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-18 Rate Proceeding

Final Proposal

Transmission Segmentation Study and Documentation

BP-18-FS-BPA-07

July 2017

TRANSMISSION SEGMENTATION STUDY AND DOCUMENTATION

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COMMONLY USED ACRONYMS AND SHORT FORMS

AC	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
aMW	average megawatt(s)
ANR	Accumulated Net Revenues
ASC	Average System Cost
BAA	Balancing Authority Area
BiOp	Biological Opinion
BPA	Bonneville Power Administration
Bps	basis points
Btu	British thermal unit
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
CP	Coincidental Peak
CRAC	Cost Recovery Adjustment Clause
CSP	Customer System Peak
CT	combustion turbine
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
EIM	Energy imbalance market

EIS	Environmental Impact Statement
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
FOIA	Freedom Of Information Act
FORS	Forced Outage Reserve Service
FPS	Firm Power and Surplus Products and Services
FPT	Formula Power Transmission
FY	fiscal year (October through September)
G&A	general and administrative (costs)
GARD	Generation and Reserves Dispatch (computer model)
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
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
kW	kilowatt
kWh	kilowatthour
LDD	Low Density Discount
LGIA	Large Generator Interconnection Agreement
LLH	Light Load Hour(s)
LPP	Large Project Program
LPTAC	Large Project Targeted Adjustment Charge
LTF	Long-term Form
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	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
NOB	Nevada-Oregon border
NORM	Non-Operating Risk Model (computer model)
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NP-15	North of Path 15
NPCC	Pacific Northwest Electric Power and Conservation Planning Council
NPV	net present value
NR	New Resource Firm Power
NRFS	NR Resource Flattening Service
NT	Network Integration
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.
OS	Oversupply
OY	operating year (August through July)
PDCI	Pacific DC Intertie
Peak	Peak Reliability (assessment/charge)
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
Project Act	Bonneville Project Act
PS	Power Services
PSC	power sales contract

PSW	Pacific Southwest
PTP	Point to Point
PUD	public or people's utility district
PW	WECC and Peak Service
RAM	Rate Analysis Model (computer model)
RCD	Regional Cooperation Debt
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation	U.S. Bureau of Reclamation
RDC	Reserves Distribution Clause
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
SCD	Scheduling, System Control, and Dispatch rate
SCS	Secondary Crediting Service
SDD	Short Distance Discount
SILS	Southeast Idaho Load Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
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
UFT	Use of Facilities Transmission
UIC	Unauthorized Increase Charge
ULS	Unanticipated Load Service
USACE	U.S. Army Corps of Engineers
USBR	U.S. Bureau of Reclamation
USFWS	U.S. Fish & Wildlife Service

VERBS	Variable Energy Resources 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

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1. OVERVIEW

The Bonneville Power Administration (BPA) segments, or groups, its transmission facilities based on the services those facilities provide. Segments are groups of transmission facilities that serve a particular function or provide a specific service, and therefore are appropriate to group together for ratemaking purposes. BPA began segmenting its transmission system in the 1979 rate case to determine the equitable allocation of costs between Federal and non-Federal uses of the transmission system, as required by Section 10 of the Federal Columbia River Transmission System Act, 16 U.S.C. § 838h.

Segmentation involves three primary steps:

1. defining the segments;
2. assigning facilities to the segments; and
3. determining the gross investment and historical operation and maintenance (O&M) expenses for the facilities in each segment.

BPA uses this information to develop the segmented transmission revenue requirement. *See* Transmission Revenue Requirement Study Documentation, BP-18-FS-BPA-09A, Tables 2.1 to 2.8. The segmented transmission revenue requirement is then used to set transmission rates. *See* Transmission Rates Study and Documentation, BP-18-FS-BPA-08.

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2. SEGMENT DEFINITIONS

For the FY 2018–2019 rate period, BPA has divided its transmission system into the following segments: (1) Generation Integration, (2) Network, (3) Southern Intertie, (4) Eastern Intertie, (5) Utility Delivery, (6) Direct Service Industry (DSI) Delivery, and (7) Ancillary Services. This Study also identifies facility investment in general plant that supports the transmission system, such as communications equipment, buildings, and vehicles. *See* § 4.1.5.

