BP-26 Rate Proceeding

Final Proposal

Transmission Revenue Requirement Study

BP-26-FS-BPA-09

July 2025

TRANSMISSION REVENUE REQUIREMENT STUDY

Table of Contents

FIGURE

TABLES 27

COMMONLY USED ACRONYMS AND SHORT FORMS

AAC	Anticipated Accumulation of Cash
ACNR	Accumulated Calibrated Net Revenue
ACS	Ancillary and Control Area Services
AF	Advance Funding
AFUDC	Allowance for Funds Used During Construction
AGC	automatic generation control
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
BPAP	Bonneville Power Administration Power
BPAT	Bonneville Power Administration Transmission
Bps	basis points
Btu	British thermal unit
CAISO	California Independent System Operator
CIP	Capital Improvement Plan
CIR	Capital Investment Review
CDQ	Contract Demand Quantity
CGS	Columbia Generating Station
CHWM	Contract High Water Mark
CNR	Calibrated Net Revenue
COB	California-Oregon border
COE	U.S. Army Corps of Engineers
COI	California-Oregon Intertie
Commission	Federal Energy Regulatory Commission
Corps	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council (see also “NPCC”)
COVID-19	coronavirus disease 2019
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CRFM	Columbia River Fish Mitigation
CSP	Customer System Peak
CT	combustion turbine
CWIP	Construction Work in Progress
CY	calendar year (January through December)
DD	Dividend Distribution
DDC	Dividend Distribution Clause
dec	decrease, decrement, or decremental
DERBS	Dispatchable Energy Resource Balancing Service

DFS	Diurnal Flattening Service
DNR	Designated Network Resource
DOE	Department of Energy
DOI	Department of Interior
DSI	direct-service industrial customer or direct-service industry
DSO	Dispatcher Standing Order
EE	Energy Efficiency
EESC	EIM Entity Scheduling Coordinator
EIM	Energy imbalance market
EIS	Environmental Impact Statement
ELMP	Extended Locational Marginal Pricing
EN	Energy Northwest, Inc.
ESA	Endangered Species Act
ESS	Energy Shaping Service
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
FERC	Federal Energy Regulatory Commission
FMM-IIE	Fifteen Minute Market – Instructed Imbalance Energy
FOIA	Freedom of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FRP	Financial Reserves Policy
F&W	Fish & Wildlife
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
GDP	Gross Domestic Product
GI	generation imbalance
GMS	Grandfathered Generation Management Service
GSP	Generation System Peak
GSR	Generation Supplied Reactive
GRSPs	General Rate Schedule Provisions
GTA	General Transfer Agreement
GWh	gigawatthour
HLH	Heavy Load Hour(s)
HOSS	Hourly Operating and Scheduling Simulator (computer model)
HYDSIM	Hydrosystem Simulator (computer model)
IE	Eastern Intertie
IIE	Instructed Imbalance Energy
IM	Montana Intertie
inc	increase, increment, or incremental

IOU	investor-owned utility
IP	Industrial Firm Power
IPR	Integrated Program Review
IR	Integration of Resources
IRD	Irrigation Rate Discount
IRM	Irrigation Rate Mitigation
IRPL	Incremental Rate Pressure Limiter
IS	Southern Intertie
kcfs	thousand cubic feet per second
KSI	key strategic initiative
kW	kilowatt
kWh	kilowatthour
LAP	Load Aggregation Point
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)
LMP	Locational Marginal Price
LPP	Large Project Program
LT	long term
LTF	Long-term Firm
Maf	million acre-feet
Mid-C	Mid-Columbia
MMBtu	million British thermal units
MNR	Modified Net Revenue
MRNR	Minimum Required Net Revenue
MW	megawatt
MWh	megawatthour
NCP	Non-Coincidental Peak
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NFB	**N**ational Marine Fisheries Service (NMFS) **F**ederal Columbia River Power System (FCRPS) **B**iological Opinion (BiOp)
NLSL	New Large Single Load
NMFS	National Marine Fisheries Service
NOAA Fisheries	National Oceanographic and Atmospheric Administration Fisheries
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
NWPA	Northwest Power Act/Pacific Northwest Electric Power Planning and Conservation Act
NP-15	North of Path 15
NPCC	Northwest Power and Conservation Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service

NRU	Northwest Requirements Utilities
NT	Network Integration
NTSA	Non-Treaty Storage Agreement
NUG	non-utility generation
NWPP	Northwest Power Pool
OATT	Open Access Transmission Tariff
O&M	operations and maintenance
OATI	Open Access Technology International, Inc.
ODE	Over Delivery Event
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
PF	Priority Firm Power
PFp	Priority Firm Public
PFx	Priority Firm Exchange
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
POR	Point of Receipt
PPC	Public Power Council
PRSC	Participating Resource Scheduling Coordinator
PS	Power Services
PSC	power sales contract
PSW	Pacific Southwest
PTP	Point-to-Point
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RAS	Remedial Action Scheme
RCD	Regional Cooperation Debt
RD	Regional Dialogue
RDC	Reserves Distribution Clause
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
REP	Residential Exchange Program
REPSIA	REP Settlement Implementation Agreement
RevSim	Revenue Simulation Model
RFA	Revenue Forecast Application (database)
RHWM	Rate Period High Water Mark
ROD	Record of Decision
RPSA	Residential Purchase and Sale Agreement
RR	Resource Replacement
RRS	Resource Remarketing Service
RSC	Resource Shaping Charge

RSS	Resource Support Services
RT1SC	RHWM Tier 1 System Capability
RTD-IIE	Real-Time Dispatch – Instructed Imbalance Energy
RTIEO	Real-Time Imbalance Energy Offset
SCD	Scheduling, System Control, and Dispatch Service
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
SMCR	Settlements, Metering, and Client Relations
SP-15	South of Path 15
T1SFCO	Tier 1 System Firm Critical Output
TC	Tariff Terms and Conditions
TCMS	Transmission Curtailment Management Service
TDG	Total Dissolved Gas
TGT	Townsend-Garrison Transmission
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
Treaty	Columbia River Treaty
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
UDE	Under Delivery Event
UFE	unaccounted for energy
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
UIE	Uninstructed Imbalance Energy
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers
USFWS	U.S. Fish & Wildlife Service
VER	Variable Energy Resource
VERBS	Variable Energy Resource Balancing Service
VOR	Value of Reserves
VR1-2014	First Vintage Rate of the BP-14 rate period (PF Tier 2 rate)
VR1-2016	First Vintage Rate of the BP-16 rate period (PF Tier 2 rate)
WECC	Western Electricity Coordinating Council
WSPP	Western Systems Power Pool

This page intentionally left blank.

1. INTRODUCTION

1.1 Purpose of the Study

The purpose of the Transmission Revenue Requirement Study (Study) is to establish the revenues from transmission and ancillary services that are necessary to recover, in accordance with sound business principles, the Federal Columbia River Transmission System (FCRTS) costs associated with the transmission of electric power. 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 the Bonneville Power Administration's (BPA) power rates. The 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.

