.3.1 Bonds Issued to the Treasury

Bonds issued to the U.S. Treasury will be the primary source of capital used to finance projected FYs 2010-2011 transmission capital program investments. Interest rates on bonds issued by BPA to the U.S. Treasury are set at market interest rates comparable to securities issued by other agencies of the U.S. Government. Interest rates on bonds projected to be issued are included in the Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, Chapter 6.

2.3.2 Federal Appropriations

This Study includes the outstanding balances of the original capital investments in the Federal transmission system that were financed by Congressional appropriations. Transmission investments were no longer funded by appropriations after the full implementation of BPA's self-funding authority under the Federal Columbia River Transmission System Act (Transmission System Act). The Bonneville Appropriations Refinancing Act (Refinancing Act) reset the unpaid principal of all outstanding BPA appropriations and reassigned current market interest rates. New principal amounts were established at the beginning of FY 1997 at the present value of the principal and annual interest payments BPA would make to the Treasury for these obligations in the absence of the Refinancing Act, plus $100 million. Before implementation of the Refinancing Act, there was $1,461.9 million in BPA appropriations outstanding. After the implementation of the Refinancing Act, $1,075.4 million in BPA appropriations was outstanding. The Refinancing Act restricted prepayment of the new principal to $100 million in the FY 1997-2001 period. Other repayment terms were unaffected. Through annual repayments, Transmission outstanding appropriations had been reduced to $489 million as of September 30, 2008.

2.3.3 Use of Cash Reserves

To fund capital investments, BPA will rely on $15 million per year from Transmission cash reserves during this Rate Period. This amount will be drawn from reserves projected to be available in the Rate Period.

2.3.4 Non-Federal Payment Obligations

The transmission revenue requirements reflect two forms of non-Federal payment obligations. The first form consists of lease financing arrangements for asset purchases. BPA entered into a transaction in 2004 with the Northwest Infrastructure Financing Corporation (NIFC), a subsidiary of JH Management, to provide for the construction of the 500 kV Schultz-Wautoma transmission line (Shultz-Wautoma line). BPA will make semi-annual lease payments for thirty years, concluding with a single payment for the principal due on the bonds issued by NFIC. Payment of the debt incurred by NIFC to construct the line is secured solely by BPA's revenues.

During the term of the lease, TS will operate the Schultz-Wautoma line and provide transmission and ancillary services over the facilities. Since the completion of the Schulz-Wautoma project, BPA has entered into additional lease financing arrangements with NIFC and will continue to do so. The revenue requirement includes all transactions completed up to the date of the Initial Proposal. It does not include forecasts of additional transactions.

The second form of non-Federal payment obligations included in the revenue requirements consists of the functional reassignment to TS of debt service (interest and principal) payment obligations associated with non-Federal Energy Northwest (EN) bonds. This reassignment is a result of BPA's Debt Optimization Program, which refinances and repays existing EN bonds before they come due and uses the revenues made available from such refinancing to replenish or create opportunities to replenish BPA's Treasury borrowing authority by retiring additional Treasury obligations in amounts equal to the amount of principal of the new EN bonds. When Treasury obligations associated with transmission investments are repaid under the Debt Optimization Program, the debt service obligation associated with new EN debt in equivalent principal amounts is assigned to the TS. The revenue requirements reflect refinancing actions that have occurred through FY 2008. The revenue requirement does not include forecasts of additional refinancing activities during the cost evaluation period.

For specific calculations regarding non-Federal payment obligations, *see* Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, Chapter 7.

2.3.5 Large Generator Interconnection Agreements (LGIA)

BPA amended its Open Access Transmission Tariff by adopting the LGIA in voluntary compliance with FERC Orders 2003 and 2003A. Under the LGIA, interconnection customers finance the cost of Network Upgrades needed to interconnect their generating facilities to BPA's transmission system, if BPA, as the transmission owner/provider, does not provide the funding.

BPA requires the interconnection customer to advance funds in an amount sufficient to cover the cost of construction. These advance funds are then returned to the interconnection customer in the form of transmission credits. The credits are used to offset charges for eligible transmission service in a customer's bill. This Study includes a forecast of the transmission credits and interest expense associated with each LGIA project.

3. DEVELOPMENT OF REPAYMENT STUDIES

Repayment studies are performed as the first step in determining revenue requirements. The studies establish the schedule of annual U.S. Treasury amortization for the rate test period and the resulting interest payments.

In this Study, as in the previous transmission rate filing, the repayment period has been set at 35 years. This study horizon reflects the fact that bonds are not issued for terms longer than 35 years and that the outstanding appropriations and bonds in the transmission system are fully repaid within this period. It also is consistent with the estimated average service life of transmission system plant (40 years) by not exceeding that average lifetime. The Revenue Requirement Study includes the results of transmission repayment studies for each year in the rate test period, FYs 2010 and 2011. In conducting the repayment studies, BPA includes outstanding and projected transmission repayment obligations for Congressional appropriations and bonds issued to the U.S. Treasury. Funding for replacements projected during the repayment period also is included in the repayment study, consistent with the requirements of RA 6120.2. *See* Chapter 5.2 of this study.

Historical BPA appropriations are scheduled to be repaid within the expected useful life of the associated facility or 50 years, whichever is less. Actual bonds issued by BPA to the Treasury may be for terms ranging from 3 to 40 years, taking into account the estimated average service lives for associated investments and prudent financing and cash management factors. In the repayment studies, all projected bonds have a term of 35 years for transmission investment and 15 years for environment investment. Some bonds are issued with a provision that allows the bond to be called after a certain time, typically five years. Bonds also may be issued with no early call provision. Early retirement of eligible bonds requires that BPA pay a bond premium to the Treasury. The premium that must be paid decreases with the age of the bond, and is equivalent, in total, to a fixed premium and a reduced interest rate. This reduced effective interest rate enters into the comparison with other Federal investments and obligations to determine which should be repaid first. Bonds are issued to finance BPA transmission and environment investments and are repaid within the provisions of each bond agreement with the Treasury.

The streams of annual debt service pertaining to non-Federal payment obligations also are included as fixed obligations that the repayment study takes into account in establishing the overall levelized debt service. This reflects the priority of revenue application in DOE Order RA 6120.2 in which these obligations have a higher priority of debt repayment. Therefore, the study scheduled the repayment of Federal debt around these obligations.

Based on these parameters, the repayment study establishes a schedule of planned Federal amortization payments and resulting gross Federal interest expense by determining the lowest levelized debt service stream necessary to repay all transmission obligations within the required repayment period. *See* repayment program tables in Appendix A. Further discussion of the repayment program is included in the Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, Chapter 12. Chapter 5.2 of this Study explains repayment policies and requirements.

4. TRANSMISSION REVENUE REQUIREMENTS

This chapter explains the cost accounting formats used to develop the revenue requirements for FYs 2010 and 2011. Section 4.1.1 provides a line-by-line description of the Revenue Requirement Income Statement and Section 4.1.2 provides a line-by-line description of the Revenue Requirement Statement of Cash Flows.

4.1 Revenue Requirement Format

For each year of a rate period, BPA prepares two tables that reflect the process by which revenue requirements are determined. The Income Statement includes projections of Total Expenses, Planned Net Revenues for Risk, and, if necessary, a Minimum Required Net Revenues component. The Statement of Cash Flows shows the analysis used to determine Minimum Required Net Revenues and the cash available for risk mitigation.

The Income Statement (Table 3 of this Study) displays the components of the annual revenue requirements, which include Total Operating Expenses (Line 9), Net Interest Expense (Line 19), Minimum Required Net Revenues (Line 21), and Planned Net Revenues for Risk (Line 22). The sum of these four major components is the Total Revenue Requirement (Line 24) for each year of the rate period.

The Minimum Required Net Revenues (Table 3, Line 21) result from an analysis of the Statement of Cash Flows (Table 4 of this Study). Minimum Required Net Revenues may be necessary to ensure that revenue requirements are sufficient to cover all cash requirements, including annual amortization of the Federal investment as determined in the transmission repayment studies.

The Statement of Cash Flows (Table 4) analyzes annual cash inflows and outflows. Cash Provided by Current Operations (Line 10), driven by the Expenses Not Requiring Cash shown in Lines 4, 5, and 6, must be sufficient to compensate for the difference between Cash Used for Capital Investments (Line 14) and Cash from Treasury Borrowing (Line 20). If cash provided by Current Operations is not sufficient, Minimum Required Net Revenues (Line 2) must be included in revenue requirements to accommodate the shortfall, yielding at least a zero Annual Increase in Cash (Line 21). The Minimum Required Net Revenues shown on the Statement of Cash Flows (Line 2) then is incorporated in the Income Statement (Table 3, Line 21).

4.1.1 Income Statement

Below is a line-by-line description of the components in the Income Statement (Table 3). The Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, Chapter 2 provides additional information on the development and use of the data contained in the tables.

Transmission Operations (Line 2). Transmission Operations includes spending for technical operations, substation operations, control center support, power system dispatching, and Transmission information technology (IT) costs, including Agency Services IT costs that are allocated to Transmission Services, and scheduling services (reservations, pre-scheduling, real-time and after-the-fact scheduling, and technical support). This category also includes spending for business strategy and assessment, billing, finance, contract management, and internal operations. *See* Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, Chapter 2.

Transmission Maintenance (Line 3). This category includes spending for all Transmission Services maintenance activities such as on-going maintenance of substations, lines, and protection control systems. This category also includes spending on environmental analysis and pollution prevention and abatement. *Id.*

Transmission Engineering (Line 4). This category includes spending on asset management and planning, design of lines/towers/substations, construction planning, construction management, and real property services. *Id*.

Transmission Acquisition & Ancillary Services (Line 5). Inter-business line expenses, resulting from functional separation, and ancillary services products, include the PBL generation inputs to ancillary services, station service and remedial action schemes, and the cost of Corps of Engineers and Bureau of Reclamation transmission facilities serving the network and utility delivery segments. *Id*.

BPA Internal Support (Line 6). This category includes spending on general and administrative programs that are allocated to BPA's two business units. These programs include legal services, finance, risk management, security and emergency management, human resources, and executive oversight and management. For the purposes of the settlement and for convenience, this category also includes the adjustment for expenses excluded from rates that was described in Chapter 2. *Id*.

Non-Federal Projects Debt Service (Line 7). Customer prepayments for Large Generator Interconnection Agreements (LGIA) are returned to customers through credits for transmission service. The amount returned is composed of the prepayment plus interest accrued on the outstanding credit balance. These projects also accrue Allowance for Funds Used During Construction (AFUDC). Non-Federal Projects Debt Service is the sum of the interest accrued during the year on all outstanding LGIA credit balances and AFUDC. *Id.* at Chapter 14.

Depreciation & Amortization (Line 8). Depreciation is the annual capital recovery expense associated with FCRTS plant-in-service. BPA transmission and general plant are depreciated by the straight-line method of calculation, using the remaining life technique.

Amortization refers to the annual capital recovery expense for other deferred Transmission assets. *Id*. at Chapter 2.

Total Operating Expenses (Line 9). Total Operating Expenses is the sum of the above expenses (Lines 2 through 8).

Debt Service Reassignment Interest (Line 11). Debt service reassignment interest consists of the interest component of the debt service reassigned to TS through the Debt Optimization Program. *Id.* at Chapter 7.

Interest on Appropriated Funds (Line 13). Interest on Appropriated Funds consists of interest on the appropriations BPA received prior to the full implementation of BPA's self-financing authority and is determined in the transmission repayment studies. *Id*. at Chapter 2

Interest on Long-Term Debt (Line 14). Interest on long-term debt includes interest on bonds that BPA issues to the Treasury to fund investments in transmission plant, environment, general plant supportive of transmission, and capital equipment. Such interest expense is determined in the transmission repayment studies. Any payments of call premiums for bonds projected to be amortized are included in this line. *Id*.

Interest Income (Line 15). Interest income is computed on the projected year-end cash balances in the BPA fund attributable to the transmission function that carries over into the next year. It is credited against bond interest. Also included is an interest income credit calculated in the transmission repayment studies on funds to be collected during each year for payments of Federal interest and amortization at the end of the fiscal year. A further explanation of the calculation of the interest credit computed within the transmission repayment studies is included in Appendix A. *Id.* at Chapter 4.

Amortization of Capitalized Bond Premiums (Line 16). When a bond issued to the Treasury is refinanced, any call premium resulting from early retirement of the original bond is capitalized and included in the principal of the new bond. The capitalized call premium then is amortized over the term of the new bond. The annual amortization is a non-cash component of interest expense. *Id*. at Chapter 2.

Capitalization Adjustment (Line 17). Implementation of the Refinancing Act entailed a change in capitalization on BPA's financial statements. Outstanding appropriations attributed to the transmission function were reduced by $470 million as a result of the refinancing. The reduction is recognized annually over the remaining repayment period of the refinanced appropriations. The annual recognition of this adjustment is based on the increase in annual interest expense resulting from implementation of the Act, as shown in repayment studies for the year of the refinancing transaction (1997). The capitalization adjustment is included on the income statement as a non-cash, contra-expense. *Id*.

Allowance for Funds Used During Construction (AFUDC) (Line 18). AFUDC is a credit against interest on long-term debt (Line 10). This non-cash reduction to interest expense reflects an estimate of interest on the funds used during the construction period of facilities that are not yet in service. AFUDC is capitalized along with other construction costs and is recovered through rates over the expected service life of the related plant as part of the depreciation expense after the facilities are placed in service.

Net Interest Expense (Line 19). Net Interest Expense is computed as the sum of Interest on Appropriated Funds (Line 13), Capitalization Adjustment (Line 17), Gross Bond Interest (Line 14), Amortization of Capitalized Bond Premiums (Line 16), and Debt Service Reassignment Interest (Line 11), AFUDC (Line 18), and Interest Income (Line 15).

Total Expenses (Line 20). Total Expenses are the sum of Total Operating Expenses (Line 8) and Net Interest Expense (Line 19).

Minimum Required Net Revenues (Line 21). Minimum Required Net Revenues, an input from Line 2 of the Statement of Cash Flows (Table 4), may be necessary to cover cash requirements in excess of accrued expenses. An explanation of the method used for determining the Minimum Required Net Revenues is included in Section 4.1.2.

Planned Net Revenues for Risk (Line 22). Planned Net Revenues for Risk is the amount of net revenues, if any, to be included in rates for financial risk mitigation. There are no Planned Net Revenues for Risk included in the Initial Rate Proposal. Starting TS reserves in FY 2010 are projected to be sufficient to mitigate risk in FYs 2010 and 2011.

Total Planned Net Revenues (Line 23). Total Planned Net Revenues is the sum of Minimum Required Net Revenues (Line 18) and Planned Net Revenues for Risk (Line 19).

Total Revenue Requirement (Line 24). Total Revenue Requirement is the sum of Total Expenses (Line 20) and Total Planned Net Revenues (Line 23).

4.1.2 Statement of Cash Flows.

Below is a line-by-line description of each of the components in the Statement of Cash Flows (Table 4). The Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, provides additional information related to the use and development of the data contained in the cash flow table.

Minimum Required Net Revenues (Line 2). Determination of this line is a result of annual cash inflows and outflows shown on the Statement of Cash Flows. Minimum Required

Net Revenues may be necessary so that the Cash Provided By Current Operations (Line 10) will be sufficient to cover the planned amortization payments (the difference between Lines 14 and 20) without causing the Annual Increase (Decrease) in Cash (Line 21) to be negative. The Minimum Required Net Revenues amount determined in the Statement of Cash Flows is incorporated in the Income Statement (Table 3, Line 21).

Depreciation & Amortization (Line 4). Depreciation is from the Income Statement (Table 3, Line 8). It is a negative item included in computing Cash Provided By Current Operations (Table 4, Line 10) because it is a non-cash expense of the FCRTS.

Non-Federal Projects Debt Service (Line 5). Non-Federal Projects Debt Service is from the Income Statement (Table 3, Line 7). It is a non-cash expense.

Amortization of Capitalized Bond Premiums (Line 6). Amortization of Capitalized Bond Premiums, from the Income Statement (Table 3, Line 16), is a non-cash expense.

Capitalization Adjustment (Line 7). The Capitalization Adjustment, from the Income Statement (Table 3, Line 17), is a non-cash (contra) expense.

Drawdown of Cash Reserves for Capital Funding (Line 8). The Drawdown of Cash Reserves for Capital Funding refers to the use of cash accumulated from transmission revenues in prior rate periods to fund capital expenditures in each year of the rate period.

Accrual Revenues (AC Intertie/Fiber/LGIA) (Line 9). BPA accounts for the AC Intertie non-Federal capacity ownership lump-sum payments received in FY 1995 as unearned revenues that are recognized as annual accrued revenues over the estimated average service life of the associated transmission facilities. Similarly, some leases of fiber optic capacity have included up-front payments, the annual accrued revenues for which are being recognized over the life of the particular contract. The annual accrual revenues, which are part of the total revenues recovering the FCRTS revenue requirement, are included here as a non-cash adjustment to cash from current operations. In addition, revenue credits associated LGIA capital projects are included in this category. LGIA customers provide an upfront payment for construction of transmission facilities that is returned to them through the credits for transmission service which result in transmission revenues that do not produce cash.

Cash Provided By Current Operations (Line 10). Cash Provided By Current Operations, the sum of Lines 2, 4, 5, 6, 7, 8, and 9 is available for the year to satisfy cash requirements.

Investment in Utility Plant (Line 13). Investment in Utility Plant represents the annual increase in capital expenditures for additions and replacements to the transmission system funded by Treasury bonds or available cash reserves. *See* Study, TR-10-E-BPA-01, Chapter 2.

Cash Used for Capital Investments (Line 14). Cash Used for Capital Investments is the sum of investments in utility plant.

Increase in Long-Term Debt (Line 16). Increase in Long-Term Debt reflects the new bonds issued by BPA to the U.S. Treasury to fund the construction and environmental capital equipment programs. Also included in this amount may be any notes issued to the U.S. Treasury. *See* Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, Chapter 6.

Debt Service Reassignment Principal (Line 17). Debt Service Reassignment Principal is the principal component of the debt service obligation reassigned to TS through the Debt Optimization Program. *See* Study, TR-10-E-BPA-01, Chapter 2.3.4.

Repayment of Long-Term Debt (Line 18). Repayment of Long-Term Debt is BPA's planned repayment of outstanding bonds issued by BPA to the U.S. Treasury, as determined in the repayment studies. *See* Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, Chapter 2.

Repayment of Capital Appropriations (Line 19). Repayment of Capital Appropriations represents projected amortization of outstanding BPA appropriations (pre-self-financing) as determined in the repayment studies. *Id*.

Cash From Treasury Borrowing and Appropriations (Line 20). Cash From Treasury Borrowing and Appropriations is the sum of Lines 16 through 19. This is the net cash flow resulting from increases in cash from new long-term debt and decreases in cash from repayment of long-term debt and capital appropriations.

Annual Increase (Decrease) in Cash (Line 21). Annual Increase (Decrease) in Cash, the sum of Lines 10, 14, and 20, reflects the annual net cash flow from current operations and investing and financing activities. Revenue requirements are set to meet all projected annual cash flow requirements, as included on the Statement of Cash Flows. A decrease shown in this line would indicate that annual revenues are insufficient to cover the year's cash requirements. In such cases, Minimum Required Net Revenues are included to offset such decrease. *See* above discussion of Minimum Required Net Revenues (Line 2).

Planned Net Revenues For Risk (Line 22). Planned Net Revenues For Risk reflects the amounts included in revenue requirements to meet BPA's risk mitigation objectives (from Table 3, Line 22.)

Total Annual Increase (Decrease) in Cash (Line 23). Total Annual Increase (Decrease) in Cash, the sum of Lines 21 and 22, is the total annual cash that is projected to be available to add to BPA's cash reserves.

4.2 Current Revenue Test

Consistent with RA 6120.2, the continuing adequacy of existing rates must be tested annually. The current revenue test determines whether the revenues expected from current rates can continue to meet cost recovery requirements.

For the rate test period, the demonstration of the adequacy of current rates is shown on Tables 5 and 6. Table 5 is a pro forma income statement for each year. Table 6, Statement of Cash Flows, tests the sufficiency of the resulting Net Revenues from Table 5 (Line 19) for making the planned annual amortization payments. The Total Annual Increase (Decrease) in Cash (Table 6, Line 21) must be at least zero to demonstrate the adequacy of the projected revenues to cover all cash payment requirements. The current revenue test shows that current rates are sufficient to satisfy cost recovery requirements in the rate period.

Table 7 shows the adequacy of current rates to satisfy cost recovery requirements over the 35-year repayment period. The focal point of this table is the Net Position (Column K), which is the amount of funds provided by revenues from current rates that remain after meeting annual expenses requiring cash for the rate period and repayment of the Federal investment. Thus, if the Net Position is zero or greater in each year of the rate approval period through the repayment period, the projected revenues from current rates demonstrate BPA's ability to repay the Federal investment in the FCRTS within the allowable time. As shown in Column K, the Net Position results are positive for each year of the rate approval period and in each year of the repayment period.

The historical data on this table have been taken from BPA's separate accounting analysis. The proposed rate approval period data have been developed specifically for this rate filing. The repayment period data are presented in a manner consistent with the requirements of RA 6120.2

5. LEGAL REQUIREMENTS AND POLICIES

This chapter summarizes the statutory framework that guides the development of BPA's transmission revenue requirement and the recovery of BPA's transmission costs among the various users of the FCRTS, and the repayment policies that BPA follows in the development of its revenue requirement.

5.1 Development of BPA's Revenue Requirements

BPA's revenue requirements are governed by three main legislative acts: the Flood Control Act of 1944, P.L. No. 78-534, 58 Stat. 890, amended 1977; the Federal Columbia River Transmission System Act (Transmission System Act) of 1974, P.L. No. 93-454, 88 Stat. 1376; and the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), P.L. No. 96-501, 94 Stat. 2697. Other statutory provisions that guide the development of BPA's revenue requirements include the Federal Power Act, as amended by the Energy Policy Act of 1992 (EPA-92), P.L. No. 102-486, 106 Stat. 2776; and the Omnibus Consolidated Rescissions and Appropriations Act of 1996, P.L. No. 104-134, Stat. 132.

DOE Order "Power Marketing Administration Financial Reporting," RA 6120.2, issued by the Secretary of Energy provides guidance to Federal power marketing agencies regarding repayment of the Federal investment. In addition, policies issued by the FERC provide guidance on transmission pricing. *See, e.g.*, Bonneville Power Administration, 25 ¶ 61,140 (1983).

5.1.1 Legal Requirement Governing BPA's Revenue Requirement.

BPA constructs, operates, and maintains the FCRTS within the Pacific Northwest and makes improvements or replacements thereto as are appropriate and required to: (a) integrate and transmit electric power from existing or additional Federal or non-Federal generating units; (b) provide service to BPA customers; (c) provide inter-regional transmission facilities; and

(d) maintain the electrical stability and reliability of the Federal system. Section 4 of the Transmission System Act , 16 U.S.C. §838b. The transmission system is built to encourage the widest possible use of all electric energy. Section 5, Flood Control Act, 16 U.S.C. §825s.

BPA's rates must be set in a manner that ensures revenue levels sufficient to recover its costs. This requirement was first set forth in Section 7 of the Bonneville Project Act, 16 U.S.C. § 832f (as amended 1977) which provided that:

> Rate schedules shall be drawn having regard to the recovery (upon the basis of the application of such rate schedules to the capacity of the electric facilities of the Bonneville project) of the cost of producing and transmitting such electric energy, including the amortization of the capital investment over a reasonable period of years.

This cost recovery principle was repeated for Army reservoir projects in Section 5 of the Flood Control Act of 1944, 16 U.S.C. 825s (as amended 1977). In 1974, Section 9 of the Transmission System Act, 16 U.S.C, § 838g, expanded the cost recovery principle so that BPA's rates also would be set to recover:

> payments provided [in the Administrator's annual budget]. . . at levels to produce such additional revenues as may be required, in the aggregate with all other revenues of the Administrator, to pay when due the principal of, premiums, discounts, and expenses in connection with the issuance of and interest on all bonds issued and outstanding pursuant to [this Act,] and amounts required to establish and maintain reserve and other funds and accounts established in connection therewith.

The Northwest Power Act reiterates and clarifies the cost recovery principle. Section 7(a)(1) of the Northwest Power Act, 16 U.S.C. § 839e(a)(1), provides that:

> The Administrator shall establish, and periodically review and revise, rates for the sale and disposition of electric energy and capacity and for the transmission of non-Federal

> power. Such rates shall be established and, as appropriate, revised to recover, in accordance with sound business principles, the costs associated with the acquisition, conservation, and transmission of electric power, including the amortization of the Federal investment in the Federal Columbia River Power System (including irrigation costs required to be repaid out of power revenues) over a reasonable period of years and the other costs and expenses incurred by the Administrator pursuant to this Act and other provisions of law. Such rates shall be established in accordance with Sections 9 and 10 of the Federal Columbia River Transmission System Act (16 U.S.C. § 838), Section 5 of the Flood Control Act of 1944, and the provisions of this Chapter.

The Northwest Power Act also provides that FERC's confirmation and approval of BPA rates shall assure that the revenue requirement is adequate to recover BPA's costs and ensure timely U.S. Treasury repayments. Section 7(a)(2), 16 U.S.C. § 839e(a)(2), provides:

> Rates established under this section shall become effective only, except in the case of interim rules as provided in subsection (i)(6), upon confirmation and approval by the Federal Energy Regulatory Commission upon a finding by the Commission, that such rates:
>
> (A) are sufficient to assure repayment of the Federal investment in the Federal Columbia River Power System over a reasonable number of years after first meeting the Administrator's other costs.
>
> (B) are based upon the Administrator's total system costs; and
>
> (C) insofar as transmission rates are concerned, equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing such system.

In October 1992, Congress amended the Federal Power Act to allow FERC to order a transmitting utility, including BPA, to provide transmission services (including the enlargement of transmission capacity necessary to provide such services) to an applicant. Section 211(a) of the Federal Power Act, 16 U.S.C. § 824j(a). In applying the Federal Power Act provisions to FERC-ordered transmission service on the FCRTS, section 212(i), 16 U.S.C. § 824k(i)(1)(B), provides that FERC shall assure that:

(i) the provisions of otherwise applicable Federal laws shall continue in full force and effect and shall continue to be applicable to the system; and

(ii) the rates for the transmission of electric power on the system shall be governed only by such otherwise applicable provisions of law and not by any provision of section 824i of this title, 824j of this title, this section, and section 824l of this title, except that no rate for the transmission of power on the system shall be unjust, unreasonable, or unduly discriminatory or preferential , as determined by the Commission

In *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12,266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 at P 190-92 (2007) (Order 890), FERC decided to retain the safe harbor protections for non-public utilities like BPA from FERC-ordered transmission service under the Federal Power Act that it had established in *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,048 (1997) (Order 888). *See* 18 CFR § 35.28(e). The safe harbor provisions apply if FERC finds the non-public utility's open access transmission tariff is an acceptable reciprocity tariff. In determining whether the non-public utility's tariff is consistent with FERC's comparability standards, FERC requires sufficient information to conclude that the non-public utility's rates associated with tariff service are comparable to the rates it charges others, and also requires separate rates be established for transmission and ancillary services. Order 888 at ¶ 31,761..

Development of the revenue requirement is a critical component of meeting the statutory cost recovery principles. The costs associated with FCRTS and associated services and expenses, as well as other costs incurred by the Administrator in furtherance of BPA's mission, are included in the Study.

5.1.2 The BPA Appropriations Refinancing Act.

As in the prior rate period, BPA's transmission rates for the FYs 2010 - 2011 rate period will reflect the requirements of the Refinancing Act, part of the Omnibus Consolidated Rescissions and Appropriations Act of 1996, P.L. No. 104-134, 110 Stat. 1321, enacted in April 1996. The Refinancing Act required that unpaid principal on BPA appropriations ("old capital investments") at the end of FY 1996 be reset at the present value of the principal and annual interest payments BPA would make to the U.S. Treasury for these obligations absent the Refinancing Act, plus $100 million. 16 U.S.C. § 838l(b). The Refinancing Act also specified that the new principal amounts of the old capital investments be assigned new interest rates from the Treasury yield curve prevailing at the time of the refinancing transaction. 16 U.S.C. §838l(a)(6)(A).

The Refinancing Act restricts prepayment of the new principal for old capital investments to $100 million during the first five years after the effective date of the financing. 16 U.S.C. § 838l(e). The Refinancing Act also specifies that repayment periods on new principal amounts may not be earlier than determined prior to the refinancing. 16 U.S.C. §838l(d). The Refinancing Act further directs the Administrator to offer to provide assurance in new or existing power, transmission, or related service contracts that the Government would not increase the repayment obligations in the future. 16 U.S.C. §838l(i).

5.2 Repayment Requirements and Policies

5.2.1 Separate Repayment Studies.

Section 10 of the Transmission System Act, 16 U.S.C. §838h, and section 7(a)(2)(C) of the Northwest Power Act, 16 U.S.C. §839e(a)(2)(C), provide that the recovery of the costs of the Federal transmission system shall be equitably allocated between Federal and non-Federal power utilizing such system. In 1982, FERC first directed BPA to provide accounting and repayment statements for its transmission system separate and apart from the accounting and repayment statements for the Federal generation system. *See* 20 FERC ¶61,142 (1982). FERC required BPA to establish books of account for the FCRTS separate from its generation costs; explained that the FCRTS shall be comprised of all investments, including administrative and management costs, related to the transmission of electric power; and directed BPA to develop repayment studies for its transmission function separate from its generation function that set forth the date of each investment, the repayment date and the amount repaid from transmission revenues. *See* 26 FERC ¶ 61,096 (1984). FERC approved BPA's methodology for separate repayment studies in 1984. 28 FERC ¶61,325 (1984).