2.1 Generation Integration Segment

The Generation Integration segment consists of facilities that connect Federal generating plants to BPA's transmission facilities. Generation Integration facilities are the same type of facilities that BPA requires other entities to provide to interconnect non-Federal generators. Because the purpose of the Generation Integration facilities is to interconnect Federal generation with BPA's transmission system, the costs associated with these facilities are assigned to and recovered through BPA's power rates.

This segment includes:

- generator step-up transformers, which transform voltage from the generation level to the transmission level;
- transmission lines between the generating facility and the first substation at which the power enters the Network segment; and
- substation terminal equipment, such as disconnect switches and circuit breakers associated with integrating Federal generation, installed and assigned to the Generation Integration segment prior to the development of the Direct Assignment Guidelines in the late 1990s (the guidelines have been revised and are now known as the Facility Ownership and Cost Assignment Guidelines). This treatment is consistent with the BP-16 Administrator's Final Record of Decision. *See* Administrator's Final Record of Decision, BP-16-A-02, at 67.

2.2 Network Segment

The Network segment is the core of BPA's transmission system. The facilities in this segment support the transmission of power from Federal and non-Federal generation sources or interties to the load centers of BPA's transmission customers in the Pacific Northwest and to other segments (*e.g.*, an intertie or delivery segment). The Network segment provides several benefits to BPA and its customers, including displacement (local generation flowing to the nearest load instead of the remote generation that is scheduled to serve that load), bulk power transfers, voltage regulation, and increased overall reliability resulting from alternative resource and transmission pathways. The costs of the Network segment are recovered through the Formula Power Transmission rate, the Integration of Resources rate, the Network Integration rate, the Advanced Funding rate, the Use-of-Facilities Transmission rate, and the Point-to-Point rate.

This segment includes:

- transmission lines, substation equipment, and associated station general that support the transmission of power from Federal and non-Federal generation sources and points of delivery to customers' systems and to other BPA segments;
- transmission lines, substation equipment, and associated station general that interconnect customer facilities with BPA's facilities and that have been determined to be BPA's responsibility to build and own based on the Facility Ownership and Cost Assignment Guidelines, and that are not included in any of the other segments; and
- facilities that have been "grandfathered" in the Network segment consistent with the decision from BP-16, even if the facilities would be directly assigned under the Facility Ownership and Cost Assignment Guidelines if constructed today. *Id.* at 69-76.

2.3 Southern Intertie Segment

The Southern Intertie segment is a system of transmission lines and substations used primarily to transmit power between the Pacific Northwest and California. Segmenting the Southern Intertie separately from the Network recognizes BPA's contractual obligations regarding the assignment of cost for the construction and ongoing use of Southern Intertie facilities. BPA recovers the costs of the Southern Intertie segment through the Southern Intertie rates.

This segment includes:

- the 1,000-kV direct-current (DC) line from the Celilo converter station near The Dalles, Oregon, to the Nevada-Oregon border, including the Celilo converter station equipment and the terminal equipment in the Big Eddy substation supporting the DC line, along with associated station general;
- the multiple 500-kV alternating-current (AC) lines from north-central Oregon to the California-Oregon border and all associated terminals and supporting station general, including BPA's share of the Alvey-Dixonville-Meridian line (jointly owned with PacifiCorp), except for (1) one of the 500-kV AC lines from Grizzly substation to Malin substation in central Oregon and associated terminals (owned by Portland General Electric Company), and (2) the Captain Jack-Malin #2 line, Summer Lake-Malin line, and Meridian-Captain Jack line, and associated terminals (owned by PacifiCorp); and
- certain other facilities determined to support the facilities specified above, including one of the 500-kV AC lines between John Day and Big Eddy substations, a portion of the 500-kV AC line between Coyote Springs and Slatt substations, a portion of the 500-kV AC line between Slatt and John Day substations, and the dynamic braking resistor at Chief Joseph substation.