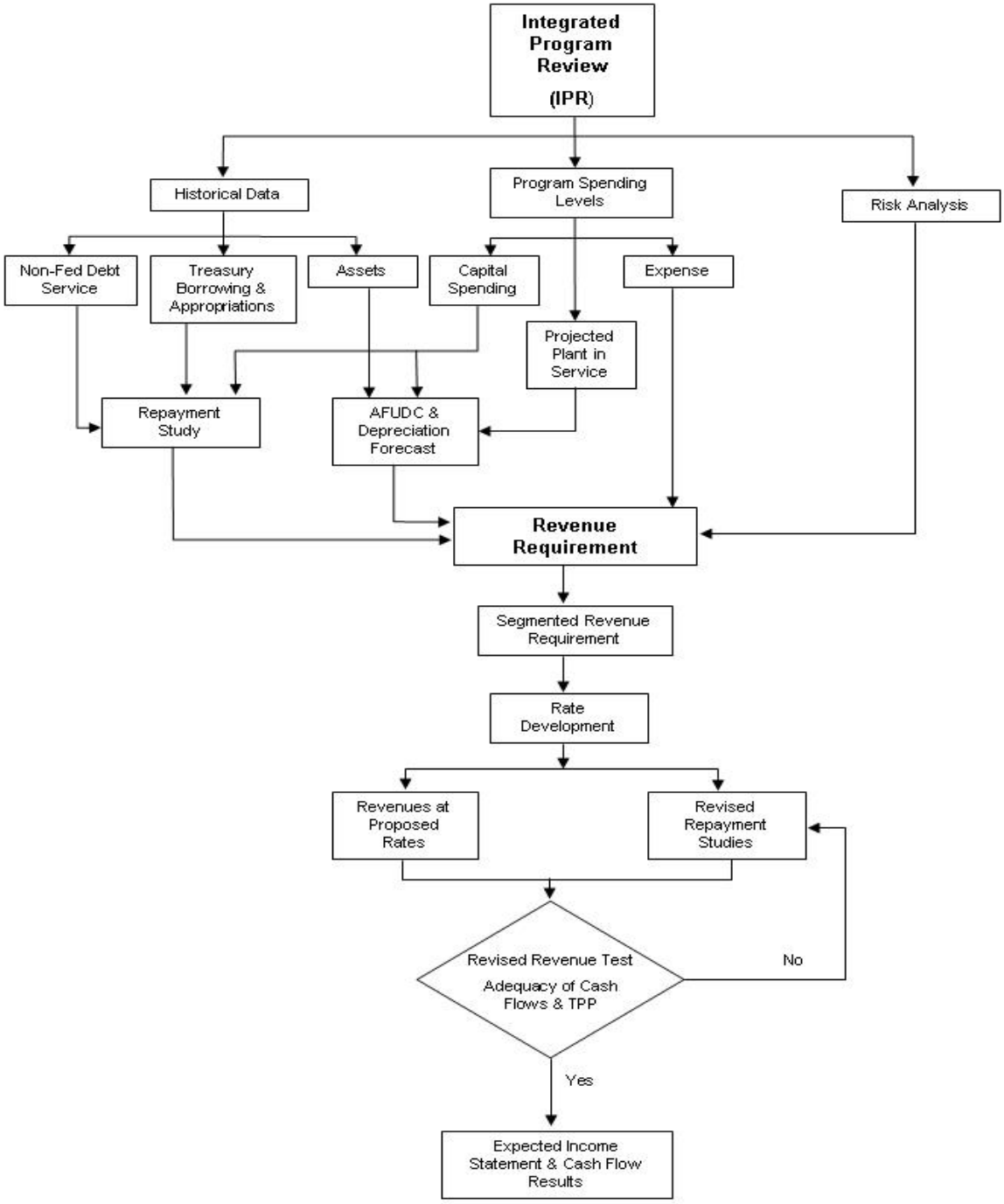
The cost evaluation period, as defined by the Federal Energy Regulatory Commission (FERC or Commission), is the period extending from the last year for which historical information is available through the proposed rate period. The cost evaluation period for this Final Proposal filing includes fiscal year (FY) 2025 and the proposed rate period, FY 2026-2028. This Study is based on transmission revenue requirements that include the results of transmission repayment studies. This Study does not include the revenue

requirement or a cost recovery demonstration for BPA's power function. *See* Power Revenue Requirement Study, BP-26-FS-BPA-02.

This Study outlines the policies, forecasts, assumptions, and calculations used to determine the transmission revenue requirement. The Transmission Revenue Requirement Study Documentation, BP-26-FS-BPA-09A, contains key technical assumptions and calculations, the results of the transmission repayment studies, and further explanation of the repayment program and its outputs.

The revenue requirement for this Study is developed using a cost accounting analysis comprised of three parts. First, repayment studies for the transmission function are prepared to determine the schedule of amortization payments and to project 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 period and extend over the 35-year repayment period. Second, transmission operating expenses and Minimum Required Net Revenue (MRNR) are projected for each year of the rate period. Third, annual Planned Net Revenues for Risk (PNRR) are determined after taking into account risks, BPA's cost recovery goals, and other risk mitigation measures, as described in the Power and Transmission Risk Study, BP-26-FS-BPA-05. From these three steps, the revenue requirement is set at the level necessary to fulfill cost recovery requirements and objectives. This process is depicted in Figure 1, below. Once the revenue requirement is completed, it is segmented and passed to the rate development process, where it is used to develop rates.

Figure 1: Transmission Revenue Requirement Process



Consistent with Department of Energy (DOE) Order RA 6120.2 and the standards applied by the Commission on review of BPA's rates, BPA must determine the adequacy of both current and proposed rates to recover the revenue requirement. BPA conducts a current revenue test to determine whether revenues projected from current rates meet cost recovery requirements for the rate period and the repayment period. If the current revenue test indicates that cost recovery and risk mitigation requirements are met, current rates could be extended through the proposed rate approval period. The current revenue test, described in Section 3.2 of this study, demonstrates that revenues from current rates would not be adequate to recover the transmission revenue requirement for the rate period.

The revised revenue test, which is performed after calculation of the proposed transmission rates, determines whether projected revenues from proposed rates meet cost recovery requirements for the rate test and repayment periods. The revised revenue test, Section 3.3 of this Study, demonstrates that revenues from the proposed transmission rates will recover transmission costs in the rate period and over the ensuing 35-year repayment period. In addition, revenues from the proposed rates, together with risk mitigation tools, are sufficient to meet BPA's 95 percent Treasury Payment Probability standard that all U.S. Treasury payments will be paid on time and in full, as discussed in the Power and Transmission Risk Study, BP-26-FS-BPA-05, §2.4.

Table 1 (see tables at end of this document) summarizes the revised revenue test and shows projected net revenues from proposed transmission rates for FY 2026-2028. These net revenues are the lowest level sufficient to achieve, in combination with other risk mitigation tools, BPA's cost recovery objectives in the face of transmission-related risks.

Table 2 shows planned transmission amortization payments 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 BPA follows in the development of its revenue requirement.

1.2.1 Governing Authorities

BPA's revenue requirements are governed primarily by four legislative acts: the Bonneville Project Act of 1937, Pub. L. No. 75-329, 50 Stat. 731, amended 1977; the Flood Control Act of 1944, Pub. L. No. 78-534, 58 Stat. 890, amended 1977; the Federal Columbia River Transmission System Act of 1974 (Transmission System Act), Pub. L. No. 93-454, 88 Stat. 1376, amended 1977; and the Pacific Northwest Electric Power Planning and Conservation Act (Northwest Power Act), Pub. L. No. 96-501, 94 Stat. 2697. The Omnibus Consolidated Rescissions and Appropriations Act of 1996, Pub. L. No. 104-134, 110 Stat. 1321, also guides the development of BPA's revenue requirements.

Department of Energy Order "Power Marketing Administration Financial Reporting," RA 6120.2, issued by the Secretary of Energy, provides guidance to federal power marketing administrations 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; and(d) maintain the electrical stability and reliability of the federal system. Transmission System Act § 4, 16 U.S.C. § 838b.

BPA's rates must be set to ensure that revenues are sufficient to recover costs. This requirement was first set forth in Section 7 of the Bonneville Project Act, 16 U.S.C. § 832f , which provides that

> [r]ate 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 Corps reservoir projects in Section 5 of the Flood Control Act of 1944, 16 U.S.C. § 825s. 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

> [t]he 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.

Section 7(a)(2) of the Northwest Power Act, 16 U.S.C. § 839e(a)(2), provides that the Commission shall issue a confirmation and approval of BPA's rates upon a finding that the 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 last rate period, BPA's transmission rates for the FY 2026-28 rate period will reflect the requirements of the Refinancing Act, 16 U.S.C. § 838l, part of the Omnibus Consolidated Rescissions and Appropriations Act of 1996, Pub. 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 U.S. Treasury yield curve prevailing at the time of the refinancing transaction. 16 U.S.C. § 838l(a)(6)(A).

