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

BP-14 Final Rate Proposal

Transmission Revenue Requirement Study

BP-14-FS-BPA-08

July 2013

TRANSMISSION REVENUE REQUIREMENT STUDY

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COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
AGC	Automatic Generation Control
ALF	Agency Load Forecast (computer model)
aMW	average megawatt(s)
AMNR	Accumulated Modified Net Revenues
ANR	Accumulated Net Revenues
ASC	Average System Cost
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Btu	British thermal unit
CDD	cooling degree day(s)
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
COE, Corps, or USACE	U.S. Army Corps of Engineers
Commission	Federal Energy Regulatory Commission
Corps, COE, or USACE	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council or NPCC	Northwest Power and Conservation Council
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
CY	calendar year (January through December)
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service
DFS	Diurnal Flattening Service
DOE	Department of Energy
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EIA	Energy Information Administration
EIS	Environmental Impact Statement
EN	Energy Northwest, Inc.
EPP	Environmentally Preferred Power
ESA	Endangered Species Act
e-Tag	electronic interchange transaction information
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FHFO	Funds Held for Others
FORS	Forced Outage Reserve Service

FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GARD	Generation and Reserves Dispatch (computer model)
GEP	Green Energy Premium
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HDD	heating degree day(s)
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
ICE	Intercontinental Exchange
inc	increase, increment, or incremental
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRMP	Irrigation Rate Mitigation Product
JOE	Joint Operating Entity
kW	kilowatt (1000 watts)
kWh	kilowatthour
LDD	Low Density Discount
LLH	Light Load Hour(s)
LRA	Load Reduction Agreement
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenues
MRNR	Minimum Required Net Revenue
MW	megawatt (1 million watts)
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	National Marine Fisheries Service (NMFS) Federal Columbia River Power System (FCRPS) Biological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPCC or Council	Pacific Northwest Electric Power and Conservation Planning Council

NPV	net present value
NR	New Resource Firm Power (rate)
NT	Network Transmission
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operation and maintenance
OATI	Open Access Technology International, Inc.
OMB	Office of Management and Budget
OY	operating year (August through July)
PF	Priority Firm Power (rate)
PFp	Priority Firm Public (rate)
PFx	Priority Firm Exchange (rate)
PNCA	Pacific Northwest Coordination Agreement
PNRR	Planned Net Revenues for Risk
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
POM	Point of Metering
POR	Point of Receipt
Project Act	Bonneville Project Act
PRS	Power Rates Study
PS	BPA Power Services
PSW	Pacific Southwest
PTP	Point to Point Transmission (rate)
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation or USBR	U.S. Bureau of Reclamation
REP	Residential Exchange Program
RevSim	Revenue Simulation Model (component of RiskMod)
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
RiskMod	Risk Analysis Model (computer model)
RiskSim	Risk Simulation Model (component of RiskMod)
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement (rate)
RRS	Resource Remarketing Service
RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition

SCS	Secondary Crediting Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
ULS	Unanticipated Load Service
USACE, Corps, or COE	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VERBS	Variable Energy Resources Balancing Service (rate)
VOR	Value of Reserves
VR1-2014	First Vintage rate of the BP-14 rate period
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

Figure 1: Transmission Revenue Requirement Process

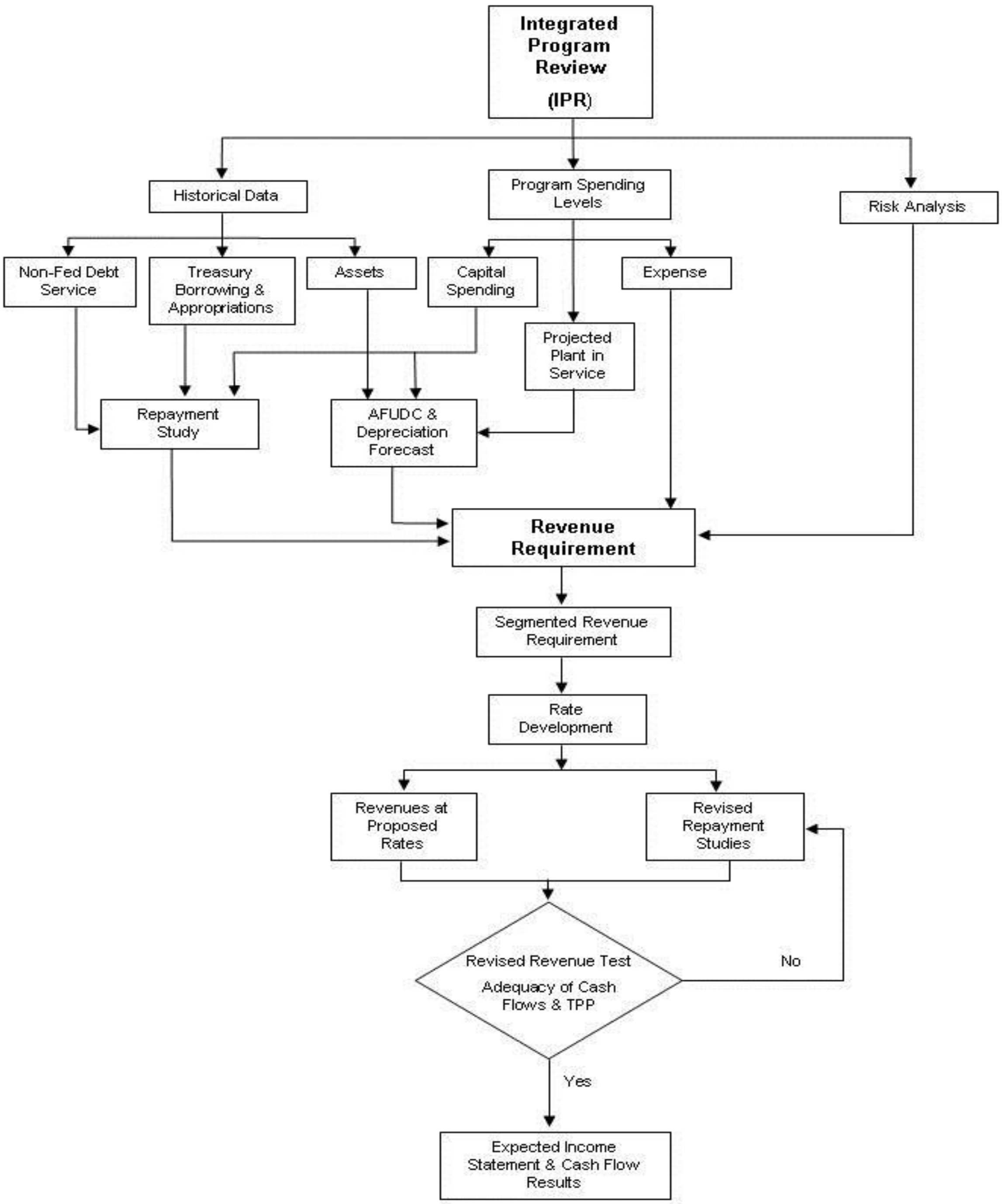
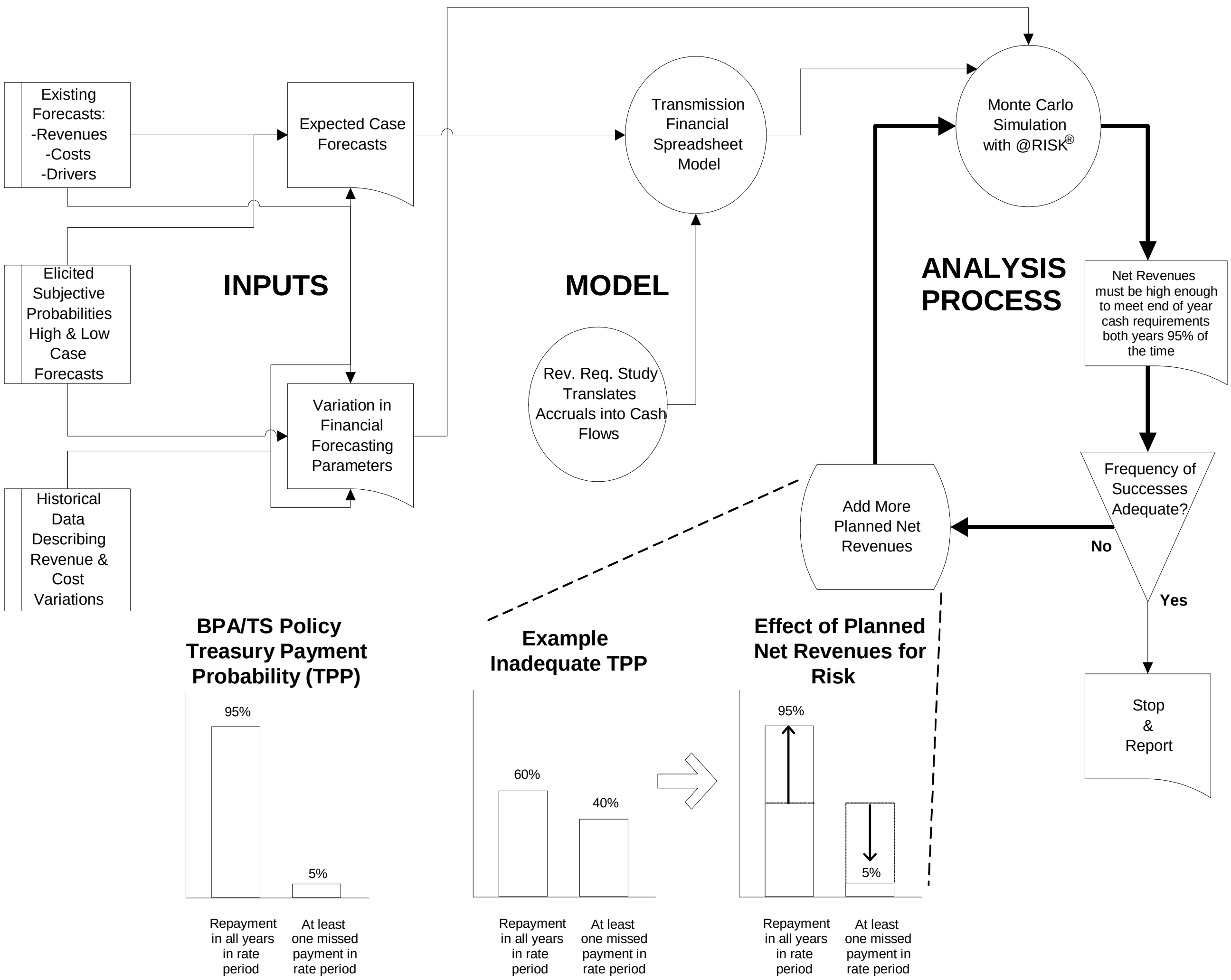