2.4 Eastern Intertie Segment

The Eastern Intertie segment facilities provide a transmission path from Montana (primarily for the Colstrip generating project) to the Network segment. These facilities were built pursuant to the Montana Intertie Agreement, which provides that the costs associated with building and maintaining the facilities will be recovered from the parties to the agreement through the Townsend-Garrison Transmission rate. This segment includes the double-circuit 500-kV line between Townsend and Garrison, Montana, and associated terminal equipment and supporting station general at Garrison substation. The costs associated with the Eastern Intertie are recovered through the Townsend-Garrison Transmission rate, the Montana Intertie rate, and the Eastern Intertie rate.

2.5 Utility Delivery Segment

The Utility Delivery segment consists of low-voltage transmission lines and substation equipment associated with supplying power directly to utility distribution systems. Utility Delivery equipment is distinguished from Network equipment in that Utility Delivery transforms power down to the customer's distribution voltage, whereas Network equipment transmits power at voltages that the customer must step down (reduce) before the power enters the customer's distribution system. Utility Delivery equipment provides service to only a small subset of BPA's transmission customers. This equipment does not provide reliability benefits to the Network segment. BPA recovers the costs of this equipment through the Utility Delivery rate.

This segment includes:

- step-down transformers and associated low-side switching and protection equipment; and
- two short low-voltage lines, one from BPA's Albany substation to DOE's National Energy Technology Laboratory, and one from BPA's Hood River substation to Hood River Electric Cooperative.

2.6 Direct Service Industry Delivery Segment

This segment consists of transformers and low-side switching and protection equipment at the Intalco, Conkelley, and Trentwood substations necessary to step down transmission voltages to industrial voltages (*i.e.*, 6.9 or 13.8 kV) to supply power to direct-service industry (DSI) customers. Because this equipment serves the distinct purpose of supplying power to DSI customers, BPA segments the equipment separately and allocates the cost to the DSI Delivery segment. Customers that utilize this equipment pay the Use-of-Facilities-Transmission rate.

2.7 Ancillary Services Segment

This segment consists of control equipment and associated communications equipment necessary for BPA to provide Scheduling, System Control, and Dispatch (SCD) service. Because this equipment serves the distinct purpose of supporting BPA's provision of SCD services, BPA assigns it to the Ancillary Services segment and recovers its costs through the SCD rate.

This segment includes:

- monitoring and supervisory control equipment;
- associated communications equipment; and
- control center hardware and software.

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3. ASSIGNING FACILITIES TO THE SEGMENTS

After the segments are defined, equipment and facilities are assigned to the various segments based on the definitions set forth in Section 2. Appendix A to this Study, which lists the facilities included in each segment, identifies:

- facilities (lines and stations) whose transmission plant investment is assigned solely to one segment;
- multi-segmented facilities whose transmission plant investment is assigned to several segments;
- facilities with depreciable land investment assigned by segment;
- facilities with ancillary service investment assigned to the Ancillary Services segment; and
- facilities with general plant investment.

The following resources may be consulted to segment the facilities:

- One-line diagrams that identify the location, interconnectivity, and ownership of transmission lines, substations, circuit breakers, and transformers.
- Installation and maintenance records that identify major equipment (*e.g.*, transformers, circuit breakers, and reactive equipment) installed or maintained by BPA. BPA uses these records to identify and associate specific equipment in the plant accounting records with the equipment identified on the one-line diagrams. This association is particularly useful in allocating investment in facilities that support more than one function and whose costs are allocated to more than one segment. Multi-segmented facilities that support more than one function are described in more detail in Section 3.1.
- Agreements, such as those relating to the construction and operation of the Southern and Eastern Interties, that specify how the costs for certain facilities will be allocated.

3.1 Multi-Segmented Facilities

Some facilities, referred to as multi-segmented facilities, support more than one segment. These facilities are identified in Appendix B to this Study. For multi-segmented lines, investment is generally allocated to multiple segments according to percentages established by contract. If the allocation of multi-segmented lines is not established by contract, BPA uses line mileage to develop percentages that reflect which segments the line supports. For example, if 2 miles of a 20-mile line are used to integrate Federal generation, and after 2 miles a tap off the line integrates a non-Federal generator into the Network, 10 percent of the line investment is segmented to Generation Integration and 90 percent is segmented to the Network.