The Refinancing Act restricted 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 will 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 books of account; 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 those for 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. This methodology has enabled BPA to set power and transmission rates separately with minimal change in repayment policy and the process for developing each revenue requirement. This Study incorporates only the repayment study for the transmission function for FY 2026-2028.

1.2.2.2 Repayment Schedules

The statutes applicable to BPA do not include directives for scheduling repayment of capital appropriations and bonds issued to the U.S. 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. 89-1409, 2d Sess., at 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 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 administrations, 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 start 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 on 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 administrations; it describes standard policies and procedures for preparing system repayment studies.

BPA and the other federal power marketing agencies were transferred to the newly established Department of Energy on October 1, 1977. Department of Energy Organization Act, 42 U.S.C. § 7101 *et seq.* 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, and 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
- as required by Pub. L. No. 89-448, § 2, 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.

Transmission has not received any Congressional appropriations since the mid-1970s and all historical appropriations have been fully repaid. If it were to receive new appropriations for construction projects, due dates would be the maximum allowable repayment period for transmission invesments, which is currently 35 years. The Refinancing Act (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 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.

2. DEVELOPMENT OF REVENUE REQUIREMENT

2.1 Forecast Cost Development

The development of forecast costs occurs outside the rate process. For the FY 2026-2028 rate period, it began in June 2024, when BPA hosted the first Integrated Program Review (IPR) workshop. This public process focused on reviewing and discussing expense projections and capital forecasts. The process provided customers and interested parties an opportunity to examine, understand, and comment on BPA's cost projections for BPA's power and transmission functions.

BPA began the IPR discussion with the release of the IPR initial publication and an opening workshop containing an overview of Power Services, Transmission Services, and corporate agency services forecast expenses and capital costs for FY 2026-2028. The opening workshop launched a public comment period, providing participants the opportunity to provide feedback on the forecast costs. The initial publication and workshop described the drivers, goals, and risks associated with the forecast expense and capital costs; and made comparisons to the last rate case.

Following the opening workshop, BPA held a series of workshops to discuss forecast costs for the program areas, including the Chief Administrative Office, Information Technology, Federal Hydro, Columbia Generating Station, Environment Fish and Wildlife, Energy Efficiency, and Transmission. While debt management actions are outside the scope of the IPR process, a workshop was held to enhance participants' understanding of the implications of past debt management decisions, forecast capital costs, and potential debt management tools. This includes forecasts of net interest expense and depreciation and

amortization expense, which includes amortization of the terminated I-5 reinforcement project. After considering the comments received, BPA released the BP-26 IPR Close-Out Report in October 2024. This Study incorporates the forecast costs identified in the BP-26 IPR Close-Out Report, which can be found on BPA's public website: https://www.bpa.gov/about/finance/bp-26-ipr.

After issuance of the BP-26 IPR Close-Out Report, and consistent with the Federal Register Notice for this rate proceeding, commenters had until March 3, 2025 to provide comments regarding any new information or changed circumstances that arose after publication of the Federal Register Notice. BPA received three comments. BPA did not modify its forecasts of transmission program spending in response to the comments received. BPA's response to the stakeholder comments was posted on May 27, 2025 and can be found on BPA's public website noted above.

2.2 Capital Investments

The forecast of BPA's capital investments for FY 2026-2028 used to develop the BP-26 transmission Final Proposal rates was published in the IPR closeout report. The following section describes the capital investment forecasts.

BPA transmission forecast capital costs including allowance for funds used during construction (AFUDC) for the FY 2026-2028 rate period are $4.3 billion. Rounded, these investments, fully loaded with AFUDC, are:

- Transmission programs ($4.2 billion)
- Environmental program ($21.8 million)
- Corporate capital program ($78.2 million)

Transmission Revenue Requirement Study Documentation, BP-26-FS-BPA-09A, Table 7-2.

2.2.1 Bonds Issued to the Treasury

Bonds issued to the U.S. Treasury will be the primary source of capital used to finance projected FY 2026-2028 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. For interest rates on bonds projected to be issued, *see id.,* Ch. 6.

2.2.2 Federal Appropriations

All Congressional Appropriations related to the Transmission system have been fully repaid. As a result, the repayment study no longer includes any obligation to repay appropriations.

2.2.3 Revenues for Capital Investment

The revenue requirement assumes that $125 million per year of the capital program is funded with current revenues.

2.2.4 Non-Federal Payment Obligations

The transmission revenue requirements reflect one form of non-federal payment obligation: the lease purchase arrangements for assets. BPA entered into its first 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). Since the completion of the Schultz-Wautoma project, BPA has entered into additional lease financing arrangements with NIFC, Port of Morrow, and Idaho Energy Resources Authority. BPA constructs the facilities financed by the lease holder. BPA makes periodic lease payments. During the

term of the lease, BPA operates the facilities. At the end of the lease, BPA has an option to purchase the facilities for a nominal fee. The revenue requirement includes all transactions BPA expects to complete by the date of the Final Proposal. BPA does not currently anticipate entering into new lease purchase arrangements in the rate period.
For specific calculations regarding non-federal payment obligations, *see id.*, Chapter. 8.

2.2.5 Customer-Financed Projects

The revenue requirements also reflect the impacts of customer-financed projects. Customers have financed capital construction projects under generator interconnection agreements (LGIA 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.

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 customer-financed projects for which customers receive credits affect the statement of cash flows because they are non-cash revenues—they provide no cash for cost recovery. Therefore, they generally increase the need for MRNR, which is 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.

2.3 Modeling of BPA's Repayment Obligations

Repayment studies are performed as part of the process for determining revenue requirements. The studies establish a schedule of annual U.S. Treasury amortization for the rate period and the resulting interest payments. Each repayment study covers a rate test year and the ensuing repayment period, which extends to the last year by which all outstanding and projected obligations must be repaid. For transmission repayment studies, that period is 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. This study horizon

is also appropriate in that it does not exceed the estimated average service life of transmission system plant (45 years).

In conducting the repayment studies, BPA includes as fixed inputs the annual debt service payments associated with its non-federal capitalized contract obligations and the fixed annual payments associated with long-term energy resource acquisition contracts. All outstanding and projected transmission repayment obligations for appropriated investments and bonds issued to the U.S. Treasury are included to be scheduled for repayment. Forecast transmission repayment obligations related to the lease purchase program are also modeled and scheduled for repayment. Funding for replacements projected during the repayment period is also included in the repayment study, consistent with the requirements of DOE Order RA 6120.2.

Appropriations and bonds are scheduled to be repaid within the expected useful life of the associated facility, or the maximum repayment period (50 years for generation and 35 years for transmission), whichever is less. Bonds issued by BPA to the U.S. Treasury have varying terms, taking into account the estimated average service lives for investments and prudent financing and cash management factors. Projected lease purchase obligations assumed in the repayment study are held to the same parameters.

In the repayment studies, all projected bonds are issued with maturities not to exceed 30 years for transmission investment, although they can be refinanced within the 35-year repayment period. Environmental investments have a maximum term of 15 years. Corporate investments, generally for information technology, are for a five-year period. Generally bonds are issued with a provision that allows the bonds to be called any time.

Bonds also may be issued with provisions such as a five-year call or a no call provision. Early retirement of eligible bonds may require that BPA pay a bond premium to the Treasury. Bonds may also be called and repaid at a discount. Bonds are issued to finance BPA transmission, environment, and corporate investments and are repaid within the provisions of each bond agreement with the Treasury.

Based on these parameters, the repayment study establishes a schedule of planned amortization payments and resulting interest expense by determining the lowest levelized debt service stream necessary to repay all transmission obligations within the required repayment period.

For further discussion of the repayment program, *see* Transmission Revenue Requirement Study Documentation, BP-26-FS-BPA-09A, Chapter 12.

2.4 Products Used by Other Studies

This Study produces the segmented revenue requirement, which allocates transmission costs among transmission segments. Chapter 2 of the documentation for this Study describes the segmentation of the revenue requirement in detail. *Id.*, Ch. 2. The segmented revenue requirement is used in the Transmission Rates Study and Documentation to develop rates for the various transmission products. More detail on the transmission segments is available in the Transmission Segmentation Study and Documentation, BP-26-FS-BPA-07.