Figure 2: Transmission Rate Case Risk Analysis Flow Diagram



1. INTRODUCTION

1.1 Purpose of the Study

The purpose of the Transmission 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. Such revenues must 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 Federal Columbia River Power System (FCRPS), which also includes the multipurpose generation facilities constructed and operated by the U.S. Army Corps of Engineers (Corps) and the U.S. Bureau of Reclamation (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 requirement developed in this Study includes 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 BPA.

The cost evaluation period, as defined by the Federal Energy Regulatory Commission (Commission), is the period extending from the last year for which historical information is available through the rate period. The cost evaluation period for this rate filing includes fiscal year (FY) 2013 and the rate period, FY 2014–2015. This Study for the rate period FY 2014–2015 is based on transmission revenue requirements that include the results of transmission repayment studies. This Study does not include revenue requirements or a cost recovery demonstration for the BPA generation function, which instead are contained in the Power Revenue Requirement Study, BP-14-FS-BPA-02.

This Study outlines the policies, forecasts, assumptions, and calculations used to determine BPA's transmission revenue requirements. Legal requirements are summarized in section 1.2 of this Study. The Documentation for the Transmission Revenue Requirement Study (Documentation), BP-14-FS-BPA-08A, contains key technical assumptions and calculations, the results of the transmission repayment studies, and a further explanation of the repayment inputs and outputs.

The revenue requirements that appear in this Study are developed using a cost accounting analysis comprised of multiple steps, as shown in 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 cost evaluation period (FY 2013–2015) and extend over the 35-year repayment period assumed for transmission assets. Second, transmission operating expenses, non-Federal debt service requirements, and Minimum Required Net Revenues (MRNR) (if needed) are projected for each year of the rate period. Third, the need for annual planned net revenues for risk is evaluated by taking into account Transmission Services' 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 current and revised revenue tests to determine whether revenues projected from current and proposed rates meet its cost recovery requirements and objectives for the rate period and repayment period. If the current revenue test indicates that cost recovery and risk mitigation requirements can be met, current rates could be extended. However, the current revenue test, discussed in section 3.2, demonstrates that current revenues are insufficient to meet cost recovery requirements and objectives for the rate period and the repayment period.

The revised revenue test determines whether projected revenues from proposed rates are sufficient to meet cost recovery requirements for the rate and repayment periods. The revised revenue test, discussed in section 3.4, demonstrates that revenues from proposed rates will recover the costs of transmission and ancillary and control area services in the rate period as well as over the ensuing 35-year 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 rate proposal provide a greater than 95 percent probability that associated U.S. Treasury payments will be made on time and in full over the two-year rate period.

Table 1 shows projected net revenues from proposed rates and summarizes the revised revenue test over the two-year rate period. These net revenues are set at the lowest level necessary to achieve, in combination with other risk mitigation tools, BPA's cost recovery objectives in the face of transmission-related risks. Risk mitigation tools are discussed further in section 2.2. Table 2 shows planned transmission amortization repayments to the U.S. Treasury for each year of the rate period.

1.2 Legal Requirements

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

1.2.1 Governing Authorities

BPA's revenue requirements are governed primarily by three 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. The Omnibus Consolidated Rescissions and Appropriations Act of 1996, P.L. No. 104-134, 110 Stat. 1321, also guides the development of BPA's revenue requirements.

Department of Energy (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 Commission provide guidance on separate accounting for transmission system costs. *See, e.g., Bonneville Power Admin.*, 25 FERC ¶ 61,140 (1983).

1.2.1.1 Legal Requirements Governing BPA's Revenue Requirement

BPA constructs, operates, and maintains the FCRTS within the Pacific Northwest and makes improvements or replacements to the transmission system 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; or (d) maintain the electrical stability and reliability of the Federal system. Section 4, Transmission System Act, 16 U.S.C. § 838b.

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 provides 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 chapter 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 the Commission shall issue a confirmation and approval of BPA's rates upon a finding that the rates are 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) of this section, 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.

Development of the revenue requirement is a critical component of meeting the statutory cost recovery principles relevant to BPA. The costs associated with the 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.

1.2.1.2 The BPA Appropriations Refinancing Act

As in the prior rate period, BPA's transmission rates for the FY 2014–2015 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 dates on new principal amounts may not be earlier than the repayment dates for old capital investments. 16 U.S.C. §838l(d). The Refinancing Act further directs the Administrator to offer to provide assurance in new or existing contracts for power, transmission, or related services that the Government would not increase the repayment obligations in the future. 16 U.S.C. §838l(i).

1.2.2 Repayment Requirements and Policies

1.2.2.1 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, the Commission 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. *Bonneville Power Admin*., 20 FERC ¶ 61,142 (1982). The Commission 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. Such studies must set forth the date of each investment, the repayment date, and the amount repaid from transmission revenues. *Bonneville Power Admin.*, 26 FERC ¶ 61,096 (1984). The Commission approved BPA's methodology for separate repayment studies in 1984. *Bonneville Power Admin*., 28 FERC ¶ 61,325 (1984). Thus, BPA has prepared separate repayment studies for its transmission and generation functions since 1984.

1.2.2.2 Repayment Schedules

The statutes applicable to BPA do not include specific directives for scheduling repayment of 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.