BPA has prepared separate repayment studies for its transmission and generation functions since 1984. BPA therefore has developed the transmission revenue requirement with no change in this repayment policy.

5.2.2 Repayment Schedules.

The statutes applicable to BPA do not include specific directives for scheduling repayment of old capital appropriations and bonds issued to Treasury other than a directive that the Federal investment be amortized over a reasonable period of years. BPA's repayment policy has been established largely through administrative interpretation of its statutory requirements, with Congressional encouragement and occasional admonishment.

There have been a number of changes in BPA's repayment policy over the years concurrent with expansion of the Federal system and changing conditions. In general, current repayment criteria first were approved by the Secretary of the Interior on April 3, 1963. These criteria were refined and submitted to the Secretary and the Federal Power Commission (the predecessor agency to FERC) in support of BPA's rate filing in September 1965.

The repayment policy was presented to Congress for its consideration for the authorization of the Grand Coulee Dam Third Powerhouse in June 1966. The underlying theory of repayment was discussed in the House of Representatives' Report related to authorization of this project, H.R. Rep. No. 1409, 89th Cong., 2d Sess. 9-10 (1966). As stated in that report:

> Accordingly, in a repayment study there is no annual schedule of capital repayment. The test of the sufficiency of revenues is whether the capital investment can be repaid within the overall repayment period established for each power project, each increment of investment in the transmission system, and each block of irrigation assistance. Hence, repayment may proceed at a faster or slower pace from year-to-year as conditions change.

This approach to repayment scheduling has the effect of averaging the year-to-year variations in costs and revenues over the repayment period. This results in a uniform cost per unit of power sold, and permits the maintenance of stable rates for extended periods. It also facilitates the orderly marketing of power and permits BPA's customers, which include both electric utilities and electro-process industries, to plan for the future with assurance.

The Secretary of the Interior issued a statement of power policy on September 30, 1970, setting forth general principles that reaffirmed the repayment policy as previously developed. The most pertinent of these principles was set forth in the Department of the Interior Manual, Part 730, Chapter 1:

A. Hydroelectric power, although not a primary objective, will be proposed to Congress and supported for inclusion in multiple-purpose Federal projects when . . . it is capable of repaying its share of the Federal investment, including operation and maintenance costs and interest, in accordance with the law.

B. Electric power generated at Federal projects will be marketed at the lowest rates consistent with sound financial management. Rates for the sale of Federal electric power will be reviewed periodically to assure their sufficiency to repay operating and maintenance costs and the capital investment within 50 years with interest that more accurately reflects the cost of money.

To achieve a greater degree of uniformity in repayment policy for all Federal power marketing agencies, the Deputy Assistant Secretary of the Department of the Interior (DOI) issued a memo on August 2, 1972, outlining: (1) a uniform definition of the commencement of the repayment period for a particular project; (2) the method for including future replacement costs in repayment studies; and (3) a provision that the investment or obligation bearing the highest interest rate shall be amortized first, to the extent possible, while still complying with the prescribed repayment period established for each increment of investment.

A further clarification of the repayment policy was outlined in a joint memo of January 7, 1974, from the Assistant Secretary for Reclamation and Assistant Secretary for Energy and Minerals. This memo states that in addition to meeting the overall objective of repaying the Federal investment or obligations within the prescribed repayment periods, revenues shall be adequate, except in unusual circumstances, to repay annually all costs for O&M, purchased power, and interest.

On March 22, 1976, the DOI issued Chapter 4 of Part 730 of the DOI Manual to codify financial reporting requirements for the Federal power marketing agencies. Included therein are standard policies and procedures for preparing system repayment studies.

BPA and other Federal power marketing agencies were transferred to the newly established Department of Energy (DOE) on October 1, 1977. *See* DOE Organization Act, 42 U.S.C. § 7101 et seq. (1994). The DOE adopted the policies set forth in Part 730 of the DOI Manual by issuing Interim Management Directive No. 1701 on September 28, 1977, which subsequently was replaced by RA 6120.2 issued on September 20, 1979, as amended on October 1, 1983.

The repayment policy outlined in DOE Order RA 6120.2, paragraph 12, provides that BPA's total revenues from all sources must be sufficient to:

1. Pay all annual costs of operating and maintaining the Federal system;
2. Pay the cost each fiscal year of obtaining power through purchase and exchange agreements, the cost for transmission services, and other costs during the year in which such costs are incurred;
3. Pay interest expense each year on the unamortized portion of the Federal investment financed with appropriated funds at the interest rates established for each Federal generating project and for each annual increment of such investment in the BPA transmission system, except that recovery of annual interest expense may be deferred in unusual circumstances for short periods of time;
4. Pay, when due, the interest and amortization portion on outstanding bonds sold to the U.S. Treasury; and
5. Repay:
   a. each dollar of power investments and obligations in the Federal generating projects within 50 years after the projects become revenue producing, except as otherwise provided by law;

b. each annual increment of Federal transmission investments and obligations within the average service life of such transmission facilities or within a maximum of 50 years, whichever is less; and

c. the cost of each replacement of the Federal system within its service life up to a maximum of 50 years.

While RA 6120.2 allows repayment period of up to 50 years, BPA has set due dates at no more than 40 years to reflect expected service lives of new transmission investment. The Refinancing Act overrides provisions in RA 6120.2 related to determining interest during construction and assigning interest rates to Federal investments financed by appropriations. This Act also contains provisions on repayment periods (due dates) for the refinanced appropriations investments. The Refinancing Act is discussed in section 5.1.2 of this Study.

In addition, other sections within RA 6120.2 require that any outstanding deferred interest payments must be repaid before any planned amortization payments are made. Also, repayments are to be made by amortizing those Federal investments and obligations bearing the highest interest rate first, to the extent possible, while still completing repayment of each increment of Federal investment and obligation within its prescribed repayment period.

ADDITIONAL TABLES

Table 3: Transmission Revenue Requirement Income Statement

($000s)

		A	B
		FY 2010	**FY 2011**
1	OPERATING EXPENSES		
2	TRANSMISSION OPERATIONS	123,083	125,435
3	TRANSMISSION MAINTENANCE	125,896	130,873
4	TRANSMISSION ENGINEERING	26,500	28,011
5	TRANSMISSION ACQ & ANCILLARY SERVICES	198,662	235,250
6	BPA INTERNAL SUPPORT	57,376	38,011
7	NON-FEDERAL PROJECTS DEBT SERVICE	10,696	13,057
8	DEPRECIATION & AMORTIZATION	186,297	197,755
9	TOTAL OPERATING EXPENSES	728,510	768,392
10	INTEREST EXPENSE		
11	DEBT SERVICE REASSIGNMENT INTEREST	55,476	55,475
12	INTEREST ON FEDERAL INVESTMENT -		
13	ON APPROPRIATED FUNDS	27,692	25,887
14	ON LONG-TERM DEBT	102,696	120,572
15	INTEREST INCOME	(25,932)	(24,296)
16	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	758	692
17	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
18	AFUDC	(11,097)	(13,605)
19	NET INTEREST EXPENSE	130,625	145,757
20	TOTAL EXPENSES	859,135	914,149
21	MINIMUM REQUIRED NET REVENUES 1/	77,936	73,507
22	PLANNED NET REVENUES FOR RISK	0	0
23	TOTAL PLANNED NET REVENUES	77,936	73,507
24	**TOTAL REVENUE REQUIREMENT**	**937,070**	**987,656**

1/ SEE NOTE ON CASH FLOW TABLE.

Table 4: Transmission Revenue Requirement Statement of Cash Flows

($000s)

		A FY 2010	B FY 2011
1	CASH FROM CURRENT OPERATIONS:		
2	MINIMUM REQUIRED NET REVENUES 1/	77,936	73,507
3	EXPENSES NOT REQUIRING CASH:		
4	DEPRECIATION & AMORTIZATION	186,297	197,755
5	NON-FEDERAL PROJECTS DEBT SERVICE	10,696	13,057
6	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	758	692
7	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
8	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	15,000	15,000
9	ACCRUAL REVENUES (AC INTERTIE/FIBER/LGIA)	(41,537)	(47,097)
10	CASH PROVIDED BY CURRENT OPERATIONS	230,182	233,946
11	CASH USED FOR CAPITAL INVESTMENTS:		
12	INVESTMENT IN:		
13	UTILITY PLANT	(421,099)	(430,523)
14	CASH USED FOR CAPITAL INVESTMENTS	(421,099)	(430,523)
15	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
16	INCREASE IN LONG-TERM DEBT	406,099	415,523
17	DEBT SERVICE REASSIGNMENT PRINCIPAL	(12)	(154)
18	REPAYMENT OF LONG-TERM DEBT	(190,251)	(140,000)
19	REPAYMENT OF CAPITAL APPROPRIATIONS	(24,919)	(78,792)
20	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	190,917	196,577
21	ANNUAL INCREASE (DECREASE) IN CASH	0	0
22	PLANNED NET REVENUES FOR RISK	0	0
23	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	0	0

1/ Line 21 must be greater than or equal to zero, otherwise net revenues will be added so that there are no negative cash flows for the year.

Table 5: Current Revenue Test Income Statement

($000s)

		A FY 2010	B FY 2011
1	REVENUES FROM CURRENT RATES	939,035	990,430
2	OPERATING EXPENSES		
3	OPERATION AND MAINTENANCE	332,855	322,330
4	TRANSMISSION ACQ & ANCILLARY SERVICES	198,662	235,250
5	NON-FEDERAL PROJECTS DEBT SERVICE	10,696	13,057
6	DEPRECIATION & AMORTIZATION	186,297	197,755
7	TOTAL OPERATING EXPENSES	728,510	768,392
8	INTEREST EXPENSE		
9	DEBT SERVICE REASSIGNMENT INTEREST	55,476	55,475
10	INTEREST ON FEDERAL INVESTMENT -		
11	ON APPROPRIATED FUNDS	27,692	25,887
12	ON LONG-TERM DEBT	102,696	120,572
13	INTEREST INCOME	(25,471)	(24,055)
14	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	758	692
15	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
16	AFUDC	(11,097)	(13,605)
17	NET INTEREST EXPENSE	131,086	145,998
18	TOTAL EXPENSES	859,596	914,390
19	NET REVENUES	79,439	76,040

Table 6: Current Revenue Test Statement of Cash Flows

($000s)

		A FY 2010	B FY 2011
1	CASH FROM CURRENT OPERATIONS:		
2	NET REVENUES	79,439	76,040
3	EXPENSES NOT REQUIRING CASH:		
4	DEPRECIATION & AMORTIZATION	186,297	197,755
5	NON-FEDERAL PROJECTS DEBT SERVICE	10,696	13,057
6	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	758	692
7	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
8	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	15,000	15,000
9	ACCRUAL REVENUES (AC INTERTIE/FIBER/LGIA)	(41,537)	(47,097)
10	CASH PROVIDED BY CURRENT OPERATIONS	231,685	236,479
11	CASH USED FOR CAPITAL INVESTMENTS:		
12	INVESTMENT IN:		
13	UTILITY PLANT	(421,099)	(430,523)
14	CASH USED FOR CAPITAL INVESTMENTS	(421,099)	(430,523)
15	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
16	INCREASE IN LONG-TERM DEBT	406,099	415,523
17	DEBT SERVICE REASSIGNMENT PRINCIPAL	(12)	(154)
18	REPAYMENT OF LONG-TERM DEBT	(190,251)	(140,000)
19	REPAYMENT OF CAPITAL APPROPRIATIONS	(24,919)	(78,792)
20	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	190,917	196,577
21	**ANNUAL INCREASE (DECREASE) IN CASH**	**1,504**	**2,533**

Table 7: Transmission Revenues from Current Rates – Results Through the Repayment Period

($000s)

	A	B	C	D	E	F	G	H	I	J	K
YEAR COMBINED CUMULATIVE	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	PURCHASE AND EXCHANGE POWER (STATEMENT D)	DEPRECIATION	NET INTEREST (STATEMENT D)	NET REVENUES (F=A-B-C-D-E)	NONCASH EXPENSES 1/ (COLUMN D)	FUNDS FROM OPERATION (H=F+G)	AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	DEBT SERVICE REASSIGNMENT PRINCIPAL	NET POSITION (K=H-I-J)
1977	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
TRANSMISSION											
1978	116,430	69,767		51,503	60,337	(65,177)	51,503	(13,674)	194		(13,868)
1979	107,017	73,801		53,756	69,112	(89,652)	53,756	(35,896)	26		(35,922)
1980	170,603	77,594		55,613	78,039	(40,643)	55,613	14,970	2		14,968
1981	202,740	87,243		59,638	87,665	(31,806)	59,638	27,832	1,236 **2/**		26,596
1982	269,200	91,562		64,458	106,190	6,990	64,458	71,448	0		71,448
1983	359,641	99,520		67,969	138,268	53,884	67,969	121,853	0		121,853
1984	417,821	101,406		60,360	158,783	97,272	60,360	157,632	26,722 **3/**		130,910
1985	510,030	141,623		71,012	160,336	137,059	71,012	208,071	199,646		8,425
1986	446,435	144,438		77,574	178,460	45,963	77,574	123,537	180,915		(57,378)
1987	456,728	148,596		85,807	177,020	45,305	85,807	131,112	148,860		(17,748)
1988	405,154	167,102		90,076	164,131	(16,155)	90,076	73,921	44,757		29,164
1989	422,202	175,240		93,076	164,044	(10,158)	93,076	82,918	119,322		(36,404)
1990	426,855	183,512		98,881	153,440	(8,978)	98,881	89,903	99,460		(9,557)
1991	439,871	199,668		98,731	139,458	2,014	98,731	100,745	70,930		29,815
1992	428,769	209,868		101,946	143,789	(26,834)	101,946	75,112	190,864		(115,752)
1993	417,555	189,926		101,929	173,271	(47,571)	101,929	54,358	130,989		(76,631)
1994	462,511	202,309		103,956	179,052	(22,806)	103,956	81,150	55,977		25,173
1995	490,264	200,501		112,940	181,744	(4,921)	112,940	264,019 **/4**	281,789		(17,770)
1996	534,456	206,128		125,961	165,175	37,192	123,219	145,411 **/5**	155,000		(9,589)
1997	503,217	197,202		124,457	176,977	4,581	109,802	114,383	125,000		(10,617)
1998	539,925	228,802		125,130	174,022	11,971	117,884	129,855	185,955		(56,100)
1999	552,134	231,410		147,176	173,574	(26)	133,779	133,753	139,784		(6,031)
2000	578,340	270,153		154,069	165,330	(11,212)	135,358	124,146	114,587		9,559
2001	646,673	282,851		154,881	165,404	43,537	151,746	195,283	59,064		136,219
2002	720,382	364,511		161,042	150,718	44,111	148,912	193,023	131,667		61,356
2003	663,601	326,248		171,129	168,996	(2,772)	160,628	473,056	470,747		2,309
2004	644,059	313,994		204,445	137,822	(12,202)	225,406	403,481 **/5**	359,500		43,981
2005	634,530	333,584		189,501	135,754	(24,309)	169,180	320,071 **/5**	345,201		(25,130)
2006	784,339	378,872		171,359	136,761	97,347	145,949	432,634 **/5**	384,947		47,687
2007	808,624	363,524	9,032	175,584	133,806	126,678	146,762	460,240 **/5**	372,100	716	87,424
2008	844,215	382,879		174,599	136,360	150,377	139,327	384,756 **/5**	277,833	4,510	102,413
COST EVALUATION PERIOD											
2009	831,809	414,319		190,648	131,568	95,274	143,409	223,683 **/5**	172,658	10,407	40,618
RATE APPROVAL PERIOD											
2010	939,035	531,517		186,297	141,930	79,291	137,246	216,537	215,170	12	1,355
2011	990,430	557,580		197,755	159,505	75,590	145,439	221,029	218,792	154	2,083
REPAYMENT PERIOD											
2012	990,430	551,102	46,867	197,755	123,809	70,897	149,882	220,779	176,688		44,091
2013	990,430	551,102	46,823	197,755	122,028	72,722	149,882	222,604	178,513		44,091
2014	990,430	551,102	79,082	197,755	120,954	41,537	149,882	191,419	147,328		44,091
2015	990,430	551,102	169,584	197,755	122,342	(50,353)	149,882	99,529	55,438		44,091
2016	990,430	551,102	149,585	197,755	128,044	(36,055)	149,882	113,827	69,736		44,091

Table 7: continued

REPAYMENT PERIOD	A REVENUES (STATEMENT A)	B OPERATION & MAINTENANCE (STATEMENT E)	C PURCHASE AND EXCHANGE POWER (STATEMENT D)	D DEPRECIATION	E NET INTEREST (STATEMENT D)	F NET REVENUES (F=A-B-C-D-E)	G NONCASH EXPENSES 1/ (COLUMN D)	H FUNDS FROM OPERATION (H=F+G)	I AMORTIZATION (REV REQ STUDY DOC,V 2,C 3)	J DEBT SERVICE REASSIGNMENT PRINCIPAL	K NET POSITION (K=H-I-J)
2017	990,430	551,102	151,276	197,755	134,230	(43,933)	149,882	105,949	61,858		44,091
2018	990,430	551,102	154,468	197,755	140,628	(53,524)	149,882	96,358	52,267		44,091
2019	990,430	551,102	164,385	197,755	148,983	(71,795)	149,882	78,087	33,996		44,091
2020	990,430	551,102	159,713	197,755	157,607	(75,747)	149,882	74,135	30,044		44,091
2021	990,430	551,102	14,042	197,755	169,807	57,724	149,882	207,606	163,515		44,091
2022	990,430	551,102	28,621	197,755	170,590	42,362	149,882	192,244	148,153		44,091
2023	990,430	551,102	28,629	197,755	172,524	40,420	149,882	190,302	146,211		44,091
2024	990,430	551,102	28,635	197,755	173,349	39,589	149,882	189,471	145,380		44,091
2025	990,430	551,102	28,658	197,755	174,535	38,381	149,882	188,263	144,172		44,091
2026	990,430	551,102	22,667	197,755	176,937	41,969	149,882	191,851	147,760		44,091
2027	990,430	551,102	3,996	197,755	180,231	57,346	149,882	207,228	163,137		44,091
2028	990,430	551,102	3,926	197,755	187,666	49,981	149,882	199,863	155,772		44,091
2029	990,430	551,102	3,865	197,755	190,097	47,611	149,882	197,493	153,402		44,091
2030	990,430	551,102	3,813	197,755	186,939	50,821	149,882	200,703	156,610		44,093
2031	990,430	551,102	3,774	197,755	196,825	40,974	149,882	190,856	146,765		44,091
2032	990,430	551,102	3,742	197,755	200,369	37,463	149,882	187,345	143,254		44,091
2033	990,430	551,102	3,726	197,755	200,148	37,699	149,882	187,581	143,490		44,091
2034	990,430	551,102	3,733	197,755	208,532	29,308	149,882	179,190	135,099		44,091
2035	990,430	551,102	32,839	197,755	211,089	(2,354)	149,882	147,528	103,437		44,091
2036	990,430	551,102	89,424	197,755	217,236	(65,086)	149,882	84,796	40,705		44,091
2037	990,430	551,102	(2,709)	197,755	226,410	17,872	149,882	167,754	123,660		44,094
2038	990,430	551,102	(2,656)	197,755	234,797	9,433	149,882	159,315	115,224		44,091
2039	990,430	551,102	(2,594)	197,755	240,143	4,024	149,882	153,906	109,815		44,091
2040	990,430	551,102	(2,520)	197,755	246,086	(1,993)	149,882	147,889	103,798		44,091
2041	990,430	551,102	(2,451)	197,755	253,078	(9,054)	149,882	140,828	96,737		44,091
2042	990,430	551,102	(2,386)	197,755	260,009	(16,050)	149,882	133,833	89,742		44,091
2043	990,430	551,102	(2,326)	197,755	267,777	(23,878)	149,882	126,004	81,913		44,091
2044	990,430	551,102	(2,271)	197,755	276,098	(32,254)	149,882	117,628	73,534		44,094
2045	990,430	551,102	(2,220)	197,755	285,063	(41,270)	149,882	108,612	64,515		44,097
2046	990,430	551,102	(2,181)	197,755	295,310	(51,556)	149,882	98,326	54,235		44,091
TRANSMISSION TOTALS	52,430,645	27,235,820	1,410,587	11,024,683	11,767,109	992,447	9,029,141	11,299,455	7,132,956	15,799	2,048,058

1/CONSISTS OF DEPRECIATION PLUS ANY ACCOUNTING WRITE-OFFS INCLUDED IN EXPENSES.

2/CONSISTS OF AMORTIZATION ($1,650) AND DEFERRAL PAYMENT ($2,760).

3/CONSISTS OF AMORTIZATION ($1,342) AND DEFERRAL PAYMENT ($190,952).

4/INCREASED BY 156,000 AC INTERTIE CAPACITY OWNERSHIP PAYMENT.

5/REDUCED BY $15,000 OF REVENUE FINANCING.

TABLES 8-10 NOT INCLUDED

FIGURES

Figure 1: Transmission Revenue Requirement Process

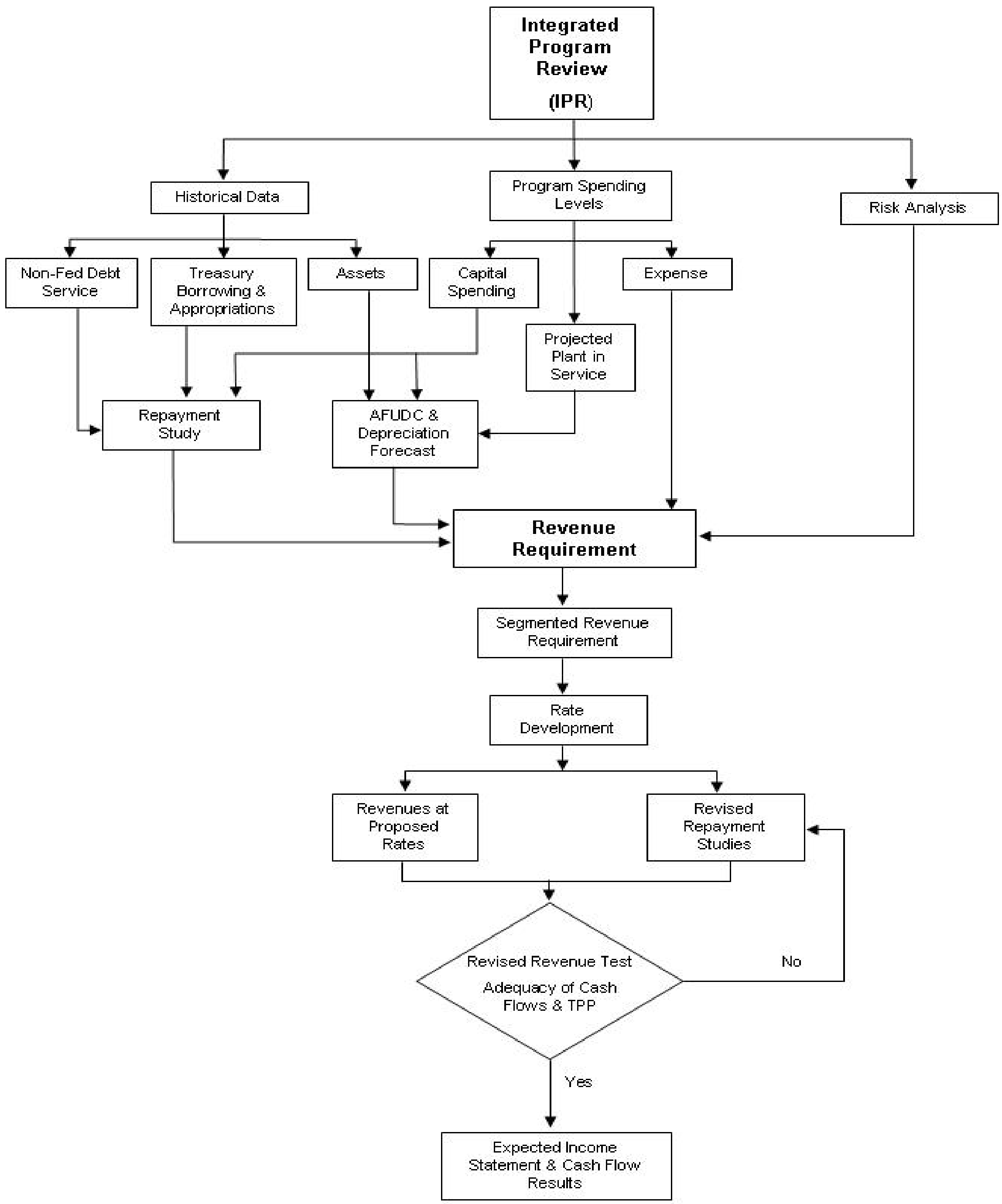
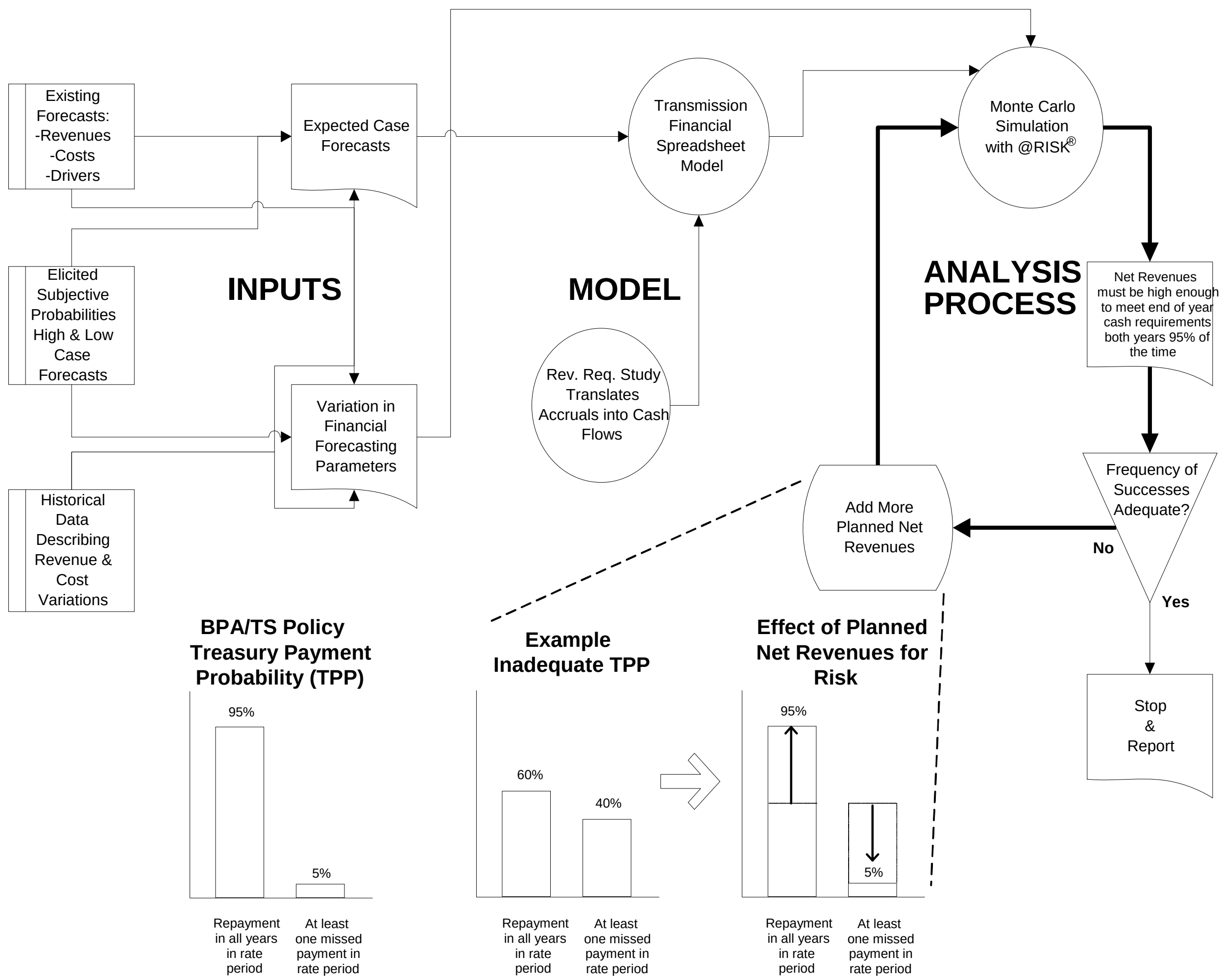


Figure 2: Transmission Rate Case Risk Analysis Flow Diagram



APPENDIX A

Integrated Program Review

Department of Energy

Bonneville Power Administration
P.O. Box 3621
Portland, Oregon 97208-3621

FINANCE

November 14, 2008

In reply refer to: F-2

To Our Customers, Constituents, Tribes and Other Stakeholders:

The Bonneville Power Administration (BPA) now brings to a close the Integrated Program Review (IPR) examination of FY 2010-2011 Power and Transmission costs that began on May 15, 2008.

