

**BP-14 Power and Transmission  
Rate Proceeding**

**ADMINISTRATOR'S DRAFT  
RECORD OF DECISION**

---

June 2013

---

BP-14-A-02





## Table of Contents

COMMONLY USED ACRONYMS AND SHORT FORMS .....	ix
PARTY ABBREVIATIONS AND JOINT PARTY DESIGNATION CODES .....	xiii
<b>1.0 GENERAL TOPICS.....</b>	<b>1</b>
1.1 Introduction.....	1
1.1.1 Procedural History of this Rate Proceeding.....	1
1.1.1.1 Issue Workshops .....	1
1.1.1.2 BP-14 Rate Proceeding.....	2
1.1.1.3 Partial Settlement of Generation Inputs and Transmission Ancillary and Control Area Services Rates .....	3
1.1.1.4 Waiver of Issues by Failure to Raise in Briefs .....	3
1.1.2 Legal Guidelines Governing Establishment of Rates .....	4
1.1.2.1 Statutory Guidelines.....	4
1.1.2.2 The Broad Ratemaking Discretion Vested in the Administrator .....	4
1.1.3 Federal Energy Regulatory Commission Confirmation and Approval of Rates .....	5
1.1.3.1 Standard of Commission Review.....	5
1.2 Related Topics and Processes .....	6
1.2.1 Integrated Program Review (IPR) .....	6
1.2.2 Ancillary and Control Area Services Practices Forum.....	7
1.2.3 Wind Integration Team Initiatives .....	7
1.2.4 Rate Period High Water Mark Process .....	8
1.2.5 Average System Cost Methodology .....	8
1.2.6 Oversupply Rate Proceeding, OS-14 .....	8
1.3 Procedural Issues .....	9
1.3.1 Order Striking MSR’s Prehearing Brief .....	9
<i>Issue 1.3.1.1 Whether the Administrator should affirm the Hearing Officer’s                 decision to strike MSR’s prehearing brief.....</i>	9
1.3.2 Accommodating Oversupply Rates in BP-14 Rates .....	10
<i>Issue 1.3.2.1 Whether BPA should include a cost recovery mechanism in its                 transmission rate schedules for the recovery of oversupply costs.....</i>	11

1.3.3	Substantial Evidence.....	12
	<i>Issue 1.3.3.1</i> .....	12
	<i>Whether the Administrator must base his decisions in the Record of Decision on the substantial evidence standard.</i> .....	12
1.4	Residential Exchange Program.....	14
1.4.1	Introduction.....	14
1.4.2	2012 REP Settlement Agreement .....	14
1.4.3	Preservation of Arguments in the Event the 2012 REP Settlement Agreement is Overturned.....	15
1.4.4	Implementation of the 2012 REP Settlement Agreement for FY 2014–2015.....	16
<b>2.0</b>	<b>POWER RATES AND POLICIES .....</b>	<b>17</b>
2.1	Power Rates and Policies .....	17
	<i>Issue 2.1.1 Whether BPA appropriately considered the impact of any power rate increase on the regional economy.</i> .....	17
	<i>Issue 2.1.2 Whether BPA is obligated to serve contracted for or committed to (CF/CT) load at the lowest firm power rates based upon the lowest-cost resources.</i> .....	19
2.2	Loads and Resources.....	23
2.2.1	Introduction.....	23
2.3	Power Revenue Requirement.....	23
2.3.1	Introduction.....	23
2.3.2	Revenue Requirement Development .....	24
2.3.3	Interest on Prepay Funds.....	25
	<i>Issue 2.3.3.1 Whether Slice customers should receive interest income earned on prepay funds deposited in the Bonneville Fund in FY 2013.</i> .....	25
2.4	Power Risk and Market Price .....	26
2.4.1	Introduction.....	26
2.4.2	Power Risk and Risk Mitigation .....	28
	<i>Issue 2.4.2.1 Whether, as part of the development of final power rates, the Administrator has the discretion to add PNRR or adjust the CRAC thresholds in order to maintain a 95 percent Treasury Payment Probability.</i> .....	28
	<i>Issue 2.4.2.2 Whether BPA should increase PNRR instead of adjusting the CRAC if risk mitigation needs to be strengthened to meet BPA’s TPP standard.</i> .....	30
	<i>Issue 2.4.2.3 Whether BPA should modify the CRAC such that recovery of a CRAC amount triggered for the first year of the rate period should be spread over a two-year period.</i> .....	31

	<i>Issue 2.4.2.4 Whether BPA has adequately accounted for the financial risks associated with meeting the Northwest Power and Conservation Council's (Council) conservation targets.</i>	33
	<i>Issue 2.4.2.5 Whether BPA should adopt an Energy Efficiency program-related automatic rate adjustment mechanism.</i>	35
2.4.3	Market Price Forecast	36
	<i>Issue 2.4.3.1 Whether BPA should use the forward price curve as an alternative to BPA's fundamentals-based spot price forecast of natural gas market prices.</i>	36
	<i>Issue 2.4.3.2 Whether the forward price curve for electricity at Mid-C should be used as the electricity market price forecast rather than the forecast Staff produces through the use of the production cost model AURORAxmp.</i>	38
	<i>Issue 2.4.3.3 Whether BPA should make AURORAxmp available to parties in future rate proceedings.</i>	41
2.5	Power Rate Development	42
2.5.1	Power Rate Development Changes	42
2.5.2	Section 7(c)(2) Typical Margin	44
	<i>Issue 2.5.2.1 Whether adjusting the industrial margin by applying the GDP Implicit Price Deflator to account for inflationary forces comports with statutory requirements.</i>	44
	<i>Issue 2.5.2.2 Whether applying the GDP Implicit Price Deflator to the BP-12 industrial margin to account for inflationary forces properly establishes the level of the industrial margin for BP-14 rates.</i>	48
	<i>Issue 2.5.2.3 Whether adjusting the industrial margin to account for inflationary forces violates the intent and purpose of the Memorandum of Understanding that was executed by BPA, PPC, and Alcoa by failing to obtain Alcoa's consent to the adjustment.</i>	52
	<i>Issue 2.5.2.4 Whether the Administrator has set the value of reserves credit applicable to the IP rate in accordance with statutory directives.</i>	54
2.5.3	Demand Rate	58
	<i>Issue 2.5.3.1 Whether BPA should use the financing cost assumptions of BPA-backed bonds for the marginal capacity resource used in calculating the demand rate.</i>	58
	<i>Issue 2.5.3.2 Whether BPA should use solely the LMS100 as the marginal resource to calculate the demand rate or use the combination of the LMS100 and demand response.</i>	61
2.5.4	Tier 2 Load Growth Rate Billing Adjustment	63
	<i>Issue 2.5.4.1 Whether BPA should defer to the next rate period the collection of the net costs of the previously purchased power that is no longer needed to meet the forecast loads of the Load Growth customer pool.</i>	63

2.5.5	Unauthorized Increase in Demand for Slice .....	66
	<i>Issue 2.5.5.1 Whether the definition of Slice customers' demand entitlement should be revised in the determination of the application of the Unauthorized Increase (UAI) charge for demand. ....</i>	66
<b>3.0</b>	<b>GENERATION INPUTS AND THE ANCILLARY AND CONTROL AREA SERVICES RATE SCHEDULE .....</b>	<b>69</b>
<b>4.0</b>	<b>TRANSMISSION TOPICS.....</b>	<b>71</b>
4.1	Transmission Segmentation .....	71
4.1.1	Introduction.....	71
4.1.2	Transmission Segmentation Approach for the FY 2014–2015 Rate Period .....	71
	<i>Issue 4.1.2.1 Whether BPA should adopt JP12's segmentation proposal to remove all facilities below 116 kV from the Integrated Network and to use the Commission's Seven Factor Test to determine which facilities above that threshold should be removed from the Integrated Network. ....</i>	71
	<i>Issue 4.1.2.2 Whether BPA should adopt Staff's segmentation proposal, including the 34.5 kV bright-line threshold, for transmission segmentation. ....</i>	75
4.1.3	Issues Regarding the 34.5 kV Bright-Line Threshold .....	77
	<i>Issue 4.1.3.1 Whether a 34.5 kV bright-line threshold complies with equitable cost allocation under section 7(a)(2)(C) of the Northwest Power Act, 16 U.S.C. § 839e(a)(2)(C), and section 10 of the Transmission System Act, 16 U.S.C. § 838h.....</i>	77
	<i>Issue 4.1.3.2 Whether the 34.5 kV bright-line threshold complies with cost causation principles. ....</i>	82
	<i>Issue 4.1.3.3 Whether the achievement of uniform rates is an important consideration for the 34.5 kV bright-line threshold for segmentation in this rate proceeding.....</i>	87
	<i>Issue 4.1.3.4 Whether the 34.5 kV bright-line threshold complies with the definition of the "Integrated Network" segment, under which the network segment consists of facilities that perform a transmission function.....</i>	92
	<i>Issue 4.1.3.5 Whether the level of analysis presented in this proceeding, when compared to the level of analysis in past segmentation studies, supports a segmentation based on a 34.5 kV bright-line threshold. ....</i>	96
	<i>Issue 4.1.3.6 Whether the 34.5 kV bright-line threshold inappropriately relies on the non-precedential settlement of the 1996 rate case. ....</i>	100
	<i>Issue 4.1.3.7 Whether the 34.5 kV bright-line threshold is inconsistent with BPA's Average System Cost Methodology.....</i>	102
	<i>Issue 4.1.3.8 Whether positions taken by BPA in other forums are relevant to the determination of whether the 34.5 kV bright-line threshold is appropriate for segmentation.....</i>	105

4.2	Transmission Revenue Requirement .....	109
4.2.1	Introduction.....	109
4.2.2	Revenue Requirement Development .....	109
4.2.3	Assumptions About the Use of Financial Reserves Attributable to Transmission.....	110
4.2.4	Transmission Risk Analysis.....	110
4.2.5	Issues.....	112
	<i>Issue 4.2.5.1 Whether BPA must use financial reserves attributable to Transmission to offset costs and reduce rates to ensure that rates are established “with a view to encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles.” .....</i>	<i>112</i>
	<i>Issue 4.2.5.2 Whether the 95 percent TPP standard is a minimum threshold to satisfy repayment requirements and a maximum threshold to keep rates as low as possible. ....</i>	<i>116</i>
	<i>Issue 4.2.5.3 Whether the TPP calculated in the Initial Proposal indicates that rates are too high. ....</i>	<i>120</i>
	<i>Issue 4.2.5.4 Whether the Transmission Risk Analysis Model (TRAM) should include the calibration adjustment proposed by Staff to adjust for uncertainty in net revenues.....</i>	<i>121</i>
	<i>Issue 4.2.5.5 Whether agency financial reserves attributable to Transmission Services in excess of the amount needed to support a 95 percent TPP should be used to mitigate the proposed transmission rate increase. ....</i>	<i>125</i>
4.3	Transmission Rate Design .....	129
4.3.1	Network Segment Cost Allocation .....	130
	<i>Issue 4.3.1.1 Whether BPA should allocate costs to PTP and IR customers based on contract demand when it allocates costs to NT customers based on peak load. ....</i>	<i>130</i>
	<i>Issue 4.3.1.2 Whether operations, administrative salaries, internal support, information technology, and Scheduling, System Control and Dispatch Service (SCD) costs are directly related to transmission facility investment and, if not, whether BPA should allocate these costs on the basis of contract demand and load.....</i>	<i>135</i>
	<i>Issue 4.3.1.3 Whether the evidence in the record supports the conclusion that BPA plans certain parts of the transmission system to meet demands on a coincident peak basis.....</i>	<i>136</i>
	<i>Issue 4.3.1.4 Whether BPA should allocate costs to NT load under the 12 CP method, because the Commission uses the 12 CP method for jurisdictional utilities, or under a non-coincident peak method. ....</i>	<i>138</i>
	<i>Issue 4.3.1.5 Whether a non-coincident peak cost allocation method is inconsistent with the pro forma tariff. ....</i>	<i>143</i>

	<i>Issue 4.3.1.6 Whether Staff’s proposal for a non-coincident peak methodology gives too much weight to the non-coincident peak load forecast assumption in BPA’s planning studies.</i>	145
	<i>Issue 4.3.1.7 Whether BPA should allocate costs to NT service on the basis of two, three, or twelve months.</i>	147
	<i>Issue 4.3.1.8 Whether BPA should credit short-term and non-firm PTP sales revenue to PTP, IR, and NT service based on the contribution of each service to excess capacity on the system.</i>	149
4.3.2	Utility Delivery Service	150
	<i>Issue 4.3.2.1 Whether cost causation principles require BPA to increase the utility delivery charge to the level necessary for the charge to fully recover the FY 2014–2015 utility delivery costs.</i>	151
	<i>Issue 4.3.2.2 Whether section 9 of the Transmission System Act requires BPA to increase the utility delivery charge to the level necessary for the charge to fully recover the FY 2014–2015 utility delivery costs.</i>	154
	<i>Issue 4.3.2.3 Whether BPA should increase the utility delivery charge by 25 percent for FY 2014–2015 or begin a series of gradual increases to transition the rate to full cost recovery in three to five rate periods</i>	156
	<i>Issue 4.3.2.4 Whether BPA should allocate to all other transmission segments the FY 2014–2015 utility delivery costs that are not recovered through the utility delivery charge.</i>	159
4.3.3	Eastern Intertie	160
	<i>Issue 4.3.3.1 Whether BPA should eliminate the Eastern Intertie segment and roll the costs of BPA’s share of Eastern Intertie capacity into the Integrated Network.</i>	160
	<i>Issue 4.3.3.2 Whether roll-in of BPA’s share of Eastern Intertie capacity would encourage development of renewable generation in the Pacific Northwest.</i>	161
	<i>Issue 4.3.3.3 Whether roll-in of BPA’s share of Eastern Intertie capacity would be consistent with sound business principles.</i>	162
	<i>Issue 4.3.3.4 Whether roll-in of BPA’s Eastern Intertie capacity would be a precedent supporting roll-in of other segments.</i>	163
4.3.4	NERC/WECC Costs	165
	<i>Issue 4.3.4.1 Whether BPA should directly assign the projected costs of reliability compliance activities it performs pursuant to agreements it has with certain customers.</i>	165
4.3.5	Billing Factor for Scheduling, System Control, and Dispatch Service Rate	168
	<i>Issue 4.3.5.1 Whether BPA should retain the existing SCD billing factor for NT customers and establish a separate SCD rate for those customers.</i>	168
<b>5.0</b>	<b>PARTICIPANT COMMENTS</b>	<b>171</b>
5.1	Introduction	171
5.2	Participant Comments	172

**6.0 NATIONAL ENVIRONMENTAL POLICY ACT ANALYSIS .....175**

**This page intentionally left blank.**

## COMMONLY USED ACRONYMS AND SHORT FORMS

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

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

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

RT1SC	RHWM Tier 1 System Capability
RTO	Regional Transmission Operator
SCADA	Supervisory Control and Data Acquisition
SCS	Secondary Crediting Service
Slice	Slice of the System (product)
T1SFCO	Tier 1 System Firm Critical Output
TCMS	Transmission Curtailment Management Service
TOCA	Tier 1 Cost Allocator
TPP	Treasury Payment Probability
TRAM	Transmission Risk Analysis Model
Transmission System Act	Federal Columbia River Transmission System Act
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
TSS	Transmission Scheduling Service
UAI	Unauthorized Increase
ULS	Unanticipated Load Service
USACE, Corps, or COE	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
USFWS	U.S. Fish and Wildlife Service
VERBS	Variable Energy Resources Balancing Service (rate)
VOR	Value of Reserves
VR1-2014	First Vintage rate of the BP-14 rate period
WECC	Western Electricity Coordinating Council (formerly WSCC)
WIT	Wind Integration Team
WSPP	Western Systems Power Pool

## PARTY ABBREVIATIONS AND JOINT PARTY DESIGNATION CODES

AC	Avista Corporation
AL	Alcoa, Inc.
AP	Association of Public Agency Customers
BC	Benton County Public Utility District No. 1
CL	Clark County Public Utility District No. 1 (Clark Public Utilities)
CO	Cowlitz County Public Utility District No. 1
CP	Calpine Corporation
CS	Caithness Shepherds Flat, LLC
ED	EDP Renewables North America, LLC
EW	Eugene Water & Electric Board
FR	Franklin County Public Utility District No. 1
GC	Grant County Public Utility District No. 2
GH	Grays Harbor Energy, LLC
IN	Industrial Customers of Northwest Utilities
IP	Idaho Power Company
IR	Iberdrola Renewables, LLC
JP	J.P. Morgan Ventures Energy Corporation
LC	Lewis County Public Utility District No. 1
MS	M-S-R Public Power Agency
NE	NextEra Energy Resources, LLC
NI	Northwest & Intermountain Power Producers Coalition
NR	Northwest Requirements Utilities
NT	Northwestern Energy
NW	Northwest Irrigation Utilities
NY	NW Energy Coalition
PC	PacifiCorp
PG	Portland General Electric Company
PN	Pacific Northwest Generating Cooperative
PO	Pend Oreille County Public Utility District No. 1
PP	Public Power Council
PS	Puget Sound Energy, Inc.
PU	Public Utility Commission of Oregon
PX	Powerex Corporation
RN	Renewable Northwest Project
SC	Southern California Edison Company
SE	City of Seattle
SN	Snohomish County Public Utility District No. 1
ST	Simpson Tacoma Kraft Company, LLC
TA	City of Tacoma, dba Tacoma Power
TC	TransAlta Energy Marketing (U.S.)
TU	Turlock Irrigation District
WC	Willow Creek Energy, LLC
WG	Western Public Agencies Group
WM	Western Montana Electric Generating and Transmission Cooperative
YP	Yakama Power

<b>Joint Party Code</b>	<b>Joint Party</b>	<b>Joint Party Members</b>
JP01	Joint Party 1	Pacific Northwest Generating Cooperative (PN) Western Public Agencies Group (WG) Northwestern Requirements Utilities (NR)
JP02	Joint Party 2	Avista Corporation (AC) PacifiCorp (PC) Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS) Northwestern Energy (NT)
JP03	Joint Party 3	Pacific Northwest Generating Cooperative (PN) Northwestern Requirements Utilities (NR)
JP04	Joint Party 4	Avista Corporation (AC) Idaho Power Company (IP) PacifiCorp (PC) Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)
JP05	Joint Party 5	Public Power Council (PP) Industrial Customers of Northwest Utilities (IN)
JP06	Joint Party 6	Avista Corporation (AC) Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)
JP07	Joint Party 7	Portland General Electric Company (PG) Puget Sound Energy, Inc. (PS)
JP08	Joint Party 8	Public Utility District No. 1 of Cowlitz County (CO) Eugene Water & Electric Board (EW) Industrial Customers of Northwest Utilities (IN)
JP09	Joint Party 9	Industrial Customers of Northwest Utilities (IN) Public Power Council (PP) Northwest Requirements Utilities (NR)

<b>Joint Party Code</b>	<b>Joint Party</b>	<b>Joint Party Members</b>
JP10	Joint Party 10	Industrial Customers of Northwest Utilities (IN) Public Power Council (PP) Northwest Requirements Utilities (NR) Western Montana Electric Generating and Transmission Cooperative (WM)
JP11	Joint Party 11	Benton County Public Utility District No. 1 (BC) Franklin County Public Utility District No. 1 (FR) City of Seattle (SE) Snohomish County Public Utility District No. 1 (SN) City of Tacoma, dba Tacoma Power (TA)
JP12	Joint Party 12	Benton County Public Utility District No. 1 (BC) Iberdrola Renewables, LLC (IR) City of Seattle (SE) Snohomish County Public Utility District No. 1 (SN) City of Tacoma, dba Tacoma Power (TA)
JP13	Joint Party 13	Benton County Public Utility District No. 1 (BC) Franklin County Public Utility District No. 1 (FR)
JP14	Joint Party 14	Cowlitz County Public Utility District No. 1 (CO) Eugene Water & Electric Board (EW) Northwest Requirements Utilities (NR) Pacific Northwest Generating Cooperative (PN) Western Public Agencies Group (WG)
JP15	Joint Party 15	Cowlitz County Public Utility District No. 1 (CO) Eugene Water & Electric Board (EW)
JP16	Joint Party 16	Cowlitz County Public Utility District No. 1 (CO) Eugene Water & Electric Board (EW) Northwest Requirements Utilities (NR) Public Power Council (PP)

<b>Joint Party Code</b>	<b>Joint Party</b>	<b>Joint Party Members</b>
JP17	Joint Party 17	Benton County Public Utility District No. 1 (BC) Clark Public Utilities (CL) Cowlitz County Public Utility District No. 1 (CO) Eugene Water & Electric Board (EW) Franklin County Public Utility District No. 1 (FR) City of Seattle (SE) Snohomish County Public Utility District No. 1 (SN) City of Tacoma, dba Tacoma Power (TA)
JP18	Joint Party 18	Iberdrola Renewables, Inc. (IR) PacifiCorp (PC)
JP19	Joint Party 19	Alcoa Inc. (AL) Clark County Public Utility District (CL) Cowlitz County Public Utility District (CO) Eugene Water & Electric Board (EW) Franklin County Public Utility District (FR) Industrial Customers of Northwest Utilities (IN) Seattle City Light (SE) Snohomish County Public Utility District No. 1 (SN) Tacoma Power (TA)
JP20	Joint Party 20	Public Utility District No. 1 of Benton County (BC) Public Utility District No. 1 of Cowlitz County (CO) Eugene Water and Electric Board (EW) Public Utility District No. 1 of Franklin County (FR) Public Utility District No. 1 of Lewis County (LC) Seattle City Light (SE) Public Utility District No. 1 of Snohomish County (SN) Tacoma Power (TA) Western Public Agencies Group (WG)
JP21	Joint Party 21	Calpine Corporation (CP) Grays Harbor Energy LLC (GH) Northwest & Intermountain Power Producers Coalition (NI) TransAlta Energy Marketing (TC) Willow Creek Energy LLC (WC)

<b>Joint Party Code</b>	<b>Joint Party</b>	<b>Joint Party Members</b>
JP22	Joint Party 22	Northwest Requirements Utilities (NR) Public Power Council (PP) Industrial Customers of Northwest Utilities (IN) Alcoa, Inc. (AL)
JP23	Joint Party 23	Northwest Requirements Utilities (NR) Pacific Northwest Generating Cooperative (PN) Cowlitz County Public Utility District No. 1 (CO) Eugene Water & Electric Board (EW)
JP24	Joint Party 24	Industrial Customers of Northwest Utilities (IN) Simpson Tacoma Kraft Company, LLC (ST)
JP25	Joint Party 25	Public Power Council (PP) Northwest Requirements Utilities (NR) Industrial Customers of Northwest Utilities (IN) Cowlitz County Public Utility District No. 1 (CO) Eugene Water & Electric Board (EW)

**This page intentionally left blank.**

## 1.0 GENERAL TOPICS

### 1.1 Introduction

The BP-14 Power and Transmission Rate Proceeding (BP-14) establishes power and transmission rate schedules and General Rate Schedule Provisions (GRSPs) that replace existing rate schedules and GRSPs, which expire on September 30, 2013.

This Draft Record of Decision (ROD) contains the preliminary decisions of the Bonneville Power Administration (BPA) Administrator, based on the record compiled in this rate proceeding to date, with respect to the adoption of power, transmission, and ancillary service rates for Scheduling, System Control, and Dispatch Service and Reactive Supply and Voltage Control from Generation Sources Service for the two-year rate period October 1, 2013, through September 30, 2015 (Fiscal Years (FY) 2014–2015). This Draft ROD follows an evidentiary hearing, initial briefing, and oral argument to the BPA Administrator. It presents the substantive issues raised by parties in this proceeding, as stated in their initial briefs. It describes the parties' and BPA Staff's positions on the issues. It then evaluates the positions and presents the Administrator's draft decisions. This Draft ROD also summarizes and responds to participant comments that were submitted during the public comment period, which ended on February 15, 2013.

Briefs on exceptions to the Draft ROD are due on July 1. The Final ROD is scheduled to be issued July 22, 2013. The Final ROD and BPA's Final Proposal will be submitted with the rate case record to the Federal Energy Regulatory Commission (FERC or Commission) no later than 60 days before October 1, 2013.

#### 1.1.1 Procedural History of this Rate Proceeding

##### 1.1.1.1 Issue Workshops

For several months prior to the release of Staff's Initial Proposal, BPA sponsored a series of workshops and technical conference calls on a variety of topics related to its power and transmission ratemaking so that BPA Staff and interested parties could develop a common understanding of specific topics, generate ideas, and bring forward alternative proposals. The workshops placed significant emphasis on transmission and ancillary and control area services rate development. BPA held 10 workshops between March 2012 and October 2012 on generation inputs issues, including balancing service for variable energy resources and for dispatchable energy resources. Regarding transmission rates, BPA held 16 workshops between November 2011 and September 2012 on segmentation, cost allocation, rate design, dynamic transfer capability, Montana Intertie, and other issues.

Conducting the issue workshops before the development of the Initial Proposal allowed BPA Staff and interested parties to freely exchange ideas and comments relevant to rate issues without the prohibition on *ex parte* communication that goes into effect upon publication of the rate

proposal in the Federal Register. The *ex parte* prohibition for this rate proceeding went into effect on November 8, 2012, and ends when BPA issues the Final ROD, scheduled for July 22, 2013. The Initial Proposal incorporated a number of the ideas and proposals that were discussed in the workshops.

### **1.1.1.2 BP-14 Rate Proceeding**

Section 7(i) of the Pacific Northwest Electric Power Planning and Conservation Act, 16 U.S.C. § 839e(i) (Northwest Power Act), requires that BPA's rates be established according to specific procedures that include, among other things, issuance of a notice in the Federal Register announcing the proposed rates; the opportunity for interested parties to submit written views, supporting information, questions, and arguments; and a decision by the Administrator based on the record. This proceeding is also governed by BPA's rules for general rate proceedings contained in the *Procedures Governing Bonneville Power Administration Rate Hearings*, 51 Fed. Reg. 7611 (1986) (hereinafter, *Procedures*). The *Procedures* implement the section 7(i) requirements.

The BP-14 rate proceeding is a consolidated case that includes both power and transmission rates in a single docket. On November 8, 2012, BPA published in the Federal Register a notice of "Fiscal Year (FY) 2014–2015 Proposed Power and Transmission Rate Adjustments; Public Hearing and Opportunities for Public Review and Comment," 77 Fed. Reg. 66966 (2012). On November 9, 2012, BPA held a scheduling conference to discuss a procedural schedule and procedural orders with prospective parties in the case. The formal rate proceeding began with a prehearing conference on November 14, 2012. After the prehearing conference the Hearing Officer issued orders establishing the schedule for the rate proceeding, special rules of practice, data request procedures, and general acronyms, and granted petitions to intervene.

BPA Staff's Initial Proposal is supported by Staff's initial studies and written testimony issued on November 14, 2012. Clarification of Staff's Initial Proposal took place November 27, 29, and 30, 2012. The parties filed their direct testimony on January 28, 2013. Clarification of parties' testimony took place on February 11, 2013. BPA and the parties filed rebuttal testimony on March 11, 2013. Clarification of the rebuttal testimony took place on March 14, 2013. Cross-examination occurred April 5, 2013.

BPA Staff met with parties at a noticed meeting on April 17, 2013, to discuss whether Slice customers should receive interest income earned on prepay funds deposited in the Bonneville Fund in FY 2013. *See* Draft ROD Issue 2.3.3.1.

The parties filed their initial briefs on May 1, 2013. Oral argument before the Administrator took place on May 10. This Draft Record of Decision is being issued on June 13, 2013.

At times, certain parties to this proceeding consolidated for the purpose of filing testimony or submitting a brief on one or more issues. *See* BP-14-HOO-02. The rate case clerks assigned each consolidated group of parties (joint party) an alphanumeric designation (*e.g.*, JP01, JP02,

JP03). For convenience, an updated list of the joint parties appears in the list of Party Abbreviations and Joint Party Designation Codes that is included at the beginning of this Draft ROD. *See also* BP-14-HOO-04.

BPA received 12 written comments during the participant<sup>1</sup> comment period, which began with the publication of the notice in the Federal Register on November 8, 2012, and ended February 15, 2013. The participant comments are part of the record upon which the Administrator bases his decisions. Participant comments are summarized and addressed separately in Draft ROD Chapter 5. Participant comments may be viewed at BPA's Web site under "Public Involvement."

#### **1.1.1.3 Partial Settlement of Generation Inputs and Transmission Ancillary and Control Area Services Rates**

Initial briefs were filed in this rate proceeding on issues concerning generation inputs and transmission ancillary and control area services rates. On May 9, 2013, all but one party agreed to support a settlement of those issues and to waive their right to preserve any issues raised in their initial briefs concerning generation inputs and certain ancillary and control area services rates. BPA Staff and the parties to the settlement agreement proposed that the Administrator adopt the settlement proposal.

On May 15, 2013, BPA issued a final Record of Decision in which the Administrator adopted the settlement. BP-14-A-01. That Record of Decision addresses the objections and issues that were preserved by the party that did not support the settlement. In addition, that Record of Decision establishes the rates for all ancillary and control area services rates except for (1) Scheduling, System Control, and Dispatch Service and (2) Reactive Supply and Voltage Control from Generation Sources Service. Thus, no issues concerning the settled generation inputs and ancillary and control area services rates are addressed in this Draft ROD.

Generation inputs and inter-business line allocations not addressed by the partial settlement are listed in section 3.

#### **1.1.1.4 Waiver of Issues by Failure to Raise in Briefs**

Pursuant to section 1010.13(b) of the *Procedures*, arguments not raised in parties' briefs are deemed to be waived. Under this provision, a party's brief must specifically address the legal or factual dispute at issue. Blanket statements that seek to preserve every issue raised in testimony will not preserve any matter at issue.

---

<sup>1</sup> For interested persons who are not eligible or do not wish to become parties to the formal evidentiary hearings, BPA's *Procedures* provide opportunities to participate in the ratemaking process through submission of comments as a "participant." *See* section 1010.5 of BPA's *Procedures*. No party may submit comments as a participant, and comments so submitted will not be included in the record. BP-14-HOO-02.

Sections 1010.13(c) and (d) of the *Procedures* set forth the requirements applicable to initial briefs and briefs on exceptions. A party need not reassert an issue in its brief on exceptions in order to avoid waiving the issue. All arguments raised by a party in its initial brief shall be deemed to have been raised in the party's brief on exceptions. BP-14-HOO-02.

## **1.1.2 Legal Guidelines Governing Establishment of Rates**

### **1.1.2.1 Statutory Guidelines**

Section 7(a)(1) of the Northwest Power Act directs the Administrator to 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. 16 U.S.C. § 839e(a)(1). Rates are to be set 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 (FCRPS) (including irrigation costs required to be paid by power revenues) over a reasonable period of years. *Id.* Section 7 of the Northwest Power Act also contains rate directives describing how rates for individual customer groups are to be derived.