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 PNRR and, if necessary, a MRNR component. The Statement of Cash Flows shows the analysis used to determine MRNR 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 23), MRNR (line 27), and PNRR (line 28). The sum of these four major components is the total revenue requirement (line 31) for each year of the rate period.

The MRNR (Table 3, line 27) results from an analysis of the Statement of Cash Flows (Table 4). MRNR 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 11), driven by expenses not requiring cash and non-cash revenues, shown in lines 3 through 10, must be sufficient to compensate for the difference between cash used for capital investments (line 16) and cash from Treasury borrowing (line 24). If cash provided by current operations is not sufficient, MRNR (line 2) must be included in revenue requirements to accommodate the shortfall, yielding at least

a zero annual increase in cash (line 26). The MRNR amount shown on the Statement of Cash Flows (line 2) then is incorporated in the Income Statement (Table 3, line 27).

In support of the BP-26 Transmission Rates Settlement Agreement, which calls for a revenue requirement that is $50 million per year lower than the Initial Proposal, this Study includes an expense offset that functions like an undistributed reduction. After refreshing forecasts of depreciation, interest expense, and debt repayment, which are costs modeled in the rate case, the expense offset was set at $48 million per year.

3.2 Current Revenue Test

Consistent with DOE Order RA 6120.2, the continuing adequacy of existing rates must be tested annually. The current revenue test, exhibited in Tables 5 and 6, determines whether the revenue expected from current rates will meet cost recovery requirements during the FY 2026-2028 rate period and the ensuing repayment period. For revenue at current rates, *see* Transmission Rate Study and Documentation, BP-26-FS-BPA-08, Table 13.

The result of the current revenue test demonstrates that projected revenue from current rates is inadequate to meet the cost recovery criteria of Order RA 6120.2 because the net position is negative in the rate period and for some years of the repayment period. *See* Table 7, column K. This means that current rates could not be extended.

3.3 Revised Revenue Test

Consistent with DOE Order RA 6120.2, the adequacy of proposed rates must be demonstrated. The revised revenue test determines whether the revenue projected from proposed rates will meet cost recovery requirements for the rate period. The revised

revenue test is conducted using the forecast of revenue under proposed rates. Transmission Rate Study and Documentation, BP-26-FS-BPA-08, Table 10.

For the rate period, the demonstration of the adequacy of proposed rates is shown in Tables 8 and 9. Table 9 tests the sufficiency of the resulting net revenues from Table 8, line 28, for making the planned annual amortization payments. The sufficiency of net revenues is demonstrated by the annual increase (or decrease) in cash (Table 9, line 28). The annual cash flow must be at least zero to demonstrate the adequacy of the projected revenues to cover all cash requirements.

The results of the revised revenue test demonstrate that proposed rates are adequate to fulfill cost recovery requirements for the rate period, FY 2026-2028. With the successful test of proposed rates, the rate development process ends.

3.4 Repayment Test at Proposed Rates

Table 10, Transmission Revenues from Proposed Rates, demonstrates whether projected revenue from proposed rates is 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 the separate accounting analysis that is an attachment to the rate filing BPA submits to the Commission. The focal point of Table 10 is the net position (column K), which is the amount of funds provided by revenues 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 of the years of the rate period through the repayment period, the projected revenues demonstrate BPA's ability to repay the federal investment in the FCRPS within the allowable time. As shown in

column K, the resulting net position is zero or greater for each year of the rate 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 rate period data have been developed specifically for this Study. The repayment period data are presented consistent with the requirements of DOE Order RA 6120.2.

Since rates are calculated based on the annual average revenue requirement for the rate period, it is not unusual for forecast revenues in a given year to be different from the forecast costs for that year. This can result in preliminary calculations that reflect significant positive cash flow in one year and significant negative cash flow in another. To address mismatches such as this in the past, previous studies have reshaped debt repayment over the rate period by moving repayment from the shortfall year to the surplus year without changing the total repayment for the rate period. Previous studies have also assumed BPA would hold surplus cash in one year and apply it in the shortfall year. In this Study, there were notable mismatches between revenues and costs in FY 2026 and FY 2028 and a small one in FY 2027. Reshaping debt repayment to match annual revenues and costs proved to be insufficient to address the issue for purposes of the repayment test, so this Study assumes that $106 million is held in reserves in FY 2026 and another $2 million held in FY 2027 to be applied against costs in FY 2028. *See* Table 9, line 12.

Table 11, Amortization of Transmission Investments Over Repayment Period, summarizes the amortization of federal investments over the repayment period. It displays the total investment costs through the cost evaluation period, forecast replacements required to maintain the system through the repayment period, the cumulative dollar amount of

investments 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), and the predetermined amortization payments for each year of the repayment period.

TABLES

This page intentionally left blank.

Table 1: Projected Net Revenues from Proposed Rates

($000s)

		A	B	C	D
		2026	2027	2028	Rate Period Average
1	PROJECTED REVENUES FROM PROPOSED RATES	1,633,713	1,668,984	1,737,816	1,680,171
2	PROJECTED EXPENSES	1,397,646	1,507,436	1,621,126	1,508,736
3	NET REVENUES	236,067	161,547	116,689	171,435

Table 2: Planned Repayments to U.S. Treasury

($000s)

		A	B	C
		BOND AMORTIZATION	APPROPRIATIONS AMORTIZATION	TOTAL
1	2026	257,434	-	257,434
2	2027	319,067		319,067
3	2028	404,689	-	404,689
4	TOTAL	981,190	-	981,190

Table 3: Transmission Revenue Requirement Income Statement

($000s)

		A	B	C
		2026	2027	2028
1	OPERATING EXPENSES			
2	TRANSMISSION OPERATIONS	219,263	236,631	252,640
3	TRANSMISSION ENGINEERING	73,817	77,373	80,793
4	TRANSMISSION MAINTENANCE INCLUDING ENVIRONM	224,667	239,518	252,998
5	TRANSMISSION ACQ & ANCILLARY SERVICES	138,190	138,190	138,190
6	BPA INTERNAL SUPPORT	202,979	219,691	230,576
7	OTHER INCOME, EXPENSES & ADJUSTMENTS	(48,005)	(48,005)	(48,005)
8	DEPRECIATION & AMORTIZATION	422,525	454,170	476,850
9	TOTAL OPERATING EXPENSES	1,233,436	1,317,568	1,384,042
10	INTEREST EXPENSE			
11	INTEREST EXPENSE			
12	FEDERAL APPROPRIATIONS	0	0	0
13	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)	(18,968)
14	ON LONG-TERM DEBT	180,469	215,876	262,336
15	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559	527
16	DEBT SERVICE REASSIGNMENT INTEREST	0	0	0
17	NON-FEDERAL INTEREST (INCL CUSTOMER FUNDEI	65,593	62,220	58,019
18	PREMIUMS/DISCOUNTS	7,875	1,468	0
19	AFUDC	(46,650)	(47,026)	(41,612)
20	INTEREST INCOME	(23,327)	(21,830)	(22,456)
21	NET INTEREST EXPENSE	165,550	192,299	237,847
22	TOTAL EXPENSES	1,398,986	1,509,867	1,621,888
23	MINIMUM REQUIRED NET REVENUE 1/	139,150	152,592	217,055
24	PLANNED NET REVENUES FOR RISK	0	0	0
25	TOTAL PLANNED NET REVENUE	139,150	152,592	217,055
26				
27	TOTAL REVENUE REQUIREMENT	**1,538,136**	**1,662,458**	**1,838,944**

1/ See note on cash flow table

Table 4: Transmission Revenue Requirement Statement of Cash Flows

($000s)