Between the opening "Overview" workshop and the end of June, eight days of technical workshops were held covering all Power and Transmission program levels through FY 2011. The Administrator hosted a management-level meeting on July 2, 2008, to hear comments personally, and a public comment period was held from May 15 through August 15, 2008. Through this process, BPA sought to provide interested parties with meaningful opportunities to examine, understand, and provide input on the cost projections that would be included in the initial proposals for FY 2010-2011 Power and Transmission rates. These initial proposals are expected to be published in February 2009. In addition, FY 2009 Power program levels were reviewed and commented on, and a final report on those cost projections was provided on July 23, 2008. BPA appreciates the participation and input you provided during this process, especially given the numerous other concurrent and important processes. We have found it beneficial.

BPA believes the program levels reflected in the attached report are an appropriate balance between minimizing impacts to ratepayers in the short term and the need to make investments for the long term. In particular, BPA identified the following areas that need investment now: the transmission system; the aging and deteriorating Federal hydro system; the reliability, safety and performance of Columbia Generating Station; environmental and regulatory obligations and safety and security needs; and the internal infrastructure necessary to support the business.

BPA identified roughly $8 million in net reductions for FY 2009 Power costs compared to draft IPR levels. For FY 2010-2011, BPA determined it is appropriate to restore the renewable rate credit, increasing costs by $2.5 million and $4 million for those years. Reductions in capital forecasts have also been made through this IPR process. These changes are detailed in the attached report. Cost forecasts for BPA's Power and Transmission rate proposals must be finalized now to allow the rate process to stay on schedule. BPA will use the attached report for this purpose.

Customers challenged us to find additional cost reductions in several areas. We do not believe it is prudent to include additional cost reductions in rates unless and until we are confident we can deliver them. We will continue to examine costs over the next several months. We believe that progress on several fronts, including the Network Open Season, Regional Dialogue, Biological Opinion, renewable and conservation activities, and asset plans over that time will make the potential for additional savings more clear. Also, the implications for BPA and the region of recent events in global financial markets and indications of a severe economic downturn need to be evaluated. Prior to submitting final rate proposals in July 2009, BPA will assess any new or updated information available and determine if we believe further cost changes are appropriate. We will conduct an abbreviated public review of these costs in the March/April time frame, with the results being incorporated into the final rate proposals. BPA accomplishes review of proposed spending levels outside its formal rate case to allow for substantial public input, and the decisions are not revisited in the rate case.

Thank you very much for your attention and input to the IPR for FY 2010-2011 Power and Transmission costs. For further information on the IPR or other issues, please contact your Customer Account Executive, Constituent Account Executive, Tribal Account Executive, or me at (503) 230-5111. The final IPR report and additional information on the process is available at www.bpa.gov/corporate/Finance/IBR/IPR/

Sincerely,

/s/ David J. Armstrong November 14, 2008

David J. Armstrong
Executive Vice President and Chief Financial Officer

Enclosure
IPR FY 2010-2011 Power and Transmission Program Levels Final Report

Bonneville Power Administration
Integrated Program Review
FY 2010-2011 Power and Transmission Program Levels

Final Report
November 14, 2008

BONNEVILLE
POWER ADMINISTRATION

Section 1

Background
and
Summary of Decisions

Integrated Program Review Final Report for FY 2010-2011 Power and Transmission Program Levels

Background

BPA began its first "Integrated Program Review" (IPR) process in May 2008 in response to customer and stakeholder requests for a consolidated program-level review of BPA's planned expenses. This process replaced prior public involvement efforts, including the Capital Program Review, Power Function Review and Transmission's Programs in Review. The IPR is part of the broader Integrated Business Review (IBR). The IBR is structured to give all of BPA's stakeholders a meaningful opportunity to understand and have input to the decisions that drive BPA's costs and the amount of costs going into rate decisions. The IPR process is designed to allow persons interested in BPA's program levels an opportunity to review and comment on all of BPA's expense and capital spending level estimates in the same forum prior to their use in setting rates. BPA intends to hold an IPR every two years, just prior to each rate case.

This initial IPR focused on FY 2010 and 2011 program levels for BPA's Power and Transmission Services as well as a review of proposed Power Services FY 2009 program levels. Decisions on FY 2009 Power Services costs were announced in a separate document released July 18, 2008. Seventeen public workshops were held throughout the IPR, proposed spending levels were presented for each of BPA's programs and active discussion was encouraged by participants. All workshop materials, responses to questions asked during workshops, and additional information requested were posted at www.bpa.gov/corporate/Finance/IBR/IPR/. A managerial level meeting was held on June 30 at which BPA received comments on FY 2010-2011 costs for both Power and Transmission programs.

Early comments included requests by participants for additional information about possible alternative program levels. Specifically, they wanted to understand what would be provided with the proposed increases in BPA spending. They were also interested in understanding the impacts on proposed programs and activities if spending levels were reduced. On July 29, BPA released a "draft report." While this draft report did not propose different spending levels for the FY 2010-2011 period, it did provide two illustrative scenarios for each program, one that explored the impacts of a 10-percent increase and one that explored the impacts of a 10-percent decrease in proposed program level spending. This material was also presented and discussed at the July 30 workshop.

The comment period for the FY 2010-2011 program levels closed August 15. This report addresses the comments received and outlines BPA's decisions regarding the FY 2010-2011 program level forecasts. These forecasts will form the basis for Power and Transmission rate case initial proposals for FY 2010-2011 rates.

Many of the forecasts in the initial IPR were not modified as a result of comments received but will be re-evaluated in an additional public process prior to the development of final rate proposals in the spring of 2009.

Summary of Decisions

BPA carefully reviewed and considered the 18 written comments and numerous oral comments on FY 2010-2011 program levels that were made during this public process. This report summarizes the comments and outlines BPA's responses.

BPA received some comments that recommended specific program level decreases or increases; however, the majority of the comments received were general in nature. For example, suggestions were made that BPA lower program levels, that the impact of program level increases on rate payers be considered, and that BPA consider whether the proposed aggressive capital plan is achievable and necessary. BPA understands the concern over potential near-term rate impacts and joins customers and constituents in the desire to minimize the impact to rates. However, as discussed in the IPR workshops, the proposed program levels reflect a number of new requirements and other factors that are exerting pressure on our costs. BPA believes that not addressing these requirements will jeopardize its ability to provide reliable power services, as well as place other key obligations at considerable risk.

The major drivers of increased Power Services costs are related to:

- Improvements and maintenance needed to increase reliability, safety and performance at the Columbia Generating Station nuclear plant (CGS).
- Improvements and maintenance needed to improve reliability in the aging and deteriorating Federal hydro system.
- New reliability standards.
- New biological opinion requirements and the implementation of Memoranda of Agreement (MOAs) with participating tribes.
- The internal costs recovered in power rates (including costs in both Power Services and Agency Services organizations) in 2008 are roughly the same as they were in 2001, seven years ago. Both inflationary pressures and the other drivers listed here require some increases in these costs.

The major drivers of increased Transmission Services costs are related to:

- New mandatory requirements (reliability, environmental, tariff, etc.).
- Integration of new wind resources into the BPA transmission system.
- Increased demand for transmission capacity.
- Need to sustain the aging Federal transmission assets.
- Need to reinvest in historically underinvested areas, such as control house buildings, access roads, etc.
- Global competition for material.
- As with Power, the internal costs both within Transmission and in Agency Services that support Transmission Services are increasing in response to the drivers shown here and the growing Transmission infrastructure.

Drivers of Agency Services costs are largely the same as those for Power and Transmission. The cost increases in many of the Agency Services activities (such as Information Technology, General Counsel, Finance, Supply Chain, and Human Capital Management) are due to the need for increased support of Power and Transmission activities. Agency Services activities are integral to both continuing activities and the achievement of enhanced programmatic goals. In addition to its more traditional General and Administration activities, Agency Services also includes the centralized Technology Innovation and Confirmation (Research and Development) program. In keeping with a long-term plan outlined in the IPR and previous public involvement efforts, the Technology Innovation and Confirmation program is in the process of ramping up to a stable program size based on a percentage of BPA revenues.

BPA has considered the above cost drivers in light of the comments received and has made the following changes to proposed program spending levels:

For FY 2009:

- For Power and Agency Services internal operations, proposed levels have been reduced by 3 percent.
- The Conservation Rate Credit is reduced by $4 million.
- The capital investment forecast for Conservation is reduced by $10 million.

These changes result in a decrease of roughly $8 million from the FY 2009 Power Services spending levels shown in the initial IPR. In addition, the 3 percent reduction in Agency Services also produces a decrease of $5 million for Transmission.

For FY 2010-2011:

- Conservation capital will be reduced by $18 million in FY 2010 and $10 million in FY 2011. These forecasted reductions reflect further analysis and a revised estimate of what the program can achieve, including a ramp-up period to the expected program levels in FY 2010-2011.
- We have reestablished the renewable rate credit in the forecast. This credit was proposed to be zero in the initial IPR. It has been increased to $4 million for FY 2010 and $2.5 million for FY 2011. This increase reflects the expectation that utilities are likely to need additional assistance in acquiring and using renewable resource power to serve their retail loads.
- We have modified the planned Transmission Services Capital as follows:
  - Reshaped the timing of the I-5 corridor project to reflect a more likely and achievable schedule, and
  - Increased the "lapse factor" for transmission capital from 15 percent to 17 percent. (The lapse factor is an assumption that a percentage of planned capital investment will be delayed into the subsequent rate period.)

  Note: The lapse factor for all other programs except fish and wildlife and CGS remains at 15 percent. No lapse factor was applied to fish and wildlife or CGS.

  The impacts to depreciation and interest expense due to changes in capital investment have been estimated in tables in the Power and Transmission sections of this document, however the final amounts will be determined in the upcoming rate cases.

Additional Review

The decisions on FY 2010-2011 program spending levels outlined here are based on the best information available. We believe that by next spring we should have additional information that may cause revisions to some program levels for FY 2010-2011. Additional information will likely become available on the following topics:

- A better understanding of BPA's role in the development of energy efficiency and renewable resources as a result of the Northwest Energy Efficiency Task Force activities, recommendations from the Northwest Power and Conservation Council's 6th Power Plan which will establish new conservation targets for the region, and a public process BPA intends to hold to discuss its role in energy efficiency;
- Better understanding of the internal costs associated with the transition to new power contracts and rates in 2012;
- More clarity on fish and wildlife costs;
- Further work on Network Open Season planning;
- Further work on BPA's asset planning and resource strategy resulting in improved estimates of realistically achievable capital spending; and
- Evaluation of the implications for BPA and the region of recent events in global financial markets and indications of a severe economic downturn.

The decisions outlined here will be the basis for our initial rate proposals. We intend to hold a subsequent, abbreviated program review next spring to reconsider the program levels in light of the increased information available at that time.

The following tables display the proposed spending levels for Power and Transmission Services by major categories. These estimates include Agency Services direct costs and allocations in support of each of the programs.

FY 2010-11 Power Expenses Summary

$ in Thousands	Initial IPR	Final IPR	Change	Initial IPR	Final IPR	Change
Power Program	FY 2010	FY 2010	FY 2010	FY 2011	FY 2011	FY 2011
Columbia Generating Station O&M	269,200	269,200	0	365,000	365,000	0
Corps & Reclamation O&M for Hydro	280,700	280,700	0	296,461	296,461	0
Long Term Generation Program	31,889	31,889	0	32,343	32,343	0
Power Purchases incl DSI Monetized Power	327,189	*	*	404,795	*	*
Residential Exchange Payments/Other	221,426	*	*	220,445	*	*
Renewables (incl rate credit)	41,588	45,588	4,000	43,438	45,938	2500
Generation Conservation (including	87,088	87,088	0	86,722	86,722	0
Internal Operations	134,609	135,627	1,018	138,857	139,910	1053
Post-Retirement Contribution	15,598	15,598	0	16,071	16,071	0
Transmission Purchases, Reserve/Ancillary	176,393	*	*	177,043	*	*
Fish & Wildlife/USF&W/Planning Council	263,541	263,541	0	270,618	270,618	0
Amortization/Depreciation	204,001	*	*	216,916	*	*
Non-Federal Debt Service	556,184	*	*	577,064	*	*
Net Interest Expense	177,657	*	*	194,291	*	*
Other – Colville Settlement, Non-Operating	25,746	25,746	0	28,082	28,082	0
Total	2,812,809	1,154,977	5,018	3,068,146	1,281,145	3,553

*These will be determined in the upcoming rate case.

FY 2009 Power Expenses Summary

(As reported in the 2009 Power Close-Out Report)

$ in Thousands	Initial IPR	Final IPR	Change	Initial IPR	Final IPR	Change
Power Program	**FY 2010**	**FY 2010**	**FY 2010**	**FY 2011**	**FY 2011**	**FY 2011**
Columbia Generating Station O&M	269,200	269,200	0	365,000	365,000	0
Corps & Reclamation O&M for Hydro	280,700	280,700	0	296,461	296,461	0
Long Term Generation Program	31,889	31,889	0	32,343	32,343	0
Power Purchases incl DSI Monetized	327,189	*	*	404,795	*	*
Residential Exchange Payments/Other	221,426	*	*	220,445	*	*
Renewables (incl rate credit)	41,588	45,588	4,000	43,438	45,938	2,500
Generation Conservation (incl ratecredit)	87,088	87,088	0	86,722	86,722	0
Internal Operations	134,609	135,627	1,018	138,857	139,910	1,053
Post-Retirement Contribution	15,598	15,598	0	16,071	16,071	0
Transmission Purchases,	176,393	*	*	177,043	*	*
Fish & Wildlife/USF&W/Planning Council	263,541	263,541	0	270,618	270,618	0
Amortization/Depreciation	204,001	*	*	216,916	*	*
Non-Federal Debt Service	556,184	*	*	577,064	*	*
Net Interest Expense	177,657	*	*	194,291	*	*
Other–Colville Settlement, Non-Op Gen	25,746	25,746	0	28,082	28,082	0
Total	2,812,809	1,154,977	5,018	3,068,146	1,281,145	3,553

FY 2010-11 Power Capital Summary

$ in Thousands	Initial IPR	Final IPR	Change	Initial IPR	Final IPR	Change
Power Program	**FY 2010**	**FY 2010**	**FY 2010**	**FY 2011**	**FY 2011**	**FY 2011**
Corps of Engineers/Bureau of Reclamation	183,200	183,200	0	199,200	199,200	0
Fish & Wildlife	70,000	70,000	0	60,000	60,000	0
Conservation	56,000	38,000	(18,000)	56,000	46,000	(10,000)
CGS	73,600	73,600	0	99,900	99,900	0
CRFM	88,000	88,000	0	96,000	96,000	0
17% Lapse Factor 1/	(36,150)	(36,150)	0	(38,550)	(38,550)	0
Total Capital	280,700	280,700	(18,000)	296,461	296,461	(10,000)

1/ Excludes CGS, CRFM, Fish & Wildlife

FY 2009 Power Capital Summary

(As reported in the 2009 Power Close-Out Report)

$ in Thousands	2009 in WP-07 Rate Case	Supplemental Rate Case	Initial IPR	Final IPR	Change Between Initial IPR and Final IPR
Description	**FY 2009**	**FY 2009**	**FY 2009**	**FY 2009**	**FY 2009**
Corps of Engineers/Bureau of Reclamation	137,000	137,000	154,950	154,950	0
Fish & Wildlife	36,000	36,000	50,000	50,000	0
Conservation	32,000	32,000	42,000	32,000	-10,000
CGS	27,700	27,700	96,700	96,700	0
CRFM	62,400	62,400	63,000	111,000	48,000
15% lapse factor1/			(29,813)	(28,313)	1,500
Total Capital	295,100	295,100	376,837	416,337	39,500

1/ Excludes CGS, CRFM, Fish & Wildlife

FY 2010-11 Transmission Expense Summary

$ in thousands

Transmission Description	Initial IPR FY 2010	Final IPR FY 2010	Change FY 2010	Initial IPR FY 2011	Final IPR FY 2011	Change FY 2011
Transmission Operations	**120,405**	**123,084**	**2,679**	**122,661**	**125,434**	**2,773**
System Operations	56,586	56,573	(13)	57,511	57,497	(14)
Scheduling	10,308	9,423	(885)	10,784	9,868	(916)
Marketing	18,836	19,500	664	19,538	20,225	687
Business Support (Including Internal Support)	34,675	37,588	2,913	34,828	37,844	3,016
Transmission Maintenance	**125,717**	**125,896**	**179**	**130,687**	**130,873**	**186**
System Maintenance	121,919	122,099	180	126,691	126,877	186
Environmental Operation	3,797	3,797	0	3,996	3,996	0
Transmission Engineering	**26,503**	**26,500**	**(3)**	**28,014**	**28,011**	**(3)**
Agency Services	**62,640**	**58,779**	**(3,861)**	**62,936**	**58,940**	**(3,996)**
Post-Retirement Contribution	**15,598**	**15,598**	**0**	**16,071**	**16,071**	**0**
Transmission Acquisition/Ancillary Services (3rd Party Sources)	**18,359**	**18,371**	**12**	**18,359**	**18,371**	**12**
Other Income, Expenses and Adjustments	**(2,000)**	**(2,000)**	**0**	**(2,000)**	**(2,000)**	**0**
Non-Federal Debt Service	**5,890**	*	*	**4,690**	*	*
Interest Expense	**150,623**	*	*	**168,664**	*	*
Amortization/Depreciation	**200,810**	*	*	**211,538**	*	*
Total	**724,546**	**366,228**	**(994)**	**761,620**	**375,700**	**(1,028)**

*These will be determined in the upcoming rate case.

FY 2010-11 Transmission Capital Summary

$ in Thousands

Transmission Program	Initial IPR FY 2010	Final IPR FY 2010	Change FY 2010	Initial IPR FY 2011	Final IPR FY 2011	Change FY 2011
Main Grid Projects	155,905	150,587	(5,318)	221,346	209,346	(12,000)
Area & Customer Service Projects	31,714	31,714	0	6,256	6,256	0
Upgrades & Additions	91,108	95,710	4,602	107,471	112,585	5,114
System Replacement Projects	134,494	134,494	0	138,423	138,423	0
Environment Projects	5,530	5,530	0	5,752	5,752	0
Customer Financed/Credits	90,165	90,165	0	102,287	102,287	0
Total Indirect Capital	86,100	87,442	1,342	88,696	96,243	7,547
17% Lapse Factor	(89,551)	(100,249)	(10,698)	(101,324)	(103,773)	(2,449)
Total Capital	505,465	495,393	(10,072)	568,907	567,119	(1,788)

Response to General Comments

Many of the comments received during the public comment period on the overall FY 2010-2011 program spending levels relate to BPA's processes, rate levels and decision making rather than to specific programs. More broadly based comments are addressed below.

1. Potential rate increases, cost controls and a budget cap:

- Tacoma Power made the following comments: **Potential Rate Increases: "**The potential rate impact of the proposed agency-wide spending levels for FY 2010-2011 is alarming." **Cost Controls:** "We urge BPA to further review areas under your control where costs could be reduced. Ensure the FY 2010-2011 cost proposal is being developed with the mindset for keeping costs in check and not funding unjustified projects and programs that appear on an organization's 'wish list.' The budgets for each workgroup appear to be created as individual silos and there does not appear to be any cross-agency prioritization. . . . . (We) recommend BPA now perform some cross-agency prioritization and reduce these increases by not funding low-priority projects and scaling some of the others." ….**Budget Philosophy**: "No funding goal (or percentage increase limit) seems to be established from one year to the next and the proposed FY 2010-2011 budget increases are substantial. BPA should exercise diligence to identify projects or program areas where costs could be reduced to offset some of the impacts of the known large cost drivers. . . . BPA should continue to look for creative ways to reduce the impacts from the primary cost drivers by confirming that these (power) funding levels are required. These Agency Services costs need to be reduced, rate of inflation or lower."
- The Joint Public Power group made the following comments. "We suggested in our comments on the 2009 IPR comments that BPA adopt an overall spending limit . . . . BPA did not respond to our suggestion in closing out the FY2009 IPR process regarding the need for an overall budgetary cap. There is no evidence of an overall spending limit…BPA should guard against raising its cost structure to the point where it may have competitiveness problems if market energy prices decline in the future…BPA should take into account cost pressures faced by its customers. . . . If secondary revenues don't stay high, BPA could easily be looking at a 20-25% (power) rate increase with the proposed budgets. Agency Services spending increases should be held to the rate of inflation." "We would still like a response to the suggestion. . . . WAPA's MOA with its utilities. . . could serve as a possible model …"

Response: BPA recognizes that utility customers have concern over the rate level that BPA establishes to recover its costs. Therefore, in the development phase of these proposed spending levels, BPA prioritized and outlined the programs and projects included in proposed spending. In its review, BPA did not employ a cost review standard for determining whether a project or program is justified or not, but rather, the resulting cost of a given project or program is driven by a rise in program requirements, including significant infrastructure improvement and obligations to meet new regulatory requirements. Such projects and programs are not the result of a "wish list" but are the result of BPA meeting its federal public purpose. Program requirements cannot be met without increasing Power and Transmission spending, as well as spending in support organizations that play an integral role in accomplishing and completing the work. While it is likely these costs will result in some level of increase in Power and, possibly, Transmission rates, we believe this level of spending is necessary to avoid significant costs and/or reductions in long term reliability. We will, however, re-assess these program levels during FY 2009, prior to developing final rate proposals.

BPA has not developed an overall budgetary cap or established a requirement to hold increases to some level, such as the rate of inflation, and does not believe it is appropriate to do so. Setting arbitrary ceilings can be counter productive and result in decisions and program levels that have negative impacts over the long term that far outweigh short-term savings. In developing program levels, BPA uses an Integrated Financial Planning Process that charts the development, approval and implementation of program levels and cost estimates. This process links BPA's internal spending level development and pre-rate development with the IPR, which allows for open public participation.

Within this framework, BPA believes it is important that the spending level development process include flexibility, allowing BPA to respond to changing circumstances and/or requirements. This flexibility was essential in determining the program levels proposed in the initial IPR for FY 2010-2011. In the development process, for example, BPA recognized that Power Services has effectively had a cap on Power internal operating costs and has been absorbing inflation for seven years. Despite the success of the Efficiency Project Improvement Processes (EPIP), which have helped BPA mitigate cost pressures in many areas, many costs actually have been deferred. This deferral has contributed to the cost pressure BPA now faces. These pressures are such that we can no longer successfully sustain flat costs while maintaining reliability and meeting other obligations. BPA also took into consideration the numerous new initiatives and drivers that are likely to require cost increases. While BPA certainly considers the impact of program levels on its customers, it also tries to find the right balance between low cost and the other "pillars" in its strategy to provide system reliability, environmental stewardship and regional accountability.

One comment suggested that an agreement such as the one that Western Area Power Marketing Administration's Rocky Mountain and Upper Great Plains Region (WAPA) has with its utility customers could be used as a model for implementing more thorough customer involvement in the front end of the budget process. WAPA, Bureau of Reclamation, and the US Army Corps of Engineers (the Agencies) executed a memorandum of understanding regarding the Pick-Sloan Missouri Basin Program/Fryingpan-Arkansas Project Work Program Review (Program Review MOU) with three preference utility customer associations.

This Program Review MOU is intended to promote active participation, communication and coordination among the Agencies and the preference associations and identifies agreed-upon schedules and formats for the Agencies to provide financial and work program information. It provides for a Technical Committee and an Executive Committee, both made up of representatives from each of the Agencies and each of the customer associations. Under the MOU, the Agencies provide the preference associations the following information, in a specified format:

- Expense budgets compared to actual expenses for the completed year, with explanations for significant differences (e.g., +/- 10%);
- Annual expenses for two completed years, the current year, and five future years' estimates, with explanations for significant differences;
- A list of cumulative capital expenditures, current year capital investments, and five future years' estimates, including replacement projects;
- FTE for two prior years, current year, and five future years' estimates;
- Comparison of indirects/overheads for two prior years, current year, and five future years' estimates, with explanations of significant differences;
- Most current Construction and Rehabilitation Program 10-year Plan, plus reporting on significant projects that may impact the Power Repayment Study or be of interest to the Technical Committee;
- Current program status report, e.g., overview of critical issues, budget line items, proposed studies, plan or program changes since the last briefing, etc.; and
- As applicable, customer advanced funding and access to receipts funding separately from appropriations, revolving fund, etc.

The Technical Committee meets at least twice per year to review and exchange financial and cost data. The Agencies are supposed to respond timely to the issues raised by the preference associations over future spending activities within the limits of the Agencies' authorities to disclose such information. Upon written notice, a preference association may request additional information and, subject to applicable federal law and regulations, shall have the right to review relevant records at the offices of the Agency. Disputes or disagreements regarding matters involving the Technical Committee may be referred to the Executive Committee for review, and disputes or disagreements regarding issues for the Executive Committee may be referred to the head of the Agency(ies). The appropriate Agency head shall respond to the issue within 20 working days.

BPA believes the Cost Review construct (now called the Integrated Business Review) described in the Regional Dialogue Policy provides all of BPA's customers and constituents a high level of transparency, including most of the same type of financial information provided for review under the Program Review MOU, and much of it in greater detail. BPA considered a formal review process conceptually similar to the Program Review MOU, called the Cost Management Group (CMG), in the Regional Dialogue. The proposed CMG had a defined number of representatives of customer and non-customer interest groups participating. However, BPA found this was one of the major problems with the CMG. As stated in the Long-Term Regional Dialogue Record of Decision (ROD), "one of the CMG's major stumbling blocks is it would represent a limited membership. While there are groups of stakeholders with similar relationships with BPA, they may have widely divergent interests and views of BPA costs. . . . As NRU notes, 'based on previous discussion and experience, it would likely be impossible to reach a broad based regional agreement regarding the size of the CMG and the proportionate representation between various stakeholder groups.'" (Regional Dialogue ROD, page 256)

The Program Review MOU provides for exchange of information that is restricted to the Agencies and the preference associations. However, as noted in the Regional Dialogue ROD, "excluding non-customers from the agency's primary cost review process is contrary to BPA's stewardship obligations because it would go a long way toward silencing non-customers. BPA needs to have the ability to receive input from constituent groups directly affected by cost decisions. These organizations can provide valuable input on the effect of spending increases and reductions. It is likely that the majority of the issues addressed in the renewables, conservation, and fish and wildlife spending, receive much non-customer attention because they affect or involve those who are doing the on-the-ground work in these areas. Creating separate forums for non-customers would result in a much more cumbersome and costly process and with little communication between the different interests. It is better, and more conducive to creating a collaborative process if all groups communicate with each other and with BPA, rather than just with BPA. . . . BPA's process does include tribes, states, environmental groups, and other stakeholders as well as customers rather than limiting it to a few customer groups." (Regional Dialogue ROD page 258)

Unlike the Program Review MOU, in the Regional Dialogue Policy BPA committed to a model which provides extensive opportunity for stakeholders as well as customers to review and give input to our forecasts of spending levels prior to finalizing them. This current IPR process is one part of the overall Integrated Business Review structure that BPA committed to in the Regional Dialogue. In IPR we have provided actual expenses, including indirects/overheads, for the prior two years, and forecasts for the current year and three additional years or through the upcoming rate period. For capital expenditures, we provided actuals for the prior two years and forecasts for the current year and five additional years. We also shared very detailed materials from various asset plans, including assessment of asset conditions and long-range capital plans. The level of detail provided in the IPR appears to be much greater than that provided under the Program Review MOU. For example, BPA provided at least eight full days of workshops and meetings on the FY 2010-2011 proposed costs, and hundreds of pages of materials, far in excess of the data called for in the Program Review MOU for most categories of costs.

The Quarterly Business Review (QBR) is the second part of the Integrated Business Review structure BPA committed to in the Regional Dialogue, and it is intended to be a forum to provide current financial forecasts, current financial results compared to forecasts, periodic updates to capital plans as they change, and information on upcoming issues that could have impact on future financial results. We will be holding the first such meeting in November. We have received input on the structure of those meetings and will solicit additional input.

In addition to information provided through the IPR and QBR processes, BPA, the Corps, and Reclamation, who manage the FCRPS hydrosystem assets through interagency Joint Operating Committees (JOCs), recognize the need for transparency and will meet with interested parties, stakeholders, and customers on an as needed basis. For example, the agencies now meet twice yearly with the Public Power Council to discuss the hydropower program financial (expense and capital budgets compared to actual costs, FTE, etc.) and operational performance (current and planned investment activities, critical maintenance accomplishments, etc.), as well as other related issues. BPA and the other agencies make a concerted effort to provide information and opportunity for customers and stakeholders to provide input.

We believe the IPR process BPA currently has and the QBR process that is being developed, though less formal than that provided by the Program Review MOU, will provide the information and transparency customers and other stakeholders are looking for, and we will continue to ask for input on how the process can be improved.

2. Levelizing Costs:

- Tacoma Power noted that "there seems to be a general theme of trying to get caught up on capital investment and maintenance. This has resulted in a front-loaded capital and maintenance program that significantly increases costs during the initial years of the program. We are asking that some levelizing take place over the next few years. . . ."