Section 7(a)(1) of the Northwest Power Act reaffirms the applicability of section 5 of the Flood Control Act of 1944 (Flood Control Act), which directs that rate schedules should encourage the widespread use of power at the lowest possible rates to consumers consistent with sound business principles. 16 U.S.C. § 825s. Section 5 of the Flood Control Act provides that rate schedules should be drawn having regard to the recovery of the cost of producing and transmitting electric energy, including the amortization of the Federal investment over a reasonable number of years. *Id.*

Section 7(a)(1) of the Northwest Power Act also reaffirms the applicability of sections 9 and 10 of the Federal Columbia River Transmission System Act of 1974, 16 U.S.C. § 838 (Transmission System Act), which contains requirements similar to those of the Flood Control Act. Section 9 of the Transmission System Act, 16 U.S.C. § 838g, provides that rates shall be established (1) with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles; (2) with regard to the recovery of the cost of producing and transmitting electric power, including amortization of the capital investment allocated to power over a reasonable period of years; and (3) at levels that produce such additional revenues as may be required to pay, when due, the principal, premiums, discounts, expenses, and interest in connection with bonds issued under the Transmission System Act. Section 10 of the Transmission System Act, 16 U.S.C. § 838h, allows for uniform rates and specifies that the costs of the Federal transmission system be equitably allocated between Federal and non-Federal power utilizing the system.

### **1.1.2.2 The Broad Ratemaking Discretion Vested in the Administrator**

The Administrator has broad discretion to interpret and implement statutory directives applicable to ratemaking. These directives focus on cost recovery and do not restrict the Administrator to

any particular rate design methodology or theory. See *Pacific Power & Light v. Duncan*, 499 F. Supp. 672 (D.C. Or. 1980); accord *City of Santa Clara v. Andrus*, 572 F.2d 660, 668 (9th Cir. 1978) (“widest possible use” standard is so broad as to permit “the exercise of the widest administrative discretion”); *Electricities of North Carolina v. Southeastern Power Admin.*, 774 F.2d 1262, 1266 (4th Cir. 1985).

The United States Court of Appeals for the Ninth Circuit (Ninth Circuit or Court) has recognized the Administrator’s ratemaking discretion. *Central Lincoln Peoples’ Utility District v. Johnson*, 735 F.2d 1101, 1120-29 (9th Cir. 1984) (“Because BPA helped draft and must administer the Northwest Power Act, we give substantial deference to BPA’s statutory interpretation”); *PacifiCorp v. FERC*, 795 F.2d 816, 821 (9th Cir. 1986) (“BPA’s interpretation is entitled to great deference and must be upheld unless it is unreasonable”); *Atlantic Richfield Co. v. Bonneville Power Admin.*, 818 F.2d 701, 705 (9th Cir. 1987) (BPA’s rate determination upheld as a “reasonable decision in light of economic realities”); *Department of Water and Power of the City of Los Angeles v. Bonneville Power Admin.*, 759 F.2d 684, 690 (9th Cir. 1985) (“Insofar as agency action is the result of its interpretation of its organic statutes, the agency’s interpretation is to be given great weight”); *Public Power Council v. Bonneville Power Admin.*, 442 F.3d 1204, 1211 (9th Cir. 2006) (“[The GRSPs] are entirely bound up with BPA’s rate making responsibilities, and we owe deference to the BPA in that area”). The Supreme Court of the United States has also recognized the Administrator’s ratemaking discretion. *Aluminum Company of America v. Central Lincoln Peoples’ Utility District*, 467 U.S. 380, 389 (1984) (“The Administrator’s interpretation of the Regional Act is to be given great weight.”).

### **1.1.3 Federal Energy Regulatory Commission Confirmation and Approval of Rates**

Under the Northwest Power Act, BPA’s rates become effective upon confirmation and approval by the Commission. 16 U.S.C. § 839e(a)(2) and (k). The Commission’s review is appellate in nature, based on the record developed by the Administrator. *United States Department of Energy—Bonneville Power Admin.*, 13 FERC ¶ 61,157, 61,339 (1980). The Commission may not modify rates proposed by the Administrator but may only confirm, reject, or remand them. *United States Department of Energy—Bonneville Power Admin.*, 23 FERC ¶ 61,378, 61,801 (1983). Pursuant to section 7(i)(6) of the Northwest Power Act, 16 U.S.C. §839e(i)(6), the Commission has promulgated rules establishing procedures for the approval of BPA rates. 18 C.F.R. Part 300 (1997).

#### **1.1.3.1 Standard of Commission Review**

The Commission reviews BPA rates under the Northwest Power Act to determine whether they (1) are sufficient to ensure repayment of the Federal investment in the FCRPS over a reasonable number of years after first meeting BPA’s other costs; and (2) are based on BPA’s total system costs. With respect to transmission rates, Commission review includes an additional requirement: to ensure that the rates equitably allocate the cost of the Federal transmission system between Federal and non-Federal power using the system. 16 U.S.C. § 839e(a)(2). See *United States Department of Energy—Bonneville Power Admin*, 39 FERC ¶ 61,078, 61,206 (1987). The limited Commission review of rates permits the Administrator substantial discretion

in the design of rates and the allocation of power costs, neither of which is subject to Commission jurisdiction. *Central Lincoln Peoples' Utility District v. Johnson*, 735 F.2d 1101, 1115 (9th Cir. 1984).

## **1.2 Related Topics and Processes**

This section includes discussion of topics and processes separate and distinct from this rate proceeding that provide information and policy context to the proceeding, including the Integrated Program Review (IPR), the Tiered Rate Methodology (TRM), Ancillary and Control Area Service Practices Forum and the Wind Integration Team, the Rate Period High Water Mark (RHWM) Process, and the 2012 Residential Exchange Program Settlement Agreement (2012 REP Settlement). Issues related to those processes are outside the scope of the BP-14 7(i) proceeding. 77 Fed. Reg. 66966, 66967 (2012).

### **1.2.1 Integrated Program Review (IPR)**

Since 1986, in a process separate from its rate proceedings, BPA has conducted a public review of planned spending levels used in the development of rates. The IPR process provides interested parties opportunity to review and provide comment on all of BPA's expense and capital spending level estimates prior to the use of those estimates in setting rates. BPA initiated the expense and capital spending level review with a meeting for utility general managers in January 2012. The 2012 Capital Investment Review (CIR), a new public process focused on reviewing and discussing draft asset strategies and 10-year capital forecasts, preceded the 2012 IPR, with workshops occurring in March and April 2012. Public comments received during the CIR informed capital cost projections for FY 2014–2015 in the 2012 IPR. BPA began the most recent IPR public process in June 2012 as a program-level review of the planned expenses that would be included in setting power and transmission rates in the BP-14 rate proceeding. Between June and August 2012, BPA held technical workshops and responded to participants' requests for additional information. The IPR and CIR processes provided opportunities for BPA and participants to review and discuss power, transmission, and agency services programs and included detailed review of asset strategies and associated program spending levels.

BPA reviewed and considered the comments on FY 2014–2015 program spending levels received during the IPR public process when making spending level decisions when developing the BP-14 Initial Proposal. On October 26, 2012, BPA issued the Final Close-Out Letter and 2012 IPR Final Close-Out Report, which summarized the comments and stated BPA's responses to comments. In the letter and report BPA presented the program-level cost estimates that were used in the BP-14 Initial Proposal. The IPR resulted in cost reductions from the spending levels proposed at the start of the IPR. For the Initial Proposal, the cost reductions amounted to an average of \$135 million annually for Power Services for each of the two fiscal years, FY 2014 and FY 2015. The IPR resulted in no overall change in Transmission Services' proposed spending levels; cost decreases were offset by cost increases, particularly in the area of compliance.

On April 26, 2013, BPA invited the region to an abbreviated “IPR2” public process to discuss proposed adjustments from the 2012 IPR. The process began with a public meeting in Portland on April 30, 2013. The comment period ended on May 7, 2013. On June 4, 2013, BPA issued the IPR2 Decision Letter and enclosed Spending Level Changes Table. This document is available on BPA’s Web site. In the letter and enclosed table BPA presented the program-level cost estimates that will be used in the BP-14 Final Proposal. The IPR2 resulted in cost changes from the spending levels proposed at the end of the IPR, mainly due to the reshaping of BPA’s capital programs and the Energy Northwest updated Long Range Plan. For the Final Proposal, the cost changes amount to a total capital and expense reduction of \$192 million for the two-year rate period, \$161 million for Transmission Services and \$31 million for Power Services.

For further information on the IPR and IPR2 processes and outcomes, see the BPA Web site under “Finance & Rates,” “Financial Processes,” “Integrated Program Review.”

As noted in the Federal Register notice BPA published for the BP-14 rate proceeding, the IPR process is separate from the rate proceeding, and challenges to the Administrator’s decisions on cost and spending levels are excluded from the official record of the rate proceeding. 77 Fed. Reg. 66966, 66967 (2012).

### **1.2.2 Ancillary and Control Area Services Practices Forum**

The Ancillary and Control Area Services Practices Forum is a series of public meetings to discuss implementation of BPA ancillary services delivery, including Variable Energy Resource Balancing Services (VERBS) base and full services, VERBS Supplemental Service, and balancing reserve capacity purchases. The Forum process and matters related to BPA ancillary services delivery are separate and distinct from this rate proceeding.

### **1.2.3 Wind Integration Team Initiatives**

The integration of Variable Energy Resources (VERs) into BPA’s balancing authority area is an important initiative and is leading to significant changes in operations and business practices. BPA is working with customers to solve the issues arising from the integration of a significant amount of VERs in several ongoing processes.

As part of the WI-09 Settlement, BPA assembled the internal cross-agency Wind Integration Team (WIT) to explore technical solutions to address the challenge of balancing loads and resources to preserve system reliability while accommodating the rapid development of wind energy in the BPA balancing authority area. The mission of the WIT is to clearly define and execute a plan for integrating wind generation in a manner that allows for the continued highly reliable operation of the Federal power and transmission system at the lowest cost consistent with sound business and operations practices.

The WIT has developed and implemented numerous initiatives that have helped allow for a steady increase in the amount of wind interconnected to BPA’s balancing authority area. These initiatives will continue in the FY 2014–2015 rate period. These initiatives include Dispatcher

Standing Order (DSO) 216, dynamic transfer capability (DTC), forecasting and state awareness tools, intra-hour scheduling, customer-supplied generation imbalance, Supplemental Service, and WebExchange (WebEx). The WIT and its initiatives are separate and distinct from this rate proceeding.

#### **1.2.4 Rate Period High Water Mark Process**

A customer's RHW M helps to define that customer's maximum eligibility to purchase power at Priority Firm Power Tier 1 rates for the rate period. Power Rates Study, BP-14-E-BPA-01, at 13. The RHW M is determined based on the customer's Contract High Water Mark (CHWM) and the RHW M Tier 1 System Capability (RT1SC) for each applicable rate period. *Id.* The determination of RT1SC and customers' RHW Ms occurs outside the rate proceeding in the RHW M Process, as described in TRM section 4.2.1. *Id.* The RHW M Process that established RHW Ms for the BP-14 rate period, FY 2014–2015, was completed in September 2012. *Id.* The RHW Ms and related outputs of the RHW M Process are combined with the rate case load forecast to forecast billing determinants and for other ratesetting purposes. *Id.* at 14. Challenges to BPA's determination of customers' FY 2014–2015 RHW Ms and other RHW M Process determinations are excluded from the record of the BP-14 rate proceeding. 77 Fed. Reg. 66966, 66968-66969 (2012).

#### **1.2.5 Average System Cost Methodology**

The ASC Methodology (ASCM) was established in a public process in 2008 and approved by the Federal Energy Regulatory Commission in 2009. Determinations of individual utilities' ASCs are made in separate processes conducted pursuant to the 2008 ASCM. Thus, the 2008 ASCM and ASC determinations are excluded from the scope of the BP-14 rate proceeding. 77 Fed. Reg. 66966, 66968 (2012).

#### **1.2.6 Oversupply Rate Proceeding, OS-14**

Concurrent with the publication of the notice of the BP-14 rate proceeding in the Federal Register on November 8, 2012, BPA published a separate notice of "Public Hearing and Opportunities for Public Review and Comment: Notice of Proposed 2014 Oversupply Rates." 77 Fed. Reg. 66963 (2012). This notice commenced the OS–14 rate proceeding to establish a rate to recover the costs incurred under the Oversupply Management Protocol included in BPA's Open Access Transmission Tariff.

Oversupply occurs when high water flows on the Columbia River, primarily during the spring and early summer, require BPA, the Army Corps of Engineers, and the Bureau of Reclamation to take all reasonable actions to avoid excess spill in order to protect endangered fish and other aquatic species in accordance with the Clean Water Act, Endangered Species Act, and court orders. To avoid spilling water beyond approved levels, other generation serving load is displaced (reduced or shut down), and an equal amount of additional hydroelectric generation is delivered to load served by that generation. Under the Oversupply Management Protocol, generators can elect to be compensated for certain costs related to displacement. The OS–14 rate

proceeding will establish rates to recover the costs incurred under the Oversupply Management Protocol.

BPA Staff initially considered combining the establishment of the OS-14 rate into the BP-14 proceeding. After a discussion with potential parties in both proceedings, it was determined that keeping the OS-14 rate development and its issues in a separate docket was the preferred outcome. The introduction of OS-14 issues was not expressly excluded from the scope of the BP-14 proceeding. One issue related to OS-14 is raised in this proceeding and is addressed in Draft ROD section 1.3.2.

### **1.3 Procedural Issues**

#### **1.3.1 Order Striking MSR's Prehearing Brief**

On February 27, 2013, the Hearing Officer granted BPA's motion to strike MSR's Prehearing Brief on the ground that the brief addressed issues that the Federal Register Notice excluded from the rate case and that, except for brief portions that could not be separated from the rest of the brief, it did not address rates issues. BP-14-HOO-26. In its Initial Brief, MSR appeals this decision to the Administrator.

##### **Issue 1.3.1.1**

*Whether the Administrator should affirm the Hearing Officer's decision to strike MSR's prehearing brief.*

##### **Parties' Positions**

In its Initial Brief, MSR does not elaborate on its appeal of the Hearing Officer's order to the Administrator. MSR Br., BP-14-B-MS-01, at 2. In its response to BPA's motion to strike, however, MSR argued that its brief was consistent with the Federal Register Notice and did not challenge decisions on costs and spending levels made in other forums. *Id.* at 3.

##### **BPA Staff's Position**

BPA Staff does not have an opportunity to respond to the parties' Initial Briefs. In its motion, however, BPA argued that the primary purpose of MSR's brief was to address operational issues that are outside the scope of the rate case. BPA Motion, BP-14-M-BPA-05.

##### **Evaluation of Positions**

A review of MSR's brief demonstrates that the Hearing Officer appropriately struck it from the record. Very little of the brief concerns rates, and much of it covers subjects specifically excluded from the rate proceeding by the Federal Register notice. As noted in BPA's motion,

the first five pages of the brief offer a history of BPA’s operations under the Northwest Power Act, while the rest of the brief is devoted primarily to criticizing BPA’s operations rather than discussing rates issues. *See* MSR Prehearing Br., BP-14-P-MS-01, at 1-5.

For example, MSR discusses BPA’s approach to integrating variable resources; BPA’s “economic and operational decisions” concerning variable resources; and BPA’s use of Dispatcher Standing Order 216 to support operations of its non-hydro generation resources. *Id.* at 7, 9, 10. None of these arguments are based on evidence in the record. In striking MSR’s brief the Hearing Officer appropriately relied on rule 1010.13(a) of BPA’s procedural rules, which requires that “[a]ll evidentiary arguments in briefs must be based on cited material contained in the record,” and rule 1010.13(e), which provides that “[t]he hearing officer shall not admit into the record any brief that does not conform” to section 1010.13.

The Hearing Officer provided a thorough and persuasive rationale for his order, and MSR offers no argument as to why the order is incorrect. As noted, in its Initial Brief MSR simply states that it appeals the order to the Administrator.

Finally, significant portions of MSR’s prehearing brief concern ancillary services rates, including the amount of balancing reserves BPA carries and the allocation of costs to the Variable Energy Resource Balancing Service rate. *See, e.g.*, MSR Prehearing Br., BP-14-P-MS-01, at 7-10. On May 13, 2013, MSR assented to the Partial Settlement of Generation Inputs and Transmission Ancillary and Control Area Services Rates. Administrator’ Record of Decision on Settlement Proposal for Generation Inputs and Transmission Ancillary and Control Area Services Rates, BP-14-A-01. In accordance with the partial settlement, MSR waived its right to preserve any issues concerning generation inputs or ancillary and control area services rates in this proceeding. Therefore, those portions of its brief that address these issues are moot.

### **Draft Decision**

*BPA appreciates MSR’s involvement in this case and its interest in the issues. At the same time, MSR, like any other party, is required to adhere to the rate case procedures. The Hearing Officer’s order striking MSR’s Prehearing Brief is affirmed.*

### **1.3.2 Accommodating Oversupply Rates in BP-14 Rates**

BPA is establishing a rate to recover oversupply costs in a separate docket, OS-14, which is described in section 1.2.6. Most issues concerned with the oversupply rate are being addressed in the OS-14 proceeding. One procedural issue was raised in this proceeding.

### **Issue 1.3.2.1**

*Whether BPA should include a cost recovery mechanism in its transmission rate schedules for the recovery of oversupply costs.*

#### **Parties' Positions**

WPAG suggests that BPA should include a cost recovery adjustment clause (CRAC) in transmission rates to allow for recovery of oversupply costs if any oversupply costs are allocated to transmission rates. WPAG Br., BP-14-B-WG-01, at 42; Saleba *et al.*, BP-14-E-WG-01, at 60-61. WPAG argues that, if oversupply costs are allocated to transmission rates and a CRAC has not been included in the transmission rate schedules, BPA will have to either reopen the BP-14 case or forgo the recovery of the costs due solely to procedural difficulties. *Id.*

JP25 argues that a forecast cost should be included in the transmission revenue requirement, or alternatively, an adjustment clause included in the transmission Network rate schedules, to allow for recovery of oversupply costs in the FY 2014–2015 rate period. JP25 Br., BP-14-B-JP25-02, at 2; Baker *et al.*, BP-14-E-JP16-01, at 3. (Note that JP25 and JP16 are essentially the same parties; ICNU joined the four JP16 parties to form JP25.) JP25 states that if BPA adopts a different cost recovery mechanism in the OS-14 proceeding, the adjustment clause would have no impact on Network rates. JP25 Br., BP-14-B-JP25-02, at 4.

#### **BPA Staff's Position**

BPA Staff did not propose any rate mechanisms to accommodate recovery of oversupply costs. Staff stated in rebuttal testimony that it does not share WPAG's procedural concerns and that, if BPA decided to include oversupply costs in transmission rates, it could propose adjustment clauses or separate rates in the OS-14 proceeding. Bliven and Parker, BP-14-E-BPA-37, at 20.

#### **Evaluation of Positions**

BPA is not precluded from any cost allocation options for oversupply costs even though it has not included an adjustment clause in the BP-14 case. Bliven and Parker, BP-14-E-BPA-37, at 20. Moreover, including a placeholder in the BP-14 case for costs being allocated in the OS-14 case would cause unnecessary confusion for all litigants and the Commission. *Id.* at 21. Injecting a highly contentious issue into the BP-14 rate proceeding could unnecessarily risk Commission approval of the BP-14 rates. *Id.* Indeed, this concern was a primary reason that parties to the BP-14 and OS-14 rate cases recommended that BPA keep the cases in separate dockets. *Id.*

JP18 argues that the WPAG and JP16 proposals prejudice the outcome of the OS-14 rate case. Beane and Obenchain, BP-14-E-JP18-01, at 3. In response, JP25 argues that, rather than prejudging the outcome, its proposal would provide a mechanism for allocating oversupply costs in case the Administrator adopts a proposal in the OS-14 case that affects rate levels determined in the BP-14 case. JP25 Br., BP-14-B-JP25-02, at 4. JP25 argues that if the Administrator

adopts another cost allocation method, the transmission adjustment clause would have no effect. *Id.* JP18, however, argues that WPAG has not proposed rate mechanisms to account for alternative cost allocations that may affect other types of rates and thus “inappropriately prejudice[s] the unknowable outcome of the OS-14 rate case.” Beane and Obenchain, BP-14-E-JP18-01, at 9. JP18 further argues that placeholder mechanisms are not needed; BPA, regardless of the ultimate decision, can use the same type of recovery mechanisms as those proposed in BPA’s OS-14 initial proposal. *Id.*

If BPA decides in the OS-14 proceeding to allocate all or a portion of oversupply costs to transmission rates, BPA can modify transmission rates in the OS-14 proceeding. No placeholder is needed in the BP-14 rates.

### **Draft Decision**

*BPA will not adopt an adjustment clause to provide for potential recovery of oversupply costs. If BPA allocates all or a portion of oversupply costs to transmission rates, BPA can adopt an appropriate recovery mechanism, or modify transmission rates, in the OS-14 case.*

### **1.3.3 Substantial Evidence**

#### **Issue 1.3.3.1**

*Whether the Administrator must base his decisions in the Record of Decision on the substantial evidence standard.*

#### **Parties’ Positions**

JP12 asserts that Staff did not provide any evidentiary support in the administrative record for its segmentation proposal. JP12 Br., BP-14-B-JP12-01, at 6-7. Therefore, JP12 claims, Staff’s proposal fails to meet the “substantial evidence” requirement in section 9(e)(2) of the Northwest Power Act, 16 U.S.C. §839f(e)(2). *Id.*

JP04 contends that Staff’s proposed calibration adjustment in effect lowers TPP and therefore can increase the BPA transmission revenue requirement. JP04 Br., BP-14-B-JP04-01, at 26. JP04 states that because Staff based its proposed calibration adjustment on historical overforecasts of net transmission revenues, it is not supported by “substantial evidence” as required by section 9(e)(2) of the Northwest Power Act. *Id.*

Alcoa objects to use of the GDP Implicit Price Deflator to adjust the industrial margin on the grounds that Staff’s use of the GDP Implicit Price Deflator instead of conducting a full margin survey is not supported by “substantial evidence.” Alcoa Br., BP-14-B-AL-01, at 3.

## **BPA Staff's Position**

This legal issue was raised for the first time in the initial briefs. BPA Staff did not take any position on this matter.

## **Evaluation of Positions**

As summarized above, parties argue that the Administrator must find in their favor on certain issues because Staff's proposal lacks the necessary "substantial evidence" to support an alternative decision. Although the Administrator has not explicitly addressed this question, he has concluded that all his decisions are supported by the record.

The Administrator bases all his decisions on the evidence and argument in the record. 16 U.S.C. § 839(e)(5). In doing so he necessarily, and explicitly, weighs the evidence and concludes that it supports the decision he has reached. Thus, in all cases he finds that there is substantial evidence in the record to support his decisions.

However, the issues in this Draft ROD are framed in terms of the substantive issues themselves. For example, the segmentation issue JP12 has raised is framed in terms of whether the Administrator should adopt JP12's segmentation proposal, rather than in terms of whether substantial evidence supports the Administrator's decision.

The substantial evidence standard is explicitly applied only on judicial review. If any of the Administrator's decisions are appealed, the appellate court will examine the record to determine whether the decisions are "supported by substantial evidence in the rulemaking record." 16 U.S.C. § 839f(e)(2). In applying this test to BPA's rates, the Ninth Circuit has said:

Rate making decisions are also entitled to deference. *See Cal. Energy Comm'n*, 909 F.2d at 1306 ("BPA is entitled to ... deference in ratemaking decisions, even where it has an interest in the outcome."). It is true that "final determinations regarding rates ... shall be supported by substantial evidence in the rulemaking record ... considered as a whole." 16 U.S.C. § 839f(e)(2). Yet, substantial evidence is simply "more than a mere scintilla. It means such relevant evidence as a reasonable mind might accept as adequate to support a conclusion." *Richardson v. Perales*, 402 U.S. 389, 401, 91 S. Ct. 1420, 1427, 28 L.Ed.2d 842 (1971) (internal quotation marks omitted).

*Pub. Power Council v. Bonneville Power Admin.*, 442 F.3d 1204, 1209 (9th Cir. 2006).

By definition, the Administrator bases his decisions on his assessment of the evidence in the record. These decisions may ultimately be reviewed by the courts to determine whether there is substantial evidence to support them.

## **Draft Decision**

*The Administrator bases his decisions on the evidence in the record, ensuring among other things that his decisions are based on sufficient relevant evidence to support his determinations. The substantial evidence standard is used for judicial review of the Administrator's final decisions, including final rate determinations.*

### **1.4 Residential Exchange Program**

#### **1.4.1 Introduction**

Section 5(c) of the Northwest Power Act establishes the statutory exchange program known generally as the “Residential Exchange Program” or REP. 16 U.S.C. § 839c(c). The REP extends the benefits of low-cost Federal power to residential and farm customers of Pacific Northwest utilities. *Pac. Power & Light Co. v. BPA*, 795 F.2d 810, 812 (9th Cir. 1986). Under the REP, a utility may offer to sell BPA an amount of power not exceeding the utility’s residential and small farm load at its “average system cost” of resources (ASC). 16 U.S.C. § 839c(c). BPA purchases the utility’s power and, in exchange, sells an equivalent amount of power to the utility at BPA’s Priority Firm Power (PF) Exchange rate. Although the REP is formally an exchange of power, the quantities are equal. 16 U.S.C. § 839c(c)(1). In practice, BPA provides monetary benefits calculated as the utility’s exchange load times the amount by which the utility’s ASC exceeds BPA’s applicable PF Exchange rate. *Pac. Power & Light*, 795 F.2d at 812. The exchanging utility must pass through 100 percent of the REP benefits to its eligible residential and farm consumers. 16 U.S.C. § 839c(c)(3). Both consumer-owned utilities (COUs) and investor-owned utilities (IOUs) may participate in the REP.

BPA recovers the cost of the REP through power rates. Section 7(b) of the Northwest Power Act, 16 U.S.C. § 839e(b), governs the calculation of PF Exchange rates used to calculate REP benefits and the PF Public rate BPA charges COUs for power to meet their general requirements. Under section 7(b)(1), the PF Public and the PF Exchange rates begin at the same level; the two may diverge under sections 7(b)(2) and 7(b)(3). 16 U.S.C. §§ 839e(b)(2)-(3). The result is that the costs that BPA may recover in the PF Public rate are limited, and BPA recovers a portion of any cost limitation from the PF Exchange rate. Power Rates Study, BP-14-E-BPA-01, section 2.1.

#### **1.4.2 2012 REP Settlement Agreement**

Since its inception, the REP has been a source of controversy in BPA’s rate cases and in litigation before the courts. *See, generally*, Residential Exchange Program Settlement Agreement Proceeding (REP-12), Administrator’s Final Record of Decision, REP-12-A-02, at 5-15 (REP-12 ROD). After years of litigation, in December 2010, six regional IOUs, three state public utility commissions, a retail customer advocacy group, and COUs representing 89 percent of BPA’s load presented BPA with a proposed long-term settlement of REP disputes (2012 REP Settlement). *Id.* at 15-20. BPA subsequently evaluated the legal, factual, and policy

merits of the 2012 REP Settlement in a section 7(i) proceeding. *Id.* Specifically, BPA conducted the statutory section 7(b)(2) rate test for each year of the 2012 REP Settlement (including the BP-14 rate period, FY 2014–2015). Based on this evaluation, BPA found that the 2012 REP Settlement complied with the section 7(b)(2) rate test because it provided significantly greater rate protection for BPA’s preference customers than absent the Settlement. *See* 2012 REP Settlement Evaluation and Analysis Study, REP-12-FS-BPA-01, at 189; *see also id.*, at Figure 1. Following this extensive evaluation of the agreement, the Administrator concluded that the 2012 REP Settlement was lawful and reasonable and adopted it in July 2011. *Id.* at 419. The 2012 REP Settlement was challenged and is currently pending review before the U.S. Court of Appeals for the Ninth Circuit.

### **1.4.3 Preservation of Arguments in the Event the 2012 REP Settlement Agreement is Overturned**

Because the Administrator previously decided in the REP-12 ROD to adopt the 2012 REP Settlement and implement its terms in future rate proceedings, challenges to the settlement and the REP-12 ROD are excluded from the scope of the BP-14 rate proceeding. *See* section 1.2.5 above. To preserve parties’ rights in the event the 2012 REP Settlement is not upheld by the Court in the pending litigation, at BPA and certain parties’ request, the Hearing Officer issued an order with the following language:

No party shall present in this proceeding any argument, testimony, or other evidence that seeks in any way to challenge BPA’s determination to adopt the 2012 REP Settlement or implement its terms. In the event that BPA’s decision to (1) adopt the 2012 REP Settlement, or (2) implement its terms in this proceeding or in a prior proceeding, is reversed or remanded, in whole or in part, by a court of competent jurisdiction, in lieu of presenting such testimony or evidence in the BP-14 proceeding prior to such reversal or remand, each party hereby preserves and will not be deemed to have waived any argument, and will have the right to present any relevant argument, testimony or other evidence from any prior proceeding in any remand of or any reconsideration of the rates proposed or set in this proceeding.

Order Granting Motion to Preserve Arguments, BP-14-HOO-11, at 1.

In accordance with the Hearing Officer’s Order, no party raised any issues with BPA’s decision to implement the 2012 REP Settlement in the BP-14 rate proceeding. Although direct challenges to the 2012 REP Settlement are not within the scope of this case, challenges to how BPA implements the 2012 REP Settlement in the BP-14 rates as being inconsistent with the terms of the 2012 REP Settlement are within the scope of this proceeding. No party claims BPA is setting the BP-14 rates in a manner inconsistent with the terms of the 2012 REP Settlement.

#### **1.4.4 Implementation of the 2012 REP Settlement Agreement for FY 2014–2015**

The 2012 REP Settlement establishes the REP benefits payments for participating IOUs for a period of 17 years, beginning with FY 2012. REP-12 ROD, Appendix A, REP-12-A-02A, at 11. Under separate agreements, REP benefits for COUs that participate in the REP are established pursuant to a negotiated formula. REP-12 ROD, Appendix B, REP-12-A-02B. Individual utility REP payments are determined by comparing each utility's ASC with BPA's utility-specific PF Exchange rates. BPA recovers the costs of these payments in its power rates. For FY 2014–2015, BPA is establishing rates to recover the costs of the REP in accordance with the terms of the 2012 REP Settlement and the Administrator's decisions in the REP-12 ROD. Forecasts of individual IOU and COU REP benefit amounts may be found in the Power Rates Study.

## 2.0 POWER RATES AND POLICIES

### 2.1 Power Rates and Policies

#### Issue 2.1.1

*Whether BPA appropriately considered the impact of any power rate increase on the regional economy.*

#### Parties' Positions

JP03 states that it is concerned by the size of the Initial Proposal PF rate increase of 9.6 percent. JP03 Br., BP-14-E-B-JP03-01, at 23. JP03 expresses concern about the potential effect on local utilities, noting that rate increases generally take money out of the local economy. *Id.* JP03 urges BPA to take a careful look at all BPA expenses to reduce the overall power rate increase on preference customers. *Id.*

JP05 urges BPA to take all reasonable actions to reduce the PF rate increase. JP05 Br., BP-14-B-JP05-01, at 1. JP05 argues that BPA should (1) not include planned net revenues for risk and (2) use more reasonable estimates of net secondary revenue. *Id.* at 4-10. JP05 argues that BPA may need to rethink its current budget and spending practices to ensure that rates are lower than market prices for the long term. *Id.* at 2. JP05 states that, in addition to pursuing financial options to reduce rate increases, BPA may need to take more aggressive actions and alter BPA's current budget and spending practices. *Id.* at 2-3. JP05 contends that costs are forecast to increase at a higher rate than in the past. *Id.* at 3.