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 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 the Federal Energy Regulatory Commission) 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 permit's Bonneville Power Administration customers, which include both electric utilities and electroprocess 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 were 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 ensuring that BPA still complies 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 and 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; it describes 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 on October 1, 1977. 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 power system;

(2) Pay the cost 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 each year on the unamortized portion of the commercial power investment financed with appropriated funds at the interest rates established

for each 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;

(5) Repay:

- each dollar of power investments and obligations in the FCRPS generating projects within 50 years after the projects become revenue-producing (50 years has been deemed a "reasonable period" as intended by Congress, except for the Yakima-Chandler Project, which has a legislated amortization period of 66 years);
- each annual increment of transmission financed by Federal investments and obligations within the average service life of such transmission facilities (currently 40 years) or within a maximum of 50 years, whichever is less [BPA has interpreted RA 6120.2 to require repayment of bonds sold to finance conservation to be within the average service lives of these projects, currently estimated to be five years, and for fish and wildlife facilities to be 15 years];
- the Federally-financed amount of each replacement within its service life up to a maximum of 50 years; and

(6) As required by P.L. No. 89-448, repay the portion of construction costs at Federal reclamation projects that is beyond the repayment ability of the irrigators, and which is assigned for repayment from commercial power revenues, within the same overall period available to the irrigation water users for making their payments on construction costs.

Although DOE Order RA 6120.2 allows a 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 (see section 1.2.1.2) overrides provisions in DOE Order 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.

Other sections within DOE Order 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 ensuring that BPA still completes repayment of each increment of Federal investment and obligation within its prescribed repayment period.

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2. DEVELOPMENT OF REVENUE REQUIREMENT

2.1 Spending Level Development

The forecasts of program spending levels are developed in the Integrated Program Review (IPR). The IPR was designed to provide customers and constituents an opportunity to examine, understand, and comment on BPA's cost projections for future years for both power and transmission. Prior to the 2012 IPR, BPA hosted the 2012 Capital Investment Review (CIR), a new public process to review and discuss draft asset strategies and 10-year capital forecasts. Public comments received during the CIR informed capital cost projections for FY 2014–2015 in the 2012 IPR.

BPA began the 2012 IPR for FY 2014–2015 program levels on June 5, 2012, with an opening workshop containing an overview of Power, Transmission, and Agency Services proposed expense spending levels for FY 2014–2015. At the same time, BPA released FY 2014–2015 proposed expense spending levels, drivers, goals, risks, and comparisons to previous IPR costs. After the opening workshop and release of information, participants were allowed three weeks to request additional information or specific workshops. BPA responded to 101 requests for additional information and held six workshops through August 10, 2012. While Federal and non-Federal debt management issues are not decided in the IPR, a workshop was held on these topics to enhance participants' understanding of the implications of past debt management decisions and proposed capital spending levels. After considering the comments received, BPA released a close-out report on October 26, 2012.

On April 26, 2013, BPA invited the region to an abbreviated "IPR2" public process to discuss proposed adjustments from the 2012 IPR. The process began with a public meeting in Portland on April 30, 2013. The comment period ended on May 7, 2013. On June 4, 2013, BPA issued the IPR2 Decision Letter and Spending Level Changes Table. In the letter and table BPA presented the program-level cost estimates to be used in the BP-14 Final Proposal. The IPR2 resulted in cost changes from the spending levels proposed at the end of the IPR, mainly for Power-related costs.

This Study incorporates the spending levels identified in the IPR process, which can be found on BPA's public Web site at Finance & Rates—Financial Public Processes— Integrated Program Review.

2.2 Financial Risk and Mitigation

BPA adopted a long-term policy in its 1993 rates that called for setting rates sufficient for the agency to achieve a 95 percent TPP; that is, a 95 percent probability of making both end-of-year U.S. Treasury payments in full and on time during each two-year rate period. 1993 Administrator's Record of Decision, WP-93-A-02, at 72–73. Beginning with the 2002 power and transmission rates, this standard was applied separately to the transmission and generation functions. The 95 percent TPP standard was reaffirmed in BPA's Financial Plan published in 2008. BPA's Financial Plan (2008) and 10-Year Financial Plan (1993) can be found on BPA's public Web site at Finance & Rates – Financial Information – Financial Plan.

The purpose of the risk analysis is to ensure that the proposed rates will be sufficient to meet BPA's TPP standard. In this rate proceeding, BPA has analyzed its transmission risks and has determined that this rate proposal meets the 95 percent two-year TPP standard for the transmission function for the two-year rate period.

2.2.1 Financial Risk Mitigation Tools

To achieve this level of TPP, the following risk mitigation tools are employed in the BP-14 Initial Proposal.

Financial reserves. Financial reserves comprise cash and other investment instruments in the BPA Fund in the U. S. Treasury and deferred borrowing. Only financial reserves attributed to Transmission Services are considered in the Transmission risk analysis; reserves attributed to Power Services are excluded. Some financial reserves are considered to be not available for risk; such encumbered reserves are not considered in the risk analysis. Encumbered reserves include customer deposits for capital projects related to Large or Small Generator Interconnection Agreements (LGIA or SGIA), Network Open Season, the Southern Intertie capital program, and Master Lease funds. These encumbered reserves are deposits from third parties to pay for specific facilities, security deposits from third parties, or advances through BPA's Master Lease program that are required by the lease agreement terms to be used only for specified projects. $125.2 million of reserves attributed to Transmission Services at the start of FY 2013 are encumbered. Financial reserves available for risk attributed to Transmission Services (TS Reserves) were $486.9 million at the beginning of FY 2013.

Planned Net Revenue for Risk (PNRR). PNRR is a component of the revenue requirement that is added if financial reserves are not sufficient to achieve a 95 percent TPP. When added to the revenue requirement, PNRR increases rates and therefore adds to cash flows, which augments financial reserves. The appropriate amount of PNRR is the amount that is just sufficient to increase TPP until it meets the TPP standard. Since the TPP in this proposal is above 95 percent, no PNRR is required. Documentation Chapter 10.7.

Two-Year Rate Period. BPA is setting 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 before rates can be set again.

2.2.2 Transmission Risk Analysis

To determine whether Transmission rates satisfy BPA's 95 percent TPP standard, BPA runs multiple simulations of the two fiscal years in the rate period and the fiscal year immediately prior to the rate period, FY 2013 through FY 2015. BPA analyzes the effects of uncertainty in expenses and revenues on transmission cash flows using a Monte Carlo simulation method, as noted on Figure 2. Monte Carlo simulation is a method of determining the probability of various outcomes by running multiple trial runs, called games, using random variables for each run. In ratesetting, this method is used to estimate the probability that financial reserves available for risk at the start of the rate period plus the cash flow during the rate period will be sufficient to meet all cash obligations during the rate period. Using the three-year timeframe permits modeling of the uncertainty in revenues and expenses between the time of preparation of the Final Studies now in FY 2013 and the beginning of the rate period. This approach is required because the level of financial reserves at the start of the FY 2014–2015 rate period, which is the primary tool for mitigating Transmission Services' FY 2014–2015 financial risk, cannot be known today; that level depends significantly on events yet to occur in FY 2013. Documentation Chapter 10.1.

The risk analysis simulates changes in reserves from year to year throughout the FY 2013–2015 period for each of 3,500 games (iterations). The analysis estimates the probability that the Treasury payment for both years of the rate period will be made. Successful Treasury payment is deemed to occur in the model when the end-of-year TS Reserves, 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 of $20 million is based on the historical monthly net cash flow patterns and monthly cash requirements for the transmission function. The value of $20 million was used in the last six Transmission ratesetting processes.

The risk analysis starts from a known level of financial reserves at the beginning of FY 2013 and simulates the variability in revenue and expenses that affects the level of reserves throughout FY 2013. When the model simulates the FY 2014–2015 rate period, it starts with the distribution of financial reserves the model simulated for FY 2013. The model then calculates the two-year TPP. If the TPP is below BPA's TPP standard, the model calculates the required amount of PNRR. Input values for point estimates of expenses come from this Study (Documentation Chapter 3), and the revenue inputs are from the revenue forecast (Transmission Rates Study Documentation, BP-14-FS-BPA-07A, Table 12). These inputs, when combined with inputs describing uncertainty in expenses and revenues (Documentation Chapter 10), provide the basis for the calculation of TPP and PNRR. The PNRR amount, in turn, if any, is provided as an input to the transmission revenue requirement, increasing the transmission revenue requirement, transmission rates, and finally TS Reserves as needed to raise TPP.