Response: As explained in the IPR workshops, the proposed capital investment levels are driven by in-depth assessments of needs through our asset management planning process and represent what BPA believes is critical to retaining reliable power generation and transmission. However, as suggested in comments, BPA has scrutinized its forecasts and made some revisions based on the recognition that the aggressive schedule for transmission and conservation capital investment may not be achievable. The final IPR levels reflect a revised schedule for one transmission capital project and an increased lapse factor applied to transmission capital (from 15 percent to 17 percent). Considering the probable need for a ramp-in period for the projected increase in conservation capital, the FY 2010-2011 conservation capital has been reduced by $18 million in FY 2010 and $10 million in FY 2011.

3. IPR Process:

- The Joint Public Power group made the following comments: A couple of changes would help in evaluating BPA's proposals: first, BPA should provide alternative packages of spending proposals for evaluation. . . .BPA made a reasonable first start at this in . . . looking at the effects of a 10% cost decrease by function . . . , but more BPA departments need to emulate the detailed analysis that BPA Public Affairs did in taking a detailed look at the impacts of spending reductions. . . . It would be useful and good budgetary practice to have BPA present a formal business case for new incremental spending proposals where BPA would calculate the benefit and the rate of return associated with the incremental spending, so that the proposal could be better evaluated.

- Tacoma Power commented that there should be clear cost-benefit analysis performed and provided as part of the IPR process. . . . BPA must establish a reliable practice to control costs and should do so with significant input from its contractual customers through the IPR process.

Response: We appreciate feedback on our first agency wide IPR process. We expect the next full IPR process to begin in the spring of FY 2010 and will take these comments into account as we plan for that process.

We will also begin Quarterly Business Review (QBR) meetings this year and expect to use these meetings to provide updates of current expense and capital spending compared to forecasts, as well as to notify customers and constituents of current or upcoming issues that could impact BPA's financial situation.

4. Tier 2 Product:

- The Joint Public Power group noted that any costs associated with the development of Tier 2 products should not be included in rates and paid for under the current subscription contracts.

Response: While we understand customer interest in this issue, this is a rate-making issue and should be addressed in the upcoming Power rate case rather than in the IPR forum.

Structure of This Report

Sections 2 through 4 of this document focus on each of the program areas identified in the workshop process and provide detailed information for the following four issues:

1) The initial IPR spending levels compared with the FY 2007-2009 rate case average,
2) A short description of what is included in the associated costs,
3) Comments received on the program area, and
4) Final decisions on cost levels for the initial rate proposal, addressing comments received.

Section 2 addresses Power Services costs, including the Fish and Wildlife Program, the Lower Snake River Compensation Plan, and Energy Efficiency/Conservation, which are fully direct-charged to Power Services. Section 3 addresses Transmission Services costs. The majority of Agency Services costs are addressed concurrently with the Power and Transmission programs they support. Section 4 addresses some remaining some Agency Services Programs as well as the Technology Innovation and Confirmation program, which impacts both Power and Transmission.

Section 2

POWER SERVICES

The first two summary tables below provide the change in FY 2010-2011 expense and capital forecasts from the Initial IPR to the Final IPR. The third and fourth tables displays the FY 2009 expense and capital forecasts from the original FY 2007-2009 rate proposal, the initial IPR, and the Final FY 2009 Power IPR Report.

FY 2010-11 Power Expenses Summary

$ in Thousands	Initial IPR	Final IPR	Change	Initial IPR	Final IPR	Change
Power Program	FY 2010	FY 2010	FY 2010	FY 2011	FY 2011	FY 2011
Columbia Generating Station O&M	269,200	269,200	0	365,000	365,000	0
Corps & Reclamation O&M for Hydro	280,700	280,700	0	296,461	296,461	0
Long Term Generation Program	31,889	31,889	0	32,343	32,343	0
Power Purchases incl DSI Monetized Power	327,189	*	*	404,795	*	*
Residential Exchange Payments/Other	221,426	*	*	220,445	*	*
Renewables (incl rate credit)	41,588	45,588	4,000	43,438	45,938	2,500
Generation Conservation (incl ratecredit)	87,088	87,088	0	86,722	86,722	0
Internal Operations	134,609	135,627	1,018	138,857	139,910	1,053
Post-Retirement Contribution	15,598	15,598	0	16,071	16,071	0
Transmission Purchases, Reserve/Ancillary	176,393	*	*	177,043	*	*
Fish & Wildlife/USF&W/Planning Council	263,541	263,541	0	270,618	270,618	0
Amortization/Depreciation	204,001	*	*	216,916	*	*
Non-Federal Debt Service	556,184	*	*	577,064	*	*
Net Interest Expense	177,657	*	*	194,291	*	*
Other–Colville Settlement, Non-Op Gen	25,746	25,746	0	28,082	28,082	0
Total	2,812,809	1,154,977	5,018	3,068,146	1,281,145	3,553

*These will be determined in the upcoming rate case.

FY 2010-11 Power Capital Summary

$ in Thousands	Initial IPR	Final IPR	Change	Initial IPR	Final IPR	Change
Power Program	FY 2010	FY 2010	FY 2010	FY 2011	FY 2011	FY 2011
Corps of Engineers/Bureau of Reclamation	183,200	183,200	0	199,200	199,200	0
Fish & Wildlife	70,000	70,000	0	60,000	60,000	0
Conservation	56,000	38,000	(18,000)	56,000	46,000	(10,000)
CGS	73,600	73,600	0	99,900	99,900	0
CRFM	88,000	88,000	0	96,000	96,000	0
17% Lapse Factor [1/]	(36,150)	(36,150)	0	(38,550)	(38,550)	0
Total Capital	280,700	280,700	(18,000)	296,461	296,461	(10,000)

1/ Excludes CGS, CRFM, Fish & Wildlife

FY 2009 Power Expenses Summary

(As reported in the 2009 Power Close Out Report)

$ in thousands	2009 in WP-07 Rate Case	Supplemental Rate Case	Initial IPR	Final IPR Forecast	Change between Initial IPR and Final IPR
Power Program	**FY 2009**	**FY 2009**	**FY 2009**	**FY 2009**	**FY 2009**
Columbia Generating Station O&M	242,842	274,342	293,700	293,700	0
Corps & Reclamation O&M for Hydro Projects	248,173	248,173	261,600	261,600	0
Long Term Generation Program	25,751	31,864	31,613	31,522	(91)
Renewables (incl rate credit)	41,917	53,414	43,955	43,955	0
Generation Conservation (including Conservation Rate Credit)	70,347	79,414	84,526	80,526	(4,000)
Internal Operations	111,566	111,566	125,030	121,018	(4,012)
Pension & Post-Retirement Benefits	15,375	15,375	15,277	15,277	0
Transmission Purchases, Reserve/Ancillary Services	177,525	177,515	176,073	176,073	0
Fish & Wildlife/USF&W/NWPCC	173,353	173,367	229,439	229,439	0
Other – Colville Settlement, Non-Operating Generation	24,649	21,049	27,413	27,413	0
Total	2,698,421	2,615,184	2,730,011	2,717,549	(8,103)

FY 2009 Power Capital Summary

(As reported in the 2009 Power Close Out Report)

$ in Thousands	2009 in WP-07 Rate Case	Supplemental Rate Case	Initial IPR	Final IPR	Change Between Initial IPR and Final IPR
Description	**FY 2009**	**FY 2009**	**FY 2009**	**FY 2009**	**FY 2009**
Corps of Engineers/Bureau of Reclamation	137,000	137,000	154,950	154,950	0
Fish & Wildlife	36,000	36,000	50,000	50,000	0
Conservation	32,000	32,000	42,000	32,000	(10,000)
CGS	27,700	27,700	96,700	96,700	0
CRFM	62,400	62,400	63,000	111,000	48,000
15% lapse factor[1/]			(29,813)	(28,313)	1,500
Total Capital	295,100	295,100	376,837	416,337	39,500

1/ Excludes CGS, CRFM, Fish & Wildlife

A. COLUMBIA GENERATING STATION O&M

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
269.2	269.2	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
365.0	365.0	0

Capital

FY 2010		
Initial IPR	**Final IPR**	**Change**
73.6	73.6	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
99.9	99.9	0

BPA pays the costs of Energy Northwest's Columbia Generating Station (CGS) nuclear power plant. Energy Northwest (EN) has continued to focus on equipment obsolescence, reliability and plant performance. EN management believes additional investments are necessary to improve safety, reliability and performance. The plant's performance indicators have been low when measured against criteria set by the Institute of Nuclear Power Operations (INPO), but capacity factors have been good.

Comments Received:

- Tacoma Power commented they are concerned with the proposed $27M increase for 2010 and $123M increase for 2011... (and) request BPA to continue efforts to influence the reduction of the proposed CGS budget.
- The Joint Public Power Group made the following comments: EN should be aware of the importance of its Long Range Plan (LRP) for BPA ratemaking... It would be most effective if the results of the LRP could set a cap on spending in the years beyond the current budget year. Also, it would be very helpful if the timing of the LRP and the BPA IPR could be better synchronized so that BPA could have reliable information as BPA and the customers go into the IPR process. In addition, BPA and EN should further explore the costs and benefits of moving CGS financial reporting to BPA's fiscal year.

Response: EN believes that the CGS program levels reflect the need to continue improvement efforts and ensure sustained high performance. The increased funding EN has identified for FY 2010-2011 is designed in general to address:

1) Deferred maintenance issues,
2) Equipment obsolescence and reliability, and

3) Performance improvement initiatives.

These investments should result in improved overall performance of CGS.

BPA has discussed, and will continue to discuss, with EN the need for cost effective, safe, reliable operation of the Columbia Generating Station to benefit the ratepayers of the Northwest. Safety and reliability are paramount goals, but it is essential that we meet those goals in the most cost-effective way possible. BPA is concerned about the rapid rate of increase in costs for CGS operations. In conjunction with Energy Northwest management, a set of performance indicators has been developed. We are actively tracking these indicators on a quarterly basis and will make this information available to the public. This tracking should help ensure that these major increases in spending actually yield the improvements they are intended to produce.

EN management has also proposed to develop a long range plan with significantly increased rigor such that it would provide greater confidence to BPA and others that actual results will be consistent with the plan. We also understand the EN Board has hired independent counsel to evaluate CGS's long range plans and budgets in terms of addressing significant station needs. We believe this is an appropriate step and encourage its continued implementation. We would be interested in working with the Board to see how we could benefit from the counsel of any independent review the Board undertakes. Finally, BPA is considering seeking independent counsel from individuals with significant nuclear plant executive management and operations experience in order to be able to complement our on-site Richland staff's experience. The focus of any contracted additional executive nuclear expertise will be to assure our budget review and oversight authority is executed in a manner that will promote the safe, reliable and cost-effective operation of CGS consistent with the project agreements. We also intend to continue to urge the EN Board to adopt the overarching principle we proposed to the Board last year. As stated below, this principle seeks to provide greater alignment throughout our organizations through focusing on the complementary nature of our missions. That principle is as follows:

> "BPA and ENW are committed to long-term, safe, reliable operation of CGS accomplished at the lowest reasonable cost necessary to achieve those objectives. It is also our objective to integrate CGS with the Federal Columbia River Power System and to achieve optimum utilization of the resources of that system taken as a whole and to achieve efficient and economical operation of that system."

BPA and customers have emphasized the importance of a credible Long Range Plan and the ability of EN to live to that plan. EN produced and updated an LRP in the spring of 2008 in conjunction with the FY 2009 budget. EN has committed to living within the costs identified in the plan, barring any unforeseen regulatory requirements. EN has revised its budget preparation cycle (long range plan) by advancing it by two months. This will allow time for meaningful customer review and input of the CGS budget before it is included in future IPR reviews. EN is exploring options for changing the EN fiscal year to coincide with BPA's fiscal years; however, it is not clear if the benefits of such a move would justify the costs.

Decision: No change to the planned CGS expense or capital forecast for FY 2010-2011.

B. CORPS AND RECLAMATION O&M

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
280.7	280.7	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
296.5	296.5	0

Capital

FY 2010		
Initial IPR	**Final IPR**	**Change**
183.2	183.2	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
199.2	199.2	0

BPA works with the U.S. Army Corps of Engineers and the Bureau of Reclamation to implement funding for both operations and maintenance (O&M) activities at 31 hydro electric facilities throughout the Northwest and to ensure implementation of all regionally cost-effective system refurbishments and enhancements. BPA's Enterprise Process Improvement Project (EPIP) included a major asset management planning effort that included Federal hydro facilities. Significant drivers of change affecting Corps and Reclamation O&M include the Western Electricity Coordinating Council (WECC) and the North American Electric Reliability Council (NERC) compliance requirements, non routine extraordinary maintenance requirements, and Biological Opinion (BiOp) requirements. BPA expects O&M spending to rise at roughly the rate of inflation (except for non routine extraordinary maintenance activities such as the Grand Coulee Dam Third Powerhouse rehabilitation and other items mentioned above.)

Columbia River Fish Mitigation Project (CRFM) includes the power portion of investment funded by Corps of Engineers appropriations for investment on mitigation efforts for fish and wildlife on the Federal Columbia River dams. BPA becomes obligated to repay the power portion of the costs to the US Treasury at the time the investment is considered complete and placed into service. While the forecast of total investment from FY 2007 through 2011 has not changed significantly, the Corps provided an updated forecast reflecting a change in the expected timing for investment being placed into service, with less than forecast going into service in FY 2007 and considerably more expected in FY 2008 than forecast in the WP-07 rate case.

Comments Received:

- The Joint Public Power group made the following comments: While improvement is always possible, it appears that the Integrated Business Management Model developed by the Corps, Reclamation and BPA has resulted in a fairly rigorous asset-based planning and management program. . . . The ramp up of capital expenditures continues to be significant. . . . The agencies should be encouraged to broaden their supplier network so they are not captive to a small number of suppliers. . . . (T)he agencies should be encouraged to take steps to reduce or eliminate inefficient O&M, rather than just escalating O&M costs by a fixed amount.

- Montana Northwest Power and Conservation Council members commented that funding for an additional turbine at Libby should be removed.
- Tacoma Power noted that BPA should exercise diligence to scale back some initiatives and stretch out implementation to offset the impacts of proposed asset management initiatives.
- Affiliated Tribes of Northwest Indians (ATNI) commented that funding for FCRPS cultural resources program must be increased, and they are concerned about the Corps not being able to finish its work with the 15-year period or by 2012.

Response: BPA, the Corps, and Reclamation developed the hydro asset planning process to ensure the hydro generating assets are operated, maintained and invested successfully to ensure benefits to the region continue over the long term. Low cost power, power reliability, and trusted stewardship are the three objectives guiding the asset planning process, and the agencies are constantly challenging themselves to maximize them. Equipment health and condition, operational requirements, financial performance, and risk and consequences are continually evaluated and assessed in determining the expense and capital resource requirements for the program. As noted in IPR workshops, the hydro system is aging and requires extensive investment to ensure its continued long term performance. Also, new regulatory requirements associated with the updated Biological Opinion and WECC/NERC reliability compliance are requiring additional O&M expense resources to ensure the agencies are in compliance. The agencies will continue to exercise diligence in managing the program by evaluating capital investments and O&M expense requirements to ensure adequate long term performance and benefits of the hydrosystem.

As encouraged in the comments received, the agencies will strive to ensure the broadest number of suppliers is available to meet the hydrosystem’s needs, consistent with government procurement practices. For example, the Corps recently met with major hydropower contractors to understand how contracts could be written to solicit more interest from them. Additionally, the agencies are continually evaluating business decisions to ensure revenue is maximized while operating and maintaining a safe, low cost, and reliable system.

Regarding cultural resources activities, the funding levels for such activities across the FCRPS were derived from the System Operations Review (SOR) and agreed to by the Corps, Reclamation, BPA, and the tribes. The term of the agreed-upon funding was for 15 years, which ends in 2012. A number of changes in the funding levels for Cultural Resources will be addressed during development of a new agreement for funding that will take effect in 2012, after the 15-year original term is completed. The agencies expect to begin work on developing a new funding agreement during FY 2009.

Regarding the comment that there is no scientific basis for funding an additional turbine at Libby to support Kootenai River sturgeon, the Libby 6th unit was identified as a potential project for planning purposes only and was listed that way while describing the system asset planning process. There was no funding included in the plan for this work as it did not meet hydro capital investment criteria; it was merely identified as a potential project. If a decision were to be made that a 6th unit at Libby was necessary due to ESA considerations, funding would have to come by displacing other capital projects in the plan.

Decision: No change to the planned Corps and Bureau of Reclamation expense or capital forecast for FY 2010-2011.

C. LONG-TERM GENERATING PROGRAM

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
31.9	31.9	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
32.3	32.3	0

This program consists of BPA's long-term acquisition contracts for output from generating resources such as Cowlitz Falls, Billing Credits Generation, Wauna Co-generation project, Elwah Dam, Idaho Falls Bulb Turbine, and Clearwater Hatchery Generation. Most of the expenses associated with the long-term generating projects are based on energy production at the generating units and, therefore, are offset by revenues. There is little opportunity for improvement because prices are fixed by contract.

Comments Received:

None

Decision: No change to the planned Long-Term Generation Project forecast for FY 2010-2011.

D. ENERGY EFFICIENCY & CONSERVATION

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
87.1	87.1	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
86.7	86.7	0

Capital

FY 2010		
Initial IPR	**Final IPR**	**Change**
56.0	38.0	18.0
FY 2011		
Initial IPR	**Final IPR**	**Change**
56.0	46.0	10.0

FY 2009 Expense			
Original WP-07	**Initial IPR**	**Final IPR**	**Change**
70.3	84.5	80.5	(4.0)
FY 2009 Capital			
Original WP-07	**Initial IPR**	**Final IPR**	**Change**
32.0	42.0	32.0	(10.0)

(As reported in the 2009 Power Close Out Report)

BPA's Energy Efficiency and Conservation program is designed to capture the anticipated 35 to 40 percent increase in public power's share of the region's conservation target in the FY 2010-2011 period (i.e., 70 aMW per year).

Comments Received:

- Idaho Conservation League commented that the IPR should include additional support for efficiency/conservation programs.
- Tacoma Power stated it does not support increases in conservation spending that would affect the Tier 1 rate.
- The Joint Public Power group raised a concern about spending increases. The region has been able to achieve conservation under current levels. They would be more comfortable with the spending if they knew what would be included in new long-term contracts.
- Columbia Inter-Tribal Fish Commission (CRITFC) supports full funding of conservation. BPA should expand conservation programs as much as possible.

Response: Tiered rates will not start until FY 2012, which is beyond the scope of this IPR. BPA's post-2011 energy efficiency costs will be included in Tier 1 rates as outlined in the Final Long Term Regional Dialogue Policy (July 2007). That said, BPA has designed its proposed spending for energy efficiency to capture the anticipated 35 to 40 percent increase in public power's share of the region's conservation target in the FY 2010-2011 period (i.e., 70 aMW per year). It is uncertain what level of utility self-funding for conservation will occur during this time. Therefore, BPA's proposed spending levels assumed that 20 percent (or 14 aMW/year) of public power's share of the regional conservation target would be delivered by utilities using their own funds. BPA also proposes energy efficiency capital spending for this period to supplement utility funding under bilateral contract arrangements. The incentives customers have, including the high water mark credits, to fund conservation themselves are not expected to be enough to ensure achievement of the cost-effective conservation targets.

There remain, however, several outstanding processes and planning areas that have not concluded at this time and need to be resolved before BPA can determine the proper level of energy efficiency capital for FY 2010-2011. These areas include:

1) The Northwest Energy Efficiency Taskforce (NEET) activities and future recommendations,
2) The Council's 6th Power Plan, which will likely establish new, higher conservation targets for the region,
3) BPA's Resource Program, and
4) BPA's public process to determine its role in energy efficiency in the post-2011 period. This last process will begin early in the 2009 calendar year.

The information acquired through these processes and plans will help BPA determine the appropriate capital funding levels for its energy efficiency program.

Despite the current lack of certainty prior to these processes BPA feels comfortable reducing the proposed capital spending by $18 million in FY 2010 and by $10 million in FY 2011. This reduction in capital assumes that utilities will deliver additional conservation savings using their own funding (i.e., 33 percent, or 23 aMW, in 2010 and 27 percent or, 19 aMW, in 2011) to guarantee higher targets are met. However, to achieve the energy efficiency targets that the agency has committed to, further reductions to the Energy Efficiency budget are not appropriate at the current time. BPA expects to have better information regarding BPA's energy efficiency program requirements before BPA considers if changes in forecasts are appropriate next spring.

Decision: No change to the planned Conservation/Energy Efficiency expense forecast for FY 2010-2011. The Capital forecast will be reduced by $18 million for FY 2010 and $10 million for FY 2011.

E. FISH AND WILDLIFE DIRECT PROGRAM

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
230.0	230.0	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
236.0	236.0	0

Capital

FY 2010		
Initial IPR	**Final IPR**	**Change**
70.0	70.0	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
60.0	60.0	0

BPA expends ratepayer revenues in the implementation of measures addressed to the recovery of Columbia River fish listed as threatened or endangered under the Endangered Species Act (ESA) and to the mitigation of impacts to fish and wildlife from the development and operation of the FCRPS. This dual mitigation and recovery responsibility requires a comprehensive approach to implementing the Direct Fish and Wildlife Program (Direct Program) that integrates the ESA requirements of the FCRPS biological opinions from the U.S. Fish and Wildlife Service and National Oceanic and Atmospheric Administration (NOAA) Fisheries, with the broad resource protection, mitigation and enhancement objectives of the *Columbia Basin Fish and Wildlife Program* adopted pursuant to the Northwest Power Act.

BPA meets these complementary fish and wildlife mitigation and recovery objectives in the Direct Program primarily through the negotiation and award of contracts to state, federal, and tribal entities. Drivers for increased contract costs in FY 2010-2011 are new Biological Opinion requirements and the 2008 Columbia Basin Accords agreements with states and tribes on fish and wildlife costs. These additional contract commitments are to be implemented as expeditiously as possible to accomplish specific projects or program outcomes addressed to the impacts of federal hydropower development and operation in the Columbia River. Project results will be credited and accounted for as contributions toward the recovery and mitigation obligations of BPA.

Comments Received:

- **New BiOP and Fish Accords, Proposed Budget Increase:** CRITFC expressed strong support for BPA's proposal to increase its fish and wildlife funding to fully implement the MOA signed on May 2, 2008. CRITFC and BPA staffs are working to better refine the expense and capital portions of this funding. CRITFC will continue working with BPA staff in the near term to better refine these expense and capital budgets. It is their understanding that these revised budgets will be included in BPA's IPR close-out letter and incorporated into the BPA rate case analysis.
- **Cost Effectiveness, Duplication and Unnecessary Efforts:** Tacoma Power stated BPA should carefully review this proposed increase and look for duplicate efforts and items that are not required. Focus needs to be placed on choosing alternatives that provide the desired results in the most cost-effective manner.
- **Budget Management Plan, Long Term Budget Cap, Carry Over and Inflation:**
    - The Joint Public Power group made several comments.
        - First, BPA needs to develop a fish and wildlife budget management plan. Program budgets should be fixed, regardless of whether the program spent

all funds in the previous year. Excepting BiOp and MOA commitments, the establishment of funding should not create a locked-in future expectation to the budgeted funds if they are not spent in the current fiscal year.

- Second, because of the risks that operational costs will be substantially higher than expected it is imperative that BPA establish and abide by a long-term budget for the Integrated Fish and Wildlife Program costs.
- Third, BPA stated it will make a decision on how to handle unspent funds as part of the development of a budget management plan for overall program budget management, and that it plans to develop the plan this summer. Customers would like BPA to set a timetable for definition of BPA funding requirements, completion of a budget management plan and a review process for customers and other stakeholders.
- Fourth, customers are uncomfortable with the automatic inflation adjustment and would like greater detail on how and when BPA plans to address the issue of a budget cap.
- Fifth, it is imperative that BPA not only consider the recommendations made by its customers, but take action to implement these recommendations. BPA needs to set a schedule for development and implementation of a budget management plan, to address how the Northwest Power and Conservation Council Program, Memoranda of Agreement with States and Tribes, a new biological opinion, and other elements of BPA's fish and wildlife budget will be integrated and managed.

Program Review:

- The Joint Public Power group commented that customers would like to see BPA work closely with the Council to ensure a comprehensive program review that involves the Independent Scientific Review Panel. In particular, RM&E needs to undergo rigorous scrutiny. There are projects currently funded by ratepayer dollars that have little relation to the effects of hydropower construction and operation and should be funded through other sources or eliminated. The funding should be seen as comprehensive for both fish and wildlife and the proposed budget should not increase beyond its current limit.
- Washington Department of Fish and Wildlife commented that BPA should continue to support, and consider costs associated with funding the following projects: Pacific States Marine Fisheries, Commission Coded Wire Tag Project, the Smolt Monitoring Program, the Fish Passage Center, Comparative Survival Study, StreamNet, the Columbia Basin Fish & Wildlife Authority, and the Lower Snake River Compensation Program.
- Washington Governor's Salmon Recovery Office commented that BPA should consider the needs of regional salmon recovery organizations in Washington. Greater funding would enable enhanced coordination to meet the needs of the 2008 BiOp and Columbia Basin Fish Accords.

Science Review:

- The Joint Public Power group recommended that the current requirements for Independent Scientific Review Panel review should be continued for all projects funded by BPA. BPA has noted a commitment to ensuring independent science review, but needs to outline the process that guarantees this.

Economic Review:

- The Joint Public Power group supports the Independent Economic Advisory Board (IEAB) and request that it be adequately funded.

Cultural Resources:

- ATNI expressed concern whether BPA can provide more information on the cost components for how these cultural resources responsibilities (for BPA Fish and Wildlife Mitigation Program Projects) will be met for FY 2009 and elaborate on the tribal consultation/ coordination components related to these costs.

Mitigation Settlement of Southern Idaho and Albeni Falls:

- Idaho Department of Fish and Game proposed consideration of a settlement of the wildlife mitigation obligation for Southern Idaho and Albeni Falls. BPA should calculate a reasonable estimate of the value for the rate case so a settlement is not foreclosed.

Response: Because a new BiOP and Fish Accords exist, BPA has made a proposed spending increase for Fish and Wildlife Program implementation in FY 2010-2011, resulting in upward adjustment in funding from the current rate period to $230 million and $236 million, respectively. These proposed spending levels reflect the funding needed to implement both the new FCRPS Biological Opinion (BiOp) and the Columbia Basin Fish Accords (Accords) without reducing funding for other non-BiOp and/or non-Accord elements of the Program. While the proposed spending includes the funding necessary to meet Fish Accord commitments to individual Accord signatories, the spending is not broken down into individual components. In total the spending proposed is what BPA believes is necessary for meeting its individual Accord and BiOp commitments while not reducing funding for other elements of the Program.

Cost Effectiveness, Duplication and Unnecessary Efforts:

BPA continues to place a premium on enhancing Fish and Wildlife Program performance and on managing and administering contract implementation to deliver project outcomes as biologically effective results – at the lowest cost and within budget. We see this as a two-pronged undertaking:

1) The Program itself must be firmly grounded in measurable performance expectations expressed as biological and environmental objectives; and

2) Projects must be designed around discrete work elements tailored to expected outcomes that are explicitly addressed to the Program's performance objectives.

A durable and sustainable shift in Program emphasis is not an overnight undertaking; it is evolutionary, requiring the persistent attention of BPA Fish and Wildlife Division staff as well as buy in and commitment from other Fish and Wildlife Program partners such as the

Northwest Power and Conservation Council and the Fish and Wildlife co-managers. BPA will continue to examine and evaluate the current portfolio of effort to better spend existing resources even as we are developing additional projects to meet BiOp responsibilities and Accord commitments. The premise for existing, expanded, or newly initiated project commitments is the same: work supported by ratepayer funds will be evaluated on the basis of results that are a contribution toward explicit objectives. This is the basis of the performance construct upon which the Council has built the Program and BPA has based its BiOp actions.

Mitigation settlements for Southern Idaho and Albeni Falls: Mitigation settlements can be an effective strategy for meeting BPA's wildlife responsibilities under the Northwest Power Act. Durable, workable settlement agreements require the participation of all affected sovereigns with jurisdictional or management authority over fish and wildlife resources in the area affected by the FCRPS and encompassed by the terms of settlement proposed. These sovereign interests need to be representative of the broad public interest in mitigation responsibilities of BPA, and serve as a surrogate for the affected resources, to whom the mitigation obligation is actually owed. These attributes can confound the likelihood and timing of successfully negotiated agreements, and make it difficult to project and incorporate cost-estimates into future Program levels and budget planning.

As a practical matter, any successfully concluded agreement would have to occur within the limitations of BPA's financial flexibility. According to a recent BPA analysis (July 2008), BPA's available Treasury borrowing authority could be fully utilized by 2016. We are not budgeting for a wildlife agreement at this time due to uncertainty about whether negotiations can be successfully concluded, and in recognition that a potential Idaho wildlife mitigation settlement must fit within the scope of BPA's limited borrowing authority. BPA continues to explore strategies for maximizing its current borrowing authority, as well as potential new alternatives that might be developed.

Budget Management Plan, Long Term Budget Cap, Carry Over and Inflation:

BPA acknowledges that with the new BiOp and Fish Accords, and the related Program spending level increases in FY 2009, there are many new management implementation complexities. Although policies are being developed, important unanswered questions remain that will need to be addressed as we gain experience.