		A 2026	B 2027	C 2028
1	CASH FROM CURRENT OPERATIONS:			
2	MINIMUM REQUIRED NET REVENUE	139,150	152,592	217,055
3	EXPENSES NOT REQUIRING CASH:			
4	DEPRECIATION & AMORTIZATION	422,525	454,170	476,850
5	TRANSMISSION CREDIT PROJECTS NET INTEREST	8,611	8,329	7,270
6	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559	527
7	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)	(18,968)
8	NON-CASH REVENUES/ACCRUAL REVENUES			
9	LGIA	(51,402)	(58,961)	(71,187)
10	AC INTERTIE CO/FIBER	(3,558)	(3,558)	(3,558)
11	CASH PROVIDED BY CURRENT OPERATIONS	**496,917**	**534,163**	**607,989**
12	CASH USED FOR CAPITAL INVESTMENTS:			
13	INVESTMENT IN:			
14	UTILITY PLANT	(1,361,000)	(1,523,300)	(1,416,500)
15	CASH USED FOR CAPITAL INVESTMENTS	**(1,361,000)**	**(1,523,300)**	**(1,416,500)**
16	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:			
17	INCREASE IN LONG-TERM DEBT	1,236,000	1,398,300	1,291,500
18	DEBT SERVICE REASSIGNMENT PRINCIPAL	0	0	0
19	REPAYMENT OF NON-FEDERAL DEBT	(114,483)	(90,096)	(78,300)
20	REPAYMENT OF LONG-TERM DEBT	(257,434)	(319,067)	(404,689)
21	REPAYMENT OF CAPITAL APPROPRIATIONS	0	0	0
22	CASH FROM TREASURY BORROWING AND APPROPRIATION	**864,083**	**989,137**	**808,511**
23	ANNUAL INCREASE (DECREASE) IN CASH 1/	0	0	0
24	PLANNED NET REVENUE FOR RISK	0	0	0
25	TOTAL ANNUAL INCREASE (DECREASE) IN CASH	0	0	0

1/ Line 27 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: Transmission Current Revenue Test Income Statement

($000s)

		A 2026	B 2027	C 2028
1	REVENUES FROM CURRENT RATES	1,302,822	1,335,378	1,401,364
2	OPERATING EXPENSES			
3	TRANSMISSION OPERATIONS	219,263	236,631	252,640
4	TRANSMISSION ENGINEERING	73,817	77,373	80,793
5	TRANSMISSION MAINTENANCE	224,667	239,518	252,998
6	TRANSMISSION ACQUISITION & ANCILLARY SERVICE	138,190	138,190	138,190
7	BPA INTERNAL SUPPORT	202,979	219,691	230,576
8	OTHER INCOME, EXPENSES & ADJUSTMENTS	(48,005)	(48,005)	(48,005)
9	DEPRECIATION & AMORTIZATION	422,525	454,170	476,850
10	TOTAL OPERATING EXPENSES	1,233,436	1,317,568	1,384,042
11	INTEREST EXPENSE			
12	INTEREST EXPENSE			
13	FEDERAL APPROPRIATIONS	-	-	-
14	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)	(18,968)
15	ON LONG-TERM DEBT	180,469	215,876	262,336
16	AMORTIZATION OF CAPITALIZED BOND PREM	559	559	527
17	DEBT SERVICE REASSIGNMENT INTEREST	-	-	-
18	NON-FEDERAL INTEREST	65,593	62,220	58,019
17	PREMIUMS/DISCOUNTS	7,875	1,468	-
19	AFUDC	(46,650)	(47,026)	(41,612)
20	INTEREST INCOME	(19,340)	(9,379)	1,852
21	NET INTEREST EXPENSE	169,538	204,750	262,154
22	TOTAL EXPENSES	1,402,974	1,522,318	1,646,196
23	NET REVENUES	(100,151)	(186,940)	(244,832)

Table 6: Transmission Current Revenue Test Statement of Cash Flows

($000s)

		A 2026	B 2027	C 2028
1	REVENUES FROM CURRENT RATES	1,302,822	1,335,378	1,401,364
2	OPERATING EXPENSES			
3	TRANSMISSION OPERATIONS	219,263	236,631	252,640
4	TRANSMISSION ENGINEERING	73,817	77,373	80,793
5	TRANSMISSION MAINTENANCE	224,667	239,518	252,998
6	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	138,190	138,190	138,190
7	BPA INTERNAL SUPPORT	202,979	219,691	230,576
8	OTHER INCOME, EXPENSES & ADJUSTMENTS	(48,005)	(48,005)	(48,005)
9	DEPRECIATION & AMORTIZATION	422,525	454,170	476,850
10	TOTAL OPERATING EXPENSES	1,233,436	1,317,568	1,384,042
11	INTEREST EXPENSE			
12	INTEREST EXPENSE			
13	FEDERAL APPROPRIATIONS	-	-	-
14	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)	(18,968)
15	ON LONG-TERM DEBT	180,469	215,876	262,336
16	AMORTIZATION OF CAPITALIZED BOND PREM	559	559	527
17	DEBT SERVICE REASSIGNMENT INTEREST	-	-	-
18	NON-FEDERAL INTEREST	65,593	62,220	58,019
17	PREMIUMS/DISCOUNTS	7,875	1,468	-
19	AFUDC	(46,650)	(47,026)	(41,612)
20	INTEREST INCOME	(19,340)	(9,379)	1,852
21	NET INTEREST EXPENSE	169,538	204,750	262,154
22	TOTAL EXPENSES	1,402,974	1,522,318	1,646,196
23	NET REVENUES	(100,151)	(186,940)	(244,832)

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

($000s)

		A	B	C	D	E	F
	YEAR	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	DEBT SERVICE OFFSETS (REV REQ STUDY DOC)	DEPRECIATION	NET INTEREST (TABLE D)	NET REVENUES (F=A-B-C-D-E)
1	**Thru 2019**	28,205,101	12,814,188	348,748	6,510,946	7,055,526	1,454,129
2	**Transmission**						
3	**2020**	1,094,215	612,982	0	339,833	148,894	(7,494)
4	**2021**	1,107,889	631,300	0	338,371	135,657	2,561
5	**2022**	1,249,958	662,229	0	338,768	140,625	108,336
6	**2023**	1,253,295	688,909	0	347,525	156,243	60,618
7	**2024**	1,323,603	792,812	0	367,597	135,275	27,919
8							
9	**COST EVALUATION**						
10	**PERIOD**						
11	**2025**	1,275,142	709,512	0	343,958	166,937	54,736
12							
13	**RATE APPROVAL**						
14	**PERIOD**						
15	**2026**	1,302,822	810,911	0	422,525	169,538	(100,151)
16	**2027**	1,335,378	863,398	0	454,170	204,750	(186,940)
17	**2028**	1,401,364	907,192	0	476,850	262,154	(244,832)
18							
19	**REPAYMENT**						
20	**PERIOD**						
21	**2029**	1,401,364	907,192	(22,467)	476,850	284,036	(244,247)
22	**2030**	1,401,364	907,192	(22,467)	476,850	286,089	(246,301)
23	**2031**	1,401,364	907,192	(22,467)	476,850	293,455	(253,667)
24	**2032**	1,401,364	907,192	(22,467)	476,850	300,836	(261,048)
25	**2033**	1,401,364	907,192	(22,467)	476,850	306,755	(266,967)
26	**2034**	1,401,364	907,192	(22,467)	476,850	310,249	(270,461)
27	**2035**	1,401,364	907,192	(22,467)	476,850	318,411	(278,623)
28	**2036**	1,401,364	907,192	(22,467)	476,850	321,569	(281,780)
29	**2037**	1,401,364	907,192	(22,467)	476,850	332,154	(292,366)
30	**2038**	1,401,364	907,192	(22,467)	476,850	341,630	(301,841)
31	**2039**	1,401,364	907,192	(22,467)	476,850	350,777	(310,989)
32	**2040**	1,401,364	907,192	(22,467)	476,850	360,565	(320,777)
33	**2041**	1,401,364	907,192	(22,467)	476,850	371,313	(331,525)
34	**2042**	1,401,364	907,192	(22,467)	476,850	381,798	(342,010)
35	**2043**	1,401,364	907,192	(22,467)	476,850	393,647	(353,859)
36	**2044**	1,401,364	907,192	(22,467)	476,850	407,475	(367,686)
37	**2045**	1,401,364	907,192	(22,467)	476,850	419,037	(379,248)
38	**2046**	1,401,364	907,192	(22,467)	476,850	427,971	(388,183)
39	**2047**	1,401,364	907,192	(22,467)	476,850	443,517	(403,728)
40	**2048**	1,401,364	907,192	(22,467)	476,850	454,658	(414,870)
41	**2049**	1,401,364	907,192	(22,467)	476,850	469,597	(429,808)
42	**2050**	1,401,364	907,192	(22,467)	476,850	481,211	(441,422)
43	**2051**	1,401,364	907,192	(22,467)	476,850	496,936	(457,147)
44	**2052**	1,401,364	907,192	(22,467)	476,850	508,439	(468,651)
45	**2053**	1,401,364	907,192	(22,467)	476,850	519,544	(479,756)
46	**2054**	1,401,364	907,192	(22,467)	476,850	532,030	(492,242)
47	**2055**	1,401,364	907,192	(22,467)	476,850	544,516	(504,727)
48	**2056**	1,401,364	907,192	(22,467)	476,850	560,492	(520,704)
49	**2057**	1,401,364	907,192	(22,467)	476,850	573,911	(534,123)
50	**2058**	1,401,364	907,192	(22,467)	476,850	589,800	(550,011)
51	**2059**	1,401,364	907,192	(22,467)	476,850	606,485	(566,697)
52	**2060**	1,401,364	907,192	(22,467)	476,850	624,190	(584,402)
53	**2061**	1,401,364	907,192	(22,467)	476,850	642,685	(602,897)
54	**2062**	1,401,364	907,192	(22,467)	476,850	662,041	(622,252)
55	**2063**	1,401,364	907,192	(22,467)	476,850	682,206	(642,417)
56							
57	**TRANSMISSION**						
58	**TOTALS**	88,596,495	51,245,151	(437,580)	26,630,286	24,175,624	(13,038,549)