WPAG notes that BPA Staff explained that the rate increase is due to a decrease in secondary revenue forecasts and increases in O&M costs related to the fish passage requirements and fish accords. WPAG Br., BP-14-B-WG-01, at 3. WPAG states that what BPA largely ignores is the impact the rate increase will have on the region's economy. *Id.*

#### BPA Staff's Position

The largest cause of the power rate increase is the expectation of lower revenue from sales of surplus energy. Bliven and Parker, BP-14-E-BPA-11, at 2. Other drivers of the proposed power rate increase include increasing O&M costs for Columbia Generating Station (CGS) and the Federal hydro projects, new fish passage requirements, and implementation of the Columbia Basin Fish Accords. *Id.* BPA is able to offset a portion of these cost increases by taking advantage of unique opportunities that decrease capital-related costs for the upcoming rate period. *Id.*

#### Evaluation of Positions

BPA is aware of the difficult economic times that have beset the region for more years than expected after the decline in 2008 and understands that any rate increase could result in a

hardship for many people and businesses in the Pacific Northwest. In response, BPA has worked with its customers and the interested public before and during the rate proceeding to reduce the level of the power rate increase. See Draft ROD section 1.2.1. BPA places a high priority on carefully managing its costs. An important aspect of cost management is the need to protect the long-term asset value of the aging FCRPS hydropower resources and the CGS nuclear generating resource. Through the IPR process, BPA, with input from customers and interested parties, was able to reduce its costs and lower the 12 to 20 percent projected power rate increase to a 9.6 percent rate increase for the Initial Proposal. Bliven and Parker, BP-14-E-BPA-11, at 4.

After issuing the Initial Proposal, BPA held an expedited IPR2 process to seek input on proposed changes in Energy Northwest's Long Range Plan, based on new information, and to update the timing of other primarily capital budgets for the rate period. See Draft ROD section 1.2.1. One of the outcomes of the IPR2 process is that BPA is incorporating changes that will result in an additional reduction of approximately \$25 million in the power revenue requirement over the two-year rate period. *Id.*

While BPA is mindful of the impact of any rate increase on the regional economy, BPA is a self-financing agency and must set its rates to recover its costs. As WPAG notes, many of the drivers for the rate increase involve costs that are beyond the direct control of BPA. The increased costs associated with the fish passage requirements and fish accords are largely beyond BPA's direct control. Likewise, the reduction in secondary revenues is largely due to depressed wholesale power prices.

It is also important to note that BPA has varied and often conflicting responsibilities. These include, but are not limited to, implementing the Northwest Power Act and BPA's other statutes to encourage conservation and energy efficiency, facilitate the development of renewable resources within the region, protect fish and wildlife impacted by the FCRPS, and ensure that the region has an adequate, efficient, economical, and reliable power supply. The Northwest Power Act requires that "the customers of the Bonneville Power Administration and their consumers continue to pay all costs necessary to produce, transmit, and conserve resources ... including the amortization on a current basis of the Federal investment in the Federal Columbia River Power System." 16 U.S.C. § 839e(a)(1). BPA must strike a balance between fulfilling its varied and conflicting obligations and trying to keep rates as low as possible consistent with sound business principles. BPA believes the current proposal strikes the appropriate balance.

### **Draft Decision**

*BPA understands the impact a rate increase has on the regional economy. BPA has taken a number of steps to mitigate the size of the rate increase through reductions in the revenue requirement. However, BPA must meet all of its varied statutory obligations and at the same time recover its costs through its rates. Further reductions to BPA's current costs would place at risk the valuable generation asset base that produces power at relatively low cost. The current proposal, modified to reflect the additional reduction of \$25 million in the generation revenue requirement over the two years, strikes the appropriate balance.*

### **Issue 2.1.2**

*Whether BPA is obligated to serve contracted for or committed to (CF/CT) load at the lowest firm power rates based upon the lowest-cost resources.*

### **Parties' Positions**

ICNU contends that BPA must serve CF/CT loads at BPA's "lowest firm power rate based on its lowest cost resources ...." ICNU Br., BP-14-B-IN-01, at 6. ICNU states that the Northwest Power Act specifically exempts CF/CT load from paying rates based "only on the costs of market resources." *Id.* ICNU argues that BPA's proposal is "inflicting economic harm" on future CF/CT loads because CF/CT load served at Tier 2 rates will pay a "significantly higher price" than if it were served at Tier 1 rates. *Id.* at 7.

JP03 disagrees with ICNU's proposed treatment of CF/CT load. JP03 Br., BP-14-B-JP03-01, at 25. JP03 states that it does not believe the Northwest Power Act provides for the special rate treatment advocated for by ICNU. *Id.* JP03 claims that the CF/CT designation means only that the load is not treated as new large single load (NLSL) and is thus excluded from service at the New Resources Firm Power (NR) rate; rather, it is part of the utility's general requirements served at the PF rate. *Id.* at 26.

### **BPA Staff's Position**

ICNU misreads the CF/CT definition; the Northwest Power Act does not create a special class of load as ICNU argues. Bliven and Parker, BP-14-E-BPA-37, at 14-15. The CF/CT designation allows the new load to be treated as part of the serving utility's general requirements, thereby allowing the utility to purchase from BPA at a PF rate. *Id.*

### **Evaluation of Positions**

ICNU is not raising a new argument with regard to the treatment of CF/CT loads. BPA Staff, JP03, and even ICNU itself point out that ICNU raised these arguments regarding the treatment of future CF/CT loads in both the TRM-12 and BP-12 rate proceedings. In both of those prior proceedings, the Administrator fully considered these same issues, as well as related issues presented by ICNU and others regarding the treatment of CF/CT loads under tiered rates, and rejected all of the arguments raised by ICNU and the other parties. TRM ROD, TRM-12-A-01, section 2.0; BP-12 ROD, BP-12-A-02, section 2.1.1; *see also* TRM Final ROD, TRM-12S-A-02, at 33. The issues were also briefed to the United States Court of Appeals for the Ninth Circuit. In this proceeding, ICNU has not raised any new arguments or pointed to new factors that would warrant a different finding; rather, ICNU is merely reiterating positions it has advocated in the past.

ICNU contends that BPA's treatment of CF/CT load violates the Northwest Power Act. ICNU Br., BP-14-B-IN-01, at 6. ICNU believes any service to CF/CT load at Tier 2 rates is

inconsistent with the Northwest Power Act because “BPA does not have the legal authority to charge preference customers with CF/CT loads at rates primarily based on the cost of new resources, the basis for Tier 2 rates under BPA’s TRM.” *Id.* at 7. According to ICNU, BPA may charge CF/CT load rates based only on the lowest-cost resources. *Id.* at 6.

JP03 and Staff disagree with ICNU’s contention that a utility that brings on CF/CT loads in the future is somehow insulated from paying Tier 2 rates. Both Staff and JP03 note that designating the load as CF/CT simply means the load is part of the general requirements of the serving utility, which BPA serves at a PF rate. Bliven and Parker, BP-14-E-BPA-37, at 14-15; JP03 Br., BP-14-B-JP03-01, at 25.

First, ICNU’s argument is misdirected. BPA does not “serve the CF/CT loads” directly. Bliven and Parker, BP-14-E-BPA-37, at 17. BPA’s rates are wholesale power rates, not retail service rates. BPA does not directly serve the retail load of its utility customers, including any CF/CT load or NLSL load, and will not serve any future CF/CT load. Retail ratesetting is the province of the local utility. *Id.* Consequently, any issue in this proceeding relates only to the rates BPA charges the local utility and not the retail rates paid by any ICNU member to its local utility.

Second, the overall premise of ICNU’s argument is incorrect. CF/CT loads are directly discussed only in section 3(13)(A) of the Northwest Power Act. That section of the Act addresses the definition of the term “new large single load.” The Northwest Power Act exempts CF/CT from the definition of an NLSL by stating:

“New large single load” means any load associated with a new facility, an existing facility, or an expansion of an existing facility—  
(A) which is not *contracted for, or committed to*, as determined by the Administrator, by a public body, cooperative, investor-owned utility, or Federal agency customer prior to September 1, 1979, and  
(B) which will result in an increase in power requirements of such customer of ten average megawatts or more in any consecutive twelve month period.

16 U.S.C. § 839a(13) (emphasis added).

Under section 7(b)(4) of the Northwest Power Act, an NLSL is not treated as part of a preference utility’s “general requirements.” 16 U.S.C. § 839e(b)(4). The Northwest Power Act uses general requirements to define which loads are eligible to be served at BPA’s PF rate or rates, which are established following the rate directives in sections 7(b)(1) and 7(b)(2). 16 U.S.C. § 839e(b)(1)-(2). As such, the portion of a preference utility’s load that is determined to be an NLSL can be served with Federal power, but only by paying BPA’s NR rate, a rate established following the rate directive in section 7(f). 16 U.S.C. § 839e(f). However, section 3(13)(A) provides an exception for the NLSL treatment if BPA has designated the load as a CF/CT load. The significance of this exception is that a preference utility’s new load that has been designated by BPA as a CF/CT load is excluded from the definition of an NLSL, and instead the load is treated as part of the utility’s “general requirements” and charged BPA’s PF rate or rates.

The CF/CT designation does not, however, create a right to a particular PF rate. Rather, it means the actual amount of CF/CT load is not treated as an NLSL and, thus, the utility is able to avoid being charged for that amount of power at the NR rate. *See* 16 U.S.C. § 839e(b)(4); H.R. Rep. No. 96-976, Part II, 96th Cong. 2d Sess., 52 (1980). Instead, because it is part of the serving utility’s “general requirements,” BPA sells power to the utility to serve the CF/CT load at one of BPA’s PF rates. 16 U.S.C. §§ 839e(b)(1), 839e(b)(4).

ICNU is incorrect in its contention that CF/CT load must be served at BPA’s “lowest firm power rate based on its lowest cost resources” and is somehow exempt from service at Tier 2 PF rates. *See* ICNU Br., BP-14-B-IN-01, at 6. The Northwest Power Act contains rate protections for general requirements loads, but no special rate protections for CF/CT loads. First, general requirements loads receive rate protection in the form of a specific allocation of resource costs pursuant to section 7(b)(1). 16 U.S.C. § 839e(b)(1). The section 7(b)(1) allocation is as follows: first Federal base system resource costs, then section 5(c) resource costs as needed, then new resource costs, if necessary. Second, section 7(b)(2) provides a rate protection to general requirements loads in the form of a rate ceiling. 16 U.S.C. § 839e(b)(2). Third, section 7(b)(3) specifies that the section 7(b)(2) rate protection costs not recoverable from public agency customers shall be recovered from power sales other than general requirements. 16 U.S.C. § 839e(b)(3). Fourth, section 7(b)(4) ensures that NLSLs will not be served at 7(b) rates. 16 U.S.C. § 839e(b)(4). Although these provisions provide important rate protections for general requirements loads (including CF/CT loads), none provides the “lowest cost” rate protection that ICNU advocates.

The Administrator has previously determined that tiered rates are consistent with all of these rate protections. BP-12 ROD, BP-12-A-02, at 43. The PF rate, which includes Tier 1 and Tier 2 rates, is determined based on allocations of Federal base system resource costs and section 5(c) resource costs. The tiered PF rates for preference customers are reduced to the rate ceiling pursuant to section 7(b)(2). No surcharge pursuant to section 7(b)(3) is included in the tiered PF rates. The tiered PF rates are applicable solely to general requirements; NLSLs are not eligible to purchase at the tiered PF rates. Nor is any cost of serving an NLSL included in the tiered PF rates.

To be sure, the costs of Federal base system resources, which will normally be BPA’s lowest-cost resources, are at the top of the cost-allocation hierarchy. However, if preference and 5(c) exchange customer loads exceed the amount of Federal base system resources, which they almost certainly will because of the inclusion of 5(c) exchange loads, then preference and exchange customers’ PF rates may include “the cost of additional electric power as needed to supply such loads,” including the costs of power acquired “from other resources.” 16 U.S.C. § 839e(b)(1). These additional resources will not always be BPA’s lowest-cost resources. As such, section 7(b)(1) does not require that preference customers’ PF rates be based only on BPA’s lowest-cost resources.

ICNU nevertheless claims that service at a rate that includes only market resources would defeat the original reason for the CF/CT designation. ICNU Br., BP-12-B-IN-01, at 7-8. ICNU's implication, that CF/CT load is being treated differently from other general requirements load, is simply not accurate. First, a utility with existing CF/CT load that was operating during FY 2010 was considered in determining the portion of general requirements that is granted the right to purchase at Tier 1 rates. Second, future CF/CT load, as well as general load growth, would be considered in the general requirements; that is, retail utilities would serve this load at either Tier 1 or Tier 2 rates (depending upon the utility's circumstances), which are both PF rates established pursuant to section 7(b)(1). There is no distinction between future CF/CT loads and other future general requirements. They are both treated in the same manner. This treatment is consistent with section 7(b), granting all existing and future general requirements load access to section 7(b)(1) rates. The fact that such rates are tiered is a matter of rate design, not one of resource cost allocation in violation of section 7(b)(1).

In contrast, a similar future large load served by a public utility with power purchased from BPA, but without CF/CT status, would be treated as an NLSL, and the utility would be charged the NR rate for that amount of load. The NR rate is allocated Federal base system or section 5(c) resource costs only if such resources are surplus to the needs of the section 7(b) rate pool. There are no surplus Federal base system resources, so the NR rate is allocated only the remaining costs of section 5(c) resources and new resources. Currently, 7(b)(1) loads are greater than 12,000 aMW, and the Federal base system is about 7,500 aMW. Power Rates Study Documentation, BP-14-E-BPA-01A, at 31. Therefore, the likelihood of surplus Federal base system resource costs being allocated to the NR rate at any point in the foreseeable future is nonexistent. Further, section 7(b)(3) exposes the NR rate to paying for a portion of the rate protection afforded preference customers through the application of section 7(b)(2). For example, the section 7(b)(3) rate surcharge for the NR-14 rate is \$7.64 per megawatthour (2014 Power Rate Schedules and General Rate Schedule Provisions, BP-14-E-BPA-09, at 19).

Thus, even if the resource costs incurred by BPA to serve an Above-RHWM Load and an NLSL were identical (which they are not—in this rate proceeding the cost of Tier 2 resources (\$38.21/MWh) is considerably below the cost of new resources (\$69.66/MWh)), the rates for the two loads would still be distinctly different. *See* Power Rates Study Documentation, BP-14-E-BPA-01A, at 29, 30, 39. Accordingly, under the PF Tier 1 and PF Tier 2 rates set in this proceeding, the BPA utility customers with CF/CT loads are receiving (and will continue to receive in the future) all of the statutory protections to which they are entitled under the Northwest Power Act. CF/CT status does not confer further protections.

### **Draft Decision**

*The CF/CT load is not entitled to the lowest firm power rate based upon the lowest-cost resources. A utility with a CF/CT load is entitled to include the load in its general requirements and to purchase its general requirements at the PF rates, according to the terms of the PF rate schedule and related GRSPs, which include tiered rates.*

## **2.2 Loads and Resources**

### **2.2.1 Introduction**

The Power Loads and Resources Study, BP-14-E-BPA-03, contains the load and resource data used to develop BPA's wholesale power rates for FY 2014–2015. Documentation supporting the results of the Power Loads and Resources Study is presented in the Power Loads and Resources Study Documentation, BP-14-E-BPA-03A. The Power Loads and Resources Study is also described in the direct testimony of Misley *et al.*, BP-14-E-BPA-12.

The Power Loads and Resources Study and supporting documentation have two primary purposes: (1) to determine BPA's load and resource balance (load-resource balance), and (2) to calculate various inputs that are used in other studies and calculations within the rate case. The purpose of BPA's load-resource balance analysis is to determine whether BPA's resources meet, are less than, or are greater than BPA's load and obligations for the rate period, FY 2014–2015. If BPA's resources are less than the amount of load forecast for the rate period, system augmentation is required to achieve load-resource balance.

The Power Loads and Resources Study includes three main components: (1) load data, including a forecast of the Federal system load and contract obligations; (2) resource data, including Federal system resource and contract purchase estimates, total Pacific Northwest regional hydro resource estimates, and the estimated amount of power purchases that are eligible for section 4(h)(10)(C) credits; and (3) the Federal system load-resource balance, which compares Federal system sales, loads, and contract obligations to the Federal system generating resources and contract purchases.

The Power Loads and Resources Study provides inputs to various other studies and calculations in the ratemaking process: (1) the Power Revenue Requirement Study, BP-14-E-BPA-02; (2) the Power Rates Study, BP-14-E-BPA-01; and (3) the Power Risk and Market Price Study, BP-14-E-BPA-04.

The Power Loads and Resources Study will be updated for the BP-14 Final Proposal. Misley *et al.*, BP-14-E-BPA-12, at 5, 7.

No party raised issues related to the Loads and Resources.

## **2.3 Power Revenue Requirement**

### **2.3.1 Introduction**

BPA's power rates are designed to recover the costs of the generation function only. The Power Revenue Requirement Study, BP-14-E-BPA-02, determines the level of revenue required to recover all costs of producing, acquiring, marketing, and conserving electric power, including, as appropriate, the repayment of the Federal investment in hydro generation, fish and wildlife

recovery, and conservation; Federal agencies' operations and maintenance expenses allocated to power; capitalized contract expenses associated with such non-Federal power suppliers as Energy Northwest; other purchase power expenses, such as system augmentation and balancing power purchases; power marketing expenses; cost to Power Services, if necessary, of purchasing transmission services; and all other generation-related costs incurred by BPA pursuant to law.

### **2.3.2 Revenue Requirement Development**

BPA develops the revenue requirement in conformance with the financial, accounting, and ratemaking requirements of DOE Order No. RA 6120.2. BPA determines the revenue requirement separately for generation and transmission. *United States Department of Energy—Bonneville Power Admin.*, 26 FERC ¶ 61,096 (1984).

The revenue requirement is developed using a cost accounting analysis comprised of the following three components.

1. Repayment studies to determine the schedule of amortization payments and to project annual interest expense for bonds and appropriations that fund the Federal investment in hydro, fish and wildlife recovery, conservation, and associated assets. Repayment studies are conducted for each year of the two-year rate test period and extend over the 50-year repayment period.
2. Operating expenses and minimum required net revenues for each year of the rate test period.
3. Annual Planned Net Revenues for Risk (PNRR), if any, based on the risks identified and quantified, the Treasury Payment Probability (TPP) standard, and other risk mitigation tools.

With these three parts, the revenue requirement is set at the lowest revenue level necessary to fulfill cost recovery requirements and objectives.

Order No. RA 6120.2 requires that BPA demonstrate the adequacy of current and proposed rates. The current revenue test determines whether revenues projected from current rates meet cost recovery requirements for the rate period and the repayment period. The revised revenue test determines whether projected revenues from proposed rates will meet cost recovery requirements and objectives for the rate test period and repayment period. The revised revenue test demonstrates that revenues from proposed power rates will recover generation costs in the rate test period and over the ensuing 50-year repayment period. Power Revenue Requirement Study, BP-14-E-BPA-02, section 3.3. In the final studies, the risks are quantified and analyzed, and risk mitigation measures are designed to achieve at least a 95 percent probability that planned payments to Treasury are recovered on time and in full over the two-year rate period.

### **2.3.3 Interest on Prepay Funds**

#### **Issue 2.3.3.1**

*Whether Slice customers should receive interest income earned on prepay funds deposited in the Bonneville Fund in FY 2013.*

#### **Parties' Positions**

JP20 argues that the Tiered Rate Methodology provides sufficient flexibility to share the interest income earned on prepay funds. JP20 Br., BP-14-B-JP20-01, at 2. JP20 states that the TRM allows for the creation of new costs or credits. *Id.* at 3-4. Alternatively, JP20 states, the TRM offers broad language that would permit the prepay funds to be added to the Composite cost pool reserves balance. *Id.* at 5.

#### **BPA Staff's Position**

Interest income earned on prepay program funds not forecast in the Initial Proposal would be directed to the non-Slice cost pool. Homenick *et al.*, BP-14-E-BPA-36, at 4. This means that the Slice customers, whose rates are based on the Composite cost pool, would not share in the interest earnings because of the allocation formula contained in the TRM. This differential impact on Slice and non-Slice customers is a result of the TRM provisions that specify such treatment. Homenick *et al.*, BP 14-E-BPA-36, at 5. Staff notes that BPA cannot apply a different treatment or unilaterally change the TRM to address this issue, and it is unlikely that the TRM could be changed prior to publication of the Final Proposal. *Id.*

#### **Evaluation of Positions**

JP20 argues that the TRM has several mechanisms that would allow interest income to be shared with Composite cost pool customers. First, JP20 notes that the TRM allows for the adoption in a rate proceeding of new costs or credits that were not anticipated at the time of the development of the TRM. JP20 Br., BP-14-B-JP20-01, at 3-4. JP20 argues that the interest income should be allocated to the Composite cost pool based on the cost allocation principles of section 2.1 of the TRM. *Id.* at 4. JP20 presents this option as one that could be done in this rate proceeding or as one that could be adopted as an interim solution that would be addressed in the BP-16 rate proceeding. *Id.* at 6-7.

Second, JP20 argues that the TRM allows for adjustments to the calculation of the Composite cost pool interest income calculation. *Id.* at 4. The Composite cost pool interest income is based on the amount of reserves attributed to Power at the end of FY 2001. Homenick *et al.*, BP-14-E-BPA-36, at 4. This base level can be adjusted for pre-2002 transactions that are not otherwise distributed to customers. *Id.* JP20 argues that the TRM section governing this calculation includes broad language allowing for other changes to the base amount of reserves. JP20 Br., BP-14-B-JP20-01, at 6. Specifically, the TRM states that “future circumstances will occur that make it reasonable and fair to make additional adjustments to the size of the base amount.” Tiered Rate Methodology, BP-12-A-03, at 9.

BPA Staff met with parties at a noticed meeting on April 17, 2013, to discuss this issue. All parties in attendance agreed that the costs and the benefits of the prepay program should be borne by both Slice and non-Slice customers. Parties indicated that their preferred approach is to create a new credit/cost.

Including this credit/cost in the interest expense section of the cost table is an appropriate resolution of this matter. Slice customers should not be excluded from the revenue associated with interest earnings associated with the prepay program. This credit will be identified as the “prepay offset credit” and will be allocated to the Composite cost pool. In this way both Slice and non-Slice customers will benefit equally from the interest earnings. The credit will be calculated using the same formula as that used for the total interest credit for the power revenue requirement. *See, e.g.*, Power Revenue Requirements Study Documentation, BP-14-E-BPA-02A, Tables 5A, 5B, 5C. The formula is:

$$(\text{Start of Year prepay balance} + \text{End of Year prepay balance}) \div 2 \times \text{interest rate}$$

The interest rate used in this calculation would be the forecast BPA Fund rate. Homenick *et al.*, BP-14-E-BPA-36, at 3. The prepay offset credit will be trued up annually to ensure that the amount of credit reflects the actual amount of interest earned on the prepay funds.

Adding a prepay offset credit will also require a modification to the calculation of the non-Slice cost pool interest credit. The non-Slice cost pool credit is calculated as total interest income minus the Composite cost pool credit. *Id.* To avoid double counting, the prepay offset credit will also need to be subtracted from total Power interest income. This is necessary because the total interest credit would include interest earned on prepay funds.

### **Draft Decision**

*Slice customers will receive interest income earned on prepay funds deposited in the Bonneville Fund. BPA will create a new credit/cost and allocate it to the Composite cost pool.*

## **2.4 Power Risk and Market Price**

### **2.4.1 Introduction**

The Power Risk and Market Price Study identifies, models, and analyzes the impacts that key risks and risk mitigation tools have on Power Services’ net revenue and cash flow. It also demonstrates that the power rates and risk mitigation tools together meet BPA’s standard for financial risk tolerance, the Treasury Payment Probability (TPP) standard. The Study presents the natural gas price forecast, the electricity market price forecast, and the quantitative and qualitative analysis of risks to Power Services’ net revenue. It also presents tools for mitigating risk and establishes the adequacy of those tools for meeting BPA’s TPP standard.

In the WP-93 rate proceeding, BPA adopted and implemented its 10-Year Financial Plan, which included a policy requiring that BPA set rates to achieve a high probability of meeting its payment obligations to the U.S. Treasury (Treasury). 1993 Final ROD, WP-93-A-02, at 72. The specific standard set in the 10-Year Financial Plan was a 95 percent probability of making both of the annual Treasury payments in the two-year rate period on time and in full. This TPP standard was established as a rate period standard; that is, it focuses upon the probability that BPA can successfully make all of its payments to Treasury over the entire rate period rather than the probability for a single year. The 10-Year Financial Plan was updated July 31, 2008, and remains in effect. The original and updated Financial Plans are available at <http://www.bpa.gov/Finance/FinancialInformation/FinancialPlan/Pages/default.aspx>

By law, BPA's payments to Treasury are the lowest priority for revenue application, meaning that payments to Treasury are the first to be missed if financial reserves are insufficient to pay all bills on time. Northwest Power Act, 16 U.S.C. § 839e (a)(2)(A). Therefore, TPP is a prospective measure of BPA's overall ability to meet its financial obligations. The following policy objectives guide the development of the risk mitigation package:

- Create a rate design and risk mitigation package that meets BPA's financial standards, particularly achieving a 95 percent two-year Treasury Payment Probability.
- Produce the lowest possible rates, consistent with sound business principles and statutory obligations, including BPA's long-term responsibility to invest in and maintain the aging infrastructure.
- Set lower, but adjustable, effective rates rather than higher, more stable rates.
- Include in the risk mitigation package only those elements that can be relied upon.
- Do not let financial reserve levels build up to unnecessarily high levels.
- Allocate costs and risks of products to the rates for those products to the fullest extent possible; in particular, prevent any risks arising from Tier 2 service from imposing costs on Tier 1 or requiring stronger Tier 1 risk mitigation.
- Rely prudently on liquidity tools, and create means to replenish them when they are used in order to maintain long-term availability.

It is important to understand that these objectives are not completely independent and may sometimes conflict with each other; thus, BPA must create a balance among these objectives when developing its overall risk mitigation strategy.

## **2.4.2 Power Risk and Risk Mitigation**

### **Issue 2.4.2.1**

*Whether, as part of the development of final power rates, the Administrator has the discretion to add PNRR or adjust the CRAC thresholds in order to maintain a 95 percent Treasury Payment Probability.*

### **Parties' Positions**

JP05 states that the Administrator should not further increase rates with PNRR. JP05 Br., BP-14-B-JP05-01-CC01, at 5. JP05 argues that BPA would be reserving the unilateral right to introduce a PNRR and adjust the CRAC after all evidence has been presented in the rate case. *Id.* at 5-6. JP05 states that parameters have not been provided regarding how PNRR and the CRAC would be adjusted, which violates the requirement that rate case parties be provided an adequate opportunity to review, refute, and rebut any materials submitted. *Id.*

### **BPA Staff's Position**

If TPP is below the 95 percent TPP standard, then the Administrator can increase PNRR or make the CRAC stronger in order to meet the TPP standard. *Id.* at 35. For the Initial Proposal, no PNRR was required to meet the TPP standard, given the other features of the risk mitigation package, including the CRAC. *Id.* at 37; Power Risk and Market Price Study, BP-14-E-BPA-04, at 74. The CRAC mechanism is described in full in the Study, in GRSP II.C., and in direct testimony. Study, BP-14-E-BPA-04, section 3.2.3.1; 2014 Power Rate Schedules and General Rate Schedule Provisions, BP-14-E-BPA-09, at 39-44; Lovell *et al.*, BP-14-E-BPA-15, at 29-34.

### **Evaluation of Positions**

The methodology used for adjusting PNRR and the CRAC in order to meet BPA's TPP standard is described in full in the Initial Proposal. During the course of the rate proceeding, parties have had multiple opportunities to review and submit testimony about this methodology and the ToolKit model, which implements it. Staff has not proposed to change this methodology between the Initial and Final Proposals.

The methodology calls for first updating risk assumptions, such as water conditions and market prices, then providing those to the ToolKit, which produces TPP results. Power Risk and Market Price Study, BP-14-E-BPA-04, at 77-83. In the event the 95 percent TPP standard is not met, PNRR and/or the CRAC parameters will be adjusted upward until the standard is met. Lovell *et al.*, BP-14-E-BPA-15, at 35. In the event the TPP standard is exceeded, PNRR will be reduced and/or the CRAC parameters will be reduced, with the constraints that PNRR can go no lower than \$0 and the CRAC thresholds cannot be adjusted below the equivalent of \$0 in Power Services reserves for risk. Lovell *et al.*, BP-14-E-BPA-15, at 30.

The balance between the level of PNRR and the CRAC parameters to maintain the 95 percent TPP standards is not mathematically determined by the ToolKit. A more robust CRAC or additional PNRR can each separately or together serve to increase TPP in the event the Toolkit output reflects less than a 95 percent TPP. As a result, the balance between adding PNRR or a more robust CRAC is something the Administrator must determine after weighing the input from the parties and Staff.

In order to address JP05's procedural concerns, Staff has agreed to keep customers and rate case parties apprised of expectations for a 2014 CRAC as FY 2013 progresses and, should FY 2013's financial conditions worsen such that the need to adjust risk mitigation tools seems likely, to hold meetings with customers in order to discuss options. Bliven and Parker, BP-14-E-BPA-11, at 21. This is consistent with JP03, JP05, and WPAG's requests for such meetings. *See, e.g.*, Brawley and Carr, BP-14-E-JP03-01, at 10-11; JP05 Br., BP-14-B-JP05-01-CC01, at 7; WPAG Br., BP-14-B-WG-01, at 43. Consistent with these requests, customers were apprised of BPA's FY 2013 financial conditions at the April Quarterly Business Review and informed that it is unlikely that PNRR or CRAC adjustments will be needed in final rates. Staff continues to believe it is highly unlikely that any adjustments to PNRR or the CRAC will be needed in order to meet the TPP standard.

JP05 requests that BPA provide additional procedural protections, such as discovery, testimony, and cross examination, prior to adding PNRR or adjusting the CRAC thresholds. JP05 Br., BP-14-B-JP05-01, at 6. While Staff agreed to hold a meeting with customers to discuss options, JP05's argument for BPA to provide additional procedural protections logically leads to undesirable ends, such as (1) the potential for a never-ending cycle of adjustment and review; (2) abandoning any adjustments to the risk package in the Final Proposal; or (3) structuring rates based on a worst-case outcome that would eliminate any need for increasing the amount of risk mitigation. As to the first possibility, at some point the opportunity to review the actual numbers must end so BPA can finalize the rates. JP05's contention that it is entitled to additional procedural protection before updates are incorporated into the risk analysis would result in recurring rounds of updates and procedure or freezing the current year assumptions in the Initial Proposal. Either one of those possibilities is untenable. As to the second possibility, ignoring actual financial conditions in the year when rates are set (*i.e.*, the year immediately prior to the rate period) is not sound business practice; nor is it likely that such practice would be countenanced by the Commission or the courts. *See, e.g., Golden Northwest Aluminum v. Bonneville Power Admin.*, 501 F.3d 1037, 1052-1053 (9th Cir. 2007). As to the third possibility, the rational response to such a requirement would be to inflate the Initial Proposal so that it would cover the worst-case situation and then reduce the risk mitigation in the Final Proposal, a procedural outcome that JP05 does not address. However, this would result in an Initial Proposal that is necessarily inflated and gives rate case parties little insight as to how the Final Proposal would most likely turn out. None of these alternatives is tenable.