2.2.3 Transmission Risk Analysis Model

The risk analysis is performed using the Transmission Risk Analysis Model (TRAM), as described in Documentation Chapter 10.1. TRAM is a Microsoft Excel® spreadsheet with the @RISK® add-in from Palisade Corporation (www.palisade.com). (TRAM can be run or interpreted only on computers with licensed copies of @RISK installed.) TRAM was developed to estimate the effects of risk and risk mitigation tools on end-of-year financial reserves and the likelihood of successful end-of-year Treasury payment for each year of the rate period. TS Reserves levels at the end of each fiscal year determine whether BPA is able to meet its Treasury payment obligation. TRAM counts the number of games in which the ending reserves levels for both FY 2014 and FY 2015 are above the liquidity reserves level of $20 million. If this count is 3,325 (95 percent of 3,500) or higher, then the 95 percent TPP standard has been met.

As described in Documentation Chapter 10.1, TRAM contains individual work sheets, including an income statement, a cash flow statement, accrual-to-cash adjustments, and individual work sheets for some revenue variables. Parameters for the probability distributions for risk variables were developed from historical data and/or judgment of subject matter experts familiar with specific areas of transmission risk as the basis for forecasting the uncertainty in those risks. *See id.* Chapters 10.3 and 10.4. The risk analysis is described in more detail in Documentation Chapter 10.

2.2.4 Transmission Risk Analysis Results

The expected value (mean) from the resulting distribution for TS Reserves at the end of FY 2013 is $470 million; at the end of FY 2014, $448 million; and at the end of FY 2015, $386 million. *Id.* Chapter 10.7. The TPP is 99.9 percent, thus meeting BPA's TPP standard. *Id.* Chapter 10.6.

2.3 Capital Investments

BPA transmission capital outlay projections for the FY 2014–2015 rate period are $1,272 million. These investments are:

- transmission programs ($1,213.9 million)
- environmental program ($10.7 million)

- capital equipment ($47.5 million)

Id. Chapter 7.

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 FY 2014–2015 transmission capital program investments. Interest rates on bonds issued by BPA to the U.S. Treasury are set at market interest rates comparable to the interest rates for securities issued by other agencies of the U.S. Government. Interest rates on bonds projected to be issued are included in Documentation 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. After the full implementation of BPA's self-funding authority under the Transmission System Act, Transmission investments were no longer funded by appropriations. The Refinancing Act reset the unpaid principal of all outstanding BPA appropriations and assigned current market interest rates to the principal. 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, $1,461.9 million in BPA appropriations was outstanding. After 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 $257 million as of September 30, 2012.

2.3.3 Use of Financial Reserves for Capital Investment

As a means to fund capital investments in lieu of borrowing, BPA will draw $15 million per year from financial reserves available for risk attributed to TS.

2.3.4 Non-Federal Payment Obligations

The transmission revenue requirements reflect two forms of non-Federal payment obligations. The first is 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 (Schultz-Wautoma line). BPA will make semiannual lease payments for 30 years, concluding with a single payment for the principal due on the bonds issued by NIFC. Payment of the debt incurred by NIFC to construct the line is secured solely by BPA's revenues. During the term of the lease, BPA will operate the Schultz-Wautoma line and provide transmission and ancillary services over the facilities. Since the completion of the Schultz-Wautoma project, BPA has entered into additional lease financing arrangements with NIFC and another entity, the Port of Morrow, and will continue to do so. The revenue requirement includes all transactions BPA expects to complete by the date of the Final Proposal. It does not include forecasts of additional transactions.

The second form of non-Federal payment obligations included in the revenue requirement is the functional reassignment to Transmission Services 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 (DOP), 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 DOP, the debt service obligation associated with new EN debt in equivalent principal amounts is assigned to Transmission Services. The revenue requirements reflect refinancing actions that have occurred through FY 2009, when DOP ended. The revenue requirement does not include forecasts of additional refinancing activities during the rate period.

Specific calculations regarding non-Federal payment obligations are included in Documentation Chapter 8.

2.3.5 Customer-Financed Projects

The revenue requirements also reflect the impacts of customer-financed projects. Customers have financed two types of capital construction projects. The first form of customer financing occurs under generation interconnection agreements (Large Generator Interconnection Agreements, or LGIA, and Small Generator Interconnection Agreements, or SGIA). BPA amended its Open Access Transmission Tariff and adopted the LGIA and SGIA in voluntary compliance with Commission Order Nos. 2003 and 2006. Under the generator interconnection agreements, interconnection customers finance the cost of Network Upgrades (facilities at or beyond the point at which the customer's interconnection facilities connect to BPA's transmission system) 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, with interest on the outstanding balance, are then returned to the interconnection customer in the form of transmission credits. These credits either offset charges for eligible transmission service in the customer's bill or are provided as monthly cash payments based on the generating facility's capacity and its plant capacity factor.

The second form of customer-financed projects is the customer-financed upgrades on the California-Oregon Intertie (COI). The COI upgrade increases COI and Pacific Direct-Current Intertie (PDCI) availability so that BPA is able to support requests for long-term firm transmission service up to the full rating of the COI and PDCI. Like the advance funds provided under generator interconnection agreements, the advance funds provided by customers for the COI upgrade, with interest, will be returned to customers in the form of transmission credits that offset eligible charges for transmission service.

These customer-financed transactions and the associated transmission credits affect several areas of the revenue requirement. Depreciation of the associated assets appears in total transmission depreciation. The interest that accrues on the outstanding credit balances is included in non-Federal interest, a component of the net interest calculation on the income statement. Both of these items increase transmission expenses. These items also appear in the statement of cash flows, because they are non-cash expenses. In addition, the revenues associated with these customer-financed projects for which credits are being returned affect the statement of cash flows because they are non-cash revenues—they provide no cash for cost recovery. Because they provide no cash for cost recovery, non-cash revenues generally increase the need for Minimum Required Net Revenues, which are added to the income statement if necessary to ensure that all cash requirements are met. Non-cash expenses (depreciation and interest on outstanding credit balances) offset non-cash revenues and decrease the need for MRNR. The non-cash expenses are subtracted from the non-cash revenues. If the difference is positive, meaning that non-cash revenues exceed non-cash expenses, the need for MRNR increases. If the difference is negative, meaning that non-cash expenses exceed non-cash revenues, the need for MRNR decreases.

The forecasts of interest expense and transmission credits associated with generator interconnection agreements and with the COI upgrade at current and proposed rates are provided in the Transmission Rates Study Documentation, BP-14-FS-BPA-07A, Tables 17.1 and 17.2.

2.4 Development of Repayment Studies

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

The repayment period is 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 that finance the transmission system are fully repaid within this period. The study horizon also is consistent with the estimated average service life of transmission system plant (40 years), in that it does not exceed that average lifetime. This Study includes the results of transmission repayment studies for each year of the rate period, FY 2014 and FY 2015. The repayment studies include 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 DOE Order RA 6120.2, discussed in section 1.2.2.2.

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 terms of 35 years for transmission investment and

15 years for environmental investment. Some bonds are issued with a provision that allows the bonds 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, which 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 obligations 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 amounts 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 approach reflects the priority of payments in legislation and DOE Order RA 6120.2, in which these non-Federal payment obligations have a higher priority of debt repayment, compared with Federal debt. Therefore, the study schedules the repayment of Federal debt around the non-Federal payment 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. Further discussion of the repayment program is included in Documentation Chapter 13. Repayment policies and requirements are discussed in section 1.2.2.

2.5 Other Uses of Financial Reserves

This Study accounts for two new uses of financial reserves. First, consistent with the decision in the Administrator's Record of Decision on Settlement Proposal for Generation Inputs and

Transmission Ancillary and Control Area Services Rates, BP-14-A-01, the Study reflects the use of $2.4 million per year of Transmission financial reserves for certain purchases for ancillary services. Second, the Study reflects the Administrator's decision to use $40 million, averaging $20 million per year of the rate period, of Transmission financial reserves to fund a portion of Transmission expenses. *See* Administrator's Record of Decision, BP-14-A-03, Issue 4.2.5.5.

2.6 Products Used by Other Studies

This Study and Documentation produce the segmented revenue requirement, which allocates transmission costs among the transmission segments. Documentation Chapter 2 describes the segmentation of the revenue requirement in detail. The segmented revenue requirement is used in the Transmission Rates Study, BP-14-FS-BPA-07, to develop rates for the various transmission products. More detail on the transmission segments is available in the Transmission Segmentation Study, BP-14-FS-BPA-06.