Consists of depreciation plus other non-cash expenses and other adjustments and any accounting write-offs included in expenses.
1/ Also removed revenue financing. Includes adjustments for non-cash revenues or other accrual to cash adjustments. FY 2019 includes a one-time decrease of $187 million to rebalancie financial reserves between the transmission and generation functions to correct for a misallocation error in the calclation of financial reserves attributed to the business units.

Table 7 (continued)

	YEAR	G NONCASH EXPENSES 1/ (COLUMN D)	H FUNDS FROM OPERATION (H=F+G)	I AMORTIZATION (REV REQ STUDY DOC,Chapter 10)	J NON-FEDERAL PRINCIPAL (REV REQ STUDY DOC,Chapter 7)	K NET POSITION (K=H-I-J)
1	**Thru 2019**	6,036,864	8,654,653	6,963,558	1,168,397	522,698
2	**Transmission**					
3	**2020**	297,230	289,736	199,900	98,999	(9,163)
4	**2021**	317,907	320,467	284,700	99,352	(63,585)
5	**2022**	263,268	371,604	214,900	98,296	58,408
6	**2023**	327,338	387,956	210,900	80,791	96,265
7	**2024**	310,393	338,312	285,100	100,812	(47,600)
8						
9	**COST EVALUATION**					
10	**PERIOD**					
11	**2025**	298,441	298,176	187,438	110,726	12
12						
13	**RATE APPROVAL**					
14	**PERIOD**					
15	**2026**	357,767	132,615	257,434	114,483	(239,301)
16	**2027**	381,571	69,631	319,067	90,096	(339,531)
17	**2028**	390,934	21,102	404,689	78,300	(461,887)
18						
19	**REPAYMENT**					
20	**PERIOD**					
21	**2029**	390,934	21,687	449,293	3,251	(430,857)
22	**2030**	390,934	19,633	420,230	30,054	(430,651)
23	**2031**	390,934	12,267	411,817	31,071	(430,621)
24	**2032**	390,934	4,886	411,527	24,012	(430,652)
25	**2033**	390,934	(1,033)	426,728	3,023	(430,784)
26	**2034**	390,934	(4,527)	320,887	104,641	(430,054)
27	**2035**	390,934	(12,689)	289,007	128,167	(429,862)
28	**2036**	390,934	(15,846)	285,687	128,326	(429,859)
29	**2037**	390,934	(26,431)	305,715	97,909	(430,056)
30	**2038**	390,934	(35,907)	296,029	98,093	(430,029)
31	**2039**	390,934	(45,054)	286,662	98,286	(430,003)
32	**2040**	390,934	(54,843)	276,673	98,461	(429,977)
33	**2041**	390,934	(65,591)	257,720	106,578	(429,889)
34	**2042**	390,934	(76,075)	265,002	88,911	(429,988)
35	**2043**	390,934	(87,925)	237,816	104,113	(429,853)
36	**2044**	390,934	(101,752)	222,488	105,570	(429,810)
37	**2045**	390,934	(113,314)	211,437	105,030	(429,781)
38	**2046**	390,934	(122,249)	202,364	105,140	(429,752)
39	**2047**	390,934	(137,794)	290,489	2,165	(430,448)
40	**2048**	390,934	(148,936)	279,184	2,287	(430,407)
41	**2049**	390,934	(163,874)	264,157	2,325	(430,356)
42	**2050**	390,934	(175,488)	252,363	2,455	(430,306)
43	**2051**	390,934	(191,213)	236,451	2,593	(430,257)
44	**2052**	390,934	(202,717)	224,758	2,737	(430,212)
45	**2053**	390,934	(213,822)	213,457	2,890	(430,169)
46	**2054**	390,934	(226,308)	200,761	3,052	(430,120)
47	**2055**	390,934	(238,793)	188,057	3,222	(430,073)
48	**2056**	390,934	(254,769)	171,849	3,402	(430,021)
49	**2057**	390,934	(268,189)	158,184	3,593	(429,965)
50	**2058**	390,934	(284,077)	142,040	3,793	(429,910)
51	**2059**	390,934	(300,763)	125,083	4,005	(429,851)
52	**2060**	390,934	(318,468)	110,620	723	(429,811)
53	**2061**	390,934	(336,963)	92,744	43	(429,750)
54	**2062**	390,934	(356,318)	73,318	46	(429,682)
55	**2063**	390,934	(376,483)	53,079	48	(429,611)
56						
57	**TRANSMISSION**					
58	**TOTALS**	22,664,405	5,984,517	17,981,363	3,540,272	(15,537,117)

1/ Consists of depreciation plus other non-cash expenses and other adjustments and any accounting write-offs included in expenses. Also removed revenue financing. Includes adjustments for non-cash revenues or other accrual to cash adjustments. FY 2019 includes a one-time decrease of $187 million to rebalancie financial reserves between the transmission and generation functions to correct for a misallocation error in the calclation of financial reserves attributed to the business units.