In coordination with the region, BPA will provide an opportunity for input and comment regarding the questions, issues, and policies surrounding the Fish and Wildlife proposed spending, including many of the comments proposed by BPA's customer representatives that will be considered in the development of this plan. Among the suggestions to be addressed in the plan are carry over of unspent funds, economic review, inflation and a long-term spending plan for the Integrated Fish and Wildlife Program. Science Review will be addressed in a separate document that is under development and will be provided to customers and other constituents for feedback.

BPA believes its future cost projections accurately reflect the range of impacts to the operation of the FCRPS related to implementation of both the new BiOp and Columbia Basin Fish Accords. Additional financial consequences relating potential outcomes associated with the BiOp litigation are too speculative to address at this time, and will be addressed as necessary in the future in base budgets. BPA has included adjustment clauses in rates in the past to address this risk, and will consider doing so in the future.

BPA customers commented that outside the BiOp and Accord commitments, unspent funds should not be carried forward nor made available for funding projects in the future. BPA believes that there is a potential for actual Fish and Wildlife Program spending to come in below the proposed spending in FY 2010, due to the ramp-up of the expanded program. This may occur because most of the new Fish Accord projects will not be in place before the end of the FY 2008 implementation period; under-spending is thus likely to continue into FY 2009 given the time needed to complete ISRP review and required permitting processes. Additionally, the FY 2009 spending projection reflects an assumption that actual expenditures for new work would occur at 75 percent of the full project budget.

This ramp-up assumption was applied for FY 2009; in actuality, many new projects have *project-year* budgets (the contract implementation period spans two fiscal years) that will spill into FY 2010, further extending the Program ramp-up period. BPA's proposed $230 million spending in FY 2010 is reflective of the funding level necessary for meeting Fish Accord and BiOp commitments, while allowing for no reduction of funding for the other non-BiOp and/or non-Accord elements of the Program. Given the potential for a more protracted ramp-up of Program spending for new BiOp and Accord commitments than expected, BPA may choose to introduce a probability distribution around this proposed spending in the formal FY 2010-2011 rate case, to model the anticipated range of uncertainty of actual spending relative to the proposed of $230 million for FY 2010.

As part of its FY 2007-2009 project funding decision BPA decided it was reasonable to carry over $8.8 million in unspent funding from the previous rate period, so as not to create a "use-it-or-lose-it" incentive. For FY 2010-2011, as it relates to projects outside the BiOp/Accords, BPA will make a decision on how to handle unspent funds as part of the development of a spending management plan for overall Program implementation planning. BPA expects to complete development of this plan during the autumn of 2008 and will provide an opportunity for Council, customer and Program stakeholder input.

BPA's FY 2009 proposed spending does not reflect an adjustment for inflation; however, BPA has proposed an annual adjustment of 2.5 percent per year starting in FY 2010. BPA agrees that with the addition of an annual inflation adjustment, the Program budget in total could function as an overall funding commitment or cap. For example, BPA does not plan to allow the general carryover of unspent funds for the non-Accord portion of the Program; those dollars would be otherwise returned to ratepayers by being kept in BPA's cash reserves. Conversely, if work can be implemented at lower than forecasted amount, flexibility from lower-than-expected contract costs may need to be used to cover potentially higher-than-forecasted needs of other projects. This approach, with the addition of the inflation adjustment, provides both flexibility and substantial certainty in making future project funding decisions within an overall established budget for FYs 2010-2011. However, longer-term, BPA's commitment under the FCRPS BiOps is to specific performance requirements and not to specific work or a set amount of money.

Customers suggested that BPA look for potential ways to reduce funding of other projects where there are duplicative efforts and/or a lack of a clear FCRPS mitigation nexus. BPA believes such an assessment is appropriate, and that it should logically occur as part of the Council's upcoming project review initiative, prior to any future solicitation for additional project proposals.

Independent Science Review: As noted earlier, BPA is committed to ensuring adequate independent science review consistent with the intent of the Science Review amendment to the Northwest Power Act. BPA, Fish Accord parties and the Council are currently drafting a white-paper outlining the process for Science Review of new project commitments in the Accords; BPA will soon be seeking customer input and feedback on this approach.

Independent Economic Advisory Board (IEAB): BPA supports the Council utilizing the IEAB for cost-effectiveness assessments, as appropriate.

Cultural Resources: Similar to prior fiscal years, BPA will continue to spend approximately $4.5 million per year in FYs 2010-2011 to meet the cultural resources requirements of the agency. Costs include compliance activities for transmission services and fish and wildlife mitigation projects, as well as the long-term funding commitments made in the System Operations Review of the FCRPS. For example, during FY 2008, the Fish and Wildlife Program (Program) directly supported two archaeologists to expedite on the ground contract actions. For FY 2009, BPA recruited an additional three archeologists dedicated to cultural resource compliance activities for Transmission Services and the Program.

As during previous years, cultural resource compliance spending in FYs 2010-2011 is part of the overall agency funding commitment for environmental assessment and protection in support of fish and wildlife mitigation and transmission projects. BPA archaeologists mostly charge their time directly to projects, but costs would total approximately $500,000 if included as a separate Program expense. In addition, some cultural resource surveys and reports are contracted out, and there are additional indirect costs associated with mitigation measures for transmission services and fish and wildlife. Environmental planning, tribal affairs, project management, and other agency staff work closely in consultation with Tribes, Tribal Historic Preservation Officers, and State Historic Preservation Officers. Although the costs of these activities are typically not attributed as a specific cultural resource expense, they are encompassed within projected program levels and expenditures.

Decision: No change was made to the planned Fish and Wildlife expense and capital forecast for FY 2010-2011. BPA will continue to examine and evaluate the current portfolio of effort, to better spend existing resources, even as we are developing additional projects to meet BiOp responsibilities and Accord commitments. BPA will develop an overall Fish and Wildlife Spending Management Plan – in coordination with the region. There will be an opportunity for input and comment to address questions, issues and policies surrounding the Fish and Wildlife proposed spending. Many of the comments proposed by BPA's customer representatives will be addressed in the development of this plan.

F. U.S. FISH AND WILDLIFE SERVICE: LOWER SNAKE RIVER FISH & WILDLIFE COMPENSATION PLAN

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
23.6	23.6	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
24.5	24.5	0

This program funds 11 hatcheries and 15 satellite facilities owned and operated by the Fish and Wildlife Service (FWS), and fisheries agencies of states of Oregon, Washington, Idaho and the Nez Perce and Shoshone-Bannock tribes and the Confederated Tribes of the Umatilla. This program is legislatively mandated to mitigate for the existence and operation of the four lower Snake River hydroelectric dams constructed in the1970s.

Comments Received:

- Washington Department of Fish and Wildlife supports the funding for the LSRCP. Note that this does not include potential future costs associated with ESA and the BiOp.
- IDFG supports the proposed LSRCP budget. BPA should recognize the need to fund hatchery programs in addition to fishery mitigation programs.
- Alaska F&W supports the funding of deferred maintenance for LSRCP hatcheries.

Response: BPA's proposed LSRCP spending reflects moderate increases in the near-term to address a backlog of non-recurring maintenance needs. Much of this non-recurring maintenance has been deferred since 2002 so as to maintain total LSRCP spending within rate case commitments.

The increase in funding is for deferred and extraordinary maintenance expenditures, and is not a permanent increase in spending for routine management, maintenance, and operations of hatchery facilities. Purposes include the avoidance of higher costs associated with addressing unexpected failure of equipment and facility infrastructure on an emergency basis, and managing the increased risk to human and fish health and safety. These risks increase as the useful life of existing equipment and infrastructure approaches and passes the threshold of biological effectiveness and cost-efficiency. Consequently, continued deferral of this maintenance could result in economic impacts that exceed the near-term savings from a deferral.

Regarding potential future additional LSRCP costs associated with ESA consultation and compliance with the FCRPS Biological Opinion, and informed by the federal hatchery review process, BPA would look first to the LSRCP cooperating parties to absorb these costs into the existing spending levels to the maximum extent possible. A related unresolved issue is that the BPA-USFWS direct funding agreement covers expense funding only (for operations, maintenance, monitoring and evaluation costs for these hatcheries). To the extent that major capital investments may become necessary, there is no funding source at this time.

The relationship between mitigation and conservation hatchery purposes, and the appropriate mix of production to support both, is beyond the scope of the IPR. However, BPA's funding responsibilities should naturally relate to activities necessary for mitigating the effects of the federal hydrosystem on fish populations. Consequently, to the extent that hatchery purposes can be segmented, BPA's responsibilities would encompass FCRPS mitigation, and not harvest augmentation.

The region continues to debate the efficacy and relative impacts of artificial production on the long-term fitness and reproductive success of native and wild stocks. Supplementation hatcheries which are operated for the purpose of rebuilding salmonid populations which have historically been depressed due to FCRPS impacts are supported at levels reflected in BPA's Fish and Wildlife Program budget commitments. Future funding for hatchery infrastructure, including expansion or reprogramming of existing capacity, will be informed by the outcome of the ongoing hatchery review process.

Decision: No change to the planned Lower Snake River Compensation Program forecast of expense and capital.

G. RENEWABLE RESOURCES

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
41.6	45.6	4.0
FY 2011		
Initial IPR	**Final IPR**	**Change**
43.4	45.9	2.5

BPA's goal for renewable resources is to ensure the development of its share of cost-effective regional renewable resources at the least possible cost to BPA ratepayers. BPA's share will be based on the regional load growth (about 40 percent) of its Public Utility customers. BPA will cover its share through power acquired by BPA from renewable resources to serve its public customers and/or renewable resources acquired by publics with or without financial assistance by BPA.

Comments Received:

- The Idaho Conservation League commented that BPA should restore renewable facilitation and use a portion to begin looking for reasonable investments in renewable resources.
- Tacoma Power stated that BPA should not increase the budget for renewable resources.
- The Joint Public Power group opposes BPA's proposal to completely remove the renewable option from the Conservation Rate Credit. They suggest that it be

ramped down gradually from $6 million today to $2 million by 2011. The renewable option should be extended to support small projects like customer-owned solar PV and it should also cover the purchase of Environmentally Preferred Power. BPA should continue to offer the $559/kw credit for solar PV. Renewable Northwest Project commented that $4 million is inadequate to meet customer needs for new renewables. BPA should continue its leadership by taking a broader approach to renewables.
- CRTIFC supports full funding of renewable resource programs.

Response: Comments received reflect opposing views, some suggesting that BPA should increase renewable resource spending and others suggesting BPA should not increase renewable spending. Joint comments submitted by the Public Power Council, Industrial Customers of Northwest Utilities, Northwest Requirements Utilities, Northwest Generating Company and the Public Generating Pool noted that some utilities may continue to need assistance in procuring renewable resource generation in the short-term and that the signing parties opposed BPA's proposal to completely remove the Renewable Option from the Conservation Rate Credit. The joint comments suggested decreasing the Renewable Option funding levels from $6 million to $4 million in 2010 and $2.5 million in 2011. The joint comments also suggested that the Renewable Option should continue to support small-scale customer-owned renewable projects and allow the purchase of Environmentally Preferred Power.

Decision: BPA agrees that utilities will likely need additional assistance in acquiring and using renewable generation to serve their loads. Therefore, BPA will include in its FY 2010-2011 initial rate proposal, $4 million in 2010 and $2.5 million in 2011 for the Renewable Option to the Conservation Rate Credit.

H. POWER INTERNAL COSTS/ POST-RETIREMENT BENEFITS

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
150.2	151.2	1.0
FY 2011		
Initial IPR	**Final IPR**	**Change**
154.9	155.9	1.0

FY 2009 Expense			
Original WP-07	Initial IPR	Final IPR	Change
126.9	140.3	136.3	4.0

(As reported in the 2009 Power Close Out Report)

Internal Operations includes Agency Services that provide support to the programs and organizations within Power Services and are either allocated to Power Services, or direct-charged to Power Services, as well as the internal operating costs of Power Services itself.

Although programs have increased in scope and responsibility, as stated earlier, Power Services has effectively had a cap on power costs for seven years and the internal operations costs in 2008 are virtually the same as they were in 2001. The deferral of costs creates cost pressures such that Power can no longer sustain flat costs. Increases over the 2001-2008 levels are necessary for FY 2009 through 2011 because of greater wind integration efforts than expected, greater-than-expected costs for Regional Dialogue contract and tiered rates work, greater-than-planned resource acquisition efforts, and increased IT, Supply Chain, Legal, Financial and other activities necessary to achieve the programs describe above.

Re-organizations that were not reflected in initial IPR numbers are reflected in the final IPR numbers. These reorganizations resulted in greater efficiencies and a more accurate allocation of Business Support function costs. The result is a slight shift in allocated costs of $1 million from Transmission internal costs to Power internal costs.

There was no change in Post-Retirement Benefits.

Decision: No change to total Agency Internal Operating Costs other than $1 million shift in allocation from Transmission to Power.

COST DECISIONS TO BE MADE AS PART OF THE RATE CASE

The following section provides information on areas for which the costs will be determined in the FY 2010-2011 rate proposal. They have been included in the IPR to provide an opportunity for participants to understand the basis for these costs.

I. POWER PURCHASES, INCLUDING MONETIZED BENEFITS TO DSIS

$ millions

FY 2010		
Initial IPR	**Final IPR**	**Change**
327.2	*	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
404.8	*	0

***** Power Purchases, including monetized benefits to DSIs, will be determined in the Final Rate Proposal.

J. TRANSMISSION PURCHASES, RESERVE/ANCILLARY SERVICES

$ millions

FY 2010		
Initial IPR	**Final IPR**	**Change**
176.4	*	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
177.0	*	0

* Transmission Purchases and Reserve and Ancillary Services will be determined in the appropriate rate cases.

K. RESIDENTIAL EXCHANGE PROGRAM

$ millions

FY 2010		
Initial IPR	**Final IPR**	**Change**
221.4	*	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
220.5	*	0

***** Residential Exchange benefits will be determined in the Final Rate Proposal.

L. TOTAL NET INTEREST, AMORTIZATION/DEPRECIATION AND NON-FEDERAL DEBT SERVICE

$ millions

Net Interest

FY 2010			
	Initial IPR	**Final IPR**	**Change**
Power	177.7	176.1*	(1.6)
FY 2011			
	Initial IPR	**Final IPR**	**Change**
Power	194.3	192.0*	(2.3)

Amortization/Depreciation

FY 2010			
	Initial IPR	**Final IPR**	**Change**
Power	204.0	197.5*	(6.5)
FY 2011			
	Initial IPR	**Final IPR**	**Change**
Power	216.9	208.1*	(8.8)

Non-Federal Debt Service

FY 2010			
	Initial IPR	**Final IPR**	**Change**
Power	556.2	556.2*	0
FY 2011			
	Initial IPR	**Final IPR**	**Change**
Power	577.1	577.1*	0

*These are a very preliminary estimates provided for information only. The final amount will be determined in the rate case and could be considerably different due to such things as updated actual 2008 data.

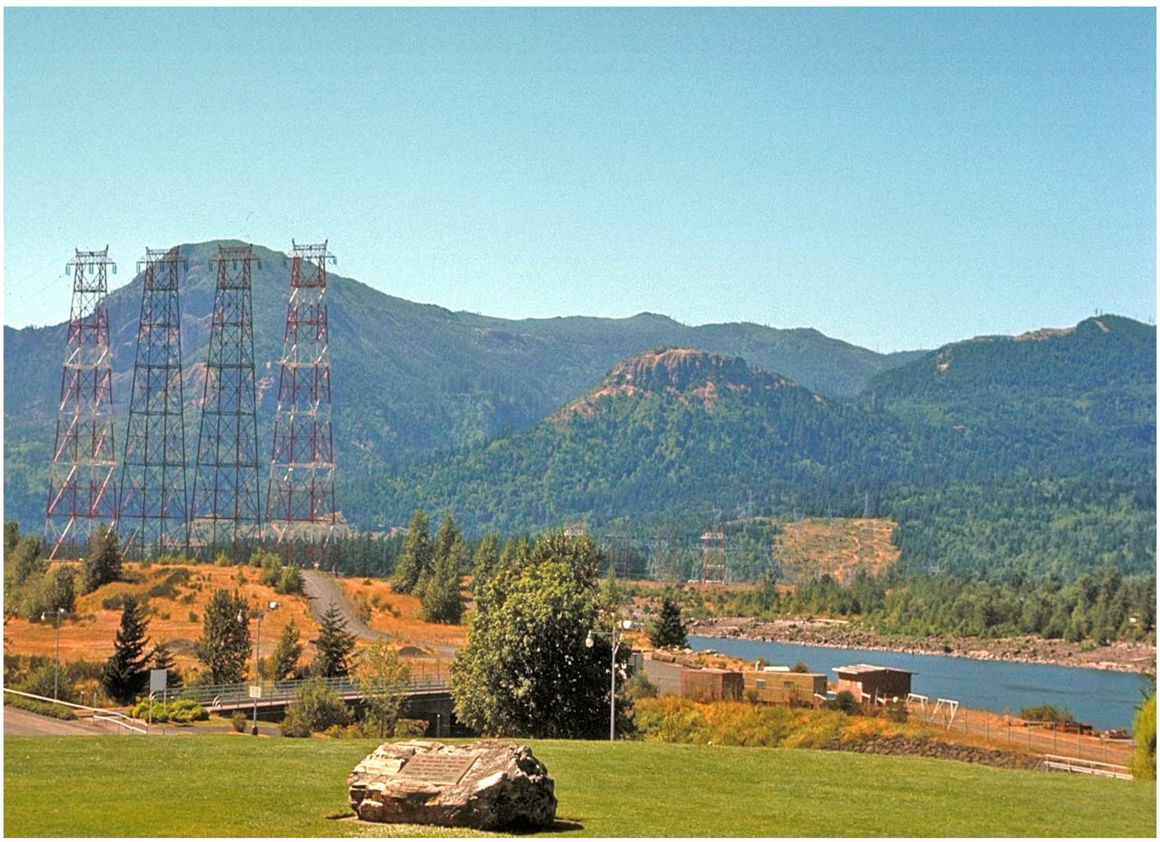
Decision: Changes since the initial IPR numbers reflect the decisions described above related to the decreased Conservation capital for FY 2010 and 2011. Other changes that affect the current estimates are revised estimates of FY 2008 investments and revised reserves estimates resulting in different interest earnings assumptions. The final levels of these forecasts will be determined in the final rate proposal.

M. DEBT MANAGEMENT

Debt management issues are not decided in the IPR. BPA's development of assumptions and decisions on debt management are rate case issues and will be discussed in that forum. However, levels of new capital investment are an important driver of the capital recovery costs in the rate case, and new capital spending is within the scope of the IPR, as discussed above, BPA believes it is important to show the impact of past and future debt management decisions in the IPR since they impact power rates. This IPR final report is intended to portray BPA's current thinking on these issues; it does not make any decisions associated with debt management issues other than new capital spending levels.

Section 3

TRANSMISSION



FY 2010-11 Transmission Expense Summary

$ thousands

Transmission Description	Initial IPR FY 2010	Final IPR FY 2010	Change FY 2010	Initial IPR FY 2011	Final IPR FY 2011	Change FY 2011
Transmission Operations	**120,405**	**123,084**	**2,679**	**122,661**	**125,434**	**2,773**
System Operations	56,586	56,573	(13)	57,511	57,497	(14)
Scheduling	10,308	9,423	(885)	10,784	9,868	(916)
Marketing	18,836	19,500	664	19,538	20,225	687
Business Support (Including Internal Support)	34,675	37,588	2,913	34,828	37,844	3,016
Transmission Maintenance	**125,717**	**125,896**	**179**	**130,687**	**130,873**	**186**
System Maintenance	121,919	122,099	180	126,691	126,877	186
Environmental Operation	3,797	3,797	0	3,996	3,996	0
Transmission Engineering	**26,503**	**26,500**	**(3)**	**28,014**	**28,011**	**(3)**
Agency Services	**62,640**	**58,779**	**(3,861)**	**62,936**	**58,940**	**(3,996)**
Post-Retirement Contribution	**15,598**	**15,598**	**0**	**16,071**	**16,071**	**0**
Transmission Acquisition/Ancillary Services (3rd Party Sources)	**18,359**	**18,371**	**12**	**18,359**	**18,371**	**12**
Other Income, Expenses and Adjustments	**(2,000)**	**(2,000)**	**0**	**(2,000)**	**(2,000)**	**0**
Non-Federal Debt Service	**5,890**	*	*	**4,690**	*	*
Interest Expense	**150,623**	*	*	**168,664**	*	*
Amortization/Depreciation	**200,810**	*	*	**211,538**	*	*
Total	**724,546**	**366,228**	**(994)**	**761,620**	**375,700**	**(1,028)**

*These will be determined in the upcoming rate case.

FY 2010-11 Transmission Capital Summary

$ in Thousands

Power Program	Initial IPR FY 2010	Final IPR FY 2010	Change FY 2010	Initial IPR FY 2011	Final IPR FY 2011	Change FY 2011
Main Grid Projects*	155,905	150,587	(5,318)	221,346	209,346	(12,000)
Area & Customer Service Projects	31,714	31,714	0	6,256	6,256	0
Upgrades & Additions**	91,108	95,710	4,602	107,471	112,585	5,114
System Replacement Projects	134,494	134,494	0	138,423	138,423	0
Environment Projects	5,530	5,530	0	5,752	5,752	0
Customer Financed/Credits	90,165	90,165	0	102,287	102,287	0
Total Indirect Capital***	86,100	87,442	1,342	88,696	96,243	7,547
17% Lapse Factor	(89,551)	(100,249)	(10,698)	(101,324)	(103,773)	(2,449)
Total Capital	505,465	495,393	(10,072)	568,907	567,119	(1,788)

*Re-spread of I-5 Corridor
**Security Enhancements
***Change in AFUDC/Corp OH

A. TRANSMISSION OPERATIONS

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
120.4	123.1	2.7
FY 2011		
Initial IPR	**Final IPR**	**Change**
122.7	125.4	2.8

Transmission Operations consists of four separate programs: Systems Operations; Transmission Scheduling; Transmission Marketing; and Business Support.

- System Operations include technical operations, substation operations, control center support, and power system dispatching.
- The Scheduling program includes expenses for reservations, pre-scheduling, real-time scheduling, scheduling after-the-fact (ATF), and technical support.
- The Marketing program contains expenses for transmission sales, contract management, and marketing business strategy and assessment.
- Business support includes expenses for logistics services, aircraft services, and the Agency Services costs that provide support to the programs and organizations within Transmission Services and are direct-charged to Transmission.
- Although programs have increased in scope and responsibility, the internal operations costs have been held virtually flat for seven years. Increases reflect the IT, Supply Chain, Legal, Financial and other activities necessary to achieve the programs described above.

Changes in this area are strictly shifts from other areas. Increases of $3.9 million in FY 2010 and $4.0 million in FY 2011 are a result of costs related to Office of Workers' Compensation being moved from Transmission Agency Services to Transmission Operations. This increase is somewhat offset as a result of reorganizations that were not reflected in the initial IPR and are reflected in the final IPR. These reorganizations result in a slight shift in allocated costs of $1 million from Transmission internal costs to Power internal costs.

B. TRANSMISSION MAINTENANCE: SYSTEM MAINTENANCE AND ENVIRONMENTAL OPERATIONS

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
125.7	125.8	0.1
FY 2011		
Initial IPR	**Final IPR**	**Change**
130.7	130.8	0.1

Maintenance consists of technical training, heavy mobile equipment maintenance, maintenance costs for system management, joint cost, power system control, system protection control, transmission line and substation.

The slight change in this area is due to reorganizations and is offset elsewhere in Transmission.

C. TRANSMISSION ENGINEERING

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
26.5	26.5	0
FY 2011		
Initial IPR	**Final IPR**	**Change**
28.0	28.0	0

Engineering consists of: the research and development program; transmission system planning and analysis; regional association fees and costs associated with cancelled capital projects and inventory adjustments.

Comments Received on Transmission Expenses Generally:

- Tacoma Power expressed concern about the rate of increase in program spending. BPA should find ways to reduce them to more acceptable levels.
- ATNI suggested that BPA should provide more information on the cost components for how these cultural resources responsibilities (for Transmission Services) will be met for FY 2009 and to elaborate on the tribal consultation/coordination components related to these costs.

Response: As noted in workshops, Transmission operating costs are increasing due to a myriad of new requirements being placed on BPA including: mandatory reliability, environmental and tariff requirements; integration of wind resources; increased demand for capacity; the need to sustain aging transmission assets; and the need to renew investment in areas that have been historically under-invested. We believe that without these increases, BPA's ability to provide reliable transmission could seriously be jeopardized. Three EPIP's have been or are being implemented that are having significant positive impacts on our processes, addressing Performance Management, "Plan, Design, Build", and Supply Chain. However, the need to expand the system, address increased reliability standards and respond to the other FERC regulatory measures, such as Order 890, results in more costs, including not only capital investment and increased operations and maintenance costs, but additional support costs as well. The increased level of support needed from IT, Supply Chain, legal, and finance put additional pressure on our spending levels.

From 2009 to 2010 Transmission Maintenance increased by 13 percent. From 2010 to 2011 the rate of increase in these programs slowed to 4 percent. The largest FY 2009 to

FY 2010 increases in Transmission Maintenance are in the areas of Non-Electric Maintenance and Right-Of-Way (ROW) Maintenance.

Non-Electric Maintenance is increasing due to the implementation of the Facilities Asset Management Plan. The Facilities Asset Management Plan specifies a program of addressing the deferred maintenance on BPA's non-electric facilities identified during recent condition assessments. This has been an area that BPA has historically cut back spending but this work can no longer be deferred. The Facilities Asset Management Plan will bring BPA's facilities up to acceptable maintenance levels over the next 6 to 7 years with a focus in FY 2010 and 2011 on addressing critical deficiencies impacting personnel safety and transmission operations. Examples of critical life safety projects include the installation of lighted exit signs, emergency egress lighting, and panic hardware on doors. The program also places priority on addressing reliability issues on facility systems and equipment that are inadequate or have exhibited failures such as failing HVACs and roofs vital to the protection of the transmission equipment.

With the ROW Maintenance program, the primary driver for this sub-program is WECC/NERC compliance. The newly developed standards went into place in June 2007, making compliance with NERC's regulations for controlling vegetation along transmission line rights-of-way mandatory. BPA experienced a tree contact in 2007 and another in June of 2008. We provided our mitigation plans to WECC, noting that we were confident we could maintain compliance with the standards. As the largest transmission owner in the Pacific Northwest and a critical partner in the Western Interconnection, BPA understands the serious consequences vegetation threats pose. We take full responsibility for ensuring the reliability of our transmission grid, and we are taking unprecedented measures to identify and remove vegetation threats along our transmission lines to ensure we are in strict compliance with the vegetation standards systemwide. As a result, our expenses for right-of-way maintenance need to increase.

For Transmission Operations, the overall increase from FY 2009 to FY 2010 was 5 percent. From FY 2010 to FY 2011 the increase was less than inflation.

The drivers for the increases in Transmission Operations are:

- Mandatory reliability compliance; documentation and reporting have increased substantially.
- Increased workload to support wind integration.
- Increased demand for transmission capacity.
- Increased training needs due to constant influx of new equipment types, models, and technologies.

The increased funding will be used to:

- Provide tools to manage the system, e.g., automate remedial action scheme (RAS) arming, voltage control, and short-term wind forecasting.
- Increase management of conditional firm initiatives.
- Increase dynamic scheduling capability.

- Recognize opportunities to create more efficient inspection, documentation and switching processes and practices through internal and external benchmarking.
- Develop recruitment efforts that can supplement the success in the Apprenticeship Program.
- Digital communication to major federal projects and neighboring Balancing Authorities (BAs).

With regard to cultural resources, in some instances transmission maintenance activities may potentially impact cultural resources but are much less likely to do so than new projects where we are constructing on previously undisturbed ground. Most maintenance activities occur on previously disturbed ground where any cultural resources are likely to be known. However, if maintenance crews are performing work that may include previously undisturbed ground (e.g., creating a new section of access road, building a new culvert, etc.), then the Regional Natural Resource Specialist will contact the potentially affected Tribe(s) and/or contact BPA's Tribal Affairs to coordinate communication. Communication would occur similarly as described in the capital section on page 47.

Proposed spending has been adequate to cover all cultural resource preservation issues related to transmission activity to date.

Decision: Overall Transmission Operations and Maintenance expenses were reduced by $1.0M per year for FY 2010 and 2011. This minor reduction was the result of efficiency related reorganizations and allocation of Agency Services costs. Additionally, there is a shift in OWCP costs from Transmission Agency Services to Transmission Operations.

D. AGENCY SERVICES/PENSION/POST-RETIREMENT BENEFITS

$ millions

Expense

FY 2010		
Initial IPR	**Final IPR**	**Change**
78.2	74.4	(3.9)
FY 2011		
Initial IPR	**Final IPR**	**Change**
79.0	75.0	(4.0)

- Agency Services in Transmission is the equivalent cost category as internal operating costs in Power Services. These Agency Services costs provide support to the programs and organizations within Transmission Services and are either allocated or direct-charged to Transmission.
- Although programs have increased in scope and responsibility, the internal operations costs have been held virtually flat for seven years. Increases reflect the IT, Supply Chain, Legal, Financial and other activities necessary to achieve the programs described above.

- Decreases of $3.9 million in FY 2010 and $4.0 million in FY 2011 are as a result of costs related to Office of Workers' Compensation being moved from Transmission Agency Services to Transmission Operations.

Decision: No change to Agency Services Costs other than to reflect moving the OWCP costs from Transmission Agency Services to Transmission Operations.