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3. TRANSMISSION REVENUE REQUIREMENTS

3.1 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, any 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) displays the components of the annual revenue requirements, which include Total Operating Expenses (Line 9), Net Interest Expense (Line 20), Minimum Required Net Revenues (Line 22), and Planned Net Revenues for Risk (Line 23). The sum of these four major components is the Total Revenue Requirement (Line 25) for each year of the rate period.

The Minimum Required Net Revenues (Table 3, Line 22) result from an analysis of the Statement of Cash Flows (Table 4). 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 12), driven by Expenses Not Requiring Cash and Non-Cash Revenues, shown in Lines 5 through 11, must be sufficient to compensate for the difference between Cash Used for Capital Investments (Line 16) and Cash from Treasury Borrowing (Line 23). 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 24). The Minimum Required Net

Revenues amount shown on the Statement of Cash Flows (Line 2) then is incorporated in the Income Statement (Table 3, Line 22).

3.2 Current Revenue Test

Consistent with DOE Order RA 6120.2, BPA tests the adequacy of existing rates to meet cost recovery requirements annually. The current revenue test determines whether the revenues expected from current rates will continue to meet cost recovery requirements. BPA forecasts revenues at current rates in the Transmission Rates Study Documentation, Table 12.

For the rate period, the test of the adequacy of current rates is shown on Tables 5 and 6 of this Study. 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 23) for making the planned annual amortization payments. The Total Annual Increase (Decrease) in Cash (Table 6, Line 23) must be at least zero to demonstrate the adequacy of the projected revenues to cover all cash payment requirements. The current revenue test, Table 6, shows that current rates are not sufficient to satisfy cost recovery requirements in the rate period.

3.3 Repayment Test at Current Rates

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 remains after meeting annual expenses requiring cash for the rate period and repayment of the Federal investment. Thus, if the Net Position (Table 7, Column K) is zero or greater in each year of the rate period and 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 negative for each year of the rate period and repayment period.

3.4 Revised Revenue Test

Consistent with DOE Order RA 6120.2, BPA also tests the adequacy of proposed rates. The revised revenue test determines whether the revenues projected from proposed rates will meet cost recovery requirements and the 95 percent Treasury Payment Probability standard for the rate period. The revised revenue test was conducted using the forecast of revenues under proposed rates. BPA forecasts revenues at proposed rates in the Transmission Rates Study Documentation, Table 12.

The test of the adequacy of proposed rates is shown on Tables 8 and 9. Table 8 presents pro forma income statements for each year. Table 9, Statement of Cash Flows, tests the sufficiency of the resulting Net Revenues from Table 8 (Line 23) for making the planned annual amortization. Sufficiency is demonstrated by the Total Annual Increase (Decrease) in Cash (Table 9, Line 23). The annual cash flow (Line 23) must be at least zero to demonstrate the adequacy of the projected revenues to cover all cash payment requirements.

To accommodate cash flows, it was necessary to shift $4.5 million in planned amortization from FY 2014 to FY 2015. The amortization was reshaped to accommodate the shape of the expected revenues without changing the total planned amortization for the rate period. *See* Table 2. This reshaping of amortization has been a common practice in BPA rate proposals. *See, e.g.*, 2007 Supplemental Wholesale Power Rate Case Final Proposal Revenue Requirement Study, WP-07-FS-BPA-10, section 4.3; 2010 Wholesale Power Rate Case Final Proposal Revenue Requirement Study, WP-10-FS-BPA-02, section 4.3. In addition, we reshaped the use of reserves described in section 2.5 by applying the entire $40 million in FY 2015. Since rates are based on the average annual revenue requirement, this reshaping has no impact on rates.

The revised revenue test (Table 9) demonstrates that the total annual impact to cash is positive, indicating that proposed rates are sufficient to satisfy cost recovery requirements in the rate period.

3.5 Repayment Test at Proposed Rates

Table 10 demonstrates whether projected revenues from proposed rates are adequate to meet the cost recovery criteria of DOE Order RA 6120.2 over the repayment period. The data are presented in a format consistent with the revised revenue tests (Tables 8 and 9) and separate accounting analyses. For the purposes of this demonstration, transmission program expenses have been normalized by averaging the two years of the rate period, because rates for transmission services and the resulting revenues are based on the average of the annual expenses and not a single test year. Expenses for each year of the repayment period are assumed to be the normalized expense figure. The focal point of Table 10 is the Net Position (Table 10, Column K), which is the amount of funds provided by revenues that remains 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 period and repayment period, the projected revenues demonstrate BPA's ability to repay the Federal investment in the FCRTS within the allowable time. As shown in Column K, the resulting Net Position is greater than zero for each year of the rate period and repayment period. Thus, the proposed rates are adequate to repay the Federal investment in the FCRTS.

The historical data on Table 10 have been taken from BPA's separate accounting analysis. The rate period data have been developed specifically for this rate proceeding. The repayment period data are presented in a manner consistent with the requirements of DOE Order RA 6120.2.

Table 11 summarizes the amortization of Federal investments over the entire repayment period. It displays the total investment costs of the transmission projects through the cost evaluation period (FY 2013–2015), forecast replacements required to maintain the system through the repayment period, the cumulative dollar amount of the generation investment placed in service, scheduled amortization payments for each year of the repayment period (due and discretionary), unamortized investments including replacements through the repayment period, and unamortized obligations as determined by a term schedule (if all obligations were paid at maturity and never early).

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TABLES

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Table 1: Projected Net Revenues From Proposed Rates

($000s)

		A	B	C
		FY 2014	**FY 2015**	**Rate Period Average**
1	Projected Revenues From Proposed Rates	$1,003,447	$1,024,896	$1,014,172
2	Projected Expenses	876,267	874,414	875,341
3	Net Revenues	$127,180	$150,482	$138,831

Table 2: Planned Repayments to U.S. Treasury

($000s)

		A	B
		Pre-Shift	**Post-Shift**
1	2014	$81,451	$76,951
2	2015	93,619	98,119
3	Total	$175,070	$175,070

Table 3: Transmission Revenue Requirement Income Statement

($000s)

		A	B
		FY 2014	FY 2015
1	OPERATING EXPENSES		
2	TRANSMISSION OPERATIONS	140,729	144,346
3	TRANSMISSION MAINTENANCE	154,234	157,893
4	TRANSMISSION ENGINEERING	41,638	41,769
5	TRANSMISSION ACQ & ANCILLARY SERVICES	125,415	125,530
6	BPA INTERNAL SUPPORT	78,428	80,902
7	OTHER INCOME, EXPENSES & ADJUSTMENTS	(20,000)	(20,000)
8	DEPRECIATION & AMORTIZATION	192,141	202,465
9	TOTAL OPERATING EXPENSES	712,585	732,905
10	INTEREST EXPENSE		
11	INTEREST EXPENSE		
12	FEDERAL APPROPRIATIONS	14,540	13,930
13	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
14	ON LONG-TERM DEBT	109,582	135,310
15	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
16	DEBT SERVICE REASSIGNMENT INTEREST	44,124	36,995
17	NON-FEDERAL INTEREST	43,371	47,967
18	AFUDC	(36,477)	(39,234)
19	INTEREST INCOME	(9,666)	(14,127)
20	NET INTEREST EXPENSE	147,068	162,434
21	TOTAL EXPENSES	859,653	895,338
22	MINIMUM REQUIRED NET REVENUE 1/	129,718	142,452
23	PLANNED NET REVENUES FOR RISK	0	0
24	TOTAL PLANNED NET REVENUE	129,718	142,452
25	**TOTAL REVENUE REQUIREMENT**	**989,371**	**1,037,791**
1/	SEE NOTE ON CASH FLOW TABLE.		

Table 4: Transmission Revenue Requirement Statement of Cash Flows

($000s)

		A	B
		FY 2014	FY 2015
1	CASH FROM CURRENT OPERATIONS:		
2	MINIMUM REQUIRED NET REVENUE 1/	129,718	142,452
3	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	15,000	15,000
4	EXPENSES NOT REQUIRING CASH:		
5	DEPRECIATION & AMORTIZATION	192,141	202,465
6	TRANSMISSION CREDIT PROJECTS NET INTEREST	2,601	1,977
7	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
8	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
9	NON-CASH REVENUES		
10	AC INTERTIE CO/FIBER	(6,583)	(6,583)
11	LGIA	(41,709)	(41,814)
12	CASH PROVIDED BY CURRENT OPERATIONS	272,761	295,090
13	CASH USED FOR CAPITAL INVESTMENTS:		
14	INVESTMENT IN:		
15	UTILITY PLANT	(662,693)	(639,534)
16	CASH USED FOR CAPITAL INVESTMENTS	(662,693)	(639,534)
17	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:		
18	INCREASE IN LONG-TERM DEBT	647,693	624,534
19	DEBT SERVICE REASSIGNMENT PRINCIPAL	(175,093)	(185,173)
20	REPAYMENT OF CAPITAL LEASES	(1,217)	(1,298)
21	REPAYMENT OF LONG-TERM DEBT	(73,050)	0
22	REPAYMENT OF CAPITAL APPROPRIATIONS	(8,401)	(93,619)
23	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	389,932	344,444
24	ANNUAL INCREASE (DECREASE) IN CASH	0	0
25	PLANNED NET REVENUES FOR RISK	0	0
26	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	0	0

1/ Line 24 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	B
		FY 2014	FY 2015
1	REVENUES FROM CURRENT RATES	911,981	932,787
2	OPERATING EXPENSES		
3	TRANSMISSION OPERATIONS	140,729	144,346
4	TRANSMISSION MAINTENANCE	154,234	157,893
5	TRANSMISSION ENGINEERING	41,638	41,769
6	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	127,848	127,963
7	BPA INTERNAL SUPPORT	78,428	80,902
8	OTHER INCOME, EXPENSES & ADJUSTMENTS	(20,000)	(20,000)
9	DEPRECIATION & AMORTIZATION	192,141	202,465
10	TOTAL OPERATING EXPENSES	715,018	735,338
11	INTEREST EXPENSE		
12	INTEREST EXPENSE		
13	FEDERAL APPROPRIATIONS	14,540	13,930
14	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
15	ON LONG-TERM DEBT	109,582	135,310
16	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
17	DEBT SERVICE REASSIGNMENT INTEREST	44,124	36,995
18	NON-FEDERAL INTEREST	49,990	47,967
19	AFUDC	(36,477)	(39,234)
20	INTEREST INCOME	(9,020)	(10,695)
21	NET INTEREST EXPENSE	154,333	165,866
22	TOTAL EXPENSES	869,351	901,203
23	NET REVENUES	42,630	31,584

Table 6: Current Revenue Test Statement of Cash Flows

($000s)

		A	B
		FY 2014	FY 2015
1	CASH FROM CURRENT OPERATIONS		
2	NET REVENUES	42,630	31,584
3	EXPENSES NOT REQUIRING CASH:		
4	DEPRECIATION & AMORTIZATION	192,141	202,465
5	TRANSMISSION CREDIT PROJECTS NET INTEREST	9,220	11,008
6	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
7	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
8	CASH FLOW ADJUSTMENT (RESERVE)/APPLICATION	0	0
	DRAWDOWN OF CASH RESERVES FOR GEN INPUT SETTLEMENT	2,433	2,433
9	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	15,000	15,000
10	ACCRUAL REVENUES (AC INTERTIE/FIBER/LGIA)	(42,170)	(50,041)
11	CASH PROVIDED BY CURRENT OPERATIONS	200,847	194,041
12	CASH USED FOR CAPITAL INVESTMENTS		
13	INVESTMENT IN:		
14	UTILITY PLANT	(662,693)	(639,534)
15	CASH USED FOR CAPITAL INVESTMENTS	(662,693)	(639,534)
16	CASH FROM TREASURY BORROWING AND APPROPRIATIONS		
17	INCREASE IN LONG-TERM DEBT	647,693	624,534
18	DEBT SERVICE REASSIGNMENT PRINCIPAL	(175,093)	(185,173)
19	REPAYMENT OF CAPITAL LEASES	(1,217)	(1,298)
20	REPAYMENT OF LONG-TERM DEBT	(73,050)	0
21	REPAYMENT OF CAPITAL APPROPRIATIONS	(8,401)	(93,619)
22	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	389,932	344,444
23	**ANNUAL INCREASE (DECREASE) IN CASH**	**(71,914)**	**(101,049)**

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

($000s)

	YEAR	A REVENUES (STATEMENT A)	B OPERATION & MAINTENANCE (STATEMENT E)	C AC INTERTIE CAPACITY OWNERSHIP CAPITAL PAYMENTS (REV REQ STUDY DOC,Chapter 8)	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,Chapter 11)	J NON-FEDERAL PRINCIPAL (REV REQ STUDY DOC,Chapter 7)	K NET POSITION (K=H-I-J)
	COMBINED CUMULATIVE											
1	**1977**	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
2	**1978-2010**	16,720,241 0	7,310,113 #	0 #	3,886,726 #	4,779,925 0	743,477 0	3,637,224 #	5,698,516 0	5,100,889 0	15,645 #	581,982
3												
4	**TRANSMISSION**											
5	**2011**	908,008	499,966		192,396	143,858	71,788	110,872	182,660	247,365	154	(64,859)
6	**2012**	965,141	556,839		189,811	129,781	88,710	119,064	207,774	200,110	41,141	(33,477)
7												
8	**COST EVALUATION**											
9	**PERIOD**											
10	**2013**	963,965	561,774		202,680	127,474	72,037	125,988	198,025	56,374	166,810	(25,159)
11	**RATE APPROVAL**											
12	**PERIOD**											
13	**2014**	911,981	539,203		192,141	154,333	26,304	140,784	167,088	76,951	176,310	(86,173)
14	**2015**	932,787	513,138		202,465	165,866	51,318	145,025	196,343	98,119	186,471	(88,247)
15												
16	**REPAYMENT**											
17	**PERIOD**											
18	**2016**	932,787	513,138	(6, 158)	202,465	380,280	(156,938)	152,038	(4,900)	78,619	0	(83,519)
19	**2017**	932,787	513,138	(6, 372)	202,465	397,155	(173,599)	152,038	(21,561)	73,147	0	(94,708)
20	**2018**	932,787	513,138	(6, 564)	202,465	392,644	(168,896)	152,038	(16,858)	77,850	0	(94,708)
21	**2019**	932,787	513,138	(6, 726)	202,465	207,956	15,954	152,038	167,992	262,700	0	(94,708)
22	**2020**	932,787	513,138	(6, 950)	202,465	227,017	(2,883)	152,038	149,155	243,863	0	(94,708)
23												
24	**2021**	932,787	513,138	(7, 138)	202,465	235,484	(11,162)	152,038	140,876	235,584	0	(94,708)
25	**2022**	932,787	513,138	(7, 310)	202,465	236,049	(11,555)	152,038	140,483	235,191	0	(94,708)
26	**2023**	932,787	513,138	(7, 491)	202,465	240,573	(15,898)	152,038	136,140	230,848	0	(94,708)
27	**2024**	932,787	513,138	(7, 649)	202,465	236,173	(11,340)	152,038	140,698	235,406	0	(94,708)
28	**2025**	932,787	513,138	(7, 808)	202,465	216,911	8,081	152,038	160,119	254,827	0	(94,708)
29												
30	**2026**	932,787	513,138	(7, 938)	202,465	220,463	4,659	152,038	156,697	251,405	0	(94,708)
31	**2027**	932,787	513,138	(8, 087)	202,465	221,962	3,309	152,038	155,347	250,055	0	(94,708)
32	**2028**	932,787	513,138	(8, 239)	202,465	220,913	4,510	152,038	156,548	251,256	0	(94,708)
33	**2029**	932,787	513,138	(8, 377)	202,465	221,734	3,827	152,038	155,865	250,573	0	(94,708)
34	**2030**	932,787	513,138	(8, 521)	202,465	225,390	315	152,038	152,353	247,061	0	(94,708)
35												
36	**2031**	932,787	513,138	(8, 664)	202,465	231,017	(5,169)	152,038	146,869	241,577	0	(94,708)
37	**2032**	932,787	513,138	(8, 822)	202,465	229,144	(3,138)	152,038	148,900	243,608	0	(94,708)
38	**2033**	932,787	513,138	(8, 999)	202,465	320,958	(94,775)	152,038	57,263	151,971	0	(94,708)
39	**2034**	932,787	513,138	(9, 147)	202,465	265,886	(39,555)	152,038	112,483	207,191	0	(94,708)
40	**2035**	932,787	513,138	(9, 268)	202,465	234,422	(7,970)	152,038	144,068	238,776	0	(94,708)
41												
42	**2036**	932,787	513,138	(9, 410)	202,465	240,454	(13,860)	152,038	138,178	232,886	0	(94,708)
43	**2037**	932,787	513,138	(9, 570)	202,465	391,837	(165,083)	152,038	(13,045)	81,663	0	(94,708)
44	**2038**	932,787	513,138	(9, 703)	202,465	371,218	(144,331)	152,038	7,707	102,415	0	(94,708)
45	**2039**	932,787	513,138	(9, 798)	202,465	275,258	(48,276)	152,038	103,762	198,470	0	(94,708)
46	**2040**	932,787	513,138	(9, 926)	202,465	287,456	(60,346)	152,038	91,692	186,397	0	(94,705)
47												
48	**2041**	932,787	513,138	(10, 072)	202,465	362,572	(135,316)	152,038	16,722	111,430	0	(94,708)
49	**2042**	932,787	513,138	(10, 190)	202,465	424,330	(196,956)	152,038	(44,918)	49,790	0	(94,708)
50	**2043**	932,787	513,138	(10, 335)	202,465	346,488	(118,969)	152,038	33,069	127,775	0	(94,706)
51	**2044**	932,787	513,138	(10, 447)	202,465	298,697	(71,066)	152,038	80,972	175,672	0	(94,700)
52	**2045**	932,787	513,138	(10, 540)	202,465	295,863	(68,139)	152,038	83,899	178,607	0	(94,708)
53												
54	**2046**	932,787	513,138	(10, 654)	202,465	305,265	(77,427)	152,038	74,611	169,319	0	(94,708)
55	**2047**	932,787	513,138	(10, 779)	202,465	316,173	(88,210)	152,038	63,828	158,536	0	(94,708)
56	**2048**	932,787	513,138	(10, 875)	202,465	328,625	(100,566)	152,038	51,472	146,180	0	(94,708)
57	**2049**	932,787	513,138	(10, 961)	202,465	341,622	(113,477)	152,038	38,561	133,269	0	(94,708)
58	**2050**	932,787	513,138	(11, 033)	202,465	355,018	(126,801)	152,038	25,237	119,945	0	(94,708)
59												
	TRANSMISSION TOTALS	54,049,668	27,940,863	(310,521)	11,952,494	15,604,244	(1,137,412)	9,600,287	9,780,690	10,111,028	586,531	(3,019,510)

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.

Table 8: Revised Revenue Test Income Statement

($000s)

		A	B
		FY 2014	FY 2015
1	REVENUES FROM PROPOSED RATES	1,003,447	1,024,896
2	OPERATING EXPENSES		
3	TRANSMISSION OPERATIONS	140,729	144,346
4	TRANSMISSION MAINTENANCE	154,234	157,893
5	TRANSMISSION ENGINEERING	41,638	41,769
6	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	125,174	127,228
7	BPA INTERNAL SUPPORT	78,428	80,902
8	OTHER INCOME, EXPENSES & ADJUSTMENTS	0	(40,000)
9	DEPRECIATION & AMORTIZATION	192,141	202,465
10	TOTAL OPERATING EXPENSES	732,344	714,603
11	INTEREST EXPENSE		
12	INTEREST EXPENSE		
13	FEDERAL APPROPRIATIONS	14,540	14,257
14	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
15	ON LONG-TERM DEBT	109,582	135,310
16	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
17	DEBT SERVICE REASSIGNMENT INTEREST	44,124	36,995
18	NON-FEDERAL INTEREST	40,207	44,568
19	AFUDC	(36,477)	(39,234)
20	INTEREST INCOME	(9,647)	(13,677)
21	NET INTEREST EXPENSE	143,923	159,812
22	TOTAL EXPENSES	876,267	874,414
23	NET REVENUES	127,180	150,482

Table 9: Revised Revenue Test Statement of Cash Flows

($000s)

		A	B
		FY 2014	FY 2015
1	CASH FROM CURRENT OPERATIONS		
2	NET REVENUES	127,180	150,482
3	EXPENSES NOT REQUIRING CASH:		
4	DEPRECIATION & AMORTIZATION	192,141	202,465
5	TRANSMISSION CREDIT PROJECTS NET INTEREST	2,601	1,977
6	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	561	561
7	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)
8	CASH FLOW ADJUSTMENT (RESERVE)/APPLICATION	0	0
9	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	15,000	15,000
10	ACCRUAL REVENUES (AC INTERTIE/FIBER/LGIA)	(48,292)	(48,397)
11	CASH PROVIDED BY CURRENT OPERATIONS	270,223	303,119
12	CASH USED FOR CAPITAL INVESTMENTS		
13	INVESTMENT IN:		
14	UTILITY PLANT	(662,693)	(639,534)
15	CASH USED FOR CAPITAL INVESTMENTS	(662,693)	(639,534)
16	CASH FROM TREASURY BORROWING AND APPROPRIATIONS		
17	INCREASE IN LONG-TERM DEBT	647,693	624,534
18	DEBT SERVICE REASSIGNMENT PRINCIPAL	(175,093)	(185,173)
19	REPAYMENT OF CAPITAL LEASES	(1,217)	(1,298)
20	REPAYMENT OF LONG-TERM DEBT	(73,050)	0
21	REPAYMENT OF CAPITAL APPROPRIATIONS	(3,901)	(98,119)
22	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	394,432	339,944
23	**ANNUAL INCREASE (DECREASE) IN CASH**	**1,962**	**3,529**

Table 10: Transmission Revenues from Proposed 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)	DEBT SERVICE OFFSETS (REV REQ STUDY DOC,Chapter?)	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,Chapter 11)	NON-FEDERAL PRINCIPAL (REV REQ STUDY DOC,Chapter 7)	NET POSITION (K=H-I-J)
1	**1977**	3,298,951	963,839	348,748	807,047	1,220,170	(40,853)	807,047	766,194	628,460		137,734
2	**1978-2012**	16,720,241 0	7,310,113 #	0 #	3,886,726 #	4,779,925 0	743,477 0	3,637,224 #	5,698,516 0	5,100,889 0	15,645 #	581,982
3												
4	**TRANSMISSION**											
5	**2011**	908,008	499,966		192,396	143,858	71,788	110,872	182,660	247,365	154	(64,859)
6	**2012**	965,141	556,839		189,811	129,781	88,710	119,064	207,774	200,110	41,141	(33,477)
7												
8	**COST EVALUATION**											
9	**PERIOD**											
10	**2013**	963,965	561,774		202,680	127,474	72,037	125,988	198,025	56,374	166,810	(25,159)
11	**RATE APPROVAL**											
12	**PERIOD**											
13	**2014**	1,003,447	540,203		192,141	143,923	127,180	128,043	255,223	76,951	176,310	1,962
14	**2015**	1,024,896	512,138		202,465	159,812	150,481	137,638	288,119	98,119	186,471	3,529
15												
17	**REPAYMENT**											
18	**PERIOD**											
19	**2016**	1,024,896	512,138	(6,158)	202,465	177,190	139,261	137,638	276,899	78,619	186,755	11,525
20	**2017**	1,024,896	512,138	(6,372)	202,465	179,290	137,375	137,638	275,013	73,147	201,530	336
21	**2018**	1,024,896	512,138	(6,564)	202,465	183,126	133,731	137,638	271,369	77,850	193,183	336
22	**2019**	1,024,896	512,138	(6,726)	202,465	185,241	131,778	137,638	269,416	262,700	6,380	336
23	**2020**	1,024,896	512,138	(6,950)	202,465	189,452	127,791	137,638	265,429	243,863	21,230	336
24												
25	**2021**	1,024,896	512,138	(7,138)	202,465	197,130	120,301	137,638	257,939	235,584	22,019	336
26	**2022**	1,024,896	512,138	(7,310)	202,465	197,530	120,073	137,638	257,711	235,191	22,184	336
27	**2023**	1,024,896	512,138	(7,491)	202,465	201,052	116,732	137,638	254,370	230,848	23,186	336
28	**2024**	1,024,896	512,138	(7,649)	202,465	201,659	116,283	137,638	253,921	235,406	18,179	336
29	**2025**	1,024,896	512,138	(7,808)	202,465	199,996	118,105	137,638	255,743	254,827	580	336
30												
31	**2026**	1,024,896	512,138	(7,938)	202,465	203,507	114,724	137,638	252,362	251,405	621	336
32	**2027**	1,024,896	512,138	(8,087)	202,465	204,962	113,418	137,638	251,056	250,055	665	336
33	**2028**	1,024,896	512,138	(8,239)	202,465	203,877	114,655	137,638	252,293	251,256	701	336
34	**2029**	1,024,896	512,138	(8,377)	202,465	204,661	114,009	137,638	251,647	250,573	738	336
35	**2030**	1,024,896	512,138	(8,521)	202,465	208,268	110,546	137,638	248,184	247,061	787	336
36												
37	**2031**	1,024,896	512,138	(8,664)	202,465	209,333	109,624	137,638	247,262	241,577	5, 349	336
38	**2032**	1,024,896	512,138	(8,822)	202,465	205,898	113,217	137,638	250,855	243,608	6, 911	336
39	**2033**	1,024,896	512,138	(8,999)	202,465	207,960	111,332	137,638	248,970	151,971	96, 663	336
40	**2034**	1,024,896	512,138	(9,147)	202,465	212,613	106,827	137,638	244,465	207,191	36, 938	336
41	**2035**	1,024,896	512,138	(9,268)	202,465	210,972	108,589	137,638	246,227	238,776	7,115	336
42												
43	**2036**	1,024,896	512,138	(9,410)	202,465	217,171	102,532	137,638	240,170	232,886	6,948	336
44	**2037**	1,024,896	512,138	(9,570)	202,465	218,550	101,313	137,638	238,951	81,663	156,952	336
45	**2038**	1,024,896	512,138	(9,703)	202,465	222,842	97,154	137,638	234,792	102,415	132,041	336
46	**2039**	1,024,896	512,138	(9,798)	202,465	226,787	93,304	137,638	230,942	198,470	32,136	336
47	**2040**	1,024,896	512,138	(9,926)	202,465	234,383	85,836	137,638	223,474	186,397	36,738	339
48												
49	**2041**	1,024,896	512,138	(10,072)	202,465	236,829	83,536	137,638	221,174	111,430	109,408	336
50	**2042**	1,024,896	512,138	(10,190)	202,465	246,863	73,620	137,638	211,258	49,790	161, 132	336
51	**2043**	1,024,896	512,138	(10,335)	202,465	256,306	64,322	137,638	201,960	127,775	73, 847	338
52	**2044**	1,024,896	512,138	(10,447)	202,465	267,238	53,502	137,638	191,140	175,672	15, 124	344
53	**2045**	1,024,896	512,138	(10,540)	202,465	279,528	41,305	137,638	178,943	178,607	0	336
54												
55	**2046**	1,024,896	512,138	(10,654)	202,465	288,930	32,017	137,638	169,655	169,319	0	336
56	**2047**	1,024,896	512,138	(10,779)	202,465	299,838	21,234	137,638	158,872	158,536	0	336
57	**2048**	1,024,896	512,138	(10,875)	202,465	312,290	8,878	137,638	146,516	146,180	0	336
58	**2049**	1,024,896	512,138	(10,961)	202,465	325,287	(4,033)	137,638	133,605	133,269	0	336
59	**2050**	1,024,896	512,138	(11,033)	202,465	338,683	(17,357)	137,638	120,281	119,945	0	336
60												
61	**TRANSMISSION**											
62	**TOTALS**	57,457,058	28,418,001	(310,521)	11,952,494	13,440,015	4,469,207	9,076,159	14,863,181	10,111,028	2,162,571	486,941

1/CONSISTS OF DEPRECIATION PLUS ANY ACCOUNTING WRITE-OFFS INCLUDED IN EXPENSES.
IN THE REPAYMENT PERIOD NON-FEDERAL DEBT SERVICE (PRINCIPAL AND INTEREST) IS INCLUDED IN NET INTEREST EXPENSE.

Table 11: Amortization of Transmission Investments Over Repayment Period

($000s)

	A	B	C	D	E	F	G	H
				Investments Placed in Service				
	Fiscal Year	Original & New Obligations	Replacements	Cumulative Amount In Service	Due Amortization	Discretionary Amortization	Unamortized Investment	Term Investment Schedule
1	2012	9,995,108	-	9,995,108	-	-	2,208,242	6,012,786
2	2013	445,956	-	10,441,064	-	56,374	2,599,294	6,331,832
3	2014	647,810	-	11,088,874	73,050	3,901	3,170,153	6,716,229
4	2015	624,650	-	11,713,524	-	98,119	3,696,684	7,025,692
5	2016	-	189,512	11,903,036	19,500	59,119	3,807,577	6,961,057
6	2017	-	196,922	12,099,958	36,400	36,747	3,931,352	6,734,230
7	2018	-	203,574	12,303,532	-	77,850	4,057,076	6,696,801
8	2019	-	208,629	12,512,161	195,790	66,910	4,003,005	6,543,658
9	2020	-	215,471	12,727,632	166,580	77,283	3,974,613	6,509,707
10	2021	-	221,414	12,949,046	105,160	130,424	3,960,442	6,562,724
11	2022	-	226,804	13,175,850	105,000	130,191	3,952,055	6,631,517
12	2023	-	232,252	13,408,102	46,000	184,848	3,953,459	6,817,769
13	2024	-	236,640	13,644,742	45,000	190,406	3,954,693	7,009,409
14	2025	-	241,160	13,885,902	102,300	152,527	3,941,026	7,125,636
15	2026	-	244,724	14,130,626	45,000	206,405	3,934,346	7,325,360
16	2027	-	248,878	14,379,504	30,000	220,055	3,933,168	7,544,238
17	2028	-	253,053	14,632,557	68,899	182,357	3,934,966	7,522,441
18	2029	-	256,959	14,889,516	55,380	195,193	3,941,352	7,708,298
19	2030	-	261,392	15,150,908	5,380	241,681	3,955,683	7,830,032
20	2031	-	265,934	15,416,842	-	241,577	3,980,040	7,795,966
21	2032	-	270,853	15,687,695	98,900	144,708	4,007,286	7,419,019
22	2033	-	276,407	15,964,102	40,000	111,971	4,131,722	6,985,464
23	2034	-	281,566	16,245,668	40,000	167,191	4,206,096	6,928,630
24	2035	-	285,629	16,531,297	165,000	73,776	4,252,949	6,924,259
25	2036	-	290,425	16,821,722	100,000	132,886	4,310,489	7,114,684
26	2037	-	295,659	17,117,381	35,000	46,663	4,524,485	7,340,343
27	2038	-	300,168	17,417,549	55,000	47,415	4,722,238	7,585,511
28	2039	-	303,420	17,720,969	141,970	56,500	4,827,188	7,711,961
29	2040	-	308,011	18,028,980	162,371	24,026	4,948,801	7,800,512
30	2041	-	313,067	18,342,047	84,220	27,210	5,150,439	8,029,359
31	2042	-	317,258	18,659,305	-	49,790	5,417,907	8,346,617
32	2043	-	322,295	18,981,600	96,500	31,275	5,612,427	8,404,622
33	2044	-	326,338	19,307,938	175,672	-	5,763,093	8,434,220
34	2045	-	329,605	19,637,543	125,270	53,337	5,914,091	8,638,555
35	2046	-	333,499	19,971,042	145,720	23,599	6,078,271	8,826,334
36	2047	-	338,102	20,309,144	139,440	19,096	6,257,837	9,024,996
37	2048	-	341,663	20,650,807	104,066	42,114	6,453,320	9,262,593
38	2049	-	344,541	20,995,348	94,280	38,989	6,664,592	9,512,854
39	2050	-	347,044	21,342,392	103,390	16,555	6,891,691	9,756,508
		$11,713,524	**$9,628,868**		**$3,006,238**	**$3,659,067**		

BONNEVILLE POWER ADMINISTRATION
DOE/BP-4544 • July 2013