It is true that the Initial Proposal incorporates the possibility of a great many outcomes for FY 2013. The Initial Proposal does so by associating a probability distribution with the set of possible outcomes. By the time of the Final Proposal, many of the outcomes that were possible

at the time of the Initial Proposal have become impossible due to the actual events in early FY 2013, and other possible outcomes have become more likely than they were at the time of the Initial Proposal. At the time the Final Proposal is prepared, BPA has much more recent information about the probabilities of the possible outcomes for FY 2013. This matters because the financial outcome for FY 2013 determines the level of reserves available for risk at the start of the FY 2014–2015 rate period. The probability distribution of starting FY 2014 reserves is one of the primary variables that determine TPP for the rate period, and thus, that determine the amount of risk mitigation needed.

As established in BPA’s Ten-Year Financial Plan, BPA’s TPP standard requires BPA to establish rates to maintain a level of financial reserves sufficient to achieve a 95 percent probability of making its U.S. Treasury payments. WP-93 ROD, WP-93-A-02, at 59. Rates are proposed in the Initial Proposal but established in the Final Proposal. Therefore, BPA must have the ability to adjust its risk mitigation tools in the Final Proposal if necessary to meet the TPP standard, or the standard would be impossible to implement and could not serve its purpose: to protect BPA’s ability to make its Treasury payments in full and on time.

### **Draft Decision**

*BPA will continue to update Initial Proposal financial assumptions for the current fiscal year when developing final rates, and thus may adjust PNRR or the CRAC thresholds in the Final Proposal in order to meet BPA’s TPP standard.*

### **Issue 2.4.2.2**

*Whether BPA should increase PNRR instead of adjusting the CRAC if risk mitigation needs to be strengthened to meet BPA’s TPP standard.*

### **Parties’ Positions**

WPAG states that, based on BPA’s second-quarter financial review, WPAG prefers that BPA rely on the CRAC rather than including PNRR in rates for the BP-14 rate period. WPAG Br., BP-14-B-WG-01, at 43. WPAG states that with PNRR, customers will pay the additional PNRR costs whether the money is needed or not, and in contrast, with a CRAC that is properly constructed, the customers will pay the additional revenues only if they are needed. *Id.* WPAG states that the choice between a certain rate increase and a possible rate increase is an easy one from the customer perspective. *Id.*

JP05 also recommends that BPA not include PNRR. JP05 Br., BP-14-B-JP05-01-CC01, at 5. JP05 states that because forecasts are less accurate than actuals, it is generally preferable to increase rates based not on the risk of a financial shortfall, but only after the shortfall has actually occurred. *Id.*

### **BPA Staff's Position**

Staff did not include PNRR in the Initial Proposal because it was not needed to meet the TPP standard. Study, BP-14-E-BPA-04, at 74; Lovell *et al.*, BP-14-E-BPA-15, at 37. Staff did not testify for or against the use of PNRR in lieu of adjusting the CRAC thresholds.

### **Evaluation of Positions**

PNRR is \$0 in the Initial Proposal. Power Risk and Market Price Study, BP-14-E-BPA-04, at 74; Lovell *et al.*, BP-14-E-BPA-15, at 37. As stated in the previous issue, it is unlikely that any adjustment in PNRR or the CRAC thresholds will be necessary for the Final Proposal. However, in the event that adjustments are necessary, the Administrator retains the discretion to adjust PNRR or the CRAC thresholds.

### **Draft Decision**

*At this point, BPA does not anticipate the need to add PNRR or modify the CRAC in order to achieve the 95 percent TPP standard; however, the Administrator retains discretion to select between adding PNRR and adjusting the CRAC thresholds if needed to meet BPA's TPP standard.*

### **Issue 2.4.2.3**

*Whether BPA should modify the CRAC such that recovery of a CRAC amount triggered for the first year of the rate period should be spread over a two-year period.*

### **Parties' Positions**

JP05 states that BPA should modify the CRAC such that any first-year CRAC amount is recovered over a two-year period rather than a one-year period as specified in the Initial Proposal. JP05 Br., BP-14-B-JP05-CC01, at 4. *See* 2014 Power Rate Schedules and General Rate Schedule Provisions (FY 2014–2015), BP-14-E-BPA-09, at 42.

### **BPA Staff's Position**

The CRAC is an upward adjustment to certain rates that can apply to rates during FY 2014 or FY 2015 or both. *Id.* The proposed CRAC terms, which are the same CRAC terms adopted in the BP-12 Final ROD, strike a prudent balance between liquidity management needs and rate stability. Lovell and Mandell, BP-14-E-BPA-39, at 6. The modification to the CRAC parameters proposed by JP05 makes it less likely that any liquidity tools used on behalf of Power Services would be restored in a timely fashion. *Id.*

### **Evaluation of Positions**

JP05 asserts that BPA has created the problem of a large potential “Day 1” CRAC by proposing that any shortfall in power financial reserves up to \$100 million be recovered entirely in the year

after the shortfall has occurred. JP05 Br., BP-14-E-JP05-01, at 6. JP05 contends that recovering the first \$100 million in the first year of the rate period is overly severe and burdensome and will lead to “rate shock.” *Id.* JP05 states that there are other options available to BPA to balance its needs for liquidity and rate stability. *Id.* at 7. JP05 recommends that BPA modify the parameters of any potential “Day 1” CRAC so that any shortfall is recovered over a two-year period. *Id.* at 6-7. JP05 states that its proposal is “reasonable” given that no customers are expecting a “Day 1” CRAC, and the chance of missing a Treasury payment is minimal. *Id.* at 7.

BPA’s CRAC is an annual rate adjustment that is evaluated on an annual basis and applied to each year of the two-year rate period separately. “Day 1” CRAC is a colloquial term that is used to refer to the CRAC applied to the first year of the rate period. The term stems from the fact that it would be applied on the first day of the rate period in addition to any other rate change that BPA is instituting on that day.

It should be noted that the terms of the CRAC were softened in the BP-12 case, such that any shortfall in excess of \$100 million would be recovered at 50 percent of the shortfall amount. Lovell and Mandell, BP-14-E-BPA-39 at 6, citing Bliven *et al.*, BP-12-E-BPA-11, at 19-20. This redesign was made because BPA recognized the difficulty a large CRAC may pose to customers. *Id.*; *see also* Deen and O’Meara, BP-14-E-JP05-01, at 7. Thus, it is not the case that BPA “has created the problem of a large potential ‘Day 1’ CRAC,” as JP05 claims, but rather that Staff has proposed the continuation of a CRAC feature—that it can trigger for the first year of a rate period—that has been in place since FY 2002 and was subsequently softened in the BP-12 rate case. The current design of the CRAC strikes a reasonable balance between the need to replenish liquidity and the desire to avoid creating a larger impact on the region. *See* BP-12 Final ROD, BP-12-A-02, at 87.

Staff explains and JP05 does not dispute that a two-year recovery period would provide less assurance that reserves will be recovered in a timely fashion than a one-year recovery period. Lovell and Mandell, BP-14-E-BPA-39, at 6. As BPA noted when this issue was first argued in the BP-12 rate proceeding, there can be no assurance that any specific amount of liquidity replenishment will actually occur even if a CRAC is implemented. BP-12 Final ROD, BP-12-A-02, at 86. Though the CRAC amount is almost certain to provide the planned incremental revenue, other aspects of BPA’s financial circumstances are subject to uncertainty, and reserves may not actually be replenished in the amount anticipated. *Id.* A more delayed repayment methodology is not prudent. Lovell and Mandell, BP-14-E-BPA-39, at 6.

The fact that JP05 believes it is unlikely that BPA will trigger the CRAC in the first year misses the point. The question is not whether circumstances will occur that would trigger the CRAC during the first year of the upcoming rate period, but rather if it is prudent to weaken the risk mitigation tool that could be implemented in those circumstances, whether they are likely or not. BPA develops its risk mitigation by factoring in a wide range of both positive and negative outcomes and fashions a risk mitigation package to achieve balance between the need for ensuring liquidity and the desire for rate stability. Assuming that risk mitigation can be

weakened because one customer believes a CRAC is unlikely to trigger potentially undermines the intended purpose of putting risk mitigation tools in place.

Additionally, JP05’s argument seems to suggest that there are two distinct CRACs, a “Day 1” CRAC and a different CRAC for the next year. There is only one CRAC, and it may apply to either one of the years in the rate period.

The same argument against collecting 100 percent of the first \$100 million of any reserves shortfall over only one year was raised in the BP-12 rate proceeding, where it was called “unnecessarily draconian.” JP05 Br., BP-12-B-JP05-01, at 2. In the instant case, JP05 terms it “overly severe and burdensome.” JP05 Br., BP-14-B-JP05-01, at 6. Parties have raised no new arguments and have presented no evidence showing that BPA should change the CRAC design adopted in the BP-12 ROD and proposed again in the BP-14 Initial Proposal.

### **Draft Decision**

*BPA will not modify the CRAC to recover any first-year CRAC amount equally over a two-year period.*

### **Issue 2.4.2.4**

*Whether BPA has adequately accounted for the financial risks associated with meeting the Northwest Power and Conservation Council’s (Council) conservation targets.*

### **Parties’ Positions**

NWEC contends that BPA’s risk assessment methodology used in this rate case considers only a limited portion of the energy efficiency (EE) program budget. NWEC Br., BP-14-B-NY-01, at 4. NWEC states that the portion of the EE budget modeled is only 15 percent of BPA’s total budget, while the Energy Efficiency Incentives (EEI) budget, which covers a majority of conservation spending, is not modeled. *Id.* at 4-5. NWEC asserts that there is a \$60 million to \$120 million risk associated with BPA meeting the Council’s 6th Power Plan conservation targets and that BPA’s risk analysis has failed to address the financial risks associated with failing to meet the Council targets. *Id.* at 5.

### **BPA Staff’s Position**

The likelihood of spending more than the budgeted EEI capital amount during the FY 2014–2015 rate period is low. Lovell and Mandell, BP-14-E-BPA-39, at 3. In the event BPA were to spend more than the budgeted amount for EEI programs, that additional spending would be capitalized and, therefore, affect BPA’s cash and revenue position during the rate period only by the amount of the interest accrued on that additional borrowing. *Id.* Therefore, EEI budget risk does not have a significant enough rate period liquidity impact to warrant modeling. *Id.* at 4.

## **Evaluation of Positions**

NWEC contends that there is \$60 million to \$120 million in financial risk associated with BPA failing to meet the Council's conservation target of 504 aMW. NWEC Br., BP-14-B-NY-01, at 6-7. NWEC's analysis is based on its assumption that BPA is likely behind on its targets by at least 30 aMW to as much as 55 aMW, at an assumed cost of \$2 million per average megawatt. NWEC's alleged budgetary shortfall of \$60 million to \$120 million is not supported by the facts. The program is currently on track to meet the conservation savings targets. Lovell and Mandell, BP-14-E-BPA-39, at 2. There is no evidence to suggest that BPA will not meet the targets.

Even if NWEC's assumptions were correct and BPA needed to spend an additional amount on EEI programs during the rate period to meet the Council's target, this additional spending would be capitalized. *Id.* at 3. The financial impact of additional spending on the EEI program would be a small fraction (roughly 1 to 8 percent) of the additional amount needed to attain the Council's targets. *Id.* The capital investment risk would be spread over a number of rate periods, and the effect on liquidity in any one rate period is generally small. *Id.* at 4. The risks associated with this potential capital investment are not significant enough to warrant modeling for ratesetting purposes. Therefore, it is not necessary to measure risk in the EEI budget. *Id.*

NWEC states that Staff testified that BPA would capitalize "additional costs for [energy efficiency] savings acquisition, but this statement is unsubstantiated by any official planning document or commitment made by BPA." NWEC Br., BP-14-B-NY-01, at 7-8. NWEC also states that there could be factors that limit BPA's ability to borrow for this cost, such as a too-short timeframe or limited borrowing authority. *Id.* at 8. NWEC states that because of those risks, BPA must address the entire amount within the confines of this rate case. *Id.*

In the event that BPA were unable to borrow or capitalize investments, EEI funding would be a small portion of the numerous, severe issues being faced by BPA. NWEC's argument is tantamount to stating that BPA should plan to collect the entire amount of all capital spending that occurs during a rate period to avoid any risk of not meeting its obligations.

NWEC has not presented evidence that BPA is falling behind on its EEI program, but has merely asserted that such is the case, in contradiction to statements by BPA's subject matter experts. NWEC has not presented evidence to refute Staff's testimony that any additional funding would be capitalized and that such capitalized costs would have only minor impacts on BPA's net revenue during the rate period.

## **Draft Decision**

*BPA has adequately accounted for the financial risks associated with meeting the Council's conservation targets.*

### **Issue 2.4.2.5**

*Whether BPA should adopt an Energy Efficiency program-related automatic rate adjustment mechanism.*

#### **Parties' Positions**

NWEC argues that BPA should adopt an automatic rate adjustment mechanism to be triggered if BPA forecasts an energy efficiency savings shortfall in the first quarter of the 2014 rate year. NWEC Br., BP-14-B-NY-01, at 8. NWEC's proposed adjustment would continue through the remainder of the FY 2014–2015 rate period. *Id.* NWEC claims that such an adjustment mechanism is necessary given the failure of BPA to account for the risks of not meeting the Council's conservation targets as a prudent and critical backstop that maintains BPA's statutory obligation to be consistent with the Council's power plan. *Id.* at 9.

JP05 acknowledges the importance of BPA's conservation programs, but states that rate adjustment mechanisms designed to match budgets to actual costs are inconsistent with basic ratemaking principles and cause unnecessary volatility in rates. JP05 Br., BP-14-B-JP05-01, at 12. JP05 states that BPA's conservation programs are only one of a number of valuable BPA programs, and there is nothing unique about BPA's conservation programs or budgets that warrants a separate automatic rate adjustment. *Id.*

#### **BPA Staff's Position**

BPA does not appear to face significant short-term liquidity risk from energy efficiency programs. Lovell and Mandell, BP-14-E-BPA-39, at 5. Rate adjustment mechanisms are generally put in place to address an immediate or near-immediate need for cash. *Id.* EEI spending is capitalized, and the financial effects are spread out over many years. *Id.* This type of risk does not require the immediate response that a rate adjustment mechanism offers, and the regular ratesetting process is sufficient to address the financial impact of this type of capital risk. *Id.*

#### **Evaluation of Positions**

NWEC requests that BPA implement a rate adjustment mechanism that would be triggered in FY 2014 based on an assessment of the likelihood of meeting the Council's 504 aMW conservation target by the end of FY 2014. NWEC Br., BP-14-B-NY-01, at 8. NWEC does not specify how BPA should calculate such a likelihood, nor a method to determine the amount of additional revenue to be collected. NWEC's argument for the automatic rate adjustment mechanism is based upon an assumption that BPA is behind on meeting the Council's targets and that as a consequence BPA faces a \$60 million to \$120 million budget shortfall in the current rate period. *Id.* at 3. As noted in the prior issue, both of these underlying assumptions are incorrect.

If BPA were required to spend more than currently budgeted to meet the Council’s targets, these additional dollars would be borrowed from the U.S. Treasury and capitalized. Lovell and Mandell, BP-14-E-BPA-39, at 3. Consequently, the only impact to BPA’s revenue and cash during the rate period would be the additional interest expense on such borrowing. *Id.* It appears that NWEA is requesting an energy efficiency rate adjustment mechanism that, if triggered, would raise additional cash to recover the entire additional amount of spending during the rate period, even though such spending would be capitalized. Such a mechanism would generate significantly more cash than is needed. There is no evidence that such a mechanism is needed to ensure the success of a program that is funded from capital; nor would such an adjustment mechanism address an actual financial risk that is relevant to risk mitigation in the rate case.

Likewise, a rate adjustment mechanism designed to recover funds that are already capitalized is counter to the objective of the risk study to ensure that power rates are set high enough that the probability that BPA can meet its cash obligations is at least as high as required by BPA’s TPP standard (95 percent). Power Risk and Market Price Study, BP-14-E-BPA-04, at 1. Only in the event that BPA is unable to borrow from the Treasury for any purpose would the cash needed for completion of the EEI program be unavailable. In that event, all of BPA’s capital-funded programs would be at serious risk, and creating a separate mechanism to deal with the impacts on a single program would not adequately address the total risk. Such an adjustment for the EEI program is unnecessary.

### **Draft Decision**

*BPA will not include an Energy Efficiency program-related automatic rate adjustment mechanism in the BP-14 Final Proposal.*

### **2.4.3 Market Price Forecast**

#### **Issue 2.4.3.1**

*Whether BPA should use the forward price curve as an alternative to BPA’s fundamentals-based spot price forecast of natural gas market prices.*

### **Parties’ Positions**

JP13 states that it favors the forward curve as a natural gas price forecasting methodology rather than Staff’s proposed method. JP13 Br., BP-14-B-JP13-01, at 5. JP13 contends that Staff’s methodology to produce a natural gas price forecast lacks transparency, robustness, and validation. *Id.* at 4. JP13 argues that the forward price curve is a superior methodology because it is based on actual transactions for what buyers paid and what sellers actually accepted. *Id.* at 5.

### **BPA Staff's Position**

BPA Staff proposes a fundamentals-based forecast of spot market natural gas prices. Power Risk and Market Price Study, BP-14-E-BPA-04, at 20-21. Staff does not believe that the forward price curve constitutes a reasonable forecast of spot market natural gas prices. Williams *et al.*, BP-14-E-BPA-38, at 10-11. The forward market cannot be said to represent “market expectation.” *Id.* at 6.

### **Evaluation of Positions**

JP13 argues that the Power Risk and Market Price Study does not describe a forecast model or shaping methodology. JP13 Br., BP-14-B-JP13-01, at 3. This assertion is misleading. Although Staff does not use a computer model to forecast natural gas prices, Staff uses a fundamentals-based methodology to forecast natural gas prices, and that methodology is clearly and thoroughly described in the Study. Study, BP-14-E-BPA-04, at 18-28. In fact, Staff has relied on this fundamentals-based analysis of natural gas supply and demand, coupled with professional judgment, to produce its natural gas price forecast in each rate case since 1985. *See, e.g.*, WP-02-FS-BPA-04, WP-07-FS-BPA-11, WP-10-FS-BPA-03, and BP-12-FS-BPA-04.

JP13, while challenging the transparency and validity of BPA’s methodology in this rate case, does not assert that the methodology falls below the standard of reasonableness, only that use of the forward price curve would be superior. JP13 Br., BP-14-B-JP13-01, at 5. BPA disagrees for the reasons next stated.

With respect to whether forward market prices represent “market expectation” of future spot prices, as JP13 asserts, forward market prices are not intrinsically price forecasts; rather, they are current prices for future delivery of a good. Williams *et al.*, BP-14-E-BPA-38, at 2. The extent to which a forward curve can or should be used as a forecast of future spot market prices is not a settled topic in academic circles. In response to JP13’s assertion that “actual [forward] market price data are generally accepted to be the most accurate means for predicting future prices,” Staff asked that JP13 provide evidence in support of the use of forward market prices to forecast future spot prices. *See* Bickford, BP-14-E-JP13-01-V01, at 5. JP13 provided references to a number of academic papers that discuss the pros and cons of the subject, but fails to establish that the forward curve constitutes the “generally accepted ... most accurate means” to forecast spot market prices for natural gas. Williams *et al.*, BP-14-E-BPA-38, at 2-5. In fact, the authors of one paper cited by JP13, Chinn and Coibion (2013), state that “the limited predictive content of commodity futures in recent years suggests that policymakers should be wary of placing too much weight on futures prices to forecast future commodity price changes.” *Id.*, Attachment 1 at 3; Chinn, Menzie and Olivier Coibion, “The Predictive Content of Commodity Futures.” Forthcoming, *Journal of Futures Markets*, at 29. The papers cited by JP13 do not support the argument that it is a superior methodology for forecasting natural gas prices to the methodology used by BPA since 1985.

With respect to the assertion that forward prices are based on “actual transactions for what buyers paid and what sellers actually accepted,” Staff challenges JP13’s assumptions about

liquidity in the forward markets. Williams *et al.*, BP-14-E-BPA-38, at 12-13. JP13 responds that it “did not perform specific analysis to quantify the liquidity and size of the natural gas market.” Williams *et al.*, BP-14-E-BPA-38, Attachment 4 at 1. As such, JP13’s argument is unsubstantiated.

In sum, JP13 presents no objective, compelling, or academically supported reason for BPA to move away from a methodology used in prior rate cases, and JP13 presents no convincing evidence that the forward curve provides a more reliable forecast of future spot prices than BPA’s methodology.

### **Draft Decision**

*BPA will continue using a fundamentals-based spot price forecast of natural gas market prices.*

### **Issue 2.4.3.2**

*Whether the forward price curve for electricity at Mid-C should be used as the electricity market price forecast rather than the forecast Staff produces through the use of the production cost model AURORAxmp.*

### **Parties’ Positions**

JP13 states that it favors the forward curve because it provides a robust and transparent forecast of forward prices. JP13 Br., BP-14-B-JP13-01, at 11. JP13 states that use of the forward curve would provide JP13’s members a financial benefit through the Load Shaping and non-Slice rates, noting that the use of the forward curve would approximately double the load shaping credit each PUD currently receives, and that JP13 “generally expect[s] that the Non-Slice charge to decrease [*sic*] ... for all Slice/Block customers.” *Id.* at 3.

JP05 argues that the assumptions for net secondary revenues are below third-party estimates of forward prices and claims that the forecast should be revised to be more reflective of expected market conditions. JP05 Br., BP-14-B-JP05-01, at 7. JP05 claims that a significant update to BPA’s assumptions will be necessary in the final studies to ensure a realistic expectation of net secondary sales revenue when setting rates. *Id.* at 8.

### **BPA Staff’s Position**

The forward curve cannot be said to represent market expectation with respect to future spot prices, as it is not intrinsically a price forecast. Williams *et al.*, BP-14-E-BPA-38, at 2-5. AURORAxmp provides a rigorous, fundamentals-based forecast of the spot market price for electricity. Power Risk and Market Price Study, BP-14-E-BPA-04, at 14-38. BPA plans to update its assumptions used to generate market prices for the Final Proposal. Williams *et al.*, BP-14-E-BPA-14, at 10-11.

## **Evaluation of Positions**

As discussed in Issue 2.4.3.1, above, forward market prices are not price forecasts, and whether they can, or should, be used in that capacity is questionable. JP13's statement that the forward curve provides a "robust and transparent forecast of forward prices" is confusing, because the forward curve *is* the forward price, not the forecast of the future spot price. *See* JP13 Br., BP-14-B-JP13-01, at 11. However, there is no evidence in the record supporting the notion that the forward curve provides a robust forecast of *future spot prices*. Transparent as it may be from a methodological perspective, the validity of using the forward curve as a spot market price forecast is unsubstantiated.

Most of JP13's argument rests on an analysis of implied heat rates, from which JP13 concludes that BPA's forecast generated with AURORAxmp is not properly validated. *See* JP13 Br., BP-14-B-JP13-01, at 5-9. JP13 calculates the BPA implied heat rate by dividing the mean electricity price forecast by the median of the natural gas price distribution. Bickford, BP-14-E-JP13-01-V01, at 6. This is not the mathematical equivalent of the average implied heat rate. The average implied heat rate is calculated by taking the simple mean of the 3,200 implied heat rates using AURORAxmp output data for a given monthly diurnal period. Importantly, these alternative methods would likely produce different implied heat rates. Moreover, JP13's derivation of the Sumas price for natural gas applies a flat basis to the monthly Henry Hub price. *Id.* at 6. This is inconsistent with BPA's method that forecasts monthly basis differentials. Study, BP-14-E-BPA-04, at 26-28. For this reason, JP13's analysis of implied heat rates is not valid.

Although Staff does not use implied heat rates in the analysis used to produce the market price forecast, Staff reviewed the distribution of implied heat rates for heavy-load hours and light-load hours and found that they correlate strongly with appropriate inputs and are reasonable in the scope of Pacific Northwest electricity markets. A meaningful critique of BPA's implied heat rates would need to account for the full distribution of monthly implied heat rates for both heavy-load hours and light-load hours calculated using a Pacific Northwest regional natural gas hub. As JP13 did not perform this analysis, support for JP13's claims regarding BPA's methodology and forecasts is lacking.

Contrary to JP13's assertion that Staff assumes the forward curve to be continually higher than the future spot price (or in contango), BPA makes no assumption regarding the relationship between future spot prices and the forward curve, and nothing in the Power Risk and Market Price Study indicates any such assumption. *See* JP13 Br., BP-14-B-JP13-01, at 9. BPA forecasts a distribution of prices. Study, BP-14-E-BPA-04, at 18. Of the distribution, which comprises 3,200 spot market price forecasts, some individual forecasts imply that the forward market is higher than the future spot price, and some imply that the forward market is lower than the future spot price. The average of the 3,200 forecasts implies that the forward market is higher than the future spot price, which is frequently the case. Again, JP13 fails to recognize that the market price forecast comprises a *distribution* of price forecasts. BPA is aware that a forward curve can serve as a robust forecast of spot prices for certain commodities but is aware of no evidence that this is the case for electricity (or natural gas, as noted above).

Whether BPA could even entertain the use of the forward curve as a market price forecast is a complicated question. A substantial share of BPA's ratemaking process relies on the full distribution of market price forecasts and each forecast's specific inputs. *Id.* at 46-47. JP13 essentially asks that BPA use the forward curve to determine the PF Load Shaping rate, noting that its members stand to benefit substantially through higher Load Shaping credits. JP13 estimates its members' combined rate period benefit to be \$1,014,525. Bickford, BP-14-JP-E-13-01-V01, at 9. JP13 states that "this ... will also affect the Non-Slice charge for all Slice/Block customers; although we did not explicitly calculate its financial impact, we generally expect that the Non-Slice charge to decrease [*sic*] (i.e. greater credit) for all Slice/Block customers." JP13 Br., BP-14-B-JP13-01, at 3. In actuality, the use of the forward market curve instead of BPA's price forecast could *increase* the Non-Slice charge. The forecast revenues from the Load Shaping charge are credited when establishing the level of the Non-Slice rate; therefore, all other things being equal, a \$1 million decrease in Load Shaping revenues will produce a \$1 million increase in the Non-Slice rate. On average, there is no net change. Because of this equal offset, any estimated windfall JP13 bases on changes to the Load Shaping rate alone is most likely overstated. Importantly, some customers could pay more due to both higher Non-Slice charges and higher Load Shaping charges based on the shape of their non-Slice product.

JP05 states that it does not suggest that BPA use the forward curve as its price forecast. Oral Tr. 290. JP05 argues that the implied premium in the forward market suggests that BPA's spot market price forecast is too low and should be updated. *Id.* JP05's primary concern appears to be that estimates of net secondary revenue are too low. JP05 Br., BP-14-B-JP05-01-CC01, at 7. Both JP13 and JP05 raise as a criticism of BPA's forecast the fact that BPA's forecast presented in the Initial Proposal does not match the forward curve. JP05 Br., BP-14-B-JP05-01, at 8; JP13 Br., BP-14-B-JP13-01, at 14. However, the forward curves cited by JP13 are from September 24, 2012, through January 18, 2013, and JP05 references the ICE forward curve from December 2012. BPA's Initial Proposal forecast was made in August of 2012 and issued in November of 2012. *Id.* The fact that a forecast of one vintage differs from a forecast of another vintage is not a valid criticism of BPA's forecast methodology. BPA's forecast will be updated to reflect current conditions at the time of the Final Proposal. Williams *et al.*, BP-14-E-BPA-14, at 10-11. However, the methodology for the forecast will remain the same as used for the Initial Proposal forecast. *See* Issue 2.4.3.1. BPA will not artificially increase the Final Proposal forecast because temporally displaced metrics retrospectively demonstrate that a dated forecast is below current market conditions. At the time the forecast for the Initial Proposal was performed, the forecast was reasonable.

### **Draft Decision**

*The forward price curve for electricity at Mid-C should not be used as the electricity market price forecast. The forecast BPA produces through the use of the production cost model embedded in AURORAxmp is a reasonable means of forecasting electricity market prices, and the record does not show that the forward curve is a superior method.*

### **Issue 2.4.3.3**

*Whether BPA should make AURORAxmp available to parties in future rate proceedings.*

#### **Parties' Positions**

JP05 argues that the Administrator should direct Staff to make the AURORAxmp model available to parties in the next rate proceeding to allow for more critical evaluation of net secondary revenues. JP05 Br., BP-14-B-JP05-01, at 8.

#### **BPA Staff's Position**

AURORAxmp is a publicly available production cost model and is not proprietary *with respect to BPA*. Williams *et al.*, BP-14-E-BPA-38, at 13-14. Based on experience in the BP-12 proceeding, where only one party requested access to the model, providing AURORAxmp to parties would cost BPA a considerable amount of money and has the potential to financially burden BPA ratepayers. *Id.*

#### **Evaluation of Positions**

JP05 argues that it is inappropriate for a utility in a regulatory proceeding to rely heavily on a proprietary model for key assumptions while not providing rate case parties an opportunity to verify its results. JP05 Br., BP-14-B-JP05-01, at 9. It is not true that rate case parties are unable to obtain access to the AURORAxmp model. Williams *et al.*, BP-14-E-BPA-38, at 13-14. AURORAxmp is a publicly available model that any party may purchase from EPIS, the program's vendor. JP05 does not point to any legal precedent that requires a utility to pay for parties' access to publicly available computer software, and BPA is aware of no such legal requirement.

If JP05 is asking BPA to fund certain parties' use of AURORAxmp, BPA is concerned that such an approach would put a financial burden on all ratepayers for the benefit of a few. *Id.* at 14. BPA is not opposed, however, to inquiring of EPIS whether it would provide a limited license to BPA rate case parties for use during future rate cases. Whether the costs of access to the model are paid by the individual parties that are requesting the license or shared by BPA will be negotiated with parties prior to the BP-16 rate proceeding. Parties desiring access to the model will need to make their wishes known prior to the beginning of the proceeding due to the time that BPA and EPIS need to work out the purchase of the access rights.

#### **Draft Decision**

*BPA will explore methods by which to facilitate access to AURORAxmp for interested parties in the next rate proceeding and will consult with parties interested in obtaining access to AURORAxmp.*

## **2.5 Power Rate Development**

The Power Rate Development section of this Draft ROD addresses the issues raised in parties' briefs related to cost allocation, rate design, implementation of TRM rate design in ratesetting, power rate schedules, and general rate schedule provisions.

The Power Rates Study (PRS) explains the processes and calculations used to develop the rates and billing determinants for BPA's wholesale power products and services. The Power Rates Study serves three primary purposes: (1) to demonstrate that the proposed rates have been developed in a manner consistent with statutory direction, including the initial allocation of costs and the subsequent reallocations directed by statute; (2) to set rates consistent with agency policy; and (3) to demonstrate that the proposed rates have been set at a level that recovers the allocated power revenue requirement for the upcoming rate period.