Table 8: Transmission Revised Revenue Test Income Statement ($000s)

		A 2026	B 2027	C 2028
1	REVENUES FROM PROPOSED RATES	1,633,713	1,668,984	1,737,816
2	OPERATING EXPENSES			
3	TRANSMISSION OPERATIONS	219,263	236,631	252,640
4	TRANSMISSION ENGINEERING	73,817	77,373	80,793
5	TRANSMISSION MAINTENANCE	224,667	239,518	252,998
6	TRANSMISSION ACQUISITION & ANCILLARY SERVICES	138,190	138,190	138,190
7	BPA INTERNAL SUPPORT	202,979	219,691	230,576
8	OTHER INCOME, EXPENSES & ADJUSTMENTS	(48,005)	(48,005)	(48,005)
9	DEPRECIATION & AMORTIZATION	422,525	454,170	476,850
10	TOTAL OPERATING EXPENSES	1,233,436	1,317,568	1,384,042
11	INTEREST EXPENSE			
12	INTEREST EXPENSE			
13	FEDERAL APPROPRIATIONS	-	-	-
14	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)	(18,968)
15	ON LONG-TERM DEBT	180,469	215,876	262,336
16	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559	527
17	DEBT SERVICE REASSIGNMENT INTEREST	-	-	-
18	NON-FEDERAL INTEREST	65,593	62,220	58,019
19	PREMIUMS/DISCOUNTS	7,875	1,468	-
19	AFUDC	(46,650)	(47,026)	(41,612)
20	INTEREST INCOME	(24,668)	(24,261)	(23,218)
21	NET INTEREST EXPENSE	164,210	189,868	237,084
22	TOTAL EXPENSES	1,397,646	1,507,436	1,621,126
23	NET REVENUES	236,067	161,547	116,689

Table 9: Transmission Revised Revenue Test Statement of Cash Flows

($000s)

		A 2026	B 2027	C 2028
1	CASH FROM CURRENT OPERATIONS:			
2	NET REVENUES	236,067	161,547	116,689
3	DRAWDOWN OF CASH RESERVES FOR CAPITAL FUNDING	-	-	-
4	EXPENSES NOT REQUIRING CASH:			
5	DEPRECIATION & AMORTIZATION	422,525	454,170	476,850
6	TRANSMISSION CREDIT PROJECTS NET INTEREST	8,611	8,329	7,270
7	AMORTIZATION OF CAPITALIZED BOND PREMIUMS	559	559	527
8	CAPITALIZATION ADJUSTMENT	(18,968)	(18,968)	(18,968)
9	NON-CASH REVENUES/ACCRUAL REVENUES			
10	LGIA	(51,402)	(58,961)	(71,187)
11	AC INTERTIE CO/FIBER	(3,558)	(3,558)	(3,558)
12	CASH FLOW ADJUSTMENT (RESERVE)/APPLICATION	(96,000)	(4,800)	100,800
13	CASH PROVIDED BY CURRENT OPERATIONS	497,834	538,318	608,424
14	CASH USED FOR CAPITAL INVESTMENTS:			
15	INVESTMENT IN:			
16	UTILITY PLANT	(1,361,000)	(1,523,300)	(1,416,500)
17	CASH USED FOR CAPITAL INVESTMENTS	(1,361,000)	(1,523,300)	(1,416,500)
18	CASH FROM TREASURY BORROWING AND APPROPRIATIONS:			
19	INCREASE IN LONG-TERM DEBT	1,236,000	1,398,300	1,291,500
20	DEBT SERVICE REASSIGNMENT PRINCIPAL	-	-	-
21	REPAYMENT OF CAPITAL LEASES	(114,483)	(90,096)	(78,300)
22	REPAYMENT OF LONG-TERM DEBT	(257,434)	(319,067)	(404,689)
23	REPAYMENT OF CAPITAL APPROPRIATIONS	-	-	-
24	CASH FROM TREASURY BORROWING AND APPROPRIATIONS	864,083	989,137	808,511
25	ANNUAL INCREASE (DECREASE) IN CASH	918	4,156	434

1/ Line 25 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 10: Transmission Revenues from Proposed Rates through the Repayment Period

($000s)

		A	B	C	D	E	F
	YEAR	REVENUES (STATEMENT A)	OPERATION & MAINTENANCE (STATEMENT E)	DEBT SERVICE OFFSETS (REV REQ STUDY DOC)	DEPRECIATION	NET INTEREST (TABLE D)	NET REVENUES (F=A-B-C-D-E)
1	**Thru 2019**	29,244,978	13,411,414	348,748	6,816,666	7,203,126	1,443,459
2	**TRANSMISSION**						
3	**2020**	1,094,215	612,982	0	339,833	148,894	(7,494)
4	**2021**	1,107,889	631,300	0	338,371	135,657	2,561
5	**2022**	1,249,958	662,229	0	338,768	140,625	108,336
6	**2023**	1,253,295	688,909	0	347,525	156,243	60,618
7	**2024**	1,323,603	792,812	0	367,597	135,275	27,919
8							
9	**COST EVALUATION**						
10	**PERIOD**						
11	**2025**	1,275,142	709,512	0	343,958	166,937	54,736
12							
13	**RATE APPROVAL**						
14	**PERIOD**						
15	**2026**	1,633,713	810,911	0	422,525	164,210	236,067
16	**2027**	1,668,984	863,398	0	454,170	189,868	161,547
17	**2028**	1,737,816	907,192	0	476,850	237,084	116,689
18							
19	**REPAYMENT**						
20	**PERIOD**						
21	**2029**	1,737,816	907,192	(22,467)	476,850	284,036	92,205
22	**2030**	1,737,816	907,192	(22,467)	476,850	286,089	90,151
23	**2031**	1,737,816	907,192	(22,467)	476,850	293,455	82,785
24	**2032**	1,737,816	907,192	(22,467)	476,850	300,836	75,404
25	**2033**	1,737,816	907,192	(22,467)	476,850	306,755	69,485
26	**2034**	1,737,816	907,192	(22,467)	476,850	310,249	65,991
27	**2035**	1,737,816	907,192	(22,467)	476,850	318,411	57,829
28	**2036**	1,737,816	907,192	(22,467)	476,850	321,569	54,672
29	**2037**	1,737,816	907,192	(22,467)	476,850	332,154	44,086
30	**2038**	1,737,816	907,192	(22,467)	476,850	341,630	34,611
31	**2039**	1,737,816	907,192	(22,467)	476,850	350,777	25,463
32	**2040**	1,737,816	907,192	(22,467)	476,850	360,565	15,675
33	**2041**	1,737,816	907,192	(22,467)	476,850	371,313	4,927
34	**2042**	1,737,816	907,192	(22,467)	476,850	381,798	(5,558)
35	**2043**	1,737,816	907,192	(22,467)	476,850	393,647	(17,407)
36	**2044**	1,737,816	907,192	(22,467)	476,850	407,475	(31,234)
37	**2045**	1,737,816	907,192	(22,467)	476,850	419,037	(42,796)
38	**2046**	1,737,816	907,192	(22,467)	476,850	427,971	(51,731)
39	**2047**	1,737,816	907,192	(22,467)	476,850	443,517	(67,276)
40	**2048**	1,737,816	907,192	(22,467)	476,850	454,658	(78,418)
41	**2049**	1,737,816	907,192	(22,467)	476,850	469,597	(93,356)
42	**2050**	1,737,816	907,192	(22,467)	476,850	481,211	(104,970)
43	**2051**	1,737,816	907,192	(22,467)	476,850	496,936	(120,696)
44	**2052**	1,737,816	907,192	(22,467)	476,850	508,439	(132,199)
45	**2053**	1,737,816	907,192	(22,467)	476,850	519,544	(143,304)
46	**2054**	1,737,816	907,192	(22,467)	476,850	532,030	(155,790)
47	**2055**	1,737,816	907,192	(22,467)	476,850	544,516	(168,276)
48	**2056**	1,737,816	907,192	(22,467)	476,850	560,492	(184,252)
49	**2057**	1,737,816	907,192	(22,467)	476,850	573,911	(197,671)
50	**2058**	1,737,816	907,192	(22,467)	476,850	589,800	(213,559)
51	**2059**	1,737,816	907,192	(22,467)	476,850	606,485	(230,245)
52	**2060**	1,737,816	907,192	(22,467)	476,850	624,190	(247,950)
53	**2061**	1,737,816	907,192	(22,467)	476,850	642,685	(266,445)
54	**2062**	1,737,816	907,192	(22,467)	476,850	662,041	(285,800)
55	**2063**	1,737,816	907,192	(22,467)	476,850	682,206	(305,965)
56							
57	**TRANSMISSION**						
58	**TOTALS**	102,413,136	51,842,377	(437,580)	26,936,006	24,277,945	(227,176)

1/ Consists of depreciation plus other non-cash expenses and other adjustments and any accounting write-offs included in expenses. Also removed revenue financing. Includes adjustments for non-cash revenues or other accrual to cash adjustments. FY 2019 includes a one-time decrease of $187 million to rebalancie financial reserves between the transmission and generation functions to correct for a misallocation error in the calclation of financial reserves attributed to the business units.