E. TRANSMISSION CAPITAL

$ millions

FY 2010		
Initial IPR	**Final IPR**	**Change**
505.5	495.4	(10.1)
FY 2011		
Initial IPR	**Final IPR**	**Change**
568.9	567.1	(1.8)

Transmission capital is made up of four categories: Main Grid, Area and Customer Service, Upgrades and Additions, and Environment. Main Grid consists of major network reinforcements including McNary-John Day, Big Eddy and I-5 corridor. Area and Customer Service projects, and Upgrades and Additions assure that BPA meet's reliability standards and contractual obligations to its customers for serving load. The Capital Environment program addresses regulatory and liability issues at facilities likely to be adversely affected by water and environmental resources.

Comments Received:

- The Joint Public Power group appreciated the development of an asset management program to set priorities based on condition and risk.
- Tacoma Power commented that too much is planned in the early years of the construction program. Cost levelizing should be performed over the next few years. Given the shortage of line construction personnel, we question if the work can actually be accomplished or that BPA will pay premium prices for labor.
- The Joint Public Power group supports BPA's efforts to make investments needed for reliability. Investments should not be made unnecessarily. Given the large increases in the capital program, BPA should delay projects in future periods if it can be done without significant risk to reliability or load service.
- CRITFC does not support any reductions that reduce system reliability.
- PPC renews its request to meet with Transmission Services regarding its capital budget prior to that budget's inclusion in the OMB budget.

Response: As noted in IPR workshops, the transmission capital forecast represents increases that are necessary to meet several important pressures. The forecast is based on in-depth evaluation, assessment and prioritization as part of asset management planning.

Several comments indicate concerns that the capital program is front-loaded. The primary concern is the rate impact in FY 2010-2011; some utility customers would like it levelized to defer some costs out to FY 2012-2013. A secondary issue is Transmission's ability to staff the significant increase in work and the accompanying costs associated with contracting work out. There were concerns that the present labor shortage for line construction personnel will not only make it difficult to complete the capital program, but also the market premium for contract labor will push the capital program up.

Given the significant increase in the forecasted capital program and the labor shortage concerns raised in comment, it may be that more of a ramp-up period will be required. A larger lapse factor than proposed in the initial IPR forecast would recognize that possibility. The application of a 17-percent lapse factor, increased from the 15-percent lapse factor in the initial IPR, to the FY 2010-2011 period and reshaping the timing of the I-5 corridor project to reflect a more likely and achievable schedule has the affect of levelizing the program to some extent. It is expected that in 2012 and beyond there would be no lapse factor applied. In addition, the revenue requirement impacts of the capital program (depreciation, non-federal debt service, and net interest expense) in 2010 and 2011 are primarily from the 2008-2009 rate period. Likewise, the 2010 and 2011 capital program impacts the 2012 and 2013 capital program.

Transmission is currently looking at a number of ways to supplement and outsource needed human and construction resources. Major supply contracts for material and labor are being implemented. Coordination of projects with neighboring utilities will be required to maintain overall competitive pricing for the region.

Line construction personnel continue to be in high demand throughout the western U.S. BPA has joined a consortium of utilities in the West to examine best practices for construction employees, engineers, and materials. All three are in high demand and given our multi-year work plans we anticipate working through many resources to ramp-up accordingly. In addition, since we are planning our asset management programs for 3-5 years, we will be able to give contractors ample time to spread their workload to achieve the necessary upgrades.

Contract labor prices remain competitive in the Northwest. Since we currently have four major contract suppliers, we hope to maintain competitive pricing. Currently much of our work is done with in-house labor supplemented with crew members from contractors. Engineering, Procurement and Construction (EPC) or turnkey contracts will also be used to meet the high demand of construction labor. As we monitor all bid awards against in-house labor costs we will strive to contain our overall costs.

As mentioned in the June 30th technical workshop on Transmission's Asset Plan, Transmission is in catch-up mode, due to aging infrastructure and the capital program is filled with time critical investments, e.g. wood pole, spacers and breaker replacement programs, which make it very difficult to levelize the capital program.

Based on an assessment of FY 2009 new projects, one half of new starts are replacement projects needed to support the aging infrastructure. The other half of our new starts are nondiscretionary; nondiscretionary projects which include emergency replacements, mandatory replacements/upgrades/additions, and tariff generated projects.

These time critical projects are defined for FY 2009 capital as follows:

- Replace critical failed equipment or operational function. Funding needed to replace failed equipment and for operational functions that is critical to the reliable operation of the BPA transmission system. Examples include: failure of a power transformer; failure of a line protective relay; failure of station or communication batteries; major component failure of a Remedial Action Scheme; failure of a transmission line circuit; failure of a control system like SCADA.

- Mandatory replacements /upgrades/additions. Funding for projects to mitigate violations or resolve non-compliance or prevent non-compliance of federal law, including regulatory requirements or standards, such as FERC, NERC, environmental, and OSHA. The project submittal identifies the statute, requirement, or standard, including the specific section or clause,that applies and states why the project must start in the fiscal year in which it is reviewed.

- Tariff Generated Projects. Funding for projects in response to a Transmission Service Request, Generation Interconnection Request or Line/Load Interconnection Request made pursuant to BPA's OATT (Tariff).

    1) 100% Customer Financed/BPA owned Projects: Funding for all customer-financed projects with executed agreement. The project submittal identifies the specific customer agreement that applies and states why the project must start in the fiscal year in which it is reviewed.

    2) Network Open Season Projects: Funding for projects developed in response to the Network Open Season. The project submittal identifies the specific customer agreements that apply, the PTSA (contract) conditions have been satisfied and states why the project must start in the fiscal year in which it is reviewed.

    3) NT Projects: Projects required to accommodate current NT load and forecasted NT load growth. The project submittal identifies the specific customer agreement that applies and states why the project must start in the fiscal year in which it is reviewed.

In response to earlier customer requests to meet with Transmission Services regarding its proposed capital spending prior to the development of the Federal budget, the Agency held the Capital Planning Review as an interim step aimed at giving the stakeholders a consolidated view of and input into BPA's capital investments. To accomplish this, BPA combined the capital review processes for the Power Services and Transmission Services. Through the Capital Planning Review, BPA involved stakeholders in capital management decisions, giving stakeholders the opportunity to influence how the agency makes capital investments that affect future power and transmission rates. Proposed spending estimates were presented for a five-year period (in response to customer comments that a longer horizon is necessary for capital). All capital projects were addressed including projects that have not yet been approved (new starts) and capital investments that are expected to be placed into service during the upcoming rate period.

As previously noted, BPA held extensive discussions with customers and other stakeholders to develop approaches to provide regional transparency and accountability for BPA cost management efforts. As a result, BPA initiated a new process this year for regional stakeholders to engage BPA on planned program spending levels that will form the basis for input to both Power Services and Transmission Services rate setting. The overall process is the Integrated Business Review (IBR) which consists of two major sub-processes: 1) the IPR and 2) the Quarterly Business Review (QBR).

For Cultural Resources, once a transmission project is in the final planning stages and we are ready to begin the environmental work, BPA sends written notification to each of the potentially affected tribes. We typically follow up with phone calls to the Cultural Resources Manager, Natural Resources Manager, and THPO. In the notification we offer formal consultation and by phone call, offer to meet at the staff level to discuss the proposed project and any issues they might have. If more than one tribe may be impacted, we typically request that one tribe represent the affected tribes as the lead tribe. Ongoing discussions are conducted with the lead Tribe which has the responsibility to inform the other tribes of any issues. The Project Manager, Environmental Lead, Tribal Account Executive (and others as appropriate) will meet periodically at the staff level to keep tribal staff informed (we send them letters as well, to keep them informed) and offer to meet with any tribal council members, as tribal staff deem appropriate.

During the estimating phase, BPA's Tribal Affairs provides an estimate of costs, typically for tribal monitoring during construction, which is included in the approved capital project proposal. The lead Tribe may share with us any cultural resource issues around the proposed project route and we try to make adjustments to avoid cultural resource sites. At times, we may uncover cultural resources that neither BPA nor a tribe was aware of (e.g., Decatur Island burial site), at which point work is stopped. BPA must then assess what is appropriate and required to preserve the resource. Any needed funding amounts goes back through the capital budget group, but in every case money is added to mitigate for cultural resource preservation (e.g., in the case of Decatur Island, over $1.5 million was added to the capital project proposal). BPA's relationship with tribes in the Pacific Northwest is important and is conducted on a government-to-government level, which ensures that matters such as cultural resource preservation is respected. Project Managers, Environmental Leads and Tribal Affairs work proactively with all potentially affected tribes on any proposed Transmission project.

Decision: BPA believes that the forecasts for capital investment do not include any "unnecessary" work, and that the schedule is based on sound assessment and prioritization of the work that is necessary. However, as suggested in comments, BPA has reviewed the timelines for its capital Transmission programs. BPA has determined that the timing of the I-5 Corridor project as proposed in the initial IPR is likely too optimistic and that an adjustment to the schedule is appropriate. For that reason, the large investment planned for FY 2011 will be moved to FY 2012. Additionally, in recognition of the difficulty in implementing such a large increase in the capital program, as pointed out in comments, the 15-percent lapse factor applied to all Transmission capital in the initial IPR forecasts has been increased to 17 percent for all Transmission capital.

COST DECISIONS TO BE MADE AS PART OF THE RATE CASE

The following section provides information on areas for which the costs will be determined in the FY 2010-2011 rate proposal. They have been included in the IPR to provide an opportunity for participants to understand the basis for these costs.

F. TRANSMISSION ACQUISITION AND ANCILLARY SERVICES

$ millions

FY 2010		
Initial IPR	**Final IPR**	**Change**
18.4	18.4*	0

FY 2011		
Initial IPR	**Final IPR**	**Change**
18.4	18.4*	0

Includes 3rd party only

***** The actual amount will be determined in the Final Rate Proposal.

G. TOTAL NET INTEREST, AMORTIZATION/DEPRECIATION AND NON-FEDERAL DEBT SERVICE

$ millions

Net Interest

FY 2010			
	Initial IPR	**Final IPR**	**Change**
Transmission	150.6	151.1*	
FY 2011			
	Initial IPR	**Final IPR**	**Change**
Transmission	168.7	168.6*	

Amortization/Depreciation

FY 2010			
	Initial IPR	**Final IPR**	**Change**
Transmission	200.8	200.8*	0
FY 2011			
	Initial IPR	**Final IPR**	**Change**
Transmission	211.5	211.5*	0

Non-Federal Debt Service

FY 2010			
	Initial IPR	**Final IPR**	**Change**
Transmission	5.9	5.9*	0
FY 2011			
	Initial IPR	**Final IPR**	**Change**
Transmission	4.7	4.7*	0

*These are a very preliminary estimates provided for information only. The final amounts will be determined in the rate case and could be considerably different due to such things as updated actual 2008 data.

Decision: Changes since the initial IPR numbers reflect the decisions described above related to the change in the planned schedule for construction of the I-5 corridor project, and the increased lapse factor applied to Transmission capital. The changes in capital result in a small reduction in interest which is offset by a reduction in AFUDC.
Other changes that affect the current estimates are revised estimates of FY 2008 investments and revised reserves estimates resulting in different interest earnings assumptions. The final levels of these forecasts will be determined in the final rate proposal.

H. DEBT MANAGEMENT

Debt management issues are not decided in the IPR. Decisions and assumptions on debt management are rate case issues and will be discussed in that forum. However, BPA believes it is important to show in the IPR the impact of past and future debt management decisions since these impact power rates. This IPR final report is intended to portray BPA's current thinking on these issues; however it does not make any decisions associated with debt management issues.

BPA's debt management process is largely driven by actual and forecasts of future capital investments in the FCRPS. Management of this program entails comprehensive review of options for reducing debt service costs based on assumptions about capital spending, interest rate yield curves, and retaining access to capital. However, the primary driver of costs in this area is capital spending levels. The IPR includes discussion on these items because it is important for participants to understand the implications of past debt management decisions and proposed capital spending levels. That said, review during the IPR has led to some changes, the impacts of which are estimated here. The levels for these cost categories may be different in the Final Rate Proposal.

Section 4
AGENCY SERVICES

AGENCY SERVICES

Agency Services include direct program support costs as well as general and administrative costs. These activities are integral to and in support of the work described in the Power and Transmission sections. The costs are distributed to and embedded in the Power and Transmission costs.

Some of the larger programs and their drivers are:

- Supply Chain's spending is driven by the programmatic levels of Transmission O&M and construction, Fish and Wildlife, Energy Efficiency, Technology Innovation, and Workplace Services (non-electric facilities build, repair and maintenance), and the agency's supplemental labor force and contract services requirements.
- General Counsel supports BPA programs through legal advice and representation.
- Internal Audit supports governance and serves BPA managers through audits, reviews, analyses, and other services.
- ColumbiaGrid was created to promote regional transmission planning in response to Federal Energy Regulatory Commission (FERC) Order 890.
- Finance provides general accounting and financial reporting, cash management, Treasury and third- party financing, accounts payable and receivable services, rate case revenue requirement development and support, financial planning, Agency budget development and support and Agency cost management support.
- Information Technology proposed spending reflects implementation of system enhancements to meet emerging business requirements and to support efficiencies in organizations across the Agency; implementing changes due to mandatory regulation such as Federal Information Security Management Act and OMB Circular A123; and maintaining the reliability of hardware through maintenance and refresh.
- The Security and Emergency Response program is designed to ensure the protection of BPA's workforce, physical and electronic assets and support the reliability of BPA's operations and services to the Pacific Northwest.
- HCM's proposed spending reflects both the significant EPIP savings and the resources to deliver the full range of HCM activities including labor relations, employee relations, hiring and recruiting, training, benefits, personnel policy development and management, etc.
- Workplace Services consists of facilities (HQ and Ross O&M and non-electric facilities including field office facilities), leases, space management, office services, printing and mail services.

Comments Received:

- Tacoma Power commented that BPA should not initiate any R&D before customers can review the projects. Customers should be involved in the Technology Confirmation/Innovation Council and have access to reports.

- Tacoma Power also noted that total internal agency costs are increasing by 39.3%. BPA should review these costs and find ways to reduce them to more acceptable levels (inflation or less).
- The Joint Public Power group commented that [Agency Services] spending increases should be held to the rate of inflation.

Response: Regarding Agency Services costs in general: Many of the Efficiency Project Improvement Program (EPIP) savings have been achieved in Agency Services, including Human Capital Management, Information Technology, and Public Affairs. Several of the EPIPs also recommended process improvements that resulted in the consolidation of many functions (from the Business Units to Agency Services), including Supply Chain, Metering and Billing, Load Forecasting, and Contract Administration. Finance also experienced a consolidation of business and management support from Power and Transmission to a central group. These consolidations have lead to a change to Agency Services costs, making them appear higher than if consolidation had not occurred.

Power and Transmission programs and projects are significant drivers of Agency Services costs. Growth in existing programs and/or new initiatives has resulted in increased demand for Agency Services supporting activities. Some of the most significant power and transmission program changes and their impacts on Agency Services are:

- Supply Chain's spending is driven by the programmatic levels of Transmission O&M and construction, Fish and Wildlife, Energy Efficiency, Technology Innovation, Workplace Services (non-electric facilities build, repair and maintenance), and the agency's supplemental labor force and contract services requirements. The FY 2010 and FY 2011 proposed spending estimates have fully incorporated the efficiency savings from the Supply Chain and Plan-Design-Build EPIPs resulting from the Work Planning and Scheduling System and the "80 percent stable work plan" for transmission. Other pressures are the redesign of inventory and purchasing processes, internal controls, and performance to ensure compliance with Agency Master Lease initiative.
- Workplace Services consists of facilities (HQ and Ross O&M and asset management), leases, space management, office services, printing, and mail services. The overall trend for Workplace Services' base program is to stay level with the exception of the new facilities asset management program. Condition assessments conducted as part of Facilities Asset Management (FAM) plan determine current risk exposure. Increased proposed funding is included to address backlog of facilities-related deferred maintenance.
- Information Technology spending was reduced before all of the efficiencies needed to support the reductions were completed; realization of the efficiencies requires expenditure of expense dollars. Pressures include:
  - Capital projects implement business units Enterprise Process Improvement Program initiatives which provide business units with savings while IT funds ongoing expense support tail. Expense support tails need to be funded as capital projects are approved. Provide automated solutions to support wind integration

  - Providing automated solutions to support Regional Dialogue.
  - Responding to emerging cyber threats (e.g. spam filters, whole disk encryption to protect Personal Identifying Information)
  - Introducing and leveraging emerging technologies (e.g. hierarchical storage, virtualization/multi-cores, IPv6)

- General Counsel’s forecast is driven by increased need for legal services in transmission due to increased investments and Transmission Service Agreements, resumptions of the Residential Exchange Program (REP) with attendant legal review, increases in Fish and Wildlife programs, new reliability standards, and compliance requirements.
- Customer Support Services program levels reflect new workload associated with implementation of increasingly complex Regional Dialogue contracts, the necessity of administering existing power subscription agreements in parallel with preparing for implementing Regional Dialogue contracts, and increased BPA data and forecasting requirements for loads, resources and REP, all requiring enhancements to billing, contracts and load forecasting systems. The impacts of specific initiatives such as WREGIS, FERC Order 890 implementation, Resource Program, etc., are not specifically known, but are expected to be addressed within the forecasted levels of FTE and budgets.
- Finance’s expense level as increased primarily due to the consolidation of staff from Power and Transmission. FY 2010-2011 cost increases are slightly higher than inflation to allow for increased financing and accounting support of growing Power and Transmission activities. Finance provides general accounting and financial reporting, cash management, Treasury and third- party financing, accounts payable and receivable services, rate case revenue requirement development and support, financial planning, Agency budget development and support and Agency cost management support.
- Growth in the Security and Emergency Response program is limited to capital spending as security has increased at Headquarters and field sites. This program is designed to ensure the protection of BPA’s workforce, physical and electronic assets and support the reliability of BPA’s operations and services to the Pacific Northwest.

No comments were received in the IPR process concerning the Northwest Power and Conservation Council proposed spending agreement. The Council’s proposal for FY 2010 is the same, $9.683 million, as presented in the IPR workshop. The Council’s proposal for FY2011 is $9.934 million, which is $73 thousand higher than the IPR workshop. The Council received no comment on the proposed spending agreement during the Council’s public process.

The proposed Agency Services program levels are essential to the accomplishment of business unit and agency initiatives.

Regarding BPA's Technology Innovation program, the Research and Development (R&D) program is driven by a strategic need to focus on solutions to technology related business challenges. Our research agenda is described in a set of publicly available technology roadmaps easily accessed from this link on BPA's home page (http://www.bpa.gov/corporate/business/innovation/). As they become available, research results are also posted to that web page.

Customer review of our research agenda, as expressed in our technology roadmaps, is welcome at any time. Roadmaps are updated periodically to address changes in the current state of technology and changes in BPA's business challenges. Comments on our roadmaps should be addressed to BPA Technology Innovation Office - DE-3, PO Box 3621, Portland Oregon 97208-3621.

We are considering a means for customer involvement in our Technology Confirmation / Innovation Council. To that end we have met with the executive leadership of several utilities including Tacoma Power. To date, no utility has expressed an interest in helping guide BPA's R&D agenda. We will continue to explore means of more fully engaging customers. Terry Oliver, BPA's Chief Technology Innovation Officer, is available to brief any party on our R&D effort. Please contact your BPA Account Executive.

Decision: No change to Agency Services total program levels as presented in the IPR workshops and as reflected in the Council’s proposed spending agreement.

APPENDIX B

Repayment Study Tables

DESCRIPTION OF REPAYMENT PROGRAM TABLES

Table 11 shows the amortization results from the Transmission revised repayment studies for FYs 2010 and 2011, summarized by year for both due and discretionary bonds and appropriations.

Tables 12, A through F, and Tables 13, A through F, show the results of the Transmission repayment studies for FYs 2010 and 2011, respectively, using revenues from current rates. Table 13 provides the application of amortization through the repayment period for transmission based upon the revenues forecast using revised rates.

Tables 12A and 13A display the repayment program results for transmission for FYs 2010 and 2011. The first column shows the applicable fiscal year. The second column shows the total investment costs of the transmission projects through the cost evaluation period. *See* Documentation for Revenue Requirement Study, TR-10-E-BPA-01A, Chapter 3. In the third column, forecasted replacements required to maintain the system are displayed through the repayment period. *Id* at Chapter 8. The fourth column shows the cumulative dollar amount of the transmission investment placed in service. This is comprised of historical plant-in-service, planned replacements and additions to plant through the cost evaluation period, and replacements from the end of the cost evaluation period to the end of the repayment study period. In these studies all additional plant is assumed to be financed by bonds. The fifth column displays scheduled amortization payments for transmission for each year of the repayment period. Unamortized transmission obligations, shown in the next column, are determined by taking the previous year's unamortized amount, adding any replacements, and subtracting scheduled amortization. The last column shows the unamortized obligations as determined by a term schedule (if all obligations were paid at maturity and never early). It should be noted that unamortized obligations are always less than the term schedule, indicating that planned repayments are in excess of repayment obligations, thereby satisfying repayment requirements. (The total of Unamortized Investment need not be zero at the end of the repayment period because of the replacements occurring subsequent to the cost evaluation period.)

Tables 12B and 13B display planned principal payments by fiscal year for Federal transmission obligations. Shown on these tables are the principal payments associated with appropriations and bonds.

Tables 12C and 13C display planned principal payments by fiscal year for non-Federal transmission obligations. Shown on these tables are the principal payments associated with the various non-Federal funding sources.

Tables 12D and 13D show the planned interest payments by fiscal year for Federal transmission obligations. Shown on these tables are the interest payments associated with appropriations and bonds.

Tables 12E and 13E display planned interest payments by fiscal year for non-federal transmission obligations. Shown on these tables is the interest payments associated with the various non-Federal funding sources.

Tables 12F and 13F show a summary of the Federal and non-Federal transmission principal and interest payments through the repayment period.

Table 14 lists by year through the 35-year repayment period the application of the transmission amortization payments, consistent with the repayment studies, by project. The projected annual amortization payments on the transmission obligations are identified by the project name, in-service date, due date, and interest rate. The amount of the obligation is shown as both the original gross amount due and the net amount after all prior amortization payments.

Table 11: Application of Amortization (FY 2011)
($000s)

		A	B	C	D	E	F	G	H	I
	Date	Project	In Service	Due	Original Balance	Amount Available	Rate	Replacement?	Rollover?	Amount Amortized
1	FY 2009	BONNEVILLE POWER ADMINISTRATION	1964	2009	4,151	4,151	7.060%	No	No	4,151
2	FY 2009	BONNEVILLE POWER ADMINISTRATION	1964	2009	5,738	5,738	7.060%	No	No	5,738
3	FY 2009	ENVIRONMENT	2006	2009	20,000	20,000	5.050%	No	No	20,000
4	FY 2009	BPA PROGRAM	2006	2009	20,000	20,000	5.050%	No	No	20,000
5	FY 2009	BPA PROGRAM	2005	2009	27,010	27,010	3.750%	No	No	27,010
6	FY 2009	BONNEVILLE POWER ADMINISTRATION	1970	2015	64,977	64,977	7.270%	No	No	25,385
7	FY 2009	BONNEVILLE POWER ADMINISTRATION	1970	2015	7,995	7,995	7.270%	No	No	7,995
8	FY 2009	BONNEVILLE POWER ADMINISTRATION	1970	2015	24,412	23,551	7.270%	No	No	23,551
9	FY 2009	BONNEVILLE POWER ADMINISTRATION	1973	2018	33,788	33,788	7.280%	No	No	33,788
10	FY 2009	BONNEVILLE POWER ADMINISTRATION	1973	2018	21,656	5,041	7.280%	No	No	5,041
11	**Subtotal**		-	-	**$229,727**	**$212,251**	-	**No**	**No**	**$172,659**
12										
13	FY 2010	BONNEVILLE POWER ADMINISTRATION	1965	2010	3,706	3,706	7.090%	No	No	3,706
14	FY 2010	BONNEVILLE POWER ADMINISTRATION	1965	2010	7,248	78	7.090%	No	No	78
15	FY 2010	ENVIRONMENT	2001	2010	30,000	30,000	6.050%	No	No	30,000
16	FY 2010	BPA PROGRAM	2001	2010	59,932	59,932	6.050%	No	No	59,932
17	FY 2010	BPA PROGRAM	2007	2010	50,000	50,000	5.200%	No	No	50,000
18	FY 2010	BPA PROGRAM	2007	2010	25,000	25,000	5.100%	No	No	25,000
19	FY 2010	BPA PROGRAM	2006	2010	5,319	5,319	4.950%	No	No	5,319
20	FY 2010	BPA PROGRAM	2006	2010	20,000	20,000	4.950%	No	No	20,000
21	FY 2010	BONNEVILLE POWER ADMINISTRATION	1970	2015	64,977	39,592	7.270%	No	No	21,135
22	**Subtotal**		-	-	**$266,182**	**$233,627**	-	**No**	**No**	**$215,170**
23										
24	FY 2011	BONNEVILLE POWER ADMINISTRATION	1966	2011	11,830	11,830	7.130%	No	No	11,830
25	FY 2011	BONNEVILLE POWER ADMINISTRATION	1966	2011	3,049	3,049	7.130%	No	No	3,049
26	FY 2011	BONNEVILLE POWER ADMINISTRATION	1966	2011	6,647	6,353	7.130%	No	No	6,353
27	FY 2011	BPA PROGRAM	1998	2011	40,000	40,000	6.200%	No	No	40,000
28	FY 2011	BPA PROGRAM	2001	2011	25,000	25,000	5.950%	No	No	25,000
29	FY 2011	BPA PROGRAM	2008	2011	40,000	40,000	3.358%	No	No	40,000
30	FY 2011	ENVIRONMENT	2008	2011	10,000	10,000	3.151%	No	No	10,000
31	FY 2011	BPA PROGRAM	2008	2011	25,000	25,000	3.151%	No	No	25,000
32	FY 2011	BONNEVILLE POWER ADMINISTRATION	1970	2015	64,977	18,457	7.270%	No	No	18,457
33	FY 2011	BONNEVILLE POWER ADMINISTRATION	1974	2019	20,984	20,984	7.270%	No	No	6,263
34	FY 2011	BONNEVILLE POWER ADMINISTRATION	1974	2019	12,563	12,563	7.270%	No	No	12,563
35	FY 2011	BONNEVILLE POWER ADMINISTRATION	1974	2019	21,826	21,826	7.270%	No	No	21,826
36	**Subtotal**		-	-	**$281,876**	**$235,062**	-	**No**	**No**	**$220,342**
37										
38	FY 2012	BONNEVILLE POWER ADMINISTRATION	1967	2012	19,003	19,003	7.160%	No	No	19,003
39	FY 2012	BONNEVILLE POWER ADMINISTRATION	1967	2012	4,566	355	7.160%	No	No	355
40	FY 2012	BPA PROGRAM	2008	2012	25,000	25,000	3.444%	No	No	25,000
41	FY 2012	BPA PROGRAM	2008	2012	30,000	30,000	3.200%	No	No	30,000
42	FY 2012	BONNEVILLE POWER ADMINISTRATION	1974	2019	12,079	12,079	7.270%	No	No	12,079
43	FY 2012	BONNEVILLE POWER ADMINISTRATION	1974	2019	20,984	14,721	7.270%	No	No	14,721
44	FY 2012	BONNEVILLE POWER ADMINISTRATION	1975	2020	32,026	32,026	7.250%	No	No	18,447
45	FY 2012	BONNEVILLE POWER ADMINISTRATION	1975	2020	21,916	21,916	7.250%	No	No	21,916
46	FY 2012	BONNEVILLE POWER ADMINISTRATION	1975	2020	17,158	17,158	7.250%	No	No	17,158
47	FY 2012	BONNEVILLE POWER ADMINISTRATION	1975	2020	11,742	11,742	7.250%	No	No	11,742
48	**Subtotal**		-	-	**$194,474**	**$184,000**	-	**No**	**No**	**$170,421**
49										
50	FY 2013	BONNEVILLE POWER ADMINISTRATION	1968	2013	41,070	18,250	7.200%	No	No	18,250
51	FY 2013	BONNEVILLE POWER ADMINISTRATION	1969	2014	42,237	19,198	7.230%	No	No	13,224
52	FY 2013	BONNEVILLE POWER ADMINISTRATION	1975	2020	32,026	13,579	7.250%	No	No	13,579
53	**Subtotal**		-	-	**$115,333**	**$51,027**	-	**No**	**No**	**$45,053**
54										
55	FY 2014	BONNEVILLE POWER ADMINISTRATION	1969	2014	42,237	5,974	7.230%	No	No	5,974
56	FY 2014	BONNEVILLE POWER ADMINISTRATION	1976	2021	61,025	61,025	7.230%	No	No	32,322
57	FY 2014	BONNEVILLE POWER ADMINISTRATION	1976	2021	2,212	2,212	7.230%	No	No	2,212
58	**Subtotal**		-	-	**$105,474**	**$69,211**	-	**No**	**No**	**$40,508**
59										
60	FY 2015	BONNEVILLE POWER ADMINISTRATION	1976	2021	61,025	28,703	7.230%	No	No	26,634
61	**Subtotal**		-	-	**$61,025**	**$28,703**	-	**No**	**No**	**$26,634**
62										
63	FY 2016	BONNEVILLE POWER ADMINISTRATION	1976	2021	61,025	2,069	7.230%	No	No	2,069
64	FY 2016	BONNEVILLE POWER ADMINISTRATION	1977	2022	33,702	33,702	7.210%	No	No	20,185
65	FY 2016	BONNEVILLE POWER ADMINISTRATION	1977	2022	4,981	4,981	7.210%	No	No	4,981
66	**Subtotal**		-	-	**$99,708**	**$40,752**	-	**No**	**No**	**$27,235**
67										
68	FY 2017	BONNEVILLE POWER ADMINISTRATION	1977	2022	33,702	13,517	7.210%	No	No	8,004
69	**Subtotal**		-	-	**$33,702**	**$13,517**	-	**No**	**No**	**$8,004**
70										
71	FY 2018	BONNEVILLE POWER ADMINISTRATION	1977	2022	3,948	3,948	7.210%	No	No	3,948
72	FY 2018	BONNEVILLE POWER ADMINISTRATION	1977	2022	5,380	5,380	7.210%	No	No	5,380
73	FY 2018	BONNEVILLE POWER ADMINISTRATION	1977	2022	33,702	5,513	7.210%	No	No	5,513
74	FY 2018	BPA PROGRAM	2011	2046	414,465	414,465	6.930%	No	No	811
75	**Subtotal**		-	-	**$457,495**	**$429,306**	-	**No**	**No**	**$15,652**
76										