For multi-segmented substations, the process is more involved. First, the segment definitions described in Section 2 are used to determine the segments a substation supports. If a substation supports the Utility Delivery segment, only the transformer and low-side equipment are assigned to the Utility Delivery segment. The remaining investment in the substation is allocated to all other applicable segments according to the following process:

1. The investment in major equipment in the substation (*e.g.*, circuit breakers, transformers, and reactive devices, all of which are tracked separately in the investment records) is grouped by type and voltage level. For example, a substation may have 230-kV equipment that supports the Network and Generation Integration segments and reactive devices that support only the Network. The investment in this substation would be separated into two groups, a 230-kV shared group that is segmented to both Generation Integration and the Network (as described below) and a reactive group that is segmented entirely to the Network.
2. The investment in common equipment for the substation and station general, such as buildings and fences, is allocated to each group based on the investment in major equipment. In the example above, if the 230-kV shared group is assigned 80 percent of

the investment in major equipment, the 230-kV group is also assigned 80 percent of the investment in common equipment and station general.

3. The total investment in each shared group is then allocated to the segments that the group supports based on the number of terminals in each segment. A terminal connects a transmission line, power transformer, or reactive device to substation bus work so that power can flow. A terminal typically consists of a power circuit breaker (or, alternatively, a circuit switcher in some stations), disconnect switches, and protective relaying. All terminals rely on the equipment in the shared group to transmit power between the lines, transformers, and reactive devices to which they are connected at the substation. Therefore, the cost of the shared group is assumed to be shared equally among the terminals. In the above example, if the 230-kV shared group supports four Network terminals and two Generation Integration terminals, two-thirds (four of six terminals) of the 230-kV shared group investment are allocated to the Network segment, and one-third (two of six) is allocated to the Generation Integration segment.

As described further in Section 4, the percentage of the total investment in each segment is used to allocate the historical O&M expenses for each facility to the different segments. Appendix A identifies the percentage of each facility allocated to each segment and the associated investment and historical O&M expenses assigned to the segment.

3.2 Facilities Not Assigned to a Segment

Some transmission equipment and facilities are not assigned to a particular segment because they cannot be identified with a particular type of service. For example, emergency equipment spares support most or all the segments and therefore are not assigned to a particular segment. The transmission plant investment associated with such equipment and facilities is allocated to all of the segments on a pro rata basis. For example, if 80 percent of the directly assigned investment in station equipment is segmented to the Network segment, then 80 percent of the investment in station equipment that is not directly assigned is also segmented to the Network. Table 2, at lines 4 and 18, shows the allocation of the investment in these facilities.

4. DETERMINING AND ALLOCATING INVESTMENT AND HISTORICAL O&M EXPENSES TO THE SEGMENTS

Once the segmentation of facilities is determined, the investment and historical O&M expenses by segment are calculated. As described below, the investment associated with each segment is determined by aggregating the investment of the facilities allocated to each segment. The historical O&M expenses are similarly aggregated by segment. The segmented investment and the historical O&M expenses are used in the Revenue Requirement Study to assign costs to each segment.

The segmented investment through September 30, 2016 is shown in Table 2. The segmented expected future plant investment is shown in Table 3.1. The historical O&M by segment for FY 2010 to FY 2016 is shown in Table 4.1.

4.1 Gross Investment in Existing Facilities

BPA's gross investment is shown in Table 1 and illustrated in the associated chart. The investment related to (1) transmission plant, including leased assets, emergency stock, and intangibles, (2) depreciable land, and (3) general plant is identified and segmented in the segmentation process. These investments are described in more detail below. The gross investment is identified from BPA's investment records as of FY 2016, which is the most recently completed fiscal year at the time that this Study is being prepared.

4.1.1 Transmission Plant Investment

Transmission plant investment refers to investment in lines and substations, as defined in FERC accounts 352 through 356, 358, 359, 390, and 391, and investment in some leased facilities (which are not classified by FERC account). *See* Table 2. The total transmission plant investment, including leased facilities but excluding Projects Funded in Advance (PFIA), is $7.6 billion as of the end of FY 2016 (Table 1, line 23). PFIA are projects funded by the customers taking service over the new facilities. The costs of the new facilities are assigned to and funded by customers consistent with the Facility Ownership and Cost Assignment Guidelines. Other than PFIA, transmission plant investment associated with specific facilities is allocated to segments based on the assignment of facilities to the segments as described in Section 3.