Section 7 of the Northwest Power Act, 16 U.S.C. § 839e, directs the allocation of costs, which is performed in the cost of service analysis, and provides a set of rate directives with further guidance on how individual rates are to be derived. BPA's rates must follow the ratesetting directives of section 7, but, as characterized in the legislative history of the Northwest Power Act, the rate directives govern the amount of revenue BPA collects from each class of customers, not the rate form. *See, e.g.*, H.R. Rep. No. 96-976, Part I, 96th Cong., 2d Sess., 69 (1980). Section 7 reserves rate design (how the revenue is collected) to the Administrator.

The cost of service analysis and the other ratemaking steps are programmed into a spreadsheet model, RAM2014, for purposes of calculating power rates. Power Rates Study, BP-14-E-BPA-01, at 17. The rate design for the BP-14 Initial Proposal power rates was for the most part unchanged from the BP-12 rates. Stiffler *et al.*, BP-14-E-BPA-16, at 2. The Power Rates Study describes how the tiered PF Public rate is designed following the cost of service and rate directives ratemaking steps. Power Rates Study, BP-14-E-BPA-01, at 52-92. The rate design for the PF Public rate was established in the TRM. The TRM restricts BPA and customers with Contract High Water Mark (CHWM) contracts from proposing changes to the TRM except in a section 7(i) rate proceeding, and only after certain procedures specified in the TRM have been followed. TRM-12S-A-03, Section 13. No such changes have been proposed by BPA, any customer with a CHWM contract, or any other party in this case. *See* Bliven and Parker, BP-14-E-BPA-11, at 3. Rates are established to recover the costs of the Residential Exchange Program in accordance with the terms of the 2012 REP settlement and the Administrator's decisions in the REP-12 Rod. *See* Draft ROD section 1.4.

### **2.5.1 Power Rate Development Changes**

There were a number of proposed changes to the rate schedules and GRSPs, outlined below. No party raises any issue with these proposed changes in its Initial Brief. Certain parties support the adoption of these proposed changes. JP03 Br., BP-14-B-JP03-01, at 23-24; WMG&T Br., BP-14-B-WM-01, at 1-3. For a more complete explanation and description of each of the changes, see the referenced testimony and exhibits.

1. **NR Energy Shaping Services for NLSLs.** NR service is expanded so it can be used to make up for any mismatch between customers' dedicated resource amounts that are based on planned NLSL loads and actual NLSL loads. Power Rates Study, BP-14-E-BPA-01, at 97; Chalier *et al.*, BP-14-E-BPA-19, at 2.
2. **Unanticipated Load Service (ULS) Availability.** ULS availability is modified to be assessed on a case-by-case basis and exclude loads less than 1 MW. Power Rates Study, BP-14-E-BPA-01, at 109; Chalier *et al.*, BP-14-E-BPA-19, at 6; Chalier *et al.*, BP-14-E-BPA-40, at 14.
3. **Load Shaping True-Up Payment Options.** Customers are given the option to pay the Load Shaping True-Up charge over three months (without interest applied) or in one month. 2014 Power Rate Schedules and General Rate Schedule Provisions, BP-14-E-BPA-09, GRSP II.L.4; Chalier *et al.*, BP-14-E-BPA-19, at 8-9.
4. **Low Density Discount/Irrigation Rate Discount (LDD/IRD).** The GRSP language is clarified on several minor points. Power Rate Schedules, BP-14-E-BPA-09, GSRP II.M. and GRSP II.K; Chalier *et al.*, BP-14-E-BPA-19, at 10.
5. **Demand Charge Adjustment for Extreme Load Shifts and Recovery Peaks.** The demand billing determinant is adjusted for occasions of "extreme load shifts" (due to a consumer's load coming back online following an extended outage, for example) or "recovery peak" (due to power restoration after an outage caused by an uncontrollable force, such as a storm). Power Rates Study, BP-14-E-BPA-01, at 66; Chalier *et al.*, BP-14-E-BPA-19, at 11.
6. **Provisional CHWM Treatment.** The retention or non-retention of Provisional CHWMs is implemented in billing determinants in the manner directed by the TRM. Power Rate Schedules, BP-14-E-BPA-09, GSRP II.Y. and GRSP II.D.3; Chalier *et al.*, BP-14-E-BPA-19, at 9, 14.
7. **Tier 2 Remarketing and Non-Federal Resource with Diurnal Flattening Service (DFS) Remarketing.** A remarketing credit is provided to customers with Regional Dialogue contract section 10 remarketing for either Tier 2 amounts or non-Federal resource amounts (to which DFS applies) that are in excess of its Above-RHWM load. Power Rates Study, BP-14-E-BPA-01, at 75, 91; Chalier *et al.*, BP-14-E-BPA-17, at 11-12.
8. **Resource Remarketing Service (RRS).** A remarketing credit is provided to customers granted RRS. Power Rates Study, BP-14-E-BPA-01, at 107; Chalier *et al.*, BP-14-E-BPA-17, at 17.

9. **General Transfer Agreement (GTA) Delivery Charge.** The GTA Delivery Charge, described in section I of the GTA-14 rate schedule, applies to PF customers for deliveries of power over third-party transmission and/or distribution systems at voltages below 34.5 kV. Miller and Yokota, BP-14-E-BPA-20, at 2; *see also* Power Rate Schedules, BP-14-E-BPA-09, at 29-30. In previous rate proceedings, the GTA Delivery Charge was designed to mirror the Utility Delivery Charge established by Transmission Services. In this proceeding, the GTA-14 Delivery Charge was designed to recover the projected low-voltage service costs (*i.e.*, below 34.5 kV) Power Services is expected to incur over the rate period. *Id.* at 2-3. The GTA-14 GTA Delivery uses the customer’s system peak as the billing determinant. *Id.* at 6-7.

## **2.5.2 Section 7(c)(2) Typical Margin**

### **Issue 2.5.2.1**

*Whether adjusting the industrial margin by applying the GDP Implicit Price Deflator to account for inflationary forces comports with statutory requirements.*

### **Parties’ Positions**

Alcoa argues that BPA’s decision to use the GDP Implicit Price Deflator to adjust the industrial margin to account for inflationary forces is not in accordance with statutory requirements, in particular, section 7(c) of the Northwest Power Act. Alcoa Br., BP-14-B-AL-01, at 2.

### **BPA Staff’s Position**

The premise for using the margin in the IP rate is that publicly owned utilities will charge their retail industrial consumers rates that reflect their costs. Chalier *et al.*, BP-14-E-BPA-40, at 19. BPA has consistently calculated the industrial margin using general and administrative costs that the retail utility adds to its power costs when determining its rates for industrial consumers. *Id.* at 20. Staff has no reason to expect that utility general and administrative costs have not experienced inflationary pressures during the past two years. *Id.*

### **Evaluation of Positions**

Section 7(c) of the Northwest Power Act is the primary directive that establishes the parameters for setting the IP rate, which is the rate applicable to power sales to DSI customers. 16 U.S.C. § 839e(c). Generally, BPA is required to ensure that the IP rate is “equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region.” 16 U.S.C. § 838e(c)(1)(B). In order to ensure that this equitable relationship is maintained, the statute requires, in part, that the rate determination be “based upon the Administrator’s applicable wholesale rates to such public body and cooperative customers and

*the typical margins included* by such public body and cooperative customers in their retail rates.” 16 U.S.C. § 839e(c)(2) (emphasis added).

In determining the proper rate level, the statute further directs BPA to take into account

The comparative size and character of loads served,

The relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions, and

Direct and indirect overhead costs.

16 U.S.C. § 838e(c)(2)(A)–(C). At issue here is what Congress intended by requiring BPA to “take into account ... direct and indirect overhead costs.” In the past, that objective has been accomplished in two ways: (1) conducting a survey of preference utilities serving industrial load to identify their “direct and indirect overhead” costs or (2) adjusting the previously existing margin to account for inflation. Alcoa argues that the second method, adjusting for inflation, is inconsistent with the statutory requirements. Alcoa Br., BP-14-B-AL-01, at 2.

Alcoa argues that BPA's interpretation of its obligations under section 7(c)(2) ignores unambiguous Congressional intent and is entitled to no deference. Alcoa states that BPA must give “effect to the unambiguously expressed intent of Congress.” Alcoa Br., BP-14-B-AL-01, at 5 (citing *M-S-R Pub. Power Agency v. Bonneville Power Admin.*, 297 F.3d 833, 841 (9th Cir. 2002) (quoting *Chevron U.S.A., Inc. v. Natural Res. Def. Council, Inc.*, 467 U.S. 837, 842-43 (1984)). Alcoa states that Staff has admitted as much in its rebuttal testimony by making a telling admission: “[i]n deciding whether or not to propose adjusting the BP-12 industrial margin for inflation, we relied upon our general knowledge of standard ratemaking practices and our experience in dealing with this issue in prior BPA rate proceedings.” Alcoa Br., BP-14-B-AL-01, at 6 (quoting Chalier *et al.*, BP-14-E-BPA-40, at 19). Alcoa insists that it is irrelevant whether BPA's proposed adjustment is “aligned with standard ratemaking practices.” Alcoa Br., BP-14-B-AL-01, at 6 (quoting Chalier *et al.*, BP-14-E-BPA-40, at 20).

Alcoa also asserts that, had Congress intended to permit BPA to make its industrial margin calculation consistent with “standard ratemaking practices,” it would have drafted the Northwest Power Act accordingly. Alcoa Br., BP-14-B-AL-01, at 6. Instead, Alcoa argues, Congress itemized the factors BPA must consider when calculating the typical margin, and BPA is obliged to adhere to that formulation. *Id.* In this connection, Alcoa cites *Church of Scientology of California v. U.S. Dep't of Justice*, 612 F.2d 417, 421 (9th Cir. 1979), for the proposition that Congress “mean[s] what it says and thus the statutory language is normally the best evidence of congressional intent.” *Id.*

Alcoa argues further that BPA may not interpret section 7(c)(2) in a manner that renders superfluous the specific mandatory factors Congress intended the agency to consider when calculating the typical margin. *Id.* (citing *Pac. Nw. Generating Coop v. Bonneville Power*

*Admin.*, 580 F.3d 792, 808 (9th Cir. 2008) for the proposition that BPA may not rely on a statutory interpretation that “would render [plain Congressional language] superfluous”). Alcoa insists that this principle has been violated because BPA has substituted its own understanding of standard ratemaking practices for the specific formulas Congress mandated. Alcoa Br., BP-14-B-AL-01, at 6. Alcoa concludes that Congress did not leave the calculation of the IP rate to BPA’s discretion; instead, it provided the agency with specific guidance and BPA “may not ignore factors Congress explicitly required be taken into account.” *Id.* (citing *Earth Island Inst. v. Hogarth*, 494 F.3d 757, 765 (9th Cir. 2007)). Based on that analysis, Alcoa concludes that BPA’s decision is entitled to no deference because, under the holding in *Earth Island*, the decision to use the GDP Implicit Price Deflator serves only to enable the agency to ignore reality, and in such cases courts need not acquiesce. Alcoa Br., BP-14-B-AL-01, at 6.

BPA disagrees with Alcoa’s argument. As reflected above, section 7(c) of the Northwest Power Act describes with some particularity how the Administrator must set the IP rate, the rate applicable to sales to DSI customers, and it generally sets forth the steps that the Administrator must follow in doing so. The primary directive is that the rate shall be “equitable in relation to the retail rates charged by the public body and cooperative customers to their industrial consumers in the region.” 16 U.S.C. § 838e(c)(1)(B). In order to accomplish that objective, the determination is required to be based in part on the Administrator’s applicable wholesale rates to such public body and cooperative customers and the “typical margins included by such public body and cooperative customers in their retail industrial rates.” 16 U.S.C. § 839e(c)(2).

As part of that determination, the Administrator is required to take into account such factors as “comparative size and character of the loads served” and “the relative costs of electric capacity, energy, and related delivery facilities provided and other service provisions.” 16 U.S.C. § 838e(c)(2)(A)–(B). However, such considerations are not determined by or related to the margin survey that BPA has conducted in prior rate cases. The only margin-relevant costs for purposes of this discussion are the costs that are actually considered by application of the margin study, and those are limited to the “direct and indirect overhead costs” experienced by preference utility customers serving industrial load. *Id.* Contrary to Alcoa’s assertions, Congress has not provided “specific formulas” that must be observed. Instead, section 7(c) states only that, in developing the rate applicable to DSI sales, the Administrator shall include an adjustment for the typical industrial margin that “shall *take into account* ... direct and indirect overhead costs.” 16 U.S.C. 839e(c) (emphasis added).

The industrial margin adjustment has generally had a very small effect on rates, as shown in the tables in the evaluation of Issue 2.5.2.2. Historically, BPA has made the adjustment in two ways. First, BPA has adjusted the industrial margin by conducting an industrial margin survey. When BPA employs the margin survey, the Public Power Council has been enlisted to collect cost of service information from preference customer utilities that serve at least one industrial load whose average power consumption is three or more megawatts. BPA personnel then analyze the information for the purpose of separating it into various cost categories: production, distribution, revenue taxes, and other.

The costs that are placed in the “other” category are the costs that are related to direct and indirect overhead costs because they are not related to the production and distribution of power or to the revenue taxes charged by only the State of Washington, and which therefore are not considered to be relevant to the “typical” industrial margin, as required by statute. Thus, the process is essentially one of excluding costs related to functions that are not direct and indirect overhead costs. These results are then incorporated into the ratesetting process by integrating the results into the industrial margin study, which can include other adjustments, as reflected in the statutory language, that are unrelated to direct and indirect overhead costs, *i.e.*, “the comparative size and character of loads served [and] ... the relative costs of electric capacity, energy, transmission, and related delivery facilities provided and other service provisions.” This method is a reasonable means of “taking account of ... direct and indirect overhead costs” as required by the rate directive.

However, the statute does not limit BPA to one method of taking such costs into account. Another legitimate means of taking such costs into account that has been used historically in the absence of conducting a margin survey is to adjust such costs by the application of the GDP Implicit Price Deflator. The GDP Implicit Price Deflator measures the effect of inflation in the economy generally. Because direct and indirect overhead costs are not in any way specialized or related to a narrow area of technical costs that might not be subject to inflation, as could be the case if the margin dealt with power generation or distribution facilities, the GDP Implicit Price Deflator is a suitable tool for adjusting the margin, particularly over the relatively brief time that is at issue here. Over a period of two years, one would not anticipate a huge change in direct and indirect overhead costs, and adjusting for inflation captures, in this case, a very small incremental change.

While this method of adjusting the margin is different from adjusting by use of a margin survey, it is nonetheless a reasonable one. That is particularly true in this instance, where BPA is not abandoning the margin survey but intends to use it in future rate cases. Continuing to use the margin survey with some frequency will serve as a means of double-checking use of the GDP Implicit Price Deflator, and the margin survey would be likely to capture and self-correct any distortions in the inflation adjustment. Similarly, use of the GDP Implicit Price Deflator might well serve to support or detract from the existence of any anomalies that might arise in the context of a margin survey. In the final analysis, whether BPA conducts the survey or adjusts the margin for inflation, it will “take into account ... direct and indirect overhead costs” as required by statute. As noted elsewhere, it is also a tool that BPA has used in the past to adjust the typical industrial margin.

Furthermore, adjusting the margin to account for inflation is consistent with the intent of Congress at the time Congress conceived of adjusting the rate applicable to DSI sales to align them with the rates BPA’s preference utilities apply to their industrial customers. The Senate Report on the Northwest Power Act noted that the rate applicable to such sales should be determined in part by “applying a typical margin of cost (‘markup’ between the preference customers’ retail industrial rates and their respective wholesale power costs) to the BPA wholesale rates to the preference customers for all power used to serve their industries.” Chalier

*et al.*, BP-14-E-BPA-40, at 19-20 (citing S. Rep. No. 96-272, 96th Cong., 1st Sess. p. 59 (1979)). BPA continues to interpret this direction as referring to the amount of general and administrative costs that the retail utility adds to its power costs when determining its rates for industrial consumers. Chalier *et al.*, BP-14-E-BPA-40, at 20. It is also notable that there is no suggestion in this piece of legislative history that Congress preferred one method over another for making the determination.

In conclusion, despite Alcoa's arguments to the contrary, there is no basis to conclude that Congress expected BPA to follow only one specific method for determining the appropriate level of the margin. Neither the statute nor the legislative history indicates that BPA has offended the intent of Congress by adjusting the margin for inflation in this instance, particularly where, as shown below, the underlying data is relatively fresh and there is every indication that application of the GDP Implicit Price Deflator is consistent with the results achieved by conducting a full margin survey. See the tables in the evaluation of Issue 2.5.2.2.

### **Draft Decision**

*Adjusting the industrial margin to account for inflationary forces by application of the GDP Implicit Price Deflator is an acceptable means of meeting the requirements of section 7(c) of the Northwest Power Act that direct and indirect overhead costs be taken into account in determining a rate level that is equitable in relation to the retail rates charged by public body and cooperative customers to their industrial consumers.*

### **Issue 2.5.2.2**

*Whether applying the GDP Implicit Price Deflator to the BP-12 industrial margin to account for inflationary forces properly establishes the level of the industrial margin for BP-14 rates.*

### **Parties' Positions**

Alcoa argues that there is no evidence whatsoever concerning whether utilities have experienced inflationary forces since the last margin study was conducted. Alcoa Br., BP-14-B-AL-01, at 3.

### **BPA Staff's Position**

There is no reason to expect that utility general and administrative costs have been exempt from inflationary pressures during the past two years. Chalier *et al.*, BP-14-E-BPA-40, at 20. Adjusting the margin for inflation is aligned with standard ratemaking practices, among which are assumptions of inflationary increases for future costs. *Id.* BPA has always adjusted the industrial margin either by assessing relevant utility costs through the margin survey or by application of an adjustment for inflation. *Id.* at 21. From 1996 to 2012, there has never been a period in which the industrial margin has not increased from the prior period. *Id.*

## **Evaluation of Positions**

For the BP-14 rate case, BPA Staff, Alcoa, and the Public Power Council (representing many of BPA's preference customers) reached agreement not to conduct a new survey of preference customers to establish the direct and indirect costs included in retail rates of industrial consumers served by preference utilities in the Pacific Northwest. *See* Memorandum of Understanding Attachment B, BP-14-E-BPA-01. The signers agreed to use the margin survey performed for the BP-12 rate case. *Id.* The MOU states that any methodology issues raised in the 2014 rate case (BP-14) regarding calculation of the industrial margin shall use data from the 2012 margin survey; these arguments shall not require performance of a new industrial margin survey. *Id.*

Alcoa challenges BPA's decision to adjust the margin for inflation by arguing that BPA's testimony and supporting data are inadequate to support adjusting the industrial margin for inflation:

... [N]either BPA's studies nor its testimony explain why Staff concluded that the proposed adjustment would be appropriate. In fact, BPA has stated that it has no work papers, studies, or analyses that support the proposed adjustment. BPA also acknowledged that there is no data in the BP-12 industrial margin survey regarding whether or not it is appropriate to adjust the industrial margin for inflation. The reason for this lack of evidence is simple – BPA agreed to forego collecting it in order to reduce the burden upon the PPC of collecting the necessary customer-specific data.

*Id.* at 4. Alcoa concludes by contesting BPA's decision to forego doing a margin study every two years and at least implicitly suggesting that a full margin study must be done every rate case regardless of the amount of time that has elapsed since the prior rate case. *Id.*

Inflation exists and can be a factor even in a slow economy. The GDP Implicit Price Deflator has been in use for many years, to the point that it has become an industry standard for measuring the effects of inflation. It is not necessary for BPA to essentially dismantle the GDP Implicit Price Deflator to prove that it does the intended job of measuring inflationary effects. It is enough that the GDP Implicit Price Deflator provides a standard that is generally accepted and commonly used. If, as suggested by Alcoa, there has been no inflation during the past two years, then one would expect the GDP Implicit Price Deflator to reveal that fact, resulting in no adjustment to the industrial margin. The GDP Implicit Price Deflator, however, does not indicate that there has been no inflation, but rather indicates that there has generally been a small but measurable incidence of inflation over the course of the current rate period.

While BPA does not believe that a full margin survey should never be conducted, it is nonetheless reasonable, and aligned with common ratemaking practices, to forego the study and make an adjustment to account for inflation in light of the fact that only two years have elapsed

since the last margin study, which was completed in June 2011.<sup>2</sup> Chalier *et al.*, BP-14-E-BPA-40, at 21. The rationale for forgoing the full margin study in this instance is:

... In the past, BPA's rate periods have been of a longer duration than the two-year rate periods BPA committed to in the TRM [Tiered Rate Methodology]. TRM-12S-A-03, at 1. During the longer rate periods, it was possible that utilities participating in the margin survey could have significant changes in their overall cost structures. Thus, it made sense to conduct a survey every rate case. Such *cost fluctuations are less likely during a two-year rate cycle, so the value of collecting and analyzing data from a full survey is considerably diminished. Meanwhile, the administrative burden on PPC, which collects the data, and BPA Staff, which conducts the analysis, is greatly increased* by performing the margin survey every two years. For that reason, we began pursuing alternatives to conducting the margin survey every two years.

Chalier *et al.*, BP-14-E-BPA-40, at 16 (emphasis added). Thus, Alcoa is incorrect to assert that BPA's goal was "to avoid burdening the PPC's members." See Alcoa Br., BP-14-B-AL-01, at 5. While that administrative burden, as well as cost, did enter the overall thinking, the primary consideration was the "considerably diminished" value of the information obtained. Questions of administrative efficiency were a secondary benefit emanating from that conclusion.

The rationale for selecting use of the GDP Implicit Price Deflator to adjust the margin for inflation for the upcoming two-year rate period is:

In deciding whether or not to propose adjusting the BP-12 industrial margin for inflation, we relied upon our general knowledge of standard ratemaking practice and our experience in dealing with this issue in prior BPA rate proceedings....

The premise for using the margin in the IP rate is based on the concept that publicly owned utilities will charge their retail industrial consumers rates that reflect their costs. ... We have found no reason to expect that utility general and administrative costs have been exempt from inflationary pressures during the past two years.

Having not conducted a new survey, we believe the margin should be aligned with standard ratemaking practices, among which are assumptions of inflationary increases for future costs.

---

<sup>2</sup> Alcoa has incorrectly asserted that "the last margin survey was conducted in 2010." In fact, the last margin study was conducted in 2011. Data was collected in the spring and the results were complete by June of that year. BPA assumes that the mistake was an oversight and that Alcoa is not trying to suggest that the information is more than two years old, which might suggest that the information is "stale," and that a new margin study is necessary for that reason. The proposed adjustment is for two years recognizing the time interval between the survey in 2011 and when a new survey would have been conducted in 2013 absent the MOU.

Chalier *et al.*, BP-14-E-BPA-40 at 19-20. BPA relies on general ratemaking practices when determining whether to adjust the margin for inflation. It also considers whether utility general and administrative costs would have been immune to inflationary forces, and Staff found no reason that they would have been. Staff makes the commonsense assumption that, even in a slow economy, utilities would be likely to pass such increased costs through to the rates of their industrial customers. Finally, the inflation adjustment conforms with standard ratemaking practices. *Id.*

As a further test, comparing the current adjustment to past BPA practices with respect to the industrial margin shows that, if anything, the inflation adjustment may well slightly understate the needed adjustment:

BPA has always adjusted the industrial margin either by assessing relevant utility costs through the margin survey or by application of an adjustment for inflation. Furthermore, in the 16 years from 1996 to 2012 there has *never been a period in which the industrial margin has not increased* from the prior period.

*Id.* at 21. The changes in the level of margin from 1996 to the present were:

WP-96 Rate Case	0.44 mills/kWh
WP-02 Rate Case	0.46 mills/kWh
WP-07 Rate Case	0.57 mills/kWh
WP-10 Rate Case	0.63 mills/kWh
BP-12 Rate Case	0.68 mills/kWh

*Id.*; *see also* Speer, BP-14-E-AL-01, Exhibit C. If the historical margin levels would have been adjusted for inflation rather than pursuant to a survey of utility overhead costs, the comparative margins would have been:

<u>Rate Case</u>	<u>Survey Year</u>	<u>Survey Margin</u>	<u>Inflated Margin</u>	<u>Error</u>
WP-96	1994	0.44		
WP-02	1998	0.46	0.47	+0.01
WP-07	2004	0.57	0.52	-0.05
WP-10	no survey		0.63	
BP-12	2009	0.68	0.65	-0.03

Uses GDP-Deflator calculator at [http://stats.areppim.com/calc/calc\\_usdlrxdeflator.php](http://stats.areppim.com/calc/calc_usdlrxdeflator.php)

*Id.* at 22. Based on these results, it appears that using an inflation adjustment tends to understate the margin. *Id.*

In view of the record as a whole, and as described fully above, there is ample evidence to conclude that the GDP Implicit Price Deflator is a sufficiently reliable indicator of the appropriate adjustment that does not unfairly or inequitably increase the IP rate or penalize DSI

customers, in spite of the small differences in results obtained by adjusting for inflation rather than conducting a margin survey.

Alcoa argues that the record does not include substantial evidence to support BPA Staff's proposal to adjust the industrial margin. Alcoa Br., BP-14-B-AL-01, at 3. The above decision is based on an assessment of the evidence, which supports the results. The substantial evidence test applies to appellate review and therefore is not explicitly addressed in this Draft ROD. *See* section 1.3.3 for further discussion.

### **Draft Decision**

*Applying the GDP Implicit Price Deflator to the BP-12 industrial margin to account for inflationary forces properly establishes the level of the industrial margin for BP-14 rates.*

### **Issue 2.5.2.3**

*Whether adjusting the industrial margin to account for inflationary forces violates the intent and purpose of the Memorandum of Understanding that was executed by BPA, PPC, and Alcoa by failing to obtain Alcoa's consent to the adjustment.*

### **Parties' Positions**

Alcoa argues that Staff's proposal to adjust the industrial margin to account for inflation is contrary to the intent and purpose of the Memorandum of Understanding that was executed by BPA, PPC, and Alcoa prior to BPA publishing its Initial Proposal. Alcoa Br., BP-14-E-AL-01, at 4-7. Alcoa states that its consent is required, whether by means of the MOU or otherwise, to allow BPA to undertake what it calls an "extra-statutory" adjustment to the industrial margin. Alcoa Br., BP-14-B-AL-01, at 8-10.

### **BPA Staff's Position**

The purpose of the MOU was to reach a consensus regarding not conducting a margin study while at the same time leaving parties free to pursue in the rate case the arguments they deem appropriate regarding calculating the Industrial Margin. Chaliar *et al.*, BP-14-E-BPA-40, at 15.

### **Evaluation of Positions**

Alcoa argues that a provision of the MOU permitting BPA to make an extra-statutory adjustment was removed from the final MOU, as executed by BPA, Alcoa, and PPC. Alcoa Br., BP-14-B-AL-01, at 8. Alcoa states that it has not agreed to an extra-statutory calculation of the industrial margin, and in the absence of such an agreement, BPA has no choice but to abide by the methodology prescribed in section 7(c)(2). *Id.* Alcoa also argues that the MOU decided on a final basis that BPA would not conduct a margin study. But that is precisely what BPA did in the MOU—it decided, on a final basis, that it would not conduct a margin study, which is the method by which the agency collects the information necessary to address the section 7(c)(2)

factors. *Id.*, citing Chalier *et al.*, BP-14-E-BPA-40, at 18. Alcoa develops its argument as follows:

*The MOU does not authorize BPA to make extra-statutory calculations when computing the industrial margin. By agreeing to waive the margin survey, BPA foreclosed its own ability to collect the data that is necessary to properly calculate the industrial margin. BPA cannot choose for administrative convenience to deprive itself of the necessary data and then credibly claim that it has no option other than to make an extra-statutory adjustment.*

*Id.* at 8-9 (emphasis added). Alcoa essentially argues that BPA has no discretion to set the industrial margin through any means other than a industrial margin survey, at least not without Alcoa providing its consent through an MOU or otherwise. All other methods of adjusting the industrial margin are apparently, in Alcoa's eyes, "extra-statutory."

Staff (one of the parties to the MOU) sets forth its understanding of what the MOU was intended to accomplish, which is quite different from Alcoa's understanding. As Staff stated, "The intent of the MOU was to dispense with the margin survey but otherwise leave all other substantive issues that might affect the calculation of the margin open for consideration in the BP-14 rate proceeding." Chalier *et al.*, BP-14-E-BPA-40, at 15-19. It appears there was never a common understanding with respect to what the parties intended by entering into the MOU. Alcoa agrees that what is underlying this debate between BPA and Alcoa on the industrial margin is really a case of mistaken expectations about a memorandum of understanding. Oral Tr. 222.

Such details would not be particularly illuminating, because the crux of the matter seems to be a difference of opinion between BPA and Alcoa regarding the scope of section 7(c)(2). As shown in Issue 2.5.2.1, BPA believes that its actions are consistent with section 7(c)(2). In other words, BPA is not making an "extra-statutory" adjustment.

The MOU states that any methodology issues raised in the BP-14 rate case regarding calculation of the industrial margin shall use data from the 2012 margin survey; these arguments shall not require performance of a new industrial margin survey. As intended, the MOU left BPA, Alcoa, and other parties free to pursue methodology arguments. Alcoa has done so, providing testimony and briefing to the effect that the inflation adjustment is not consistent with statutory requirements and is not supported by substantial evidence. Those arguments have been fully evaluated.

To the extent that Alcoa wished to raise arguments regarding the other factors, it certainly was free to do so. One of the main purposes of the MOU was to leave parties open to do just that. The only proviso in the MOU was that, to the extent that arguments required evidentiary support from a margin study, the 2012 margin survey would serve as a surrogate for a new survey. It remains unclear exactly what Alcoa's primary concern is, but it appears to be Alcoa's belief that consent of all relevant parties would be required in order to make any adjustment to the 2012 survey results. It does not appear that Alcoa argues that deletion of the provision from the MOU

had implications beyond that. Nonetheless, it is fair to point out that the MOU expressly does not preclude any party from making any arguments with respect to the industrial margin calculation or the factors that should be considered when making that adjustment.

Instead, as noted in Alcoa's brief, all roads appear to lead back to Alcoa's assertion that section 7(c) precludes any margin adjustments other than those made pursuant to a margin survey. BPA has made clear that it disagrees with that assessment but in no way contests Alcoa's right to present such arguments for consideration.

It is regrettable that Staff's attempt to be transparent and inclusive in the development of its Initial Proposal appears to have resulted in a misunderstanding with respect to the scope and purpose of the MOU. Fortunately, this misunderstanding has had no bearing on the procedural rights of the parties or interfered with the task of evaluating all of the arguments that parties to the rate case wished to present in connection with the industrial margin.

Still, it would undoubtedly have been preferable to avoid the misunderstanding and any hard feelings resulting from that misunderstanding. It is certainly not BPA's nor Staff's intention to create ill will. Thus, despite the dozens of emails that were sent back and forth between the parties to reach agreement on the MOU and the cooperative spirit that was exemplified by those discussions from all participants, BPA regrets the apparent breakdown in communication regardless of the reasons for it. For the future, BPA commits to making even greater efforts to ensure that it fully and accurately communicates its objectives.

### **Draft Decision**

*Adjusting the BP-12 industrial margin for inflation does not violate the intent and purpose of the MOU. Neither is Alcoa's consent to the adjustment required. In spite of the misunderstanding between Alcoa and BPA regarding the purpose of the MOU, BPA will adjust the industrial margin for inflation.*

### **Issue 2.5.2.4**

*Whether the Administrator has set the value of reserves credit applicable to the IP rate in accordance with statutory directives.*

### **Parties' Positions**

JP05 argues that the value of any and all reserves obtained from Alcoa must be set as part of the section 7(c) value of reserves credit in a section 7(i) rate proceeding. JP05 Br., BP-14-B-JP05-01, at 10-11.

### **BPA Staff's Position**

Only the statutorily required minimum DSI reserve requirement, defined in the GRSPs and DSI contracts as "Minimum DSI Operating Reserve – Supplemental," is valued as part of setting the

value of reserves credit. *See* 2014 Power Rate Schedules and General Rate Schedule Provisions (FY 2014-2015), BP-14-E-BPA-09, GRSP II.F.

### **Evaluation of Positions**

JP05 states:

BPA should properly credit the DSIs for the value of any reserves they provide; however, the methodology for crediting must be set in a section 7(i) rate proceeding and should not be determined through bilateral negotiations between BPA and any of the DSIs. Alcoa should raise any concerns with the reserve calculation in this proceeding, and the Administrator should reject any effort to set the Industrial Firm Power (“IP”) rate or reserve credit outside of the rate case process.

JP05 Br., BP-14-B-JP05-01, at 10. JP05 argues that the Administrator’s authority to provide a credit for reserves is in Northwest Power Act section 7(c)(1), the statutory provision for setting rates that contains rate directives for establishing the IP rate. *Id.* JP05 apparently believes the Administrator is restricted to obtaining demand side management services from DSI customers in only one manner, *i.e.*, by conducting a section 7(i) rate proceeding to determine the value of such services:

The statute explicitly states that when establishing the IP rate, the Administrator ‘shall adjust such rates to ... account’ for the value of reserves.... Therefore, the statute contemplates that the adjustment will not be negotiated through contract, but will be an adjustment to the IP rate that will be made when setting rates.

*Id.* BPA disagrees. It does not appear that any party has presented an argument to the effect that the IP rate or reserve credit could or should be set in any manner other than in the context of a section 7(i) ratemaking proceeding. To the extent such an argument may have been raised implicitly, BPA rejects it, because such a ratesetting practice would be inconsistent with clear statutory directives. To be even clearer, no consideration has been given to negotiating or re-negotiating the IP rate or reserve credit through bilateral contract negotiations, as such an action would not be supported by statute.

It is possible that JP05 misunderstands the somewhat confusing testimony proffered by Alcoa, which tends to conflate the two types of products available from DSI customers and does not clearly explain the difference in how the two are treated. *See* Speer, BP-14-E-AL-01, at 14-17. In order to clarify, it is important to understand the distinction between the two types of reserves, which can be summarized as follows:

1. First are the statutorily required “minimum” operating reserves (*i.e.*, Minimum DSI Operating Reserve – Supplemental) that must be provided through a contractual right for the Administrator to interrupt DSI load in the event of a

system disturbance. These are the only reserves that are subject to the “value of reserves” credit, and their value is determined in a section 7(i) process.

2. Second are additional reserves and demand side management products that may be made available from time to time on an “as needed” basis but which the Administrator is not required to purchase from the DSIs. These are not part of the “value of reserves” credit because their prospective availability creates no present “right” to interrupt DSI load, as required by the statutory provision establishing the value of reserves credit. 16 U.S.C. § 839e(c)(3). If and when such reserves are needed and available, they are acquired consistent with the methodology established in GRSP Section II.F. on a negotiated bilateral basis. Additionally, these additional reserves, or other products, are acquired according to BPA’s business needs at the time of acquisition and undergo the same rigorous reviews required of BPA commercial trading floor acquisitions. Any products acquired from the DSIs would be compared against similar products available from other market participants.

*See, generally, 2014 Power Rate Schedules and General Rate Schedule Provisions, BP-14-E-BPA-09, GRSP II.F, at 49-50.*

With that clarification, it appears that the JP05 position may also be predicated on a misunderstanding of relevant statutory provisions. First, section 5(b) of the Northwest Power Act provides that “sales [to DSI customers] shall provide a portion of the Administrator’s reserves for firm power loads within the region.” 16 U.S.C. § 839c(d)(1)(A). BPA has established that, in order to comply with this requirement, DSI contracts must provide the Administrator with a right to interrupt 10 percent of the customer’s total load in the event of a system disturbance. The 10 percent of interruptible load ensures that a “portion” of the reserves for firm power loads is being provided in compliance with the statutory command.

As specified in the DSI contracts and the GRSPs, these reserves must be available on 10 minutes’ notice and must be made available for up to 105 minutes for each occurrence, with no limit on the number of times those reserves may be called upon. 2014 Power Rate Schedules and General Rate Schedule Provisions, BP-14-E-BPA-09, GRSP II.F, at 49-50. Moreover, as part of its Final Proposal, BPA plans to revise the GRSPs to restore language that had been used previously in the GRSPs to delineate more clearly between required reserves and optional reserves that may be purchased on a case-by-case basis but that are not required.

The value of reserves credit required by section 7(c)(3) of the Northwest Power Act applies only to the Minimum DSI Operating Reserve – Supplemental, the operating reserves required by statute. This result is appropriate, because the statute states that the value of reserves rate credit shall “take into account the value of power system reserves made available to the Administrator *through his rights to interrupt or curtail* service to such direct service industrial customers.” 16 U.S.C § 839e(c)(3) (emphasis added). The Administrator has a present “right to interrupt or curtail” established by contract and through the ratemaking process to call on 10 percent of DSI

load in the event of a system disturbance. No other rights presently exist, and therefore, consistent with the statutory language, cannot be valued as part of the value of reserves credit.

It is true that additional opportunities may arise in the future where Alcoa may offer, or BPA may request, additional reserves or other demand side management products. Typically these would arise “as needed” and require decisionmaking on a short-term or even real-time basis that might preclude conducting a public process, especially a section 7(i) ratemaking process, in order to obtain the benefits of such a purchase. Trying to incorporate such additional future unknown demand side management products that may be offered by Alcoa in the value of reserves credit is not possible; nor would it comport with sound business principles or current agency policy. The Administrator is not required to conduct a public process if he makes short-term purchases of additional reserves on an “as-needed” basis from Alcoa or any other vendor of such services. These decisions are made based on business need and have separate commercial terms that may be tailored to meet specific criteria or serve particular purposes. That said, any additional reserves purchased by BPA do not, and shall not, result in any renegotiation of the IP rate or the section 7(c) value of reserves credit. However, in the exercise of his business judgment, the Administrator may bilaterally negotiate the price for any reserve products beyond the statutorily required minimum.

The Administrator will essentially treat any such purchases in the same manner as he would a purchase of such products from any other purveyor of such services on the open market. There does not appear to be any reason why a DSI customer should be singled out for disparate treatment by requiring a public process that would essentially make it impracticable or impossible for the Administrator to consider making such acquisitions. Moreover, to reiterate, making purchases in this manner does not involve or require adjusting the IP rate or the value of required reserves associated with the IP rate.

Finally, it is difficult to understand why JP05 would want to restrict the Administrator’s ability to obtain additional reserves beyond those that are statutorily required on a negotiated basis in the manner set forth at GRSP II.F. The ability to obtain such products from Alcoa consistent with sound business principles creates a more competitive market for such services and ultimately provides benefits to all ratepayers. It is possible that Alcoa may be able to offer these services at a lower price and with better consistency than many other market participants. As such, Alcoa’s presence in the market should benefit BPA by creating more competition, which should have the effect of containing costs and improving the quality of such products.

BPA believes the methodology set forth in the GRSPs is sufficient to establish the business parameters that will govern any purchases of additional reserves or demand side management products from DSI customers that are not part of the statutory minimum quantified by the value of reserves credit. It should be noted, in this regard, that negotiations for non-mandatory reserves and products are governed by a price cap. BPA believes it is sound business to keep this avenue for acquiring reserves and other services open for the benefit of BPA and BPA’s customers.

## **Draft Decision**

*The value of reserves credit has been established in a manner that is consistent with statutory requirements. The possibility of acquiring additional reserves or demand side management products from DSI customers is recognized in the GRSPs and the DSI contracts. The methodology for making such purchases, established in GRSP II.F, makes clear that any such purchases will be negotiated in a manner that is consistent with sound business principles.*

### **2.5.3 Demand Rate**

#### **Issue 2.5.3.1**

*Whether BPA should use the financing cost assumptions of BPA-backed bonds for the marginal capacity resource used in calculating the demand rate.*

#### **Parties' Positions**

JP19 argues that BPA should assume private financing by a regional independent power producer (IPP) or IOU for the costs of financing a marginal capacity resource for calculating the demand rate rather than the BPA-backed consumer-owned utility financing assumption Staff proposed. JP19 Br., BP-14-B-JP19-01, at 6.

#### **BPA Staff's Position**

The demand rate is calculated using cost assumptions of BPA-backed bonds for the financing costs of an LMS100 combustion turbine, which is the least-cost option for acquiring a marginal capacity resource and thus the type of resource BPA would acquire if resource acquisition was needed. Chalier *et al.*, BP-14-E-BPA-40, at 2. This option sends the appropriate price signal to customers planning to develop demand response projects. *Id.*

#### **Evaluation of Positions**

JP19 states that it is reasonable to use the LMS100 gas turbine for the marginal capacity resource to establish the demand rate. JP19 Br., BP-14-B-JP19-01, at 6. However, while JP19 agrees with the selection of the LMS100, it states that BPA underestimates the financing costs associated with the construction of such a unit by assuming the financing will be through BPA or a consumer-owned utility (tax-exempt) financing rather than through an IOU or IPP. *Id.* JP19 argues that a substantial purpose of the demand rate is to send customers a price signal regarding the cost of capacity and thereby provide an incentive for the pursuit of resources or programs to reduce their exposure to the demand rate. *Id.* at 6.

JP19 states that the demand rate should reflect the actual cost of capacity BPA would face in the upcoming rate period. *Id.* at 8. According to JP19, a rate reflecting the actual cost is consistent with the TRM requirement to use the marginal capacity resource and provides the best incentive to invest in new resources or programs. *Id.* JP19 contends that using BPA-backed bonds as a

financing assumption is unreasonable, because preference customers served by BPA are not likely to build capacity resources using bonds backed by BPA. *Id.* at 6. JP19 suggests that the only entities likely to build capacity resources are regional IOUs that are planning to meet future load growth, and IPPs. *Id.* Given that no preference customers are projected to build any peaking capacity, JP19 states, BPA should use the financing assumptions of a regional IPP or IOU to determine the cost of the marginal resource used to calculate the demand rate. *Id.* at 9.

In the BP-12 ROD, the Administrator rejected the very arguments raised by JP19 in this proceeding. BP-12 ROD, BP-12-A-02, at 110-114. Using the BPA-backed financing assumption produces a demand rate that is sufficient to induce public utilities to procure resources and other programs that would reduce their exposure to the demand rate. Chalier *et al.*, BP-14-E-BPA-40, at 3.

JP19's contention that assuming BPA-backed financing would not send the appropriate price signal or reflect the actual costs to BPA is misplaced. JP19 bases these conclusions on its assumption that it is more likely that an IPP or IOU would construct a plant as opposed to a consumer-owned utility, but that is not the point. Whether in today's environment it is more likely that an IOU or IPP might construct a new plant is not the question. The question is what would be a reasonable and likely option for BPA in the event it needed to acquire a capacity resource. As the BP-12 ROD stated, "BPA has a long history of acquiring the output of resources from municipal/PUD developments. Columbia Generating Station and Cowlitz Falls are some examples of municipal/PUD financing using BPA-backed bonds. Idaho Falls and Wauna are other examples of resources that BPA has acquired from municipals and PUDs." BP-12 ROD, BP-12-A-02, at 112. Given BPA's history of acquiring output of resources financed using BPA-backed bonds, JP19's assumption regarding what type of entity would construct a resource that BPA might acquire is not as supportable as JP19 implies. BPA would continue to look first at least-cost options, which likely would involve BPA-backed financing of a consumer-owned project.

It is also not a foregone conclusion that basing the demand rate calculation on a BPA-backed project would not send the proper price signal. One aspect of the design of the demand rate is to send a price signal to encourage resource and program development. Chalier *et al.*, BP-14-E-BPA-40, at 3. However, the demand rate cannot be totally divorced from the costs associated with BPA's acquisition of the output of the marginal resource. The TRM uses the fixed costs associated with the marginal capacity resource to emulate what it might cost BPA to acquire the capacity. The TRM provides that:

BPA will identify the marginal capacity resource and the annual fixed costs associated with that resource for each Rate Period.... Such marginal capacity resource may be based on BPA's Resource Program and/or costs of BPA's recent capacity additions. Or it may be based on third-party sources, which may include, but are not limited to, the Energy Information Administration, EPRI Technical Assessment Guide, the Northwest Power and Conservation Council, and Integrated Resource Plans of the Pacific Northwest electric utilities.

TRM, BP-12-A-03, section 5.3.6.

While the TRM ROD states that the objective of the Demand Charge is to pass on to customers the actual cost of capacity, there are several options under the TRM for the identification of the marginal resource. Tiered Rate Methodology ROD, TRM-12-A-01, at 72. Each of the several sources of information listed in the TRM provides information related to costs of potential resource acquisitions by BPA. As previously noted, BPA would first look at the least-cost option, which would involve BPA-backed financing. Under the TRM, the first two sources for identifying the capacity resource listed in the TRM are from BPA itself and include either a forecast of a future resource acquisition cost in BPA's Resource Program or the cost of a resource actually acquired by BPA. Even though there are other third-party options listed, the implication of listing the BPA resources is that these other sources should be representative of the potential cost to BPA.

Contrary to the implication of JP19's argument, the price signal from the demand charge appears to be working. As WPAG notes, there are a number of pilot demand response projects being undertaken by customers that seek to lessen the utilities' exposure to the demand rate. *See Saleba et al.*, BP-14-E-WG-02, at 4. While the current efforts by the various utilities are small pilot projects, the level of interest in these projects indicates that the price signal is providing the necessary incentive to encourage demand response, at least at this point in time.

While an IPP/IOU financing assumption would increase the demand rate and in theory provide additional incentive, increasing the demand rate will not necessarily result in the appropriate price signal. *Chalier et al.*, BP-14-E-BPA-40, at 3. BPA wants to provide incentives for the development of cost-effective projects. If the demand rate is higher than costs associated with BPA acquiring the capacity resource, it could provide incentive for projects that are not the least-cost options for the region.

In the BP-12 ROD, the Administrator noted that if circumstances changed such that it was no longer appropriate to use a BPA-backed financing assumption, BPA could modify its financing assumption or use another source for the capacity resource. BP-12 ROD, BP-12-A-02, at 114. However, in this proceeding, JP19 has not presented any new evidence that would require a different decision. JP19 has for the most part reiterated arguments made in the BP-12 proceeding without presenting evidence of a change in circumstances that would warrant a change.

It should be noted, however, that the TRM provides that the appropriate capacity resource and the associated resource fixed costs will be determined in each 7(i) process, as will the source of the data and the assumptions used within each of the data sources. TRM, BP-12-A-03, section 5.3.6. As noted in the BP-12 ROD, if circumstances warrant a change in a future 7(i) process, BPA will consider it then. Currently there is no compelling reason to modify the decision made in the BP-12 ROD.

## **Draft Decision**

*BPA will use the financing cost assumptions of BPA-backed bonds in calculating the demand rate.*

### **Issue 2.5.3.2**

*Whether BPA should use solely the LMS100 as the marginal resource to calculate the demand rate or use the combination of the LMS100 and demand response.*

### **Parties' Positions**

WPAG argues that BPA should adopt a 50/50 marginal capacity resource approach for calculating the demand rate that includes both demand response and LMS100 resource costs as the marginal resources used in calculating the demand rate. WPAG Br., BP-14-B-WG-01, at 49.

JP19 argues that WPAG's 50/50 proposal should be rejected. JP19 Br., BP-14-B-JP19, at 4-5. JP19 contends that using demand response is inappropriate because it is not a viable long-term solution to capacity concerns and would mute the price signals the demand rate is designed to send. *Id.* JP19 states that WPAG's contention that demand response is a viable option is not based upon sound evidence. *Id.* at 5.

### **BPA Staff's Position**

The demand rate is based on cost estimates of the LMS100 gas turbine as the marginal capacity resource. Chalier *et al.*, BP-14-E-BPA-40, at 3. Staff disagreed with WPAG's proposal, noting that the demand response projects cited by WPAG are all small-scale, proof-of-concept, technology field test projects, not a long-term asset that would serve as a marginal capacity addition. *Id.*

### **Evaluation of Positions**

WPAG argues that BPA should base the marginal capacity resource used in the calculation of the demand rate on both demand response and the LMS100 gas turbine. WPAG Br., BP-14-B-WG-01, at 49. WPAG argues that both demand side management and combustion turbines are serving the region's marginal demand, and therefore, both resources ought to be included in the calculation of BPA's demand rate. *Id.* WPAG notes that marginal capacity turbines such as the LMS100 are higher-cost resources when compared to other alternatives such as demand response, and good utility practice dictates that a utility choose the least-cost marginal resource to meet its demand. *Id.* at 50. WPAG claims that by continuing to use the LMS100 as the sole measure of the marginal resource, BPA is overstating the demand rate and therefore is not sending a price signal that communicates the actual cost of capacity to serve its customers. *Id.*

JP19 counters WPAG's position, explaining that demand response is not a viable solution for the region's capacity needs. JP19 Br., BP-14-B-JP19-01, at 3. JP19 contends that peak demand will

be met by dispatchable thermal generating resources. *Id.* JP19 also points out that the Pacific Northwest Utilities Conference Committee (PNUCC) estimated that the region will need to acquire 2,000 to 3,000 MW of firm peak capacity for winter and summer peak demand over the next 10 years. *Id.* JP19 notes that PNUCC's estimate takes into account all the savings expected from demand-side programs, and it means the region needs new generating resources to maintain a reliable system. *Id.* JP19 states that PNUCC's estimate is consistent with those prepared by investor-owned utilities throughout the region. *Id.*

JP19 also argues that WPAG's proposal will mute the price signals the Demand Rate is intended to send. *Id.* at 4. JP19 states that WPAG's proposal is based upon anecdotal evidence of a call option and quotes from call options that undermine WPAG's assertions about the present viability of demand response as a capacity resource and would not allow BPA to recover the costs actually incurred to meet peak demand. *Id.* at 4. JP19 states that a lower rate encourages customers to place higher demands on BPA by muting the price signal that the demand rate is intended to send and would allow customers to avoid seeking other economical alternatives such as demand response. *Id.* at 5.

Staff also disagrees with WPAG's proposal of a 50/50 approach because demand response programs in the region cannot fully or partially represent a true marginal capacity resource. Chalier *et al.*, BP-14-E-BPA-40, at 5. Also, by WPAG's own admission, a majority of the 19 utilities cited that are undertaking demand response pilot programs are receiving or have received grants from BPA, which distorts the true economic costs of implementing demand response in the region. *Id.* at 4. Demand response in the Pacific Northwest currently is limited to small-scale, proof-of-concept, technology field test projects. *Id.* at 3.

The TRM ROD states that the objective of the demand charge is to pass on to BPA's customers the actual cost of capacity. TRM ROD, TRM-12-A-01, at 76. There seems to be little dispute over whether the LMS100 gas turbine represents the marginal resource. The question here is whether demand response is also a viable resource in today's market.

The marginal resource must reflect the costs BPA would face to acquire a capacity resource. *Id.* BPA recognizes that demand response is a utility resource that has the future potential to assist in managing and balancing peak loads with resources through time. BPA recognizes that demand response is more fully developed in other parts of the country. However, at this point in time, demand response in the Pacific Northwest has not developed to the point that it represents a viable capacity resource that would be used to meet load growth. All of the examples of demand response projects cited by WPAG to support its position are small pilot projects that are not sufficiently developed to be considered assets that could serve as capacity resources to serve future load. Consequently, demand response does not yet represent the actual cost of capacity that BPA would face.

BPA will continue to support efforts to develop demand response in the region and gain a market understanding of the economic costs and benefits associated with demand response and its impact to the region and its customers. However, given the infancy of demand response in the

Pacific Northwest, BPA will continue to use the LMS100 as its marginal capacity resource for calculating the demand rate for the FY 2014-2015 rate period.

### **Draft Decision**

*BPA will use solely the LMS100 as the marginal resource to calculate the demand rate in the FY 2014-2015 rate period. BPA will revisit this issue in future rate cases to ensure that the demand rate is based upon the appropriate capacity resource.*

## **2.5.4 Tier 2 Load Growth Rate Billing Adjustment**

### **Issue 2.5.4.1**

*Whether BPA should defer to the next rate period the collection of the net costs of the previously purchased power that is no longer needed to meet the forecast loads of the Load Growth customer pool.*

### **Parties' Positions**

WPAG opposes the Tier 2 Load Growth Rate Billing Adjustment (Billing Adjustment) for the FY 2014-2015 rate period. WPAG Br., BP-14-B-WG-01, at 43-48. WPAG argues that Staff has misinterpreted the spirit and letter of the TRM in its proposal. *Id.* at 44. WPAG argues that BPA should collect the Billing Adjustment costs from the Load Growth rate customers in the next rate period, once there are more customers in the pool with a billing determinant. *Id.* at 47. WPAG argues that the Billing Adjustment approach is more consistent with the letter of the TRM. *Id.*

### **BPA Staff's Position**

The cost of the Billing Adjustment should be allocated to the Load Growth rate customers in the pool that have above-RHWM load between zero and 8,760 MWh on a pro-rata basis, using their above-RHWM amounts as the allocator, in FY 2015. Chalier *et al.*, BP-14-E-BPA-17, at 9; Chalier *et al.*, BP-14-E-BPA-40, at 6.

### **Evaluation of Positions**

In the BP-12 rate case, BPA allocated 5 aMW of a 51 aMW power purchase completed in 2012 to the Tier 2 Load Growth rate for FY 2015. In the RHWM Process preceding the BP-14 rate case, it was determined that in FY 2015 the Tier 2 Load Growth obligation (1.673 aMW before real power losses) will be less than the 5 aMW of power purchased to meet the anticipated need for the Load Growth rate pool. The TRM states that the unneeded portion of the purchase is to be remarketed to other Tier 2 pools at current market rates. TRM, TRM-12S-A-03, at 27. The difference between the remarket value and BPA's purchase price will create a cost/credit for the remaining purchasers in the Load Growth Pool. *Id.* For FY 2015, the price for flat blocks of power is less than the price BPA paid in 2012, resulting in a net cost that should be allocated to the remaining Load Growth customers. Chalier *et al.*, BP-14-E-BPA-40, at 10. In 2015,

however, there is only one customer, meaning the entire shortfall could be borne by that single customer.

WPAG and Staff agree that allocating all the shortfall cost to one customer would produce an inequitable result. WPAG Br., BP-14-B-WG-01 at 47; Chalier *et al.*, BP-14-E-BPA-17, at 8-9. To solve this problem, WPAG argues, BPA should collect these costs from the Load Growth rate customers in the next rate period (*i.e.*, FY 2016-2017), once there are more customers in the pool with a billing determinant. WPAG Br., BP-14-B-WG-01, at 47. WPAG argues that the proposal to allocate the costs to customers that elected the Load Growth rate and have Above-RHWM loads below 8,760 MWh is inconsistent with the TRM. *Id.* at 46. WPAG states that the TRM “does not give BPA the latitude to charge preference customers Tier 2 costs through a Tier 2 rate when they are not purchasing power under their CHWM Contract to meet Above-RHWM Load.” *Id.* at 45. WPAG claims that the Billing Adjustment results in the costs being borne by customers that cannot purchase Tier 2 power and that are already paying for the limited Above-RHWM load through the Load Shaping rate. *Id.* WPAG also states that it is important to abide by the terms of the TRM even when it results in a “difficult situation”; otherwise it will become an “empty letter.” *Id.* at 47.

Staff believes that the proposal to allocate the shortfall costs to customers that have elected to serve their Above-RHWM Load at the Load Growth rate and currently have Above-RHWM load less than 8,760 MWh is consistent with the TRM. Chalier *et al.*, BP-14-E-BPA-40, at 6. The proposal would be consistent with the TRM because it attempts to collect the unrecovered costs from the pool of Load Growth customers on whose behalf BPA made the purchase initially. *Id.* at 8.

Allocating the shortfall to the lone member of the Tier 2 Load Growth pool is an inequitable result; therefore, the question becomes what is the best method to allocate these stranded costs consistent with the TRM. WPAG’s proposal to defer these costs to the next rate period when WPAG assumes there will be additional billing factors to spread the costs is speculative and inconsistent with BPA’s accounting policies and cost recovery rate directives under the Northwest Power Act. *See* WPAG Br., BP-14-B-WG-01, at 47; Chalier *et al.*, BP-14-E-BPA-40, at 9.

WPAG’s proposal to carry these costs to the next rate period ignores the fact that BPA cannot guarantee with any degree of certainty that there will be additional load served at the Load Growth rate in the next rate period. Chalier *et al.*, BP-14-E-BPA-40, at 9-10. BPA could again face the same dilemma in the next rate period if the number of customers in the Load Growth pool does not increase significantly. *Id.* at 9.

Even if one could know with some degree of certainty that there would be additional customers to spread the cost, the proposal is at odds with the rate directives of the Northwest Power Act. A fundamental principle under the Northwest Power Act is that BPA must set rates to recover its costs. 16 U.S.C. § 839e(a)(1). WPAG’s proposal to defer these costs to the next rate period directly conflicts with this core statutory obligation.

Additionally, BPA's Accounting for Regulatory Assets and Liabilities Policy, which is based on Financial Accounting Standards Board, Accounting Standards Codification 980, Regulated Operations, requires that costs incurred must be recoverable through rates for the regulated services or products. Chalier *et al.*, BP-14-E-BPA-40, at 9. Deferring the costs in the manner proposed by WPAG is inconsistent with this policy. While the Accounting Policy allows for certain costs to be deferred, it is done on a case-by-case basis and is reserved for large, unexpected, one-time expenditures. *Id.* The stranded costs associated with the Load Growth rate do not fit these requirements. These costs are relatively small (roughly \$50,000), are not unexpected, and could occur again in the future. *Id.*

WPAG's attempt to use the Oversupply Management Protocol as an example of BPA deferring costs is also misplaced. *See* WPAG Br., BP-14-B-WG-01, at 48. The Oversupply Management Protocol costs were deferred based on the fact these costs would be allocated based on decisions in the OS-14 Oversupply rate proceeding. As previously noted, the Load Growth costs lack certainty of recovery from potential future customers. Chalier *et al.*, BP-14-E-BPA-40, at 9-10. As compared to the OMP costs, these costs are not certain to be recovered in the next rate period and therefore cannot be deferred. *Id.* at 9.

BPA purchased the 5 aMW of power associated with this shortfall based upon notices provided by customers and forecast load. Chalier *et al.*, BP-14-E-BPA-17, at 10. Now that these customers no longer have the load to support the purchase means there is a cost associated with the remarketed power that BPA needs to recover. Allocating these costs to the customer pool on whose behalf BPA made the purchases in the period in which those costs are incurred is consistent with the cost causation principles embedded in the TRM. Rather than allocating to the lone Load Growth customer or the Composite cost pool, this proposal strikes a balance by allocating the costs to the pool of customers for which BPA incurred the costs.

### **Draft Decision**

*BPA will not defer to the next rate period the collection of the net costs of the previously purchased power that is no longer needed to meet the forecast loads of the Load Growth customer pool. The BP-14 Load Growth Rate Billing Adjustment will be adopted to collect the current costs from current customers.*

## **2.5.5 Unauthorized Increase in Demand for Slice**

### **Issue 2.5.5.1**

*Whether the definition of Slice customers' demand entitlement should be revised in the determination of the application of the Unauthorized Increase (UAI) charge for demand.*

### **Parties' Positions**

JP17 proposes calculating the Demand UAI charge based upon the difference between the actual Slice power delivery from BPA and the Slice Customer's demand entitlement based upon "the largest, final hourly feasible maximum generation amount associated with the final hourly Delivery Request (Right To Power) ... as such terms are defined in the Slice/Block CHWM Contract." JP17 Br., BP-14-B-JP17-01, at 3.

### **BPA Staff's Position**

BPA Staff proposes calculating the Demand UAI charge as the difference between the actual Slice power delivery from BPA for an hour and the customer's demand entitlement calculated using the largest final hourly Delivery Request (Right To Power). 2014 Power Rate Schedules and General Rate Schedule Provisions (FY 2014-2015), BP-14-E-BPA-09, at 94-95. The billing factor for Demand UAI should be calculated based on an actual requested amount rather than a theoretical amount. Chalier *et al.*, BP-14-E-BPA-40, at 24.

### **Evaluation of Positions**

The Demand UAI charge is assessed to any customer taking more power from BPA than it is contractually entitled to take. Chalier *et al.*, BP-14-E-BPA-40, at 23. The charge for Demand UAI is based on the amount of demand during a heavy load hour that exceeds the amount of demand the customer is contractually entitled to take. *Id.* JP17 proposes to calculate any Demand UAI based upon the "feasible maximum Slice delivery amount ... as ... defined in the Slice/Block CHWM Contract." JP17 Br., BP-14-B-JP17-01, at 3. JP17 thus advocates having any Demand UAI calculated based on the largest hourly amount a customer is entitled by contract to take. On the other hand, Staff proposes calculating the Demand UAI based on the customer's demand entitlement as defined by the customer's request for the hour in question. Chalier *et al.*, BP-14-E-BPA-40, at 23-24.

The Slice Water Routing Simulator, described in the Slice/Block CHWM Contracts, Exhibit M, is a computer model that simulates generation in the next hour, based on Slice customer requests. For each hour, the Simulator connects a customer's current final hourly simulated Right To Power to energy entitlement in future hours. *Id.* at 24. Thus, the computer program simulates real FCRPS operation where the turbine discharge (generation) at one project on one hour has downstream consequences in future hours. *Id.* at 24-25. The theoretical feasible maximum generation value as proposed by JP17, if realized as a Delivery Request in a Slice Customer's simulated operations for a given hour, would result in a different pattern of both future Delivery

Requests and computed feasible maximum generation amounts. *Id.* at 25. This different pattern is not consistent with the continuity in time required by the sequential hourly simulation of the Slice Water Routing Simulator. *Id.*

Slice customers are able to schedule power including capacity amounts for an hour based on their approved *requests* to BPA, which result from the Slice Water Routing Simulator. JP17's proposal seeks to have a Slice customer's demand entitlement for the UAI charge be based on "a[n] associated final hourly maximum capacity value up to which the Slice customer *could* have submitted or requested as a final hourly Delivery Request." JP17 Br., BP-14-B-JP-17-01, at 2 (emphasis in original). The distinction between the two proposals is whether the Demand UAI is based on what a customer might have submitted as its simulation, or on what was actually simulated for the customer based on its request.

JP17 argues that in a meeting or meetings connected with the BP-12 rate case, Staff provided a definition of demand entitlement that was based on the largest hourly maximum capacity. JP17 Br., BP-14-B-JP17-01, at 1-2; Wright *et al.*, BP-14-E-JP17-01, at 2. JP17 provides no evidence to support this proposition, but instead implies that the GRSPs fail to accurately reflect JP17's understanding of a definition provided in an unspecified meeting. Whether such a definition was ever provided or agreed to between BPA's Slice staff and Slice customers is mooted by the fact that the Administrator in the BP-12 ROD adopted a GRSP that did not include the definition of demand entitlement that was based on the largest hourly maximum capacity.

Demand UAI has evolved with the Slice product. In the BP-12 GRSP the Demand UAI was stated as: "For a Slice customer, the demand in excess of its demand entitlement is any excess Slice delivered amount on the highest Slice delivery hour during the HLH period of the month." 2012 Power Rate Schedules and General Rate Schedule Provisions (FY 2012-2013), at 91. This definition was expanded in the BP-14 Initial Proposal to clarify that excess demand would be measured for Slice using the Right To Power as calculated by the Slice Water Routing Simulator. 2014 Power Rate Schedules and General Rate Schedule Provisions (FY 2014-2015), BP-14-E-BPA-09, at 94-95. This change was made possible because the Slice Water Routing Simulator went live in October 2012, one year after the product was initialized and after the close of the BP-12 rate case.

The Initial Proposal considered the technical implementation of the Simulator and the computations of a customer's hourly Right to Power and characterized the UAI measurement as: "(i) the largest, hourly amount of Slice power delivery from BPA for any HLH hour of a month (tagged + untagged energy), minus (ii) the largest, final hourly Delivery Request (Right To Power) computed using the Slice Water Routing Simulator for any HLH of the same month...." *Id.*

The use of feasible maximum generation as JP17 proposes would base the determination of Demand UAI on a theoretical measurement. However, the purpose of the Simulator is for each customer to benefit from, or endure, the consequence of its prior simulations of FCRPS operation. Chalier *et al.*, BP-14-E-BPA-40, at 25. Using the theoretical feasible maximum

generation amount is inconsistent with the intended UAI design to assess a penalty for excess amounts measured against what was taken by the customer and not against an amount the customer might have taken.

As an additional matter, Staff noted that Demand UAI treatment for Slice customers was different from that used for Load Following customers. Chalier *et al.*, BP-14-E-BPA-40, at 25-26. In the Initial Proposal the treatment of Demand UAI for Slice customers was not based upon a single hour comparison and thus was not on the same time-basis as the treatment of Demand UAI used for Load Following customers. 2014 Power Rate Schedules and General Rate Schedule Provisions (FY 2014-2015), BP-14-E-BPA-09, at 94-95. Staff addressed this difference in its rebuttal testimony and proposed an adjustment. Chalier *et al.*, BP-14-E-BPA-40, at 25-26.

In the Load Following product the excess demand is tied to the Customer System Peak (CSP) hour for a given month. This means that the Demand UAI billing determinant occurs on the same hour of the month as the CSP hour. The Initial Proposal Slice Demand UAI treatment allowed two different hours to be used for computing any delivery excess. The JP17 proposal also allows the use of two different hours and therefore has the same infirmity. See Wright *et al.*, BP-14-E-JP17-01, at 4.

Staff proposed a correction for the discrepancy it found, a modification to the timing method based on a single hour to make the timing for Slice customers the same as that for Load Following customers. Chalier *et al.*, BP-14-E-BPA-40, at 26-27. This approach reduces the disparity between the time-basis for assessing a Demand UAI among preference customers taking power service and allows the application of the Demand UAI to operate as a disincentive for excess power actually taken.

### **Draft Decision**

*The revisions proposed by JP17 to the definition of Slice customers' demand entitlement to describe application of the Unauthorized Increase charge for demand will not be made. Rather, Right To Power as defined by BPA Staff will be used for purposes of computing Demand UAI for Slice customers. Additionally, the time-basis for determining Slice and Load Following customers' demand and entitlement amounts will be conformed.*

### **3.0 GENERATION INPUTS AND THE ANCILLARY AND CONTROL AREA SERVICES RATE SCHEDULE**

The purpose of the generation inputs portion of the rate proceeding is to assign certain power costs from Power Services to Transmission Services. Many products and services that Transmission Services provides to its customers require generation to supply capacity or energy. This generation is referred to as generation inputs, and these inputs are necessary for most of the ancillary and control area services that Transmission Services provides under its Open Access Transmission Tariff.

On May 15, 2013, the Administrator signed and issued a final ROD adopting a partial settlement of generation inputs and certain transmission ancillary and control area services rates. Administrator's Record of Decision on Settlement Proposal for Generation Inputs and Transmission Ancillary and Control Area Services Rates, BP-14-A-01. The ROD covers the rates for Regulation and Frequency Response, Variable Energy Resource Balancing Service (VERBS), Dispatchable Energy Resource Balancing Service (DERBS), Operating Reserve – Spinning and Operating Reserve – Supplemental, Energy Imbalance and Generation Imbalance. These rates were adopted in the Record of Decision on the Settlement Proposal for Generation Inputs and Transmission Ancillary and Control Area Services Rates and, therefore, are not addressed in this Draft ROD.

Generation inputs also includes certain cost assignments for specific services that Transmission either requires to maintain system reliability or offers to its customers. These generation inputs include Synchronous Condensing, Generation Dropping, Redispatch, and Station Service. The final Generation Inputs Study will include the quantity forecast for each product and the methodology for allocating those costs associated with that product. The inter-business line assignment of costs also includes the segmentation of U.S. Corps of Engineers and U.S. Bureau of Reclamation transmission facilities. These segmented costs are not a generation input, but they are a cost in the Power Services' revenue requirement that is assigned to Transmission Services. No party raised issues related to these generation inputs or inter-business line assignments in this proceeding

**This page intentionally left blank.**

## 4.0 TRANSMISSION TOPICS

### 4.1 Transmission Segmentation

#### 4.1.1 Introduction

Segmentation is the process whereby BPA assigns its transmission facilities to “segments” based on the types of services those facilities provide and then assigns to each segment the investment and historical operations and maintenance (O&M) expenses associated with the facilities in that segment. Messinger *et al.*, BP-14-E-BPA-29, at 2. The segmented investment and historical O&M are then used to apportion the transmission revenue requirement among the various segments for the purpose of setting rates to recover the assigned costs. *Id.* at 2-3.

For the FY 2014–2015 rate period, BPA Staff proposes seven segments: Generation Integration, Integrated Network, Southern Intertie, Eastern Intertie, Utility Delivery, Direct Service Industry (DSI) Delivery, and Ancillary Services. Transmission Segmentation Study, BP-14-E-BPA-06, at 1-5; Transmission Segmentation Documentation, BP-14-E-BPA-06A; Messinger *et al.*, BP-14-E-BPA-29, at 3.

One aspect of Staff’s proposal drew both strong opposition and support. Staff proposes using a 34.5 kV bright-line threshold for separating facilities between the Integrated Network and Utility Delivery segments. Transmission Segmentation Study, BP-14-E-BPA-06, at 4, 6; Messinger *et al.*, BP-14-E-BPA-29, at 3-4. JP06, JP12, MSR, and Powerex oppose this proposal, while JP03 and WPAG support it. The 34.5 kV bright-line threshold for segmentation originated in a non-precedential settlement of the 1996 transmission rate case and has been perpetuated through non-precedential settlements of the subsequent transmission rate cases prior to this proceeding.

JP12 makes a counterproposal regarding what facilities should comprise the Integrated Network segment. JP12 Br., BP-14-B-JP12-01, at 16-17; Hanser *et al.*, BP-14-E-JP12-01, at 25-30.

#### 4.1.2 Transmission Segmentation Approach for the FY 2014–2015 Rate Period

##### Issue 4.1.2.1

*Whether BPA should adopt JP12’s segmentation proposal to remove all facilities below 116 kV from the Integrated Network and to use the Commission’s Seven Factor Test to determine which facilities above that threshold should be removed from the Integrated Network.*

##### Parties’ Positions

JP12 proposes a two-step segmentation process for determining which facilities should be in the Integrated Network segment. JP12 Br., BP-14-B-JP12-01, at 16-17. Under JP12’s proposed segmentation, BPA would begin with the Bulk Electric System (BES) definition of 100 kV and above, but replace that threshold with a 116 kV “soft” threshold. Oral Tr. 287; JP12 Br., BP-14-B-JP12-01, at 16-17. Facilities that do not meet the BES definition would not be included in the

Integrated Network segment. BPA would then apply the Commission's Seven Factor Test to the remaining facilities to eliminate any that serve a distribution-like purpose. *Id.* at 16. According to JP12's analysis, this proposal would result in removing approximately \$714 million of investment and \$24 million of O&M from the Integrated Network segment. *Id.* at 7.

Powerex argues that BPA should adopt JP12's segmentation proposal because it is more consistent with cost causation and the concept of an integrated network than Staff's proposal. Powerex Br., BP-14-B-PX-01, at 23-24. Powerex requests that BPA analyze the customer rate impacts of JP12's proposal. *Id.* at 24-25. Powerex suggests that the facilities that are removed from the Integrated Network segment could be assigned to the Utility Delivery segment, assigned to a new segment, or directly assigned to the customers using the individual facilities. *Id.* at 24. Powerex suggests that BPA could use transmission reserves or phase in the rate impacts over a number of rate periods to mitigate the financial impact of JP12's proposal. *Id.* at 25.

JP03 and WPAG strongly oppose JP12's proposal and raise several arguments against adopting it:

- JP12's proposal is inconsistent with BPA's historical mission of rural electrification and providing for the most widespread use of Federal power. JP03 Br., BP-14-B-JP03-01, at 4-9; WPAG Br., BP-14-B-WG-01, at 5-10.
- JP12's proposal is inconsistent with BPA's uniform rate policy. JP03 Br., BP-14-B-JP03-01, at 10-13; WPAG Br., BP-14-B-WG-01, at 12-13.
- The Commission's Seven Factor Test does not apply to BPA, since it is a non-jurisdictional entity that provides only wholesale transmission service. JP03 Br., BP-14-B-JP03-01, at 15-16; WPAG Br., BP-14-B-WG-01, at 14-15.
- The BES definition applies to system reliability and has no application to BPA ratemaking. JP03 Br., BP-14-B-JP03-01, at 16-17; WPAG Br., BP-14-B-WG-01, at 16.
- The facilities that JP12's analysis determines to be distribution-like are actually transmission facilities. JP03 Br., BP-14-B-JP03-01, at 17-19.

### **BPA Staff's Position**

Staff proposes using a 34.5 kV bright-line threshold for separating facilities between the Integrated Network and Utility Delivery segments. Transmission Segmentation Study, BP-14-E-BPA-06, at 4, 6; Messinger *et al.*, BP-14-E-BPA-29, at 3-4. Staff raises several concerns regarding JP12's proposal:

- JP12's proposal is inconsistent with BPA's mission of rural electrification and promotion of the most widespread use of electric power in the Pacific Northwest. Bliven *et al.*, BP-14-E-BPA-42, at 20. JP12's proposal is also inconsistent with BPA's longstanding uniform rates policy, which BPA adopted to achieve widespread use of electric power. *Id.*
- Many of the facilities that JP12 argues perform a distribution-like function are transmission facilities. *Id.* at 20-27, 33.

- JP12 focuses on Factors 1, 2, 3, 5, and 7 of the Seven Factor Test in its analysis of BPA’s lower-voltage facilities. It does not analyze Factor 4—when power enters a local distribution system, it is not reconsigned or transported on to some other market—and Factor 6—meters are based at transmission/local distribution interface—which indicate that facilities it would exclude from the Network segment predominantly serve a transmission function. *Id.* at 31.
- The BES definition generally relates to the reliability of higher-voltage facilities to ensure interconnected security of the grid. *Id.* at 41-44. It has not been used for ratemaking purposes. *Id.*
- Although Commission policy preferring rolling the costs of facilities into network rates is not binding on BPA, JP12’s proposal to carve out a large portion of facilities from the Integrated Network segment is likely not consistent with that policy. *Id.* at 49-52.
- JP12’s proposal could undermine BPA’s ability to plan and build transmission facilities based on engineering and financial considerations designed to lead to the maximum efficiency and cost-effectiveness of the grid. *Id.* at 26-27 and 53-54.
- JP12’s analysis contains errors and data gaps that would need to be addressed before JP12’s proposal could be adopted. *Id.* at 53.
- JP12’s proposal would likely increase the number of transfer customers’ points of delivery (PODs) subject to the GTA Delivery Charge. *Id.* at 55 (citing Yokota and Miller, BP-14-E-BPA-41, at section 5).

### **Evaluation of Positions**

JP12’s alternative segmentation addresses only the composition of the Integrated Network segment. JP12’s segmentation, based on its analysis, would remove approximately \$714 million of investment and \$24 million of historical O&M from Staff’s proposed Integrated Network segment. JP12 Br., BP-14-B-JP12-01, at 7. While there is no analysis in the record detailing the rate impact to customers, customers taking delivery of power at lower voltages (34.5 to 115 kV) would likely bear the brunt of removing these facilities from the Integrated Network segment. JP12 does not indicate the segment into which it would place the facilities that do not pass its functional test, but Powerex provides three possibilities: roll them into the Utility Delivery segment, create a new segment, or directly assign them to the customers using them. Powerex Br., BP-14-B-PX-01, at 24. There was not sufficient time in this proceeding for Staff or other parties to analyze these possibilities, their viability, and their rate impacts.

Staff, JP03, and WPAG also raise serious questions regarding whether JP12’s proposal is consistent with the most widespread use requirement set forth in section 6 of the Bonneville Project Act and section 10 of the Transmission System Act. Bliven *et al.*, BP-14-E-BPA-42, at 20; JP03 Br., BP-14-B-JP03-01, at 12-13; WPAG Br., BP-14-B-WG-01, at 5-10. JP12’s proposal would likely allocate more costs to smaller, more rural customers than is currently the case. Therefore, the proposal raises concerns that are difficult to address without further analysis and discussion in the region to determine if it is consistent with the most widespread use requirement.

JP12's proposal also raises serious questions about whether BPA should abandon its uniform rates policy. BPA is not required to adopt uniform rates, but it has done so for the most part throughout its history. Bliven *et al.*, BP-14-E-BPA-42, at 11-13; JP03 Br., BP-14-B-JP03-01, at 10-13; WPAG Br., BP-14-B-WG-01, at 5-10. While BPA has discretion regarding the form of rates it may adopt, section 6 of the Bonneville Project Act and section 9 of the Transmission System Act require that BPA's rates promote the most widespread use of power in the Pacific Northwest. There is no evidence in the record demonstrating that JP12's proposal promotes the most widespread use of power.

JP12 focuses its analysis on Factors 1, 2, 3, 5 and 7. Hanser *et al.*, BP-14-E-JP12-01, at 30-33. JP12 does not analyze Factor 4—when power enters a local distribution system, it is not reconsigned or transported on to some other market—and Factor 6—meters are based at transmission/local distribution interface—which indicate that BPA's lower-voltage (34.5 to 115 kV) facilities predominantly serve a transmission function. Bliven *et al.*, BP-14-E-BPA-42, at 31. While the Seven Factor Test allows for the weighing of the factors in determining whether a facility serves a transmission or distribution function, the record demonstrates that a full and thorough analysis of all the factors is needed before this type of functional approach is adopted for segmentation. Hanser *et al.*, BP-14-E-JP12-01, at 32; Bliven *et al.*, BP-14-E-BPA-42, at 31. Moreover, such a review would also resolve the errors and data gaps identified in JP12's analysis. Bliven *et al.*, BP-14-E-BPA-42, at 53.

Staff and JP03 dispute JP12's determination that the lower-voltage facilities rolled into the Network serve a distribution-like function. *Id.* at 20-27, 33; JP03 Br., BP-14-B-JP03-01, at 4, 17-19. This dispute is addressed in Issue 4.1.3.4, below.

JP12 does not exclude from the Integrated Network higher-voltage facilities that perform functions similar to those performed by the lower-voltage facilities that it excludes from the Integrated Network segment. Bliven *et al.*, BP-14-E-BPA-42, at 25-26. Assuming that BPA were to adopt JP12's proposed functional analysis, it should be applied to all of BPA's transmission facilities, because there are higher-voltage facilities that effectively serve the same function as the lower-voltage facilities that JP12 proposes to exclude. *Id.* The 230 kV facilities serving Seattle City Light provide one such example. *Id.* Thus, further work would need to be performed before adopting JP12's proposal to ensure that it is being applied fairly and consistently throughout the Pacific Northwest.

JP12's proposal would likely increase the number of transfer customers' PODs subject to the GTA Delivery Charge, which is also a concern. *Id.* at 55 (citing Yokota and Miller, BP-14-E-BPA-41, at section 5). The GTA Delivery Charge is a charge for deliveries of Federal power made over a third-party transmission system at voltages below 34.5 kV. Miller and Yokota, BP-14-E-BPA-20, at 2. Under the Agreement Regarding Transfer Service (ARTS), BPA committed to acquire and pay for the transmission of Federal power to customers served by transfer over non-BPA facilities for a period of 20 years. Yokota and Miller, BP-14-E-BPA-41, at 7. As part of this agreement, BPA also committed to initially propose to roll in the costs of these transfer acquisitions to the PF rate. *Id.* BPA is obligated to roll into the PF rate only the costs of acquiring Transfer Service over the *type* of facilities that Transmission Services includes

in its Integrated Network segment. *Id.* A change in segmentation, such as JP12 proposed, would likely trigger GTA cost shifts. Thus, further analysis on GTA impacts would need to be performed before adopting JP12's proposal.

### **Draft Decision**

*JP12's segmentation proposal will not be adopted for the FY 2014–2015 rate period.*

### **Issue 4.1.2.2**

*Whether BPA should adopt Staff's segmentation proposal, including the 34.5 kV bright-line threshold, for transmission segmentation.*

### **Parties' Positions**

As described in more detail in section 4.1.3 below, JP06, JP12, Powerex, and MSR generally oppose the 34.5 kV bright-line threshold, while JP03 and WPAG support it. The opposing parties argue that the threshold:

- (1) does not comply with equitable cost allocation requirements;
- (2) does not comply with general cost causation principles;
- (3) does not comply with the Integrated Network segment definition;
- (4) is not supported by any analysis;
- (5) inappropriately relies on the non-precedential settlement of the 1996 rate case;
- (6) is inconsistent with BPA's Average System Cost Methodology; and
- (7) is inconsistent with statements made by BPA in other forums.

In addition to opposing the 34.5 kV bright-line threshold, JP06 contends that BPA could reconstitute the former Fringe segment as a "sub-transmission" segment for which only the customers that use such facilities are charged, regardless of whether those facilities are used to transmit Federal or non-Federal power. JP06 Br., BP-14-B-JP06-01, at 6.

JP12 argues that the record does not include substantial evidence to support BPA Staff's segmentation proposal. JP12 Br., BP-14-B-JP12-01, at 6-7.

JP12 and Powerex state that if BPA adopts Staff's proposal for this rate period, BPA should not preclude the use of a functional analysis in the future and should establish a series of workshops and technical conferences to discuss the applicability of such analysis and possible cost recovery methods. JP12 Br., BP-14-B-JP12-01, at 24-25; Powerex Br., BP-14-B-PX-01, at 24.

MSR suggests that BPA adopt Staff's proposal for this rate period but initiate a new segmentation analysis using JP12's functional approach immediately upon the conclusion of this rate case. MSR Br., BP-14-B-MS-01, at 10-11; Arthur, BP-14-E-MS-01, at 35.

### **BPA Staff's Position**

BPA Staff proposes seven segments—Generation Integration, Integrated Network, Southern Intertie, Eastern Intertie, Utility Delivery, Direct Service Industry (DSI) Delivery, and Ancillary Services—for the FY 2014–2015 rate period. Transmission Segmentation Study, BP-14-E-BPA-06, at 1-5; Transmission Segmentation Documentation, BP-14-E-BPA-06A; Messinger *et al.*, BP-14-E-BPA-29, at 3. Staff's proposal includes a 34.5 kV bright-line threshold to distinguish between facilities in the Integrated Network and Utility Delivery segments. Messinger *et al.*, BP-14-E-BPA-29, at 3. This segmentation proposal equitably allocates costs between Federal and non-Federal uses. Bliven *et al.*, BP-14-E-BPA-42, at 39.

There is not sufficient time to conduct a comprehensive analysis of JP12's proposal for this rate period. *Id.* at 56. Should the Administrator determine to further consider JP12's proposal, Staff recommends that he give all stakeholders the opportunity to participate in formulating a cost recovery mechanism. *Id.*

### **Evaluation of Positions**

Section 4.1.3 below addresses and analyzes the issues raised in this proceeding regarding the 34.5 kV bright-line threshold. The conclusions in section 4.1.3 are that the threshold:

- (1) complies with equitable cost allocation requirements (*see* Issue 4.1.3.1);
- (2) complies with general cost causation principles (*see* Issue 4.1.3.2);
- (3) is consistent with BPA's longstanding uniform rate policy (*see* Issue 4.1.3.3);
- (4) complies with the segment definition (*see* Issue 4.1.3.4);
- (5) is supported by analysis (*see* Issue 4.1.3.5);
- (6) does not rely on the non-precedential settlement of the 1996 rate case (*see* Issue 4.1.3.6);
- (7) is consistent with BPA's Average System Cost Methodology (*see* Issue 4.1.3.7); and
- (8) is consistent with statements made by BPA in other forums (*see* Issue 4.1.3.8).

While BPA is not required to implement uniform rates, section 6 of the Bonneville Project Act and section 10 of the Transmission System Act expressly provide that BPA may adopt uniform rates as a means of complying with the "most widespread use" requirement in section 6 of the Bonneville Project Act and section 9 of the Transmission System Act.

JP06 contends that Fringe facilities could be reconstituted as a separate segment regardless of whether those facilities are used to transmit Federal or non-Federal power, since they serve a subset of customers. JP06 Br., BP-14-B-JP06-01, at 6. However, JP06 offers no basis on which to make such a decision other than that these facilities served a "subset" (preference customers) prior to 1996. Adding this segment would result in some of BPA's customers paying a pancaked rate (one rate for Network and another rate for the Fringe) based only on the customer's choice of power supplier *prior* to 1997, without any regard to the sources of power the customer uses today. As described in Issue 4.1.3.1 below, beginning in 1996 preference customers executed transmission service agreements under BPA's tariff to transmit power over BPA's transmission system to their load centers. They can transmit Federal and non-Federal power under those agreements. The distinction that the Fringe segment was premised on is no longer relevant.

As explained in section 4.1.2.1 above, the parties that oppose the Staff proposal raise policy alternatives that require further analysis regarding impacts to customers. The record in this case (see section 4.1.3 below) demonstrates that Staff's proposed segmentation meets BPA's statutory requirements and policy goals. There are many instances throughout BPA's ratemaking history where ideas have been raised but not fully developed in a rate proceeding, and subsequent consultations have been held for further review after the conclusion of the proceeding. Segmentation is one such issue that will benefit from further consideration outside the confines of a rate proceeding.

### **Draft Decision**

*The 34.5 kV bright-line threshold meets BPA's statutory requirements and policy goals and will be adopted for segmenting the transmission system for the FY 2014–2015 rate period. This decision is based on an assessment of the evidence and the law. The substantial evidence test raised by JP12 in its initial brief applies to appellate review and, therefore, is not explicitly addressed in this decision. See section 1.3.3 above for further discussion. BPA does not preclude the use of an alternative segmentation in the future. Before the next rate case BPA will engage the region regarding the segmentation policy.*

## **4.1.3 Issues Regarding the 34.5 kV Bright-Line Threshold**

### **Issue 4.1.3.1**

*Whether a 34.5 kV bright-line threshold complies with equitable cost allocation under section 7(a)(2)(C) of the Northwest Power Act, 16 U.S.C. § 839e(a)(2)(C), and section 10 of the Transmission System Act, 16 U.S.C. § 838h.*

### **Parties' Positions**

JP06, JP12, and Powerex argue that the 34.5 kV bright-line threshold violates section 7(a)(2)(C) of the Northwest Power Act and section 10 of the Transmission System Act, which require BPA to equitably allocate transmission costs between Federal and non-Federal power utilizing the transmission system. JP06 Br., BP-14-B-JP06-01, at 13-15; JP12 Br., BP-14-B-JP12-01, at 10-11; Powerex Br., BP-14-B-PX-01, at 22-23. Their argument is premised on the notion that the equitable allocation requirement is met by demonstrating that BPA's rates are consistent with general cost causation principles. JP12 Br., BP-14-B-JP12-01, at 10-11; Powerex Br., BP-14-B-PX-01, at 22-23; Oral Tr. 287. JP12 and Powerex argue that the 34.5 kV bright-line threshold is not equitable because it violates general cost causation principles. JP12 Br., BP-14-B-JP12-01, at 10-11; Powerex Br., BP-14-B-PX-01, at 22-23. According to JP12 and Powerex, the 34.5 kV bright-line threshold requires network customers to inappropriately subsidize other customers, because facilities used by only a subset of customers will be rolled into the Integrated Network segment. JP12 Br., BP-14-B-JP12-01, at 10-11; Powerex Br., BP-14-B-PX-01, at 22-23. Powerex also cites Staff testimony prepared in the 1985 rate case as evidence that in the past BPA has equated the equitable allocation requirement with general cost causation

principles for purposes of segmentation. Powerex Br., BP-14-B-PX-01, at 22 (citing Revitch, WP-85-E-BPA-27, at 16).

JP06 argues that the 34.5 kV bright-line threshold does not meet the equitable allocation requirement because it inappropriately rolls former Fringe segment facilities into the Integrated Network. JP06 Br., BP-14-B-JP06-01, at 15. The premise of JP06's argument is as follows: the Fringe facilities were used exclusively to deliver power to preference power customers prior to 1996 and continue to serve only preference power customers, so they should not be rolled into the Integrated Network segment for this rate period. *Id.* JP06 asserts that the costs of these facilities should be allocated to a separate "sub-transmission" segment. *Id.* Powerex asserts more generally that because rates are artificially lowered for Federal power customers when non-integrated facilities are rolled into the Integrated Network, Federal power is advantaged over non-Federal power. Powerex Br., BP-14-B-PX-01, at 23.

JP03 and WPAG argue that the 34.5 kV bright-line threshold meets the equitable allocation requirement. JP03 Br., BP-14-B-JP03-01, at 13-14; WPAG Br., BP-14-B-WG-01, at 11-13. WPAG asserts that compliance with this requirement is met as long as BPA can show that its rates do not favor either Federal or non-Federal power using the transmission system. WPAG Br., BP-14-B-WG-01, at 11. JP03 and WPAG assert that the use of a uniform rate for all customers demonstrates that BPA meets this requirement. JP03 Br., BP-14-B-JP03-01, at 13-14; WPAG Br., BP-14-B-WG-01, at 13.

JP03 and WPAG note that traditional preference power customers have been diversifying their portfolio of resources since 1996 to include more non-Federal generation. JP03 Br., BP-14-B-JP03-01, at 14; WPAG Br., BP-14-B-WG-01, at 11-12. A key policy driver of the Regional Dialogue contracts is to encourage preference customers to secure more non-Federal power to serve their loads. *Id.* As a result, the lower-voltage facilities used to serve these customers no longer deliver only Federal power. *Id.*

### **BPA Staff's Position**

All transmission customers pay the same rates for the same service, so neither Federal nor non-Federal power is advantaged. Bliven *et al.*, BP-14-E-BPA-42, at 39. Moreover, public power customers that traditionally have used lower-voltage transmission facilities to receive Federal power to serve their loads began diversifying their power supplies in 1996 to include non-Federal generation. *Id.* Today, 73 of 133 preference power customers are taking some amount of non-Federal power. *Id.* at 40. Staff's analysis shows that 91 percent of 34.5 kV points of delivery (PODs), 67 percent of 50-69 kV PODs, and 82 percent of 100-115 kV PODs are used for non-Federal power deliveries. *Id.*

### **Evaluation of Positions**

Section 7(a)(2)(C) of the Northwest Power Act and section 10 of the Transmission System Act require BPA to equitably allocate the costs of the Federal transmission system between Federal and non-Federal power utilizing the system. Section 7(a)(2)(C) requires the Commission to find that BPA's transmission rates meet this requirement before it can approve them. In determining

whether costs are equitably allocated, the Commission has found that BPA's rates are equitably allocated when its ratesetting follows common utility practices and reaches reasonable results. *United States Dep't of Energy – Bonneville Power Admin.*, 39 FERC ¶ 61,078, at 61206, 61209 (1987).

Use of the transmission system has changed significantly since the time when only preference power customers used lower-voltage facilities for the delivery of Federal power. Prior to 1996, BPA's sole criterion for distinguishing between Fringe and Integrated Network facilities was the *deemed* source of power using the facilities, not the functional or operational characteristics of the facilities. Bliven *et al.*, BP-14-E-BPA-42, at 15. BPA segmented facilities that delivered only Federal power to the Fringe segment and included the costs of such facilities in power rates. *Id.* at 15-17; *see also* JP03 Br., BP-14-B-JP03-01, at 13-14; WPAG Br., BP-14-B-WG-01, at 11-12. For all intents and purposes, BPA held the transmission rights on BPA's system to transmit power to preference customers' loads, and most preference customers relied almost exclusively on Federal power to serve their loads. Bliven *et al.*, BP-14-E-BPA-42, at 15-16. Some preference customers used non-Federal resources to serve their loads. Facilities used to transmit power for these customers were included in the Integrated Network rather than the Fringe, and those customers were charged network wheeling rates for that use. *Id.*

In 1996, BPA unbundled its power and transmission rates and began delivering Federal power at the Federal busbar. *Id.* Preference customers were required to secure transmission service under BPA's open access tariff to transmit power to their loads. *Id.* An increasing number of preference customers began purchasing non-Federal power to serve their loads. *Id.*; JP03 Br., BP-14-B-JP03-01, at 14; WPAG Br., BP-14-B-WG-01, at 11-12. BPA's Tiered Rate Methodology and Regional Dialogue contracts continue this trend by encouraging preference customers to secure more non-Federal power to serve portions of their loads. Bliven *et al.*, BP-14-E-BPA-42, at 40-41; JP03 Br., BP-14-B-JP03-01, at 13-14; WPAG Br., BP-14-B-WG-01, at 11-12. Staff's analysis shows that 73 of 133 preference power customers are taking some amount of non-Federal power today, and 91 percent of 34.5 kV PODs, 67 percent of 50–69 kV PODs, and 82 percent of 100–115 kV PODs are currently used for non-Federal power deliveries. Bliven *et al.*, BP-14-E-BPA-42, at 40.

Staff explains how segmentation plays a role in equitable allocation:

Before 1996, it played an important role. Transmission costs assigned to Federal power were recovered in bundled power rates. Transmission costs assigned to non-Federal power were recovered through transmission rates. Thus, Federal and non-Federal power paid different rates, and it was important to ensure equitable allocation through segmentation and allocation.

As we described earlier, beginning in 1996, conditions in the electric utility industry changed. Unbundled power rates, open access transmission, and comparability resulted from national policies intended to ensure that transmission providers charged other users of their systems the same rates they charged themselves. BPA implemented this policy by removing transmission costs from

power rates, signing open access transmission contracts with power customers, and charging all users the same rates for transmission service.

With these changes, the focus of segmentation changed from identifying the Network segment based on facilities that were used by both Federal and non-Federal power to a Network segment based on the facilities necessary to provide transmission service to all customers.

*Id.* at 39. Thus, segmentation that classifies (or segments) facilities based on Federal and non-Federal uses to ensure equitable allocation is no longer appropriate and, therefore, is not used today.

JP06 mischaracterizes how BPA determined which facilities were included in the Fringe segment by stating that this determination was based on the type of customer (preference and non-preference) served by those facilities. *See* JP06 Br., BP-14-B-JP06-01, at 15. While it is true that preference power customers used the Fringe to transmit Federal power prior to 1996, the determination of which facilities were segmented to the Fringe was not based on the type of customer; rather, it was based on the power transmitted over those facilities being deemed to have been sourced at a Federal generator. Prior to 1996, if a preference customer was wheeling non-Federal power, the facilities used by that customer were included in the Network segment. For example, the 69 kV lines serving the City of Milton-Freewater, a preference customer, were segmented to the Network segment before 1996 because they were used, as they are today, to wheel non-Federal power from the Priest Rapids and Wanapum projects to the city's load center. *Bliven et al.*, BP-14-E-BPA-42, at 36-37. Therefore, JP06 is incorrect in focusing on the type of customer.

JP06 argues that the number of customers using a facility was a determining factor for Fringe designation and that each facility in the Fringe was built for the benefit of one or a handful of BPA's customers. JP06 Br., BP-14-B-JP06-01, at 15, 19. This is also incorrect. The number of customers served from the facilities was not a factor in designating Fringe facilities. The Network facilities connecting Milton-Freewater serve only Milton-Freewater and one other customer. Despite this, the facilities were designated as Network facilities based on their use to wheel non-Federal power.

Thus, if the Fringe segment had been removed prior to 1996, the facilities comprising the Fringe segment would likely have been consolidated into a segment that closely resembles the Integrated Network segment proposed in this case. In addition, if the criterion for segmenting facilities to the Fringe was applied to today's transmission system, most of the facilities formerly in the Fringe segment would now be in the Integrated Network segment, because the customers using these facilities are wheeling non-Federal power over them. Therefore, JP06's assertion that BPA should continue distinguishing between Fringe and Network is unavailing.

The statutory requirement is to equitably allocate between Federal and non-Federal power using the transmission system. The premise of JP06's argument is that because the Fringe facilities were used exclusively to deliver power to preference power customers, they should not be rolled

into the Integrated Network. JP06 Br., BP-14-B-JP06-01, at 15. JP06 focuses on the customer using the system, not the source of power. The statutory requirement is not to equitably allocate between preference and non-preference customers; it is to equitably allocate between Federal and non-Federal uses.

Allocating between Federal and non-Federal uses also comports with the Administrator's discretion under section 10 of the Transmission System Act. Under that section, the Administrator's transmission rates may provide for uniform rates or rates uniform throughout prescribed transmission areas. All users pay the uniform rate, but how much they pay depends on their use. If Federal use is greater, Federal use will recover more of the costs of the transmission system; if Federal use is less, it will recover less. The same holds for non-Federal use. That is the ultimate test of equitable allocation.

JP12 and Powerex equate BPA's equitable allocation requirement with general cost causation principles. JP12 Br., BP-14-B-JP12-01, at 10-11; Powerex Br., BP-14-B-PX-01, at 22-23; Oral Tr. 287. The requirement is not so broad as to encompass all questions of cost causation, however. Rather, the requirement relates specifically to the allocation of costs between Federal and non-Federal power. 16 U.S.C. §§ 839(a)(2)(C) and 838h. The statutory requirement does not address questions of equity among customers, voltage of facilities used, choice of network service (PTP or NT), or other factors not related to distinguishing between Federal and non-Federal power.

Powerex cites BPA Staff testimony prepared in the 1985 rate case as evidence that BPA has previously equated equitable allocation requirements with general cost causation principles for purposes of segmentation. Powerex Br., BP-14-B-PX-01, at 22 (citing Revitch, WP-85-E-BPA-27, at 16). Responding to a question asking whether BPA's Cost of Service Analysis (COSA) performed in the 1985 case equitably allocates costs between Federal and non-Federal users, Staff said that:

The segmentation process used in the COSA demonstrates an intent to identify the various parts of the FCRTS so that customer classes are charged only for portions of the system that are used to serve their loads. The allocation process demonstrates an intent to charge customer classes only for their use of individual FCRTS segments in relation to total use of a segment. The measurement of use of the system reflects cost causation, and such measurement of use is applied consistently to all customers, both Federal and non-Federal, who use the various segments of the FCRTS.

Revitch, WP-85-E-BPA-27, at 16. This testimony from the 1985 rate case established that charging transmission users for the segments of the transmission system they were using reflects both cost causation and equitable allocation of transmission costs between Federal and non-Federal power using the system. This is still true today: transmission customers continue to be charged for only the segments of the transmission system they use. The only difference today is with the facilities that comprise the Integrated Network segment. In 1985, many, but not all, of the facilities that JP12 and Powerex contend should be excluded from the Integrated Network

segment were in the Fringe segment. However, a number of the facilities that JP12's analysis identifies as local distribution were in the Integrated Network segment in 1985, including, for example, the 69 kV facilities serving the City of Milton-Freewater described above. Bliven *et al.*, BP-14-E-BPA-42, at 36-37. Thus, the functional criteria for segmentation that Powerex argues for now were not the criteria used in 1985.

The sole question is whether, by including lower-voltage facilities (34.5 kV–115 kV), the bright-line threshold results in equitable allocation of transmission costs between Federal and non-Federal power using BPA's transmission system. Beginning in 1996, BPA proposed no longer to allocate costs separately between Federal and non-Federal power using its system; rather, it would offer all transmission customers a choice of open access transmission service, and customers would pay the same rate regardless of the source of the power. The bright-line threshold supports this paradigm by including in the Network segment the facilities necessary to provide open access service to all customers at the same rates. Bliven *et al.*, BP-14-E-BPA-42, at 19, 24, 36, 37, 39. The threshold does not advantage either Federal or non-Federal power and, in fact, creates a level playing field between both forms of power competing for new loads using BPA's transmission system. Bliven *et al.*, BP-14-E-BPA-42, at 40-41.

### **Draft Decision**

*The 34.5 kV bright-line threshold equitably allocates costs between Federal and non-Federal power.*

### **Issue 4.1.3.2**

*Whether the 34.5 kV bright-line threshold complies with cost causation principles.*

### **Parties' Positions**

JP12 and Powerex argue that the 34.5 kV bright-line threshold violates general cost causation principles because it includes facilities in the Integrated Network segment that are not integrated with the bulk transmission system. JP12 Br., BP-14-B-JP12-01, at 7-8, 9-10; Powerex Br., BP-14-B-PX-01, at 23-24. These parties argue that Integrated Network customers should not bear the burden of paying for non-integrated facilities that serve only certain customers and provide no systemwide benefit. JP12 Br., BP-14-B-JP12-01, at 9; Powerex Br., BP-14-B-PX-01, at 16-17. JP12 presents an analysis using the Commission's BES definition, modified to establish the nominal threshold at 116 kV instead of 100 kV, and the Seven Factor Test. Its analysis shows that approximately \$714 million of investment and \$24 million of operation and maintenance expenses should be excluded from the Integrated Network segment because those facilities serve a distribution-like function. JP12 Br., BP-14-B-JP12-01, at 7-8; *see also* Hanser *et al.*, BP-14-E-JP12-01 at 29. JP12 notes that Staff used four of the seven factors to distinguish facilities in the Utility Delivery segment. JP12 Br., BP-14-B-JP12-01, at 5-6 (citing Messinger *et al.*, BP-14-E-BPA-29, at 4). JP12 argues that Staff did no analysis of its facilities to actually apply these factors; otherwise, Staff would have found that many of the facilities included in the

Integrated Network segment perform distribution-like functions and would not have assigned these facilities to that segment. JP12 Br., BP-14-B-JP12-01, at 5.

JP12 also argues that the 34.5 kV bright-line threshold is inconsistent with the Commission's integration test (the *Mansfield* test; see further explanation below), although JP12 does acknowledge that BPA is not required to follow the Commission's method of determining integration. JP12 Br., BP-14-B-JP12-01, at 11.

JP03 argues that the 34.5 kV bright-line threshold accurately classifies assets in the Integrated Network segment as transmission assets serving a transmission function. JP03 Br., BP-14-B-JP03-01, at 17-19.

### **BPA Staff's Position**

The 34.5 kV bright-line threshold correctly delineates facilities as transmission and includes them in the Integrated Network segment because at least 83 percent of BPA's 34.5 kV facilities are performing a transmission function. Bliven *et al.*, BP-14-E-BPA-42, at 33-34. These facilities are being used for transmission purposes, not for distribution-like purposes. *Id.* at 17, 22-27, 33. Facilities below the 34.5 kV threshold are predominantly distribution-like facilities, because they are not necessary for BPA to provide transmission service. *Id.* at 18. These Delivery segment facilities "step down" or reduce the voltage from BPA's transmission facilities to distribution voltages. *Id.* Therefore, the 34.5 kV bright-line threshold is consistent with general cost causation principles because it rolls transmission assets into the Integrated Network segment. *Id.*

Staff did not address JP12's argument that the 34.5 kV bright-line threshold is inconsistent with FERC's integration test because the argument was introduced for the first time in JP12's initial brief.

### **Evaluation of Positions**

JP12 and Powerex argue that the 34.5 kV bright-line threshold includes non-integrated facilities in the Integrated Network segment. JP12 Br., BP-14-B-JP12-01, at 7-8, 9-10; Powerex Br., BP-14-B-PX-01, at 23-24. JP12's argument is based on its analysis using the BES definition, after modifying the nominal threshold from 100 kV to 116 kV, and then applying Factors 1, 2, 3, 5, and 7 of the Seven Factor Test. Hanser *et al.*, BP-14-E-JP12-01 at 30-33. According to JP12, 16.6 percent of the facilities that Staff includes in the Integrated Network segment serve a distribution-like function and should not be segmented to the Integrated Network segment. JP12 Br., BP-14-B-JP12-01, at 7; *see also* Hanser *et al.*, BP-14-E-JP12-01 at 29. JP12's proposal would result in removing approximately \$714 million of investment and \$24 million of operation and maintenance expenses from the Integrated Network segment. *Id.*

The BES definition is used by the North American Electric Reliability Corporation to determine which facilities are subject to its reliability standards. Hanser *et al.*, BP-14-E-JP12-01 at 23. The Commission has not used the BES definition for ratemaking purposes; nor is it known whether the Commission would ever use a reliability determination to differentiate costs in

ratemaking. BPA believes that it is premature to consider applying the BES definition in the segmentation of BPA's facilities.

The Seven Factor Test is a jurisdictional test that applies to public utilities under the Federal Power Act and determines whether facilities serve a transmission function (subject to the Commission's jurisdiction) or distribution function (subject to state jurisdiction). Hanser *et al.*, BP-14-E-JP12-01 at 22-23; Bliven *et al.*, BP-14-E-BPA-42, at 30; *see also Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC STATS. & REGS. ¶ 31,036, at 31,783-84 (1996). Even if BPA was required to apply the Commission's tests for transmission, which it is not, BPA's transmission system would not pass the first screen employed by the Commission, because it is used only for wholesale transmission:

Accordingly, the NOPR set forth our jurisdictional analysis and several technical factors, for determining what constitutes "facilities used in local distribution." For unbundled wholesale wheeling, the NOPR proposed to apply a functional test, *i.e.*, whether the entity to whom the power is delivered is a lawful reseller. For unbundled retail wheeling, the NOPR proposed to apply a combination functional-technical test that would take into account technical characteristics of the facilities used for the wheeling.

*Id.* The overwhelming majority of BPA's facilities would not pass through this screen because they deliver wholesale power—94 percent of the power transmitted over BPA's system is resold once it leaves BPA's system. Power Loads and Resources Documentation, BP-14-E-BPA-03A, at 8, 9 (the other 6 percent is delivered directly to DSIs and Federal agencies). Thus, BPA's facilities would not reach the Seven Factor Test. JP03 Br., BP-14-B-JP03-01, at 15.

Moreover, the legal analysis attached to Order 888 notes that "while there is no uniform breakout point between transmission and distribution, it appears that utilities account for facilities operated at greater than 30 kV as transmission and that distribution facilities are usually less than 40 kV." Order No. 888, Appendix G, FERC STATS. & REGS. ¶ 31,036 at 31,981 n.100. Staff's proposed 34.5 kV bright-line threshold separating transmission and distribution falls within this range.

JP12 also argues that in the Initial Proposal Staff used four of the seven factors to distinguish facilities in the Utility Delivery segment. JP12 Br., BP-14-B-JP12-01, at 5-6 (citing Messinger *et al.*, BP-14-E-BPA-29, at 4). The four factors are: (1) the facilities provide for the radial delivery of power to customers close to their retail load (not parallel or looped facilities); (2) the facilities would not economically transmit power over long distances due to line losses and voltage drop; (3) the facilities are not used to transmit power to other markets; and (4) rarely, if ever, is there bi-directional power flow on the facilities. *Id.* JP12 argues that Staff did no analysis of its facilities to actually apply these factors; otherwise, Staff would have found that many of the facilities included in the Integrated Network segment perform distribution-like

functions and would not have assigned those facilities to that segment. JP12 Br., BP-14-B-JP12-01, at 5.

The record does not support JP12's assertion that had Staff conducted a facility-by-facility analysis it would have come to many of the same conclusions that JP12 did. The record shows that Staff considered the four factors cited by JP12 to assess whether the 34.5 kV bright-line threshold generally accomplished a segmentation consistent with delineating an appropriate boundary between network and delivery facilities. Messinger *et al.*, BP-14-E-BPA-29, at 4. Staff concluded that the bright-line threshold provided results that placed facilities that meet the four factors into the Utility Delivery segment and facilities that did not meet the four factors into the Integrated Network segment. *Id.* Having come to this conclusion, Staff determined that the bright-line criterion used to assign facilities to the Network segment did not require a functional analysis of every facility as JP12 argues. *Id.*

Staff performed a more in-depth analysis of a significant portion of BPA's 34.5 kV facilities in light of JP12's and Powerex's direct cases. Bliven *et al.*, BP-14-E-BPA-42, at 22-23, 33. Staff analyzed the type of service provided by 83 percent of BPA's 34.5 kV facilities and determined that they are used to move wholesale power from generation sources to load centers, which is a transmission function. *Id.* at 33.

Staff also examined the two factors of the Seven Factor Test that JP12 did not analyze: Factor 4—when power enters a local distribution system, it is not reconsigned or transported on to some other market—and Factor 6—meters are based at transmission/local distribution interface. *Id.* at 31. Staff's analysis of these factors shows that these lower-voltage facilities predominantly serve a transmission function rather than a distribution-like function. *Id.*

The lower-voltage (34.5 kV through 115 kV) facilities that Staff proposes to include in the Integrated Network transmit wholesale power from generation sources to load centers, which is a transmission function. While not every user of the Integrated Network segment may benefit from these facilities, it is also true that not every customer using these lower-voltage facilities benefits from all of BPA's higher-voltage facilities. The same is true with respect to the geographical location of customers on BPA's system. Customers east of the Cascades may not benefit from BPA's facilities west of the Cascades,<sup>3</sup> but their rates include the costs of BPA's Integrated Network segment, including facilities west of the Cascades. The concept of an integrated network is one that operates as a single machine to move power in bulk from sources to load centers. Bliven *et al.*, BP-14-E-BPA-42, at 24, 26. Based on the evidence in the record, the 34.5 kV bright-line threshold results in placing facilities performing a transmission function into the Integrated Network.

---

<sup>3</sup> BPA notes that Powerex misquotes Staff as saying that the City of Minidoka does not use high-voltage facilities east of the Cascades. Powerex Br., BP-14-B-PX-01, at 19. Staff states that Minidoka does not use high-voltage facilities west of the Cascades. Bliven *et al.*, BP-14-E-BPA-42, at 24. Staff is drawing a corollary to Powerex's contention that it is not using lower-voltage facilities by stating that Minidoka does not rely on westside facilities, which are about 46 percent of BPA's network investment, to move generation from the Federal generation generally located in central Washington to its load in southern Idaho. *Id.* The same situation holds for 75 of BPA's 135 power customers located east of the Cascades.

JP12’s analysis under the Seven Factor Test is incomplete and presumes that Factors 1, 2, 3, 5, and 7 should outweigh Factors 4 and 6, which indicate a transmission function. However, as JP12 acknowledges, “the primary functionality of the facility or system plays a substantial role in application of the seven factor test.” Hanser *et al.*, BP-14-E-JP12-01, at 23. As described above, the primary function of facilities in the Integrated Network segment is to move wholesale power generation to load centers in the Pacific Northwest. This is a transmission function, not a distribution-like function.

JP12 and Powerex spend considerable time in their initial briefs arguing that the lower-voltage facilities that Staff proposes to roll into the Integrated Network segment are not integrated facilities and, therefore, should be not be rolled into that segment. JP12 Br., BP-14-B-JP12-01, at 6, 8, 9, 10, 11-12; Powerex Br., BP-14-B-PX-01, at 7, 8, 9, 10, 16, 23. In its direct case, however, JP12 focused its analysis on distinguishing between transmission and distribution-like facilities, not integrated and non-integrated facilities. Hanser *et al.*, BP-14-E-JP12-01 at 25-26, 29-30. The question of integration is distinct from both reliability and jurisdiction. Integration denotes a network operating as a single machine to move power in bulk from generation sources to load centers. Bliven *et al.*, BP-14-E-BPA-42, at 24, 26.

For jurisdictional utilities, the test for whether a facility is transmission or distribution is different from the test for integration. The Commission’s integration test—known as the *Mansfield* test—contains five factors to determine whether transmission facilities are integrated (the costs should be rolled into network transmission rates) or not integrated (the costs should be directly assigned to the user). *Mansfield Muni. Elec. Dept. v. New England Power Co.*, 97 FERC ¶ 61,134, at 61,613-14 (2001); *see also San Diego Gas & Electric Co.*, 139 FERC ¶ 61,006, at P 13 (2012). Because integration addresses whether the costs of transmission facilities should be rolled into network rates or directly assigned, the Commission’s *Mansfield* test applies only to transmission facilities, not to distribution facilities.

While Factors 2 and 3 of the Seven Factor Test are similar to Factors 1 and 2 of the *Mansfield* Test, the other factors in the two tests are different. Compare *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC STATS. & REGS. ¶ 31,036, at 31,783-84 (1996) to *Mansfield Muni. Elec. Dept. v. New England Power Co.*, 97 FERC ¶ 61,134, at 61,613-14 (2001). Moreover, unlike the Seven Factor Test, under which a balancing of the seven factors guides the outcome, the *Mansfield* test requires that *all* five factors be met before a facility can be considered non-integrated and its costs directly assigned. *Pinnacle West Capital Corp.*, 133 FERC ¶ 61,034, at P 8 n.16 (2010). In doing so, the *Mansfield* test effectively creates a rebuttable presumption of integration, recognizing the Commission’s strong preference for rolling the cost of transmission facilities into network rates. *See, e.g., California Dept. of Water Resources v. FERC*, 489 F.3d 1029, 1037-38 (9th Cir. 2007) (“[Commission] precedent clearly demonstrates a consistent policy favoring the rolled-in method of transmission pricing where the system operates as an integrated whole.”).

Therefore, in concluding that the 34.5 kV bright-line threshold includes non-integrated facilities in the Integrated Network segment, both JP12 and Powerex err by relying on the BES definition and the Seven Factor Test. There is no *Mansfield* analysis in the record.

Based on the preceding evaluation, the 34.5 kV threshold is consistent with general cost causation principles because facilities at and above that voltage serve a transmission function. It is also worth noting that the *Bonbright* principles that JP06, JP12, and Powerex appeal to in their cost causation arguments (JP06 Br., BP-14-B-JP06-01, at 14; Hanser *et al.*, BP-14-E-JP12-01, at 35-36; Opatrny, BP-14-E-PX-01, at 6, 20) expressly recognize an exception for rural electrification:

Lest the foregoing remarks be taken to imply an adherence to a cost standard more rigid than the facts would justify, let us at once note exceptions. In the first place, the principle is followed far more closely as a measure of general rate levels than as a measure of individual rate schedules. In the second place, it is deliberately violated by those municipal utility operations, once thought to be fairly numerous, that use the sale of their services as a source of profits for the city treasury. *And in the third place, it has been waived to a minor degree through the use of indirect subsidies in support of rural electrification in the United States; and waived to a major degree through the use of heavy subsidies for rural electrification in the province of Ontario.*

Bonbright, James C., Danielsen, Albert L., Kamerschen, David R., *Principles of Public Utility Rates*, Second Edition (Arlington, Virginia, Public Utilities Reports, Inc., 1988), at 110 (emphasis added). The third of *Bonbright's* exceptions coincides with the rural electrification component of BPA's organic statutes, promoting the widespread use of electric power throughout the Pacific Northwest.

### **Draft Decision**

*The 34.5 kV bright-line threshold complies with general cost causation principles.*

### **Issue 4.1.3.3**

*Whether the achievement of uniform rates is an important consideration for the 34.5 kV bright-line threshold for segmentation in this rate proceeding.*

### **Parties' Positions**

JP12 argues that BPA's adoption of a uniform rate for transmission service is inconsistent with cost allocation because the proposed 34.5 kV bright-line threshold results in rolling non-integrated facilities into the Integrated Network. JP12 Br., BP-14-B-JP12-01, at 23. JP12 notes that BPA is not required to adopt uniform rates and that the reason for adopting uniform rates—rural electrification—is no longer necessary today, and, therefore, BPA should not use uniform rates as the basis for establishing the 34.5 kV bright-line threshold. *Id.* at 24.

JP06 and Powerex argue that BPA's rates are inconsistent with the concept of uniform rates and, therefore, reliance upon that concept to justify the 34.5 kV bright-line threshold is not credible. JP06 Br., BP-14-B-JP06-01, at 16-18; Powerex Br., BP-14-B-PX-01, at 21-22. These parties contend that FPT, IR, NT, and PTP rates are not uniform because FPT rates have facility and distance charges, and IR, NT and PTP rates have a short-distance discount. *Id.* JP06 argues that BPA's rates have been non-uniform from the very beginning because BPA offered both a 15-mile busbar rate and a rate for all other customers. JP06 Br., BP-14-B-JP06-01, at 16. Powerex argues that BPA offers a low density discount to power customers that already protects small public power customers. Powerex Br., BP-14-B-PX-01, at 22.

JP06 states that under BPA's pre-1996 segmentation policy, rural customers using the Delivery and Fringe segments paid higher rates, citing this as an example of the fact that "BPA's rate history is full of examples of non-uniform rates." JP06 Br., BP-14-B-JP06-01, at 17. JP06 also argues that BPA's prior customer service policy that allowed BPA to build delivery facilities for some customers but not others should be considered and addressed in BPA's ratesetting process. *Id.* at 6, 7.

### **BPA Staff's Position**

BPA adopted uniform rates to promote "the most widespread use" of its power and transmission systems in the Pacific Northwest. Bliven *et al.*, BP-14-E-BPA-42 at 4-20; *see also* JP03 Br., BP-14-B-JP03-01, at 4-13; WPAG Br., BP-14-B-WG-01, at 5-9. Although section 6 of the Bonneville Project Act does not require uniform rates, it does expressly provide the Administrator with the discretion to adopt a uniform rate structure, which BPA's first Administrator, J.D. Ross, did after receiving overwhelming support at a series of public meetings on the issue. *Id.* at 4-13. Staff explained in detail how the uniform rate policy has been implemented over BPA's 75-year history, including the few excursions from uniform rates that JP12 and Powerex cite. *Id.* at 13-20.

There was a distance discount in BPA's uniform rate design from the very beginning. *Id.* at 13. For deliveries within 15 miles of the Bonneville Dam, BPA had an "at-site" annual rate of \$14.50 per kilowatt instead of the \$17.50 per kilowatt that was charged to deliveries beyond 15 miles. *Id.* The at-site rate continued in BPA's rates until 1979. There does not appear to have been much use of the discount. *Id.*

BPA began offering FPT contracts to wheeling customers in 1976. *Id.* at 13-14. The FPT rate structure includes distance components. *Id.* BPA stopped offering FPT contracts in the 1980s when it started offering IR contracts to wheeling customers. *Id.* at 14. The IR contracts include a discount for transmission distances under 75 miles. *Id.*

### **Evaluation of Positions**

The uniform rate policy, which began 75 years ago, distributes Federal power throughout the Pacific Northwest region utilizing rates that do not distinguish among customers by size and location. Bliven *et al.*, BP-14-E-BPA-42, at 7. Today, the purpose of the policy is to promote

the widest possible diversified use of electric power at the lowest possible rates throughout the region. 16 U.S.C. § 838g. The policy does not extend to extra-regional deliveries and, therefore, does not include the intertie segments. Prior to 1996, BPA installed low-voltage facilities for some customers but not for others under its customer service policy. JP06 Br., BP-14-B-JP06-01, at 6-7. BPA has sought to restore some parity in delivery voltage by instituting a delivery rate for customers taking low-voltage delivery (currently below 34.5 kV) over BPA facilities. Bliven *et al.*, BP-14-E-BPA-42, at 18. BPA now has a policy to sell its delivery facilities whenever feasible to the customers using them. *Id.* While it is true that BPA’s FPT transmission rates may not have conformed to the uniform rates policy, FPT agreements were not used to deliver Federal power within the region. *See* Transmission, Ancillary and Control Area Service Rate Schedules and General Rate Schedule Provisions, BP-14-E-BPA-10, at 1.

JP12 argues correctly that BPA is not required to adopt uniform rates. *See* JP12 Br., BP-14-B-JP12-01, at 24. Section 6 of the Bonneville Project Act and section 10 of the Transmission System Act clearly provide that the Administrator “may” adopt uniform rates but is not required to do so. Staff proposes a segmentation that supports uniform rates for network transmission, which are expressly provided for under these statutes.

JP12 argues that the rationale for adopting uniform rates—rural electrification—is no longer necessary today and, therefore, BPA should not adopt Staff’s segmentation methodology. *Id.* JP12 inappropriately limits BPA’s rationale and justification for uniform rates. Without question, the development and construction of a power system and transmission grid capable of providing electricity to isolated farms and communities in the Northwest was a primary driver of the uniform rate structure in the early years of BPA’s existence. Bliven *et al.*, BP-14-E-BPA-42, at 4-11. However, the “most widespread use” requirement in BPA’s organic statutes is not limited to rural electrification and remains a statutory obligation. *See, e.g.*, 16 U.S.C. §§ 832a(b), 832e, 825s, 838g. The benefits of BPA’s power and transmission assets were intended to benefit as many people over as wide an area in the Pacific Northwest as possible, not only rural communities and farms:

This is not in the Boulder Canyon Act, it is not in the Muscle Shoals Act. It is sought by their provision to make certain that any benefits which may accrue shall not be provincial in their application but shall be distributed as far as is practicable, a matter which can only be worked out through experience and study. *But we have placed no limitations on the area of distribution. The language encourages a wide and equitable distribution of the benefits of the rates which may be enjoyed by the people who live in the great Northwest section of this country.*

Sen. Charles L. McNary, Oregon, Senate Congressional Record, August 9, 1937, at 8523 (emphasis added).

BPA’s first Administrator, J.D. Ross, set out to implement this requirement. Bliven *et al.*, BP-14-E-BPA-42, at 11-13. After conducting a series of regional public meetings in 1938 in which an overwhelming majority of participants supported uniform rates, he implemented a

uniform rate to distribute the benefits of the Federal system across the Northwest. *Id.* at 12-13; JP03 Br., BP-14-B-JP03-01, at 9. The rationale for implementing uniform rates still applies today. All BPA's customers, not just rural customers, benefit from using facilities in the Integrated Network segment, which are spread across the entire Pacific Northwest.

JP06's and Powerex's arguments that BPA has not employed a uniform rate consistently throughout its history are effectively arguments that BPA has never had a uniform rate policy. Such arguments are incorrect. BPA implemented a policy of uniform rates from its very beginning and has continued that policy through the present day. Bliven *et al.*, BP-14-E-BPA-42, at 4-20; JP03 Br., BP-14-B-JP03-01, at 4-13; WPAG Br., BP-14-B-WG-01, at 5-9. The fact that there are exceptions does not diminish the overarching goal of the policy: widespread distribution of the benefits of the Federal system to all the people in the Pacific Northwest that does not advantage or disadvantage customers based on location or size.

As JP06 and Powerex point out, there have been some exceptions to the policy. JP06 Br., BP-14-B-JP06-01, at 16-18; Powerex Br., BP-14-B-PX-01, at 21-22. The 15-mile at-site discount included in BPA's rates prior to 1979 and the 75-mile short-distance discount applicable to IR, NT and PTP service are two such exceptions. There were sound policy reasons for applying these policies, primarily to encourage customers to use BPA's transmission system rather than constructing their own short-distance lines parallel to BPA's lines.

In the 1981 rate case ROD, the Administrator concluded that the FPT rate structure, with its distance component and facility use factors, was not necessarily the best transmission rate structure, but that he would retain the rate structure because of contract requirements. The Administrator stated:

Schedule FPT-2 represents a revision of the transmission components of the BPA "wheeling formula" that was developed in the 1950's and has been incorporated in some of BPA's wheeling contracts since that time. The FPT-2 rate schedule includes unit costs of various components of the FCRTS. Some comments have indicated that the separate identification of specific services under the FPT-2 is unjustifiable given the postage stamp service that firm power customers receive. Such services as distance, identification of network facilities, and one-way wheeling between specific points of interconnection are variously objected to. The IR-1 rate is an attempt to avoid such practices and to eliminate the need to identify specifically such other charges as station service to a customer's off-line generator. While I feel that the costs of the portions of the Integrated Network should not be subdivided or allocated according to distance and types of facilities, some FPT contracts appear to require continuation of this historical rate design, and the process I have used to design the FPT-2 rate conforms to the contract constraints.

WP-81 Wholesale Power and Transmission Rate ROD, WP-81-A-02, at VIII-4. At the same time, the Administrator considered whether to include a distance factor in the new Integration of Resources rate. He concluded that:

In an integrated network the distance between most resources and loads cannot be identified as a cost causation factor because of the effects of displacement. The network provides benefits to all customers that do not relate to distance between resources and load. These include services such as transmission and generation reliability, generation backup, reduced losses and a market for nonfirm power. Using distance as a billing determinant would be inconsistent with the networkwide service being offered under IR-1.

*Id.* at VIII-12 to VIII-13. The Administrator stated his reason for favoring the IR contracts and rates over the FPT contracts and rates:

BPA's current FPT contracts reflect many historical arrangements with regard to costs and services. The purpose of offering the IR-1 rate is to discard those historical arrangements to the extent that they are inequitable or inappropriate.

*Id.* at VIII-15. Later, BPA included the short-distance discount in the IR rate because:

The "postage stamp" design of the IR rate represents a change from BPA's formula power contracts. Specific facilities are not identified and full use of the integrated Network and access to the FCRTS are provided. Necessary compromises were made in the rate design to recognize the wheeling transactions that use