Table 11: Application of Amortization (FY 2011)
($000s)

	A	B	C	D	E	F	G	H	I
Date	**Project**	**In Service**	**Due**	**Original Balance**	**Amount Available**	**Rate**	**Replacement?**	**Rollover?**	**Amount Amortized**
FY 2019	BPA PROGRAM	2011	2046	414,465	413,654	6.930%	No	No	186,608
Subtotal		-	-	**$414,465**	**$413,654**	-	**No**	**No**	**$186,608**
FY 2020	BONNEVILLE POWER ADMINISTRATION	1975	2020	32,026	-0	7.250%	No	No	-0
FY 2020	BPA PROGRAM	2011	2046	414,465	227,046	6.930%	No	No	173,535
Subtotal		-	-	**$446,491**	**$227,046**	-	**No**	**No**	**$173,535**
FY 2021	BONNEVILLE POWER ADMINISTRATION	1976	2021	61,025	0	7.230%	No	No	0
FY 2021	BPA PROGRAM	1998	2021	72,700	72,700	4.540%	No	Yes	72,700
FY 2021	BPA PROGRAM	2011	2046	414,465	53,511	6.930%	No	No	53,511
FY 2021	BPA PROGRAM	2012	2047	152,244	152,244	6.840%	Yes	No	50,592
Subtotal		-	-	**$700,434**	**$278,455**	-	**Yes**	**Yes**	**$176,802**
FY 2022	BONNEVILLE POWER ADMINISTRATION	1977	2022	33,702	-0	7.210%	No	No	-0
FY 2022	BPA PROGRAM	2012	2047	152,244	101,652	6.840%	Yes	No	101,652
FY 2022	BPA PROGRAM	2013	2048	156,038	156,038	6.840%	Yes	No	69,614
Subtotal		-	-	**$341,984**	**$257,690**	-	**Yes**	**No**	**$171,267**
FY 2023	BPA PROGRAM	2013	2048	156,038	86,424	6.840%	Yes	No	86,424
FY 2023	BPA PROGRAM	2014	2049	159,853	159,853	6.840%	Yes	No	83,639
Subtotal		-	-	**$315,891**	**$246,277**	-	**Yes**	**No**	**$170,062**
FY 2024	ENVIRONMENT	2009	2024	4,402	4,402	4.720%	No	No	4,402
FY 2024	BPA PROGRAM	2014	2049	159,853	76,214	6.840%	Yes	No	76,214
FY 2024	BPA PROGRAM	2015	2050	163,547	163,547	6.840%	Yes	No	94,185
Subtotal		-	-	**$327,802**	**$244,163**	-	**Yes**	**No**	**$174,802**
FY 2025	BPA PROGRAM	1999	2025	59,050	59,050	6.100%	No	Yes	59,050
FY 2025	ENVIRONMENT	2010	2025	5,369	5,369	5.870%	No	No	5,369
FY 2025	BPA PROGRAM	2015	2050	163,547	69,362	6.840%	Yes	No	69,362
FY 2025	BPA PROGRAM	2016	2051	167,165	167,165	6.840%	Yes	No	60,509
Subtotal		-	-	**$395,131**	**$300,946**	-	**Yes**	**Yes**	**$194,290**
FY 2026	ENVIRONMENT	2011	2026	5,581	5,581	6.220%	No	No	5,581
FY 2026	BPA PROGRAM	2007	2026	40,000	40,000	6.200%	No	Yes	40,000
FY 2026	BPA PROGRAM	2008	2026	30,000	30,000	6.200%	No	Yes	30,000
FY 2026	BPA PROGRAM	2001	2026	50,000	50,000	6.080%	No	Yes	50,000
FY 2026	BPA PROGRAM	2016	2051	167,165	106,656	6.840%	Yes	No	70,975
Subtotal		-	-	**$292,746**	**$232,237**	-	**Yes**	**Yes**	**$196,556**
FY 2027	BPA PROGRAM	2016	2051	167,165	35,681	6.840%	Yes	No	35,681
FY 2027	BPA PROGRAM	2017	2052	170,739	170,739	6.840%	Yes	No	154,009
Subtotal		-	-	**$337,904**	**$206,420**	-	**Yes**	**No**	**$189,690**
FY 2028	BPA PROGRAM	1998	2028	50,000	50,000	6.650%	No	No	50,000
FY 2028	BPA PROGRAM	1998	2028	112,300	112,300	5.850%	No	No	112,300
FY 2028	BPA PROGRAM	2017	2052	170,739	16,730	6.840%	Yes	No	16,730
FY 2028	BPA PROGRAM	2018	2053	174,139	174,139	6.840%	Yes	No	17,331
Subtotal		-	-	**$507,178**	**$353,169**	-	**Yes**	**No**	**$196,361**
FY 2029	BPA PROGRAM	2018	2053	174,139	156,808	6.840%	Yes	No	156,808
FY 2029	BPA PROGRAM	2019	2054	177,611	177,611	6.840%	Yes	No	30,898
Subtotal		-	-	**$351,750**	**$334,419**	-	**Yes**	**No**	**$187,707**
FY 2030	BPA PROGRAM	2019	2054	177,611	146,713	6.840%	Yes	No	146,713
FY 2030	BPA PROGRAM	2020	2055	181,138	181,138	6.840%	Yes	No	39,778
Subtotal		-	-	**$358,749**	**$327,851**	-	**Yes**	**No**	**$186,490**
FY 2031	BPA PROGRAM	1998	2031	106,500	106,500	5.510%	No	Yes	106,500
FY 2031	BPA PROGRAM	2020	2055	181,138	141,360	6.840%	Yes	No	83,489
Subtotal		-	-	**$287,638**	**$247,860**	-	**Yes**	**Yes**	**$189,989**
FY 2032	BPA PROGRAM	1998	2032	98,900	98,900	6.700%	No	No	98,900
FY 2032	BPA PROGRAM	2020	2055	181,138	57,871	6.840%	Yes	No	57,871
FY 2032	BPA PROGRAM	2021	2056	184,559	184,559	6.840%	Yes	No	30,456
Subtotal		-	-	**$464,597**	**$341,330**	-	**Yes**	**No**	**$187,227**
FY 2033	BPA PROGRAM	2003	2033	40,000	40,000	5.550%	No	No	40,000
FY 2033	BPA PROGRAM	2021	2056	184,559	154,103	6.840%	Yes	No	114,767
Subtotal		-	-	**$224,559**	**$194,103**	-	**Yes**	**No**	**$154,767**
FY 2034	BPA PROGRAM	2004	2034	40,000	40,000	5.600%	No	No	40,000
FY 2034	BPA PROGRAM	2021	2056	184,559	39,337	6.840%	Yes	No	39,337
FY 2034	BPA PROGRAM	2022	2057	187,871	187,871	6.840%	Yes	No	16,114
Subtotal		-	-	**$412,430**	**$267,208**	-	**Yes**	**No**	**$95,451**
FY 2035	BPA PROGRAM	2005	2035	40,000	40,000	5.500%	No	No	40,000

Table 11: Application of Amortization (FY 2011)
($000s)

		A	B	C	D	E	F	G	H	I
	Date	Project	In Service	Due	Original Balance	Amount Available	Rate	Replacement?	Rollover?	Amount Amortized
154	FY 2035	BPA PROGRAM	2005	2035	40,000	40,000	5.400%	No	No	40,000
155	FY 2035	BPA PROGRAM	2005	2035	45,000	45,000	5.250%	No	No	45,000
156	FY 2035	BPA PROGRAM	2022	2057	187,871	171,757	6.840%	Yes	No	56,577
157	**Subtotal**		**-**	**-**	**$312,871**	**$296,757**	**-**	**Yes**	**No**	**$181,577**
158										
159	FY 2036	BPA PROGRAM	2007	2037	35,000	35,000	6.400%	No	No	34,999
160	FY 2036	BPA PROGRAM	2022	2057	187,871	115,180	6.840%	Yes	No	115,180
161	FY 2036	BPA PROGRAM	2023	2058	191,173	191,173	6.840%	Yes	No	9,457
162	**Subtotal**		**-**	**-**	**$414,044**	**$341,353**	**-**	**Yes**	**No**	**$159,635**
163										
164	FY 2037	BPA PROGRAM	2007	2037	35,000	1	6.400%	No	No	1
165	FY 2037	BPA PROGRAM	2005	2037	40,000	40,000	5.410%	No	Yes	40,000
166	**Subtotal**		**-**	**-**	**$75,000**	**$40,001**	**-**	**No**	**Yes**	**$40,001**
167										
168	FY 2038	BPA PROGRAM	2006	2038	70,000	70,000	5.470%	No	Yes	70,000
169	FY 2038	BPA PROGRAM	2023	2058	191,173	181,716	6.840%	Yes	No	53,179
170	**Subtotal**		**-**	**-**	**$261,173**	**$251,716**	**-**	**Yes**	**Yes**	**$123,179**
171										
172	FY 2039	BPA PROGRAM	2023	2058	191,173	128,537	6.840%	Yes	No	128,537
173	FY 2039	BPA PROGRAM	2024	2059	194,392	194,392	6.840%	Yes	No	37,558
174	**Subtotal**		**-**	**-**	**$385,565**	**$322,929**	**-**	**Yes**	**No**	**$166,095**
175										
176	FY 2040	BPA PROGRAM	2024	2059	194,392	156,834	6.840%	Yes	No	156,834
177	FY 2040	BPA PROGRAM	2025	2060	197,370	197,370	6.840%	Yes	No	6,909
178	**Subtotal**		**-**	**-**	**$391,762**	**$354,204**	**-**	**Yes**	**No**	**$163,743**
179										
180	FY 2041	BPA PROGRAM	2010	2045	405,094	405,094	6.790%	No	No	47,492
181	FY 2041	BPA PROGRAM	2025	2060	197,370	190,461	6.840%	Yes	No	115,104
182	**Subtotal**		**-**	**-**	**$602,464**	**$595,555**	**-**	**Yes**	**No**	**$162,595**
183										
184	FY 2042	BPA PROGRAM	2010	2045	405,094	357,602	6.790%	No	No	163,630
185	FY 2042	BPA PROGRAM	2025	2060	197,370	75,358	6.840%	Yes	No	0
186	**Subtotal**		**-**	**-**	**$602,464**	**$432,960**	**-**	**Yes**	**No**	**$163,630**
187										
188	FY 2043	BPA PROGRAM	2009	2044	277,265	277,265	5.350%	No	No	119,792
189	FY 2043	BPA PROGRAM	2010	2045	405,094	193,973	6.790%	No	No	41,832
190	**Subtotal**		**-**	**-**	**$682,359**	**$471,238**	**-**	**No**	**No**	**$161,623**
191										
192	FY 2044	BPA PROGRAM	2009	2044	277,265	157,473	5.350%	No	No	157,473
193	FY 2044	BPA PROGRAM	2010	2045	405,094	152,141	6.790%	No	No	6
194	**Subtotal**		**-**	**-**	**$682,359**	**$309,615**	**-**	**No**	**No**	**$157,480**
195										
196	FY 2045	BPA PROGRAM	2010	2045	405,094	152,135	6.790%	No	No	152,135
197	FY 2045	BPA PROGRAM	2025	2060	197,370	75,357	6.840%	Yes	No	4
198	**Subtotal**		**-**	**-**	**$602,464**	**$227,492**	**-**	**Yes**	**No**	**$152,139**

Table 12A: Transmission Investments Placed in Service (FY 2010)
($000s)

		A	B	C	D	E	F	G
	Fiscal Year	Initial Project	Replacements	Cumulative Amount in Service	Amortization	Discretionary Amortization	Unamortized Investment	Term Investment Schedule
1	2009	1,910,316	-	1,910,316	-	-	1,910,316	5,212,968
2	2010	281,667	-	2,191,983	76,899	95,760	2,019,324	5,235,036
3	2011	410,463	-	2,602,446	194,035	22,583	2,213,169	5,428,921
4	2012	-	145,191	2,747,637	161,232	46,991	2,150,137	5,360,872
5	2013	-	148,963	2,896,600	74,358	93,090	2,131,652	5,303,530
6	2014	-	152,734	3,049,334	18,250	23,936	2,242,201	5,329,354
7	2015	-	156,566	3,205,900	19,198	18,556	2,361,012	5,236,507
8	2016	-	160,313	3,366,213	-	24,003	2,497,322	5,181,433
9	2017	-	164,045	3,530,258	-	24,733	2,636,634	5,110,831
10	2018	-	167,759	3,698,017	-	5,636	2,798,757	4,891,241
11	2019	-	171,303	3,869,320	-	13,463	2,956,597	4,821,541
12	2020	-	174,891	4,044,211	-	186,501	2,944,987	4,838,980
13	2021	-	178,490	4,222,701	-	172,141	2,951,335	4,934,628
14	2022	-	181,955	4,404,656	72,700	102,468	2,958,122	5,053,346
15	2023	-	185,323	4,589,979	-	169,815	2,973,630	5,190,658
16	2024	-	188,717	4,778,696	-	168,677	2,993,670	5,379,375
17	2025	-	192,018	4,970,714	4,402	169,084	3,012,201	5,566,991
18	2026	-	195,061	5,165,775	64,419	128,534	3,014,309	5,641,750
19	2027	-	197,787	5,363,562	120,000	74,940	3,017,157	5,839,537
20	2028	-	200,150	5,563,712	-	188,720	3,028,587	6,039,687
21	2029	-	202,131	5,765,843	162,300	32,822	3,035,596	5,973,018
22	2030	-	203,568	5,969,411	-	186,971	3,052,193	6,160,864
23	2031	-	204,618	6,174,029	-	185,851	3,070,961	6,231,204
24	2032	-	205,213	6,379,242	106,500	82,780	3,086,894	6,136,417
25	2033	-	205,493	6,584,735	98,900	87,731	3,105,756	5,793,010
26	2034	-	205,504	6,790,239	40,000	114,444	3,156,816	5,328,552
27	2035	-	205,027	6,995,266	40,000	55,071	3,266,772	5,235,179
28	2036	-	204,432	7,199,698	125,000	56,429	3,289,775	5,314,611
29	2037	-	203,810	7,403,508	-	159,716	3,333,869	5,518,421
30	2038	-	203,009	7,606,517	40,004	-	3,496,873	5,686,430
31	2039	-	202,139	7,808,656	70,000	53,466	3,575,547	5,888,569
32	2040	-	201,332	8,009,988	-	166,675	3,610,204	6,089,901
33	2041	-	200,643	8,210,631	-	164,382	3,646,465	6,290,544
34	2042	-	200,138	8,410,769	-	161,991	3,684,612	6,490,682
35	2043	-	199,826	8,610,595	-	159,480	3,724,958	6,690,508
36	2044	-	199,785	8,810,380	-	160,612	3,764,131	6,890,293
37	2045	-	200,141	9,010,521	157,751	-	3,806,521	6,813,169
38	**Total**	**$2,602,446**	**$6,408,075**	**-**	**$1,645,948**	**$3,558,051**	**-**	**$208,128,558**

Table 12B: Federal Principal Payments (FY 2010)
($000s)

		A	B	C
	Fiscal Year	**Bonds**	**Appropriations**	**Total**
1	2009	67,010	105,649	172,659
2	2010	190,251	26,367	216,618
3	2011	140,000	68,223	208,223
4	2012	55,000	112,448	167,448
5	2013	-	42,186	42,186
6	2014	-	37,754	37,754
7	2015	-	24,003	24,003
8	2016	-	24,733	24,733
9	2017	-	5,636	5,636
10	2018	-	13,463	13,463
11	2019	158,358	28,143	186,501
12	2020	172,141	-	172,141
13	2021	175,168	-	175,168
14	2022	169,815	-	169,815
15	2023	168,677	-	168,677
16	2024	173,486	-	173,486
17	2025	192,953	-	192,953
18	2026	194,940	-	194,940
19	2027	188,720	-	188,720
20	2028	195,122	-	195,122
21	2029	186,971	-	186,971
22	2030	185,851	-	185,851
23	2031	189,280	-	189,280
24	2032	186,631	-	186,631
25	2033	154,444	-	154,444
26	2034	95,071	-	95,071
27	2035	181,429	-	181,429
28	2036	159,716	-	159,716
29	2037	40,004	-	40,004
30	2038	123,466	-	123,466
31	2039	166,675	-	166,675
32	2040	164,382	-	164,382
33	2041	161,991	-	161,991
34	2042	159,480	-	159,480
35	2043	160,612	-	160,612
36	2044	157,751	-	157,751
37	2045	145,788	-	145,788
38	**Total**	**$4,861,183**	**$488,605**	**$5,349,788**

Table 12C: Non-Federal Principal Payments (FY 2010)
($000s)

		A	B	C	D
	Fiscal Year	**EN**	**Schultz-Wautoma**	**Master Lease**	**Total**
1	2009	10,407	-	-	10,407
2	2010	12	-	-	12
3	2011	154	-	-	154
4	2012	41,118	-	-	41,118
5	2013	163,609	-	-	163,609
6	2014	167,654	-	-	167,654
7	2015	178,385	-	-	178,385
8	2016	176,133	-	-	176,133
9	2017	193,455	-	-	193,455
10	2018	183,731	-	-	183,731
11	2019	4,837	-	-	4,837
12	2020	19,588	-	-	19,588
13	2021	20,567	-	-	20,567
14	2022	21,592	-	-	21,592
15	2023	22,674	-	-	22,674
16	2024	17,637	-	-	17,637
17	2025	-	-	-	-
18	2026	-	-	-	-
19	2027	-	-	-	-
20	2028	-	-	-	-
21	2029	-	-	-	-
22	2030	-	-	-	-
23	2031	-	-	-	-
24	2032	-	-	-	-
25	2033	-	29,896	-	29,896
26	2034	-	89,689	-	89,689
27	2035	-	-	-	-
28	2036	-	-	15,255	15,255
29	2037	-	-	134,997	134,997
30	2038	-	-	49,063	49,063
31	2039	-	-	-	-
32	2040	-	-	-	-
33	2041	-	-	-	-
34	2042	-	-	-	-
35	2043	-	-	-	-
36	2044	-	-	-	-
37	2045	-	-	-	-
38	Total	**$1,221,551**	**$119,585**	**$199,315**	**$1,540,451**

Table 12D: Federal Interest Payments (FY 2010)
($000s)

	Fiscal Year	A Transmission Bonds	B Transmission Appropriations	C Total
1	2009	78,881	35,356	114,237
2	2010	95,704	27,692	123,396
3	2011	104,242	25,782	130,024
4	2012	108,978	20,852	129,830
5	2013	121,581	12,709	134,290
6	2014	132,117	9,660	141,777
7	2015	143,232	6,930	150,161
8	2016	154,123	5,194	159,317
9	2017	165,723	3,406	169,129
10	2018	176,912	3,000	179,912
11	2019	192,340	2,029	194,369
12	2020	194,283	-	194,283
13	2021	191,293	-	191,293
14	2022	196,686	-	196,686
15	2023	197,851	-	197,851
16	2024	199,242	-	199,242
17	2025	198,330	-	198,330
18	2026	196,413	-	196,413
19	2027	202,694	-	202,694
20	2028	196,344	-	196,344
21	2029	204,535	-	204,535
22	2030	205,687	-	205,687
23	2031	202,273	-	202,273
24	2032	204,915	-	204,915
25	2033	207,996	-	207,996
26	2034	210,785	-	210,785
27	2035	216,559	-	216,559
28	2036	222,963	-	222,963
29	2037	223,896	-	223,896
30	2038	235,327	-	235,327
31	2039	244,401	-	244,401
32	2040	246,629	-	246,629
33	2041	248,960	-	248,960
34	2042	251,416	-	251,416
35	2043	250,233	-	250,233
36	2044	253,053	-	253,053
37	2045	262,837	-	262,837
38	**Total**	**$7,139,436**	**$152,609**	**$7,292,045**

Table 12E: Non-Federal Interest Payments (FY 2010)
($000s)

		A	B	C	D
	Fiscal Year	**ENW**	**Schultz-Wautoma**	**Master Lease**	**Total**
1	2009	3,945	6,499	13,346	23,790
2	2010	2,961	6,502	13,346	22,808
3	2011	1,928	6,504	13,346	21,778
4	2012	844	6,506	13,346	20,696
5	2013	-	6,509	13,346	19,855
6	2014	-	6,511	13,346	19,857
7	2015	-	6,514	13,346	19,860
8	2016	-	6,517	13,346	19,863
9	2017	-	6,520	13,346	19,866
10	2018	-	6,523	13,346	19,869
11	2019	-	6,526	13,346	19,872
12	2020	-	6,529	13,346	19,875
13	2021	-	5,728	13,346	19,074
14	2022	-	2,489	13,346	15,835
15	2023	-	-	13,346	13,346
16	2024	-	-	13,346	13,346
17	2025	-	-	9,589	9,589
18	2026	-	-	2,379	2,379
19	2027	-	-	-	-
20	2028	-	-	-	-
21	2029	-	-	-	-
22	2030	-	-	-	-
23	2031	-	-	-	-
24	2032	-	-	-	-
25	2033	-	-	-	-
26	2034	-	-	-	-
27	2035	-	-	-	-
28	2036	-	-	-	-
29	2037	-	-	-	-
30	2038	-	-	-	-
31	2039	-	-	-	-
32	2040	-	-	-	-
33	2041	-	-	-	-
34	2042	-	-	-	-
35	2043	-	-	-	-
36	2044	-	-	-	-
37	2045		-	-	-
38	**Total**	**$9,677**	**$86,375**	**$225,506**	**$321,558**

Table 12F: Summary of Payments (FY 2010)
($000s)

		A	B	C	D	E	F
		Principal			Interest		
	Fiscal Year	Federal	Non-Federal	Total	Federal	Non-Federal	Total
1	2009	172,659	10,407	183,066	114,237	23,790	138,027
2	2010	216,618	12	216,630	123,396	22,808	146,205
3	2011	208,223	154	208,376	130,024	21,778	151,802
4	2012	167,448	41,118	208,565	129,830	20,696	150,526
5	2013	42,186	163,609	205,795	134,290	19,855	154,145
6	2014	37,754	167,654	205,409	141,777	19,857	161,634
7	2015	24,003	178,385	202,388	150,161	19,860	170,021
8	2016	24,733	176,133	200,866	159,317	19,863	179,180
9	2017	5,636	193,455	199,091	169,129	19,866	188,995
10	2018	13,463	183,731	197,193	179,912	19,869	199,781
11	2019	186,501	4,837	191,338	194,369	19,872	214,241
12	2020	172,141	19,588	191,730	194,283	19,875	214,158
13	2021	175,168	20,567	195,735	191,293	19,074	210,367
14	2022	169,815	21,592	191,407	196,686	15,835	212,521
15	2023	168,677	22,674	191,351	197,851	13,346	211,197
16	2024	173,486	17,637	191,123	199,242	13,346	212,588
17	2025	192,953	-	192,953	198,330	9,589	207,920
18	2026	194,940	-	194,940	196,413	2,379	198,792
19	2027	188,720	-	188,720	202,694	-	202,694
20	2028	195,122	-	195,122	196,344	-	196,344
21	2029	186,971	-	186,971	204,535	-	204,535
22	2030	185,851	-	185,851	205,687	-	205,687
23	2031	189,280	-	189,280	202,273	-	202,273
24	2032	186,631	-	186,631	204,915	-	204,915
25	2033	154,444	29,896	184,340	207,996	-	207,996
26	2034	95,071	89,689	184,759	210,785	-	210,785
27	2035	181,429	-	181,429	216,559	-	216,559
28	2036	159,716	15,255	174,972	222,963	-	222,963
29	2037	40,004	134,997	175,001	223,896	-	223,896
30	2038	123,466	49,063	172,528	235,327	-	235,327
31	2039	166,675	-	166,675	244,401	-	244,401
32	2040	164,382	-	164,382	246,629	-	246,629
33	2041	161,991	-	161,991	248,960	-	248,960
34	2042	159,480	-	159,480	251,416	-	251,416
35	2043	160,612	-	160,612	250,233	-	250,233
36	2044	157,751	-	157,751	253,053	-	253,053
37	2045	145,788	-	145,788	262,837	-	262,837
38	**Totals**	**$5,349,788**	**$1,540,451**	**$6,890,240**	**$7,292,045**	**$321,558**	**$7,613,603**

Table 13A: Transmission Investments Placed in Service (FY 2011)
($000s)

		A	B	C	D	E	F	G
	Fiscal Year	Initial Project	Replacements	Cumulative Amount in Service	Amortization	Discretionary Amortization	Unamortized Investment	Term Investment Schedule
1	2009	1,910,316	-	1,910,316	-	-	1,910,316	5,212,968
2	2010	281,667	-	2,191,983	76,899	95,760	2,019,324	5,235,036
3	2011	410,463	-	2,602,446	194,035	21,135	2,214,617	5,428,921
4	2012	420,046	-	3,022,492	161,232	59,110	2,414,322	5,635,727
5	2013	-	152,244	3,174,736	74,358	96,063	2,396,145	5,581,666
6	2014	-	156,038	3,330,774	18,250	26,803	2,507,130	5,610,794
7	2015	-	159,853	3,490,627	5,974	34,534	2,626,475	5,521,234
8	2016	-	163,547	3,654,174	-	26,634	2,763,388	5,469,394
9	2017	-	167,165	3,821,339	-	27,235	2,903,318	5,401,912
10	2018	-	170,739	3,992,078	-	8,004	3,066,053	5,185,302
11	2019	-	174,139	4,166,217	-	15,652	3,224,540	5,118,438
12	2020	-	177,611	4,343,828	-	186,608	3,215,543	5,138,597
13	2021	-	181,138	4,524,966	-	173,535	3,223,146	5,236,893
14	2022	-	184,559	4,709,525	72,700	104,102	3,230,902	5,358,215
15	2023	-	187,871	4,897,396	-	171,267	3,247,507	5,498,075
16	2024	-	191,173	5,088,569	-	170,062	3,268,617	5,689,248
17	2025	-	194,392	5,282,961	4,402	170,400	3,288,208	5,879,238
18	2026	-	197,370	5,480,331	64,419	129,871	3,291,288	5,956,306
19	2027	-	200,060	5,680,391	125,581	70,975	3,294,792	6,150,785
20	2028	-	202,425	5,882,816	-	189,690	3,307,527	6,353,210
21	2029	-	204,416	6,087,232	162,300	34,061	3,315,582	6,288,826
22	2030	-	205,837	6,293,069	-	187,707	3,333,713	6,478,941
23	2031	-	206,825	6,499,894	-	186,490	3,354,047	6,551,488
24	2032	-	207,329	6,707,223	106,500	83,489	3,371,387	6,458,817
25	2033	-	207,481	6,914,704	98,900	88,327	3,391,641	6,117,398
26	2034	-	207,284	7,121,988	40,000	114,767	3,444,159	5,654,720
27	2035	-	206,590	7,328,578	40,000	55,451	3,555,298	5,562,910
28	2036	-	205,764	7,534,342	125,000	56,577	3,579,485	5,643,674
29	2037	-	204,878	7,739,220	-	159,635	3,624,728	5,848,552
30	2038	-	203,804	7,943,024	40,001	-	3,788,530	6,017,356
31	2039	-	202,682	8,145,706	70,000	53,179	3,868,033	6,220,038
32	2040	-	201,642	8,347,348	-	166,095	3,903,580	6,421,680
33	2041	-	200,717	8,548,065	-	163,743	3,940,554	6,622,397
34	2042	-	199,999	8,748,064	-	162,595	3,977,958	6,822,396
35	2043	-	199,488	8,947,552	-	163,630	4,013,816	7,021,884
36	2044	-	199,309	9,146,861	-	161,623	4,051,502	7,221,193
37	2045	-	199,529	9,346,390	157,473	6	4,093,551	7,143,457
38	2046	-	200,066	9,546,456	152,135	4	4,141,478	6,938,429
39	Total	**3,022,492**	**6,523,964**		**1,790,159**	**3,614,819**		**225,696,115**

Table 13B: Federal Principal Payments (FY 2011)
($000s)