4.1.2 Intangible Investment

Intangible investment is BPA's share of financial participation in facilities owned by other entities (BPA's capacity rights). In each case, the investment supports either the Network or the Southern Intertie segment. For the FY 2018–2019 rate period, the investment is segmented to one of these two segments based on the segment each facility supports. As shown in Table 2, line 29, BPA has $9.6 million of intangible investment.

4.1.3 Land Investment

Land owned by BPA is not depreciated, and therefore no amortized costs for land need to be segmented. However, BPA does have leased land that is depreciable ($48.7 million, Table 2, line 37) and which therefore must be segmented. Most of the leased land ($47.7 million, Table 2, line 34, columns H and I) is used for rights-of-way for transmission lines and is segmented according to the type of service provided by the associated transmission lines. For example, leased land that supports a transmission line segmented to the Network segment is allocated to that segment.

BPA also has depreciable leased land ($0.72 million, Table 2, line 35) associated with radio stations that is not assigned to a specific segment because communication facilities, such as radio stations, generally support all the segments. Therefore, the investment associated with this leased land is prorated to the segments based on the total of the line and station investment allocated to each segment.

4.1.4 Ancillary Service Investment

BPA has $185.7 million in ancillary service investment. Table 2, line 41. This investment includes equipment designated as control equipment ($76.1 million, line 43), hardware and software at the control centers supporting scheduling and dispatch ($48.7 million, line 46), and communications equipment supporting Supervisory Control and Data Acquisition (SCADA) ($60.9 million, line 52). This investment is all allocated to the Ancillary Services segment.

4.1.5 General Plant Investment

General plant investment is associated with equipment of a general nature (FERC accounts 390 through 398, with some amounts identified in FERC accounts 352, 353, and 356). *See* Table 2. BPA's telecommunications system facilities (such as radio stations), maintenance buildings, and vehicles are examples of general plant investment. Through FY 2016, BPA's general plant investment (less PFIA) was $1.05 billion. Table 2, line 41. General plant investment is not allocated to the segments in this Study. In the Transmission Revenue Requirement Study, the depreciation cost associated with this investment is treated as an overhead expense and allocated pro rata to the segments based on the segmented O&M expenses. *See* Transmission Revenue Requirement Study Documentation, BP-18-FS-BPA-09A, § 2.2.

4.2 Retirement of Existing Facilities and Installation of New Facilities

As this Study is being prepared, BPA has the actual investment figure for facilities in place as of the end of FY 2016. To estimate the investment that will be in place during the FY 2018–2019 rate period, this figure is adjusted to remove investment in facilities expected to be retired or sold, and to include the forecast of facilities expected to be installed after the end of FY 2016 and before the end of FY 2019. Table 3.1 summarizes the expected station and line investment by segment for fiscal years 2017 through 2019.

New facility investment is identified in BPA's Integrated Program Review (IPR) process. No specific facilities are identified for retirement in this Study. However, as discussed in the Transmission Revenue Requirement Study, the expected investment in new station facilities has been reduced based on historical ratios of retired equipment to new replacement equipment. Transmission Revenue Requirement Study Documentation, BP-18-FS-BPA-09A, § 9.2.

4.3 Operations and Maintenance Expense

This Study includes historical O&M expenses from plant record data for the last seven fiscal years (2010 through 2016). O&M expenses are categorized into three groups (*see* Table 4.2):

1. O&M allocated to lines and substations;
2. scheduling and system operations allocated to the Ancillary Services segment; and
3. marketing and business support identified as overhead.

The O&M expenses allocated to lines and substations include substation operations, various transmission maintenance programs, technical training, vegetation management, and environmental expenses, such as pollution controls. These expenses are segmented according to the facilities supported (*see* Table 4.3). The seven-year historical line and substation O&M expenses average $167.0 million annually (Table 4.1, line 16). The segmented historical costs are used to allocate the projected future O&M costs. *See* Transmission Revenue Requirement Study Documentation, BP-18-FS-BPA-09A, § 2.2.

Scheduling costs and system operations costs are for staff and technology associated with reserving, scheduling, monitoring, controlling, and dispatching the transmission system. The seven-year average historical scheduling and dispatch cost is $52.4 million (Table 4.1, line 18). Rate period forecast scheduling and system operations costs are directly assigned to the Ancillary Services segment and recovered through the SCD service rate. *See* Transmission Revenue Requirement Study Documentation, BP-18-FS-BPA-09A, § 2.2.

Marketing and business support costs are associated with general business functions, including sales and contract management, billing, business strategy, legal support, aircraft services, and general administration and executive services. The seven-year historical marketing and support costs average $48.7 million (Table 4.1, line 18). Rate period forecast costs are allocated pro rata on a net plant basis based on the directly assigned investment. *See* Transmission Revenue Requirement Study Documentation, BP-18-FS-BPA-09A, § 2.2.

4.3.1 Historical Line and Station O&M Assignment to Segments

The following process is used to segment historical O&M expenses:

1. Historical O&M expenses are identified by fiscal year and category, as shown in Table 4.2. Categories are expense programs within BPA's transmission business line, such as substation operations and transmission line maintenance.
2. Approximately one-third of the historical O&M expenses are associated with a specific line, substation, or metering location (*i.e.*, facility type). These expenses, identified as direct O&M expenses, are allocated to segments in the same proportion as was the investment in the specific facility. Thus, if certain O&M expenses are associated with a given substation, and 60 percent of the substation investment was allocated to the Network, 60 percent of those O&M expenses are allocated to the Network. If the investment in a substation is allocated entirely to one segment, then the O&M is also allocated entirely to that segment. The

allocation of O&M for each facility is identified in Appendix A. The direct O&M expenses are then aggregated by category and facility type. S*ee* Table 4.3.

3. Non-direct O&M expenses (that is, expenses not identified with a specific facility) are aggregated by category and allocated to the facility types (transmission lines, substations, or metering locations) in the same proportions as the direct O&M expenses. For example, if 80 percent of direct O&M expenses for substation maintenance are assigned to substations, then 80 percent of non-direct O&M expenses for substation maintenance are assigned to substations. Technical training and environmental analysis have no direct O&M expense and are allocated to facility type in the same proportions as the total direct O&M expenses for each facility type. Thus, for example, since about 18 percent of direct expenses are allocated to transmission lines, 18 percent of technical training expenses are allocated to transmission lines. Non-direct O&M expenses for transmission line maintenance, vegetation management, and right-of-way maintenance are allocated entirely to transmission lines.

4. The sum of the non-direct O&M expense for each facility type is shown in Table 4.3, line 15. These amounts are allocated to the segments in the same proportion as the direct expenses for each facility type. For example, 90 percent of direct O&M expenses for transmission lines were allocated to the Network. Therefore, 90 percent of non-direct O&M expenses for transmission lines are allocated to the Network. Table 4.1, lines 11 and 13.

4.4 U.S. Army Corps of Engineers and U.S. Bureau of Reclamation Facilities

The investment and annual O&M expenses for the U.S. Army Corps of Engineers (Corps) and U.S. Bureau of Reclamation (Reclamation) facilities that function as part of BPA's transmission system are included in the transmission revenue requirement, even though BPA does not own these facilities. The total Corps and Reclamation expenses allocated to transmission were identified in the BP-18 generation inputs settlement. Fredrickson & Fisher, BP-18-E-BPA-18, Appendix A, Attachment 3. The segmentation of these expenses is based on an analysis of the Corps and Reclamation facilities summarized in Table 5. As shown, 97.9 percent of the expenses are segmented to the Network and 2.1 percent of the expenses are segmented to Utility Delivery.

TABLES

Appendix A

BP-18 Rate Case Final Proposal Segmentation Details

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Appendix B

BP-18 Rate Case Final Proposal
Multi-Segmented Facilities Summary

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BONNEVILLE POWER ADMINISTRATION
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