Table 10 (continued)

	YEAR	G NONCASH EXPENSES 1/ (COLUMN D)	H FUNDS FROM OPERATION (H=F+G)	I AMORTIZATION (REV REQ STUDY DOC,Chapter 10)	J NON-FEDERAL PRINCIPAL (REV REQ STUDY DOC,Chapter 7)	K NET POSITION (K=H-I-J)
1	**Thru 2019**	6,043,325	8,650,445	7,198,574	1,185,701	266,170
2	**TRANSMISSION**					
3	**2020**	297,230	289,736	199,900	98,999	(9,163)
4	**2021**	317,907	320,467	284,700	99,352	(63,585)
5	**2022**	263,268	371,604	214,900	98,296	58,408
6	**2023**	327,338	387,956	210,900	80,791	96,265
7	**2024**	310,393	338,312	285,100	100,812	(47,600)
8						
9	**COST EVALUATION**					
10	**PERIOD**					
11	**2025**	298,441	298,176	187,438	110,726	12
12						
13	**RATE APPROVAL**					
14	**PERIOD**					
15	**2026**	261,767	372,834	257,434	114,483	918
16	**2027**	376,771	413,318	319,067	90,096	4,155
17	**2028**	491,734	483,424	404,689	78,300	434
18						
19	**REPAYMENT**					
20	**PERIOD**					
21	**2029**	491,734	458,939	449,293	3,251	6,395
22	**2030**	491,734	456,885	420,230	30,054	6,601
23	**2031**	491,734	449,519	411,817	31,071	6,631
24	**2032**	491,734	442,138	411,527	24,012	6,600
25	**2033**	491,734	436,219	426,728	3,023	6,468
26	**2034**	491,734	432,725	320,887	104,641	7,198
27	**2035**	491,734	424,563	289,007	128,167	7,390
28	**2036**	491,734	421,406	285,687	128,326	7,393
29	**2037**	491,734	410,820	305,715	97,909	7,196
30	**2038**	491,734	401,345	296,029	98,093	7,223
31	**2039**	491,734	392,197	286,662	98,286	7,249
32	**2040**	491,734	382,409	276,673	98,461	7,275
33	**2041**	491,734	371,661	257,720	106,578	7,363
34	**2042**	491,734	361,176	265,002	88,911	7,264
35	**2043**	491,734	349,327	237,816	104,113	7,399
36	**2044**	491,734	335,500	222,488	105,570	7,442
37	**2045**	491,734	323,938	211,437	105,030	7,471
38	**2046**	491,734	315,003	202,364	105,140	7,500
39	**2047**	491,734	299,458	290,489	2,165	6,804
40	**2048**	491,734	288,316	279,184	2,287	6,845
41	**2049**	491,734	273,378	264,157	2,325	6,896
42	**2050**	491,734	261,764	252,363	2,455	6,946
43	**2051**	491,734	246,039	236,451	2,593	6,995
44	**2052**	491,734	234,535	224,758	2,737	7,040
45	**2053**	491,734	223,430	213,457	2,890	7,083
46	**2054**	491,734	210,944	200,761	3,052	7,132
47	**2055**	491,734	198,459	188,057	3,222	7,179
48	**2056**	491,734	182,482	171,849	3,402	7,231
49	**2057**	491,734	169,063	158,184	3,593	7,287
50	**2058**	491,734	153,175	142,040	3,793	7,342
51	**2059**	491,734	136,489	125,083	4,005	7,401
52	**2060**	491,734	118,784	110,620	723	7,441
53	**2061**	491,734	100,289	92,744	43	7,502
54	**2062**	491,734	80,934	73,318	46	7,570
55	**2063**	491,734	60,769	53,079	48	7,641
56						
57	**TRANSMISSION**					
58	**TOTALS**	26,198,867	22,330,352	18,216,379	3,557,575	556,398

1/ Consists of depreciation plus other non-cash expenses and other adjustments and any accounting write-offs included in expenses. Also removed revenue financing. Includes adjustments for non-cash revenues or other accrual to cash adjustments. FY 2019 includes a one-time decrease of $187 million to rebalancie financial reserves between the transmission and generation functions to correct for a misallocation error in the calclation of financial reserves attributed to the business units.

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)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	2025	16,967,798	-	16,967,798	104,000	100	4,933,540	8,522,435
2	2026	1,236,000	-	18,203,798	101,000	156,434	5,912,106	9,657,435
3	2027	1,398,300	-	19,602,098	266,000	53,067	6,991,339	10,789,735
4	2028	1,871,470	-	21,473,568	404,687	2	8,458,120	12,026,917
5	2029	-	539,801	22,013,369	423,545	25,749	8,548,627	12,143,173
6	2030	-	539,801	22,553,169	402,160	18,070	8,668,198	12,280,813
7	2031	-	539,801	23,092,970	389,942	21,875	8,796,181	12,430,672
8	2032	-	539,801	23,632,771	393,733	17,793	8,924,455	12,576,739
9	2033	-	539,801	24,172,571	412,682	14,047	9,037,528	12,703,858
10	2034	-	539,801	24,712,372	311,129	9,757	9,256,442	12,932,530
11	2035	-	539,801	25,252,173	270,491	18,515	9,507,236	13,176,839
12	2036	-	539,801	25,791,973	284,448	1,239	9,761,350	13,382,192
13	2037	-	539,801	26,331,774	291,120	14,595	9,995,435	13,630,873
14	2038	-	539,801	26,871,575	270,284	25,745	10,239,207	13,722,390
15	2039	-	539,801	27,411,376	269,897	16,765	10,492,345	13,974,905
16	2040	-	539,801	27,951,176	255,278	21,395	10,755,472	14,242,662
17	2041	-	539,801	28,490,977	225,890	31,830	11,037,553	14,556,573
18	2042	-	539,801	29,030,778	233,223	31,780	11,312,351	14,863,151
19	2043	-	539,801	29,570,578	201,968	35,848	11,614,336	15,200,984
20	2044	-	539,801	30,110,379	183,068	39,421	11,931,649	15,557,717
21	2045	-	539,801	30,650,180	166,970	44,467	12,260,013	15,854,548
22	2046	-	539,801	31,189,980	186,734	15,630	12,597,450	16,185,615
23	2047	-	539,801	31,729,781	227,044	63,445	12,846,762	16,467,372
24	2048	-	539,801	32,269,582	242,320	36,864	13,107,378	16,745,853
25	2049	-	539,801	32,809,382	241,579	22,577	13,383,022	17,022,395
26	2050	-	539,801	33,349,183	222,915	29,447	13,670,460	17,339,280
27	2051	-	539,801	33,888,984	186,335	50,116	13,973,810	17,692,746
28	2052	-	539,801	34,428,784	173,048	51,710	14,288,852	18,032,498
29	2053		539,801	34,968,585	178,973	34,484	14,615,196	18,093,475
30	2054	-	539,801	35,508,386	174,333	26,427	14,954,236	18,458,943
31	2055	-	539,801	36,048,187	123,979	64,078	15,305,979	18,843,764
32	2056	-	539,801	36,587,987	156,664	15,185	15,673,931	19,101,911
33	2057	-	539,801	37,127,788	102,918	55,266	16,055,548	19,523,608
34	2058	-	539,801	37,667,589	89,624	52,415	16,453,309	20,004,519
35	2059	-	539,801	38,207,389	50,350	74,733	16,868,026	20,493,970
36	2060	-	539,801	38,747,190	45,443	65,177	17,297,207	20,988,327
37	2061	-	539,801	39,286,991	41,970	50,774	17,744,264	21,486,158
38	2062	-	539,801	39,826,791	41,960	31,358	18,210,746	21,983,998
39		**$21,473,568**	**$18,353,223**		**$8,347,704**	**$1,338,183**		

BONNEVILLE POWER ADMINISTRATION
DOE/BP-5451 • July 2025