		A	B	C
	Fiscal Year	Bonds	Appropriations	Total
1	2009	67,010	105,649	172,659
2	2010	190,251	24,919	215,170
3	2011	140,000	80,342	220,342
4	2012	55,000	115,421	170,421
5	2013	-	45,053	45,053
6	2014	-	40,508	40,508
7	2015	-	26,634	26,634
8	2016	-	27,235	27,235
9	2017	-	8,004	8,004
10	2018	811	14,841	15,652
11	2019	186,608	-	186,608
12	2020	173,535	-	173,535
13	2021	176,802	-	176,802
14	2022	171,267	-	171,267
15	2023	170,062	-	170,062
16	2024	174,802	-	174,802
17	2025	194,290	-	194,290
18	2026	196,556	-	196,556
19	2027	189,690	-	189,690
20	2028	196,361	-	196,361
21	2029	187,707	-	187,707
22	2030	186,490	-	186,490
23	2031	189,989	-	189,989
24	2032	187,227	-	187,227
25	2033	154,767	-	154,767
26	2034	95,451	-	95,451
27	2035	181,577	-	181,577
28	2036	159,635	-	159,635
29	2037	40,001	-	40,001
30	2038	123,179	-	123,179
31	2039	166,095	-	166,095
32	2040	163,743	-	163,743
33	2041	162,595	-	162,595
34	2042	163,630	-	163,630
35	2043	161,623	-	161,623
36	2044	157,480	-	157,480
37	2045	152,139	-	152,139
38	2046	142,492	-	142,492
39	Total	**$5,058,865**	**$488,605**	**$5,547,470**

Table 13C: Non-Federal Principal Payments (FY 2011)
($000s)

		A	B	C	D
	Fiscal Year	EN	Schultz-Wautoma	Master Lease	Total
1	2009	10,407	-	-	10,407
2	2010	12	-	-	12
3	2011	154	-	-	154
4	2012	41,118	-	-	41,118
5	2013	163,609	-	-	163,609
6	2014	167,654	-	-	167,654
7	2015	178,385	-	-	178,385
8	2016	176,133	-	-	176,133
9	2017	193,455	-	-	193,455
10	2018	183,731	-	-	183,731
11	2019	4,837	-	-	4,837
12	2020	19,588	-	-	19,588
13	2021	20,567	-	-	20,567
14	2022	21,592	-	-	21,592
15	2023	22,674	-	-	22,674
16	2024	17,637	-	-	17,637
17	2025	-	-	-	-
18	2026	-	-	-	-
19	2027	-	-	-	-
20	2028	-	-	-	-
21	2029	-	-	-	-
22	2030	-	-	-	-
23	2031	-	-	-	-
24	2032	-	-	-	-
25	2033	-	29,896	-	29,896
26	2034	-	89,689	-	89,689
27	2035	-	-	-	-
28	2036	-	-	15,255	15,255
29	2037	-	-	134,997	134,997
30	2038	-	-	49,063	49,063
31	2039	-	-	-	-
32	2040	-	-	-	-
33	2041	-	-	-	-
34	2042	-	-	-	-
35	2043	-	-	-	-
36	2044	-	-	-	-
37	2045	-	-	-	-
38	2046	-	-	-	-
39	Total	**$1,221,551**	**$119,585**	**$199,315**	**$1,540,451**

Table 13D: Federal Interest Payments (FY 2011)
($000s)

		A	B	C
	Fiscal Year	Transmission Bonds	Transmission Appropriations	Total
1	2009	78,881	35,356	114,237
2	2010	95,738	27,692	123,430
3	2011	113,322	25,887	139,210
4	2012	128,085	20,076	148,161
5	2013	141,007	11,720	152,727
6	2014	151,865	8,466	160,331
7	2015	163,302	5,537	168,839
8	2016	174,511	3,611	178,123
9	2017	186,423	1,647	188,070
10	2018	197,962	1,070	199,032
11	2019	215,573	-	215,573
12	2020	214,201	-	214,201
13	2021	210,972	-	210,972
14	2022	216,549	-	216,549
15	2023	217,780	-	217,780
16	2024	219,242	-	219,242
17	2025	218,310	-	218,310
18	2026	216,113	-	216,113
19	2027	223,039	-	223,039
20	2028	216,421	-	216,421
21	2029	225,114	-	225,114
22	2030	226,362	-	226,362
23	2031	222,877	-	222,877
24	2032	225,630	-	225,630
25	2033	228,982	-	228,982
26	2034	231,711	-	231,711
27	2035	237,714	-	237,714
28	2036	244,344	-	244,344
29	2037	245,195	-	245,195
30	2038	256,907	-	256,907
31	2039	266,269	-	266,269
32	2040	268,552	-	268,552
33	2041	269,637	-	269,637
34	2042	268,543	-	268,543
35	2043	270,496	-	270,496
36	2044	274,594	-	274,594
37	2045	279,898	-	279,898
38	2046	287,406	-	287,406
39	Total	**$8,129,526**	**$141,062**	**$141,062**

Table 13E: Non-Federal Interest Payments (FY 2011)
($000s)

		A	B	C	D
	Fiscal Year	**EN**	**Schultz-Wautoma**	**Master Lease**	**Total**
1	2009	3,945	6,499	13,346	23,790
2	2010	2,961	6,502	13,346	22,808
3	2011	1,928	6,504	13,346	21,778
4	2012	844	6,506	13,346	20,696
5	2013	-	6,509	13,346	19,855
6	2014	-	6,511	13,346	19,857
7	2015	-	6,514	13,346	19,860
8	2016	-	6,517	13,346	19,863
9	2017	-	6,520	13,346	19,866
10	2018	-	6,523	13,346	19,869
11	2019	-	6,526	13,346	19,872
12	2020	-	6,529	13,346	19,875
13	2021	-	5,728	13,346	19,074
14	2022	-	2,489	13,346	15,835
15	2023	-	-	13,346	13,346
16	2024	-	-	13,346	13,346
17	2025	-	-	9,589	9,589
18	2026	-	-	2,379	2,379
19	2027	-	-	-	-
20	2028	-	-	-	-
21	2029	-	-	-	-
22	2030	-	-	-	-
23	2031	-	-	-	-
24	2032	-	-	-	-
25	2033	-	-	-	-
26	2034	-	-	-	-
27	2035	-	-	-	-
28	2036	-	-	-	-
29	2037	-	-	-	-
30	2038	-	-	-	-
31	2039	-	-	-	-
32	2040	-	-	-	-
33	2041	-	-	-	-
34	2042	-	-	-	-
35	2043	-	-	-	-
36	2044	-	-	-	-
37	2045		-	-	-
38	2046	-	-	-	-
39	Total	**$9,677**	**$86,375**	**$225,506**	**$321,558**

Table 13F: Summary of Payments (FY 2011)
($000s)

		A	B	C	D	E	F
		Principal			Interest		
	Fiscal Year	Federal	Non-Federal	Total	Federal	Non-Federal	Total
1	2009	172,659	10,407	183,066	114,237	23,790	138,027
2	2010	215,170	12	215,182	123,430	22,808	146,238
3	2011	220,342	154	220,495	139,210	21,778	160,988
4	2012	170,421	41,118	211,538	148,161	20,696	168,857
5	2013	45,053	163,609	208,663	152,727	19,855	172,582
6	2014	40,508	167,654	208,162	160,331	19,857	180,188
7	2015	26,634	178,385	205,019	168,839	19,860	188,699
8	2016	27,235	176,133	203,368	178,123	19,863	197,985
9	2017	8,004	193,455	201,458	188,070	19,866	207,936
10	2018	15,652	183,731	199,383	199,032	19,869	218,900
11	2019	186,608	4,837	191,445	215,573	19,872	235,445
12	2020	173,535	19,588	193,123	214,201	19,875	234,076
13	2021	176,802	20,567	197,369	210,972	19,074	230,046
14	2022	171,267	21,592	192,859	216,549	15,835	232,384
15	2023	170,062	22,674	192,736	217,780	13,346	231,126
16	2024	174,802	17,637	192,438	219,242	13,346	232,588
17	2025	194,290	-	194,290	218,310	9,589	227,899
18	2026	196,556	-	196,556	216,113	2,379	218,492
19	2027	189,690	-	189,690	223,039	-	223,039
20	2028	196,361	-	196,361	216,421	-	216,421
21	2029	187,707	-	187,707	225,114	-	225,114
22	2030	186,490	-	186,490	226,362	-	226,362
23	2031	189,989	-	189,989	222,877	-	222,877
24	2032	187,227	-	187,227	225,630	-	225,630
25	2033	154,767	29,896	184,663	228,982	-	228,982
26	2034	95,451	89,689	185,139	231,711	-	231,711
27	2035	181,577	-	181,577	237,714	-	237,714
28	2036	159,635	15,255	174,891	244,344	-	244,344
29	2037	40,001	134,997	174,998	245,195	-	245,195
30	2038	123,179	49,063	172,242	256,907	-	256,907
31	2039	166,095	-	166,095	266,269	-	266,269
32	2040	163,743	-	163,743	268,552	-	268,552
33	2041	162,595	-	162,595	269,637	-	269,637
34	2042	163,630	-	163,630	268,543	-	268,543
35	2043	161,623	-	161,623	270,496	-	270,496
36	2044	157,480	-	157,480	274,594	-	274,594
37	2045	152,139	-	152,139	279,898	-	279,898
38	2046	142,492	-	142,492	287,406	-	287,406
39	Total	**$5,374,811**	**$1,530,044**	**$6,904,855**	**$8,156,351**	**$297,768**	**$8,454,119**

Table 14: Application of Amortization (FY 2011)
($000s)

		A	B	C	D	E	F	G	H	I
	Date	Project	In Service	Due	Original Balance	Amount Available	Rate	Replacement?	Rollover?	Amount Amortized
1	FY 2009	BONNEVILLE POWER ADMINISTRATION	1964	2009	4,151	4,151	7.060%	No	No	4,151
2	FY 2009	BONNEVILLE POWER ADMINISTRATION	1964	2009	5,738	5,738	7.060%	No	No	5,738
3	FY 2009	ENVIRONMENT	2006	2009	20,000	20,000	5.050%	No	No	20,000
4	FY 2009	BPA PROGRAM	2006	2009	20,000	20,000	5.050%	No	No	20,000
5	FY 2009	BPA PROGRAM	2005	2009	27,010	27,010	3.750%	No	No	27,010
6	FY 2009	BONNEVILLE POWER ADMINISTRATION	1970	2015	64,977	64,977	7.270%	No	No	25,385
7	FY 2009	BONNEVILLE POWER ADMINISTRATION	1970	2015	7,995	7,995	7.270%	No	No	7,995
8	FY 2009	BONNEVILLE POWER ADMINISTRATION	1970	2015	24,412	23,551	7.270%	No	No	23,551
9	FY 2009	BONNEVILLE POWER ADMINISTRATION	1973	2018	33,788	33,788	7.280%	No	No	33,788
10	FY 2009	BONNEVILLE POWER ADMINISTRATION	1973	2018	21,656	5,041	7.280%	No	No	5,041
11	**Subtotal**		-	-	**$229,727**	**$212,251**	-	**No**	**No**	**$172,659**
12										
13	FY 2010	BONNEVILLE POWER ADMINISTRATION	1965	2010	3,706	3,706	7.090%	No	No	3,706
14	FY 2010	BONNEVILLE POWER ADMINISTRATION	1965	2010	7,248	78	7.090%	No	No	78
15	FY 2010	ENVIRONMENT	2001	2010	30,000	30,000	6.050%	No	No	30,000
16	FY 2010	BPA PROGRAM	2001	2010	59,932	59,932	6.050%	No	No	59,932
17	FY 2010	BPA PROGRAM	2007	2010	50,000	50,000	5.200%	No	No	50,000
18	FY 2010	BPA PROGRAM	2007	2010	25,000	25,000	5.100%	No	No	25,000
19	FY 2010	BPA PROGRAM	2006	2010	5,319	5,319	4.950%	No	No	5,319
20	FY 2010	BPA PROGRAM	2006	2010	20,000	20,000	4.950%	No	No	20,000
21	FY 2010	BONNEVILLE POWER ADMINISTRATION	1970	2015	64,977	39,592	7.270%	No	No	21,135
22	**Subtotal**		-	-	**$266,182**	**$233,627**	-	**No**	**No**	**$215,170**
23										
24	FY 2011	BONNEVILLE POWER ADMINISTRATION	1966	2011	11,830	11,830	7.130%	No	No	11,830
25	FY 2011	BONNEVILLE POWER ADMINISTRATION	1966	2011	3,049	3,049	7.130%	No	No	3,049
26	FY 2011	BONNEVILLE POWER ADMINISTRATION	1966	2011	6,647	6,353	7.130%	No	No	6,353
27	FY 2011	BPA PROGRAM	1998	2011	40,000	40,000	6.200%	No	No	40,000
28	FY 2011	BPA PROGRAM	2001	2011	25,000	25,000	5.950%	No	No	25,000
29	FY 2011	BPA PROGRAM	2008	2011	40,000	40,000	3.358%	No	No	40,000
30	FY 2011	ENVIRONMENT	2008	2011	10,000	10,000	3.151%	No	No	10,000
31	FY 2011	BPA PROGRAM	2008	2011	25,000	25,000	3.151%	No	No	25,000
32	FY 2011	BONNEVILLE POWER ADMINISTRATION	1970	2015	64,977	18,457	7.270%	No	No	18,457
33	FY 2011	BONNEVILLE POWER ADMINISTRATION	1974	2019	20,984	20,984	7.270%	No	No	6,263
34	FY 2011	BONNEVILLE POWER ADMINISTRATION	1974	2019	12,563	12,563	7.270%	No	No	12,563
35	FY 2011	BONNEVILLE POWER ADMINISTRATION	1974	2019	21,826	21,826	7.270%	No	No	21,826
36	**Subtotal**		-	-	**$281,876**	**$235,062**	-	**No**	**No**	**$220,342**
37										
38	FY 2012	BONNEVILLE POWER ADMINISTRATION	1967	2012	19,003	19,003	7.160%	No	No	19,003
39	FY 2012	BONNEVILLE POWER ADMINISTRATION	1967	2012	4,566	355	7.160%	No	No	355
40	FY 2012	BPA PROGRAM	2008	2012	25,000	25,000	3.444%	No	No	25,000
41	FY 2012	BPA PROGRAM	2008	2012	30,000	30,000	3.200%	No	No	30,000
42	FY 2012	BONNEVILLE POWER ADMINISTRATION	1974	2019	12,079	12,079	7.270%	No	No	12,079
43	FY 2012	BONNEVILLE POWER ADMINISTRATION	1974	2019	20,984	14,721	7.270%	No	No	14,721
44	FY 2012	BONNEVILLE POWER ADMINISTRATION	1975	2020	32,026	32,026	7.250%	No	No	18,447
45	FY 2012	BONNEVILLE POWER ADMINISTRATION	1975	2020	21,916	21,916	7.250%	No	No	21,916
46	FY 2012	BONNEVILLE POWER ADMINISTRATION	1975	2020	17,158	17,158	7.250%	No	No	17,158
47	FY 2012	BONNEVILLE POWER ADMINISTRATION	1975	2020	11,742	11,742	7.250%	No	No	11,742
48	**Subtotal**		-	-	**$194,474**	**$184,000**	-	**No**	**No**	**$170,421**
49										
50	FY 2013	BONNEVILLE POWER ADMINISTRATION	1968	2013	41,070	18,250	7.200%	No	No	18,250
51	FY 2013	BONNEVILLE POWER ADMINISTRATION	1969	2014	42,237	19,198	7.230%	No	No	13,224
52	FY 2013	BONNEVILLE POWER ADMINISTRATION	1975	2020	32,026	13,579	7.250%	No	No	13,579
53	**Subtotal**		-	-	**$115,333**	**$51,027**	-	**No**	**No**	**$45,053**
54										
55	FY 2014	BONNEVILLE POWER ADMINISTRATION	1969	2014	42,237	5,974	7.230%	No	No	5,974
56	FY 2014	BONNEVILLE POWER ADMINISTRATION	1976	2021	61,025	61,025	7.230%	No	No	32,322
57	FY 2014	BONNEVILLE POWER ADMINISTRATION	1976	2021	2,212	2,212	7.230%	No	No	2,212
58	**Subtotal**		-	-	**$105,474**	**$69,211**	-	**No**	**No**	**$40,508**
59										
60	FY 2015	BONNEVILLE POWER ADMINISTRATION	1976	2021	61,025	28,703	7.230%	No	No	26,634
61	**Subtotal**		-	-	**$61,025**	**$28,703**	-	**No**	**No**	**$26,634**
62										
63	FY 2016	BONNEVILLE POWER ADMINISTRATION	1976	2021	61,025	2,069	7.230%	No	No	2,069
64	FY 2016	BONNEVILLE POWER ADMINISTRATION	1977	2022	33,702	33,702	7.210%	No	No	20,185
65	FY 2016	BONNEVILLE POWER ADMINISTRATION	1977	2022	4,981	4,981	7.210%	No	No	4,981
66	**Subtotal**		-	-	**$99,708**	**$40,752**	-	**No**	**No**	**$27,235**
67										
68	FY 2017	BONNEVILLE POWER ADMINISTRATION	1977	2022	33,702	13,517	7.210%	No	No	8,004
69	**Subtotal**		-	-	**$33,702**	**$13,517**	-	**No**	**No**	**$8,004**
70										
71	FY 2018	BONNEVILLE POWER ADMINISTRATION	1977	2022	3,948	3,948	7.210%	No	No	3,948
72	FY 2018	BONNEVILLE POWER ADMINISTRATION	1977	2022	5,380	5,380	7.210%	No	No	5,380
73	FY 2018	BONNEVILLE POWER ADMINISTRATION	1977	2022	33,702	5,513	7.210%	No	No	5,513
74	FY 2018	BPA PROGRAM	2011	2046	414,465	414,465	6.930%	No	No	811
75	**Subtotal**		-	-	**$457,495**	**$429,306**	-	**No**	**No**	**$15,652**
76										

Table 14: Application of Amortization (FY 2011)
($000s)

	A	B	C	D	E	F	G	H	I
Date	Project	In Service	Due	Original Balance	Amount Available	Rate	Replacement?	Rollover?	Amount Amortized
FY 2019	BPA PROGRAM	2011	2046	414,465	413,654	6.930%	No	No	186,608
Subtotal		**-**	**-**	**$414,465**	**$413,654**	**-**	**No**	**No**	**$186,608**
FY 2020	BONNEVILLE POWER ADMINISTRATION	1975	2020	32,026	-0	7.250%	No	No	-0
FY 2020	BPA PROGRAM	2011	2046	414,465	227,046	6.930%	No	No	173,535
Subtotal		**-**	**-**	**$446,491**	**$227,046**	**-**	**No**	**No**	**$173,535**
FY 2021	BONNEVILLE POWER ADMINISTRATION	1976	2021	61,025	0	7.230%	No	No	0
FY 2021	BPA PROGRAM	1998	2021	72,700	72,700	4.540%	No	Yes	72,700
FY 2021	BPA PROGRAM	2011	2046	414,465	53,511	6.930%	No	No	53,511
FY 2021	BPA PROGRAM	2012	2047	152,244	152,244	6.840%	Yes	No	50,592
Subtotal		**-**	**-**	**$700,434**	**$278,455**	**-**	**Yes**	**Yes**	**$176,802**
FY 2022	BONNEVILLE POWER ADMINISTRATION	1977	2022	33,702	-0	7.210%	No	No	-0
FY 2022	BPA PROGRAM	2012	2047	152,244	101,652	6.840%	Yes	No	101,652
FY 2022	BPA PROGRAM	2013	2048	156,038	156,038	6.840%	Yes	No	69,614
Subtotal		**-**	**-**	**$341,984**	**$257,690**	**-**	**Yes**	**No**	**$171,267**
FY 2023	BPA PROGRAM	2013	2048	156,038	86,424	6.840%	Yes	No	86,424
FY 2023	BPA PROGRAM	2014	2049	159,853	159,853	6.840%	Yes	No	83,639
Subtotal		**-**	**-**	**$315,891**	**$246,277**	**-**	**Yes**	**No**	**$170,062**
FY 2024	ENVIRONMENT	2009	2024	4,402	4,402	4.720%	No	No	4,402
FY 2024	BPA PROGRAM	2014	2049	159,853	76,214	6.840%	Yes	No	76,214
FY 2024	BPA PROGRAM	2015	2050	163,547	163,547	6.840%	Yes	No	94,185
Subtotal		**-**	**-**	**$327,802**	**$244,163**	**-**	**Yes**	**No**	**$174,802**
FY 2025	BPA PROGRAM	1999	2025	59,050	59,050	6.100%	No	Yes	59,050
FY 2025	ENVIRONMENT	2010	2025	5,369	5,369	5.870%	No	No	5,369
FY 2025	BPA PROGRAM	2015	2050	163,547	69,362	6.840%	Yes	No	69,362
FY 2025	BPA PROGRAM	2016	2051	167,165	167,165	6.840%	Yes	No	60,509
Subtotal		**-**	**-**	**$395,131**	**$300,946**	**-**	**Yes**	**Yes**	**$194,290**
FY 2026	ENVIRONMENT	2011	2026	5,581	5,581	6.220%	No	No	5,581
FY 2026	BPA PROGRAM	2007	2026	40,000	40,000	6.200%	No	Yes	40,000
FY 2026	BPA PROGRAM	2008	2026	30,000	30,000	6.200%	No	Yes	30,000
FY 2026	BPA PROGRAM	2001	2026	50,000	50,000	6.080%	No	Yes	50,000
FY 2026	BPA PROGRAM	2016	2051	167,165	106,656	6.840%	Yes	No	70,975
Subtotal		**-**	**-**	**$292,746**	**$232,237**	**-**	**Yes**	**Yes**	**$196,556**
FY 2027	BPA PROGRAM	2016	2051	167,165	35,681	6.840%	Yes	No	35,681
FY 2027	BPA PROGRAM	2017	2052	170,739	170,739	6.840%	Yes	No	154,009
Subtotal		**-**	**-**	**$337,904**	**$206,420**	**-**	**Yes**	**No**	**$189,690**
FY 2028	BPA PROGRAM	1998	2028	50,000	50,000	6.650%	No	No	50,000
FY 2028	BPA PROGRAM	1998	2028	112,300	112,300	5.850%	No	No	112,300
FY 2028	BPA PROGRAM	2017	2052	170,739	16,730	6.840%	Yes	No	16,730
FY 2028	BPA PROGRAM	2018	2053	174,139	174,139	6.840%	Yes	No	17,331
Subtotal		**-**	**-**	**$507,178**	**$353,169**	**-**	**Yes**	**No**	**$196,361**
FY 2029	BPA PROGRAM	2018	2053	174,139	156,808	6.840%	Yes	No	156,808
FY 2029	BPA PROGRAM	2019	2054	177,611	177,611	6.840%	Yes	No	30,898
Subtotal		**-**	**-**	**$351,750**	**$334,419**	**-**	**Yes**	**No**	**$187,707**
FY 2030	BPA PROGRAM	2019	2054	177,611	146,713	6.840%	Yes	No	146,713
FY 2030	BPA PROGRAM	2020	2055	181,138	181,138	6.840%	Yes	No	39,778
Subtotal		**-**	**-**	**$358,749**	**$327,851**	**-**	**Yes**	**No**	**$186,490**
FY 2031	BPA PROGRAM	1998	2031	106,500	106,500	5.510%	No	Yes	106,500
FY 2031	BPA PROGRAM	2020	2055	181,138	141,360	6.840%	Yes	No	83,489
Subtotal		**-**	**-**	**$287,638**	**$247,860**	**-**	**Yes**	**Yes**	**$189,989**
FY 2032	BPA PROGRAM	1998	2032	98,900	98,900	6.700%	No	No	98,900
FY 2032	BPA PROGRAM	2020	2055	181,138	57,871	6.840%	Yes	No	57,871
FY 2032	BPA PROGRAM	2021	2056	184,559	184,559	6.840%	Yes	No	30,456
Subtotal		**-**	**-**	**$464,597**	**$341,330**	**-**	**Yes**	**No**	**$187,227**
FY 2033	BPA PROGRAM	2003	2033	40,000	40,000	5.550%	No	No	40,000
FY 2033	BPA PROGRAM	2021	2056	184,559	154,103	6.840%	Yes	No	114,767
Subtotal		**-**	**-**	**$224,559**	**$194,103**	**-**	**Yes**	**No**	**$154,767**
FY 2034	BPA PROGRAM	2004	2034	40,000	40,000	5.600%	No	No	40,000
FY 2034	BPA PROGRAM	2021	2056	184,559	39,337	6.840%	Yes	No	39,337
FY 2034	BPA PROGRAM	2022	2057	187,871	187,871	6.840%	Yes	No	16,114
Subtotal		**-**	**-**	**$412,430**	**$267,208**	**-**	**Yes**	**No**	**$95,451**
FY 2035	BPA PROGRAM	2005	2035	40,000	40,000	5.500%	No	No	40,000

Table 14: Application of Amortization (FY 2011)
($000s)

		A	B	C	D	E	F	G	H	I
	Date	Project	In Service	Due	Original Balance	Amount Available	Rate	Replacement?	Rollover?	Amount Amortized
154	FY 2035	BPA PROGRAM	2005	2035	40,000	40,000	5.400%	No	No	40,000
155	FY 2035	BPA PROGRAM	2005	2035	45,000	45,000	5.250%	No	No	45,000
156	FY 2035	BPA PROGRAM	2022	2057	187,871	171,757	6.840%	Yes	No	56,577
157	**Subtotal**		**-**	**-**	**$312,871**	**$296,757**	**-**	**Yes**	**No**	**$181,577**
158										
159	FY 2036	BPA PROGRAM	2007	2037	35,000	35,000	6.400%	No	No	34,999
160	FY 2036	BPA PROGRAM	2022	2057	187,871	115,180	6.840%	Yes	No	115,180
161	FY 2036	BPA PROGRAM	2023	2058	191,173	191,173	6.840%	Yes	No	9,457
162	**Subtotal**		**-**	**-**	**$414,044**	**$341,353**	**-**	**Yes**	**No**	**$159,635**
163										
164	FY 2037	BPA PROGRAM	2007	2037	35,000	1	6.400%	No	No	1
165	FY 2037	BPA PROGRAM	2005	2037	40,000	40,000	5.410%	No	Yes	40,000
166	**Subtotal**		**-**	**-**	**$75,000**	**$40,001**	**-**	**No**	**Yes**	**$40,001**
167										
168	FY 2038	BPA PROGRAM	2006	2038	70,000	70,000	5.470%	No	Yes	70,000
169	FY 2038	BPA PROGRAM	2023	2058	191,173	181,716	6.840%	Yes	No	53,179
170	**Subtotal**		**-**	**-**	**$261,173**	**$251,716**	**-**	**Yes**	**Yes**	**$123,179**
171										
172	FY 2039	BPA PROGRAM	2023	2058	191,173	128,537	6.840%	Yes	No	128,537
173	FY 2039	BPA PROGRAM	2024	2059	194,392	194,392	6.840%	Yes	No	37,558
174	**Subtotal**		**-**	**-**	**$385,565**	**$322,929**	**-**	**Yes**	**No**	**$166,095**
175										
176	FY 2040	BPA PROGRAM	2024	2059	194,392	156,834	6.840%	Yes	No	156,834
177	FY 2040	BPA PROGRAM	2025	2060	197,370	197,370	6.840%	Yes	No	6,909
178	**Subtotal**		**-**	**-**	**$391,762**	**$354,204**	**-**	**Yes**	**No**	**$163,743**
179										
180	FY 2041	BPA PROGRAM	2010	2045	405,094	405,094	6.790%	No	No	47,492
181	FY 2041	BPA PROGRAM	2025	2060	197,370	190,461	6.840%	Yes	No	115,104
182	**Subtotal**		**-**	**-**	**$602,464**	**$595,555**	**-**	**Yes**	**No**	**$162,595**
183										
184	FY 2042	BPA PROGRAM	2010	2045	405,094	357,602	6.790%	No	No	163,630
185	FY 2042	BPA PROGRAM	2025	2060	197,370	75,358	6.840%	Yes	No	0
186	**Subtotal**		**-**	**-**	**$602,464**	**$432,960**	**-**	**Yes**	**No**	**$163,630**
187										
188	FY 2043	BPA PROGRAM	2009	2044	277,265	277,265	5.350%	No	No	119,792
189	FY 2043	BPA PROGRAM	2010	2045	405,094	193,973	6.790%	No	No	41,832
190	**Subtotal**		**-**	**-**	**$682,359**	**$471,238**	**-**	**No**	**No**	**$161,623**
191										
192	FY 2044	BPA PROGRAM	2009	2044	277,265	157,473	5.350%	No	No	157,473
193	FY 2044	BPA PROGRAM	2010	2045	405,094	152,141	6.790%	No	No	6
194	**Subtotal**		**-**	**-**	**$682,359**	**$309,615**	**-**	**No**	**No**	**$157,480**
195										
196	FY 2045	BPA PROGRAM	2010	2045	405,094	152,135	6.790%	No	No	152,135
197	FY 2045	BPA PROGRAM	2025	2060	197,370	75,357	6.840%	Yes	No	4
198	**Subtotal**		**-**	**-**	**$602,464**	**$227,492**	**-**	**Yes**	**No**	**$152,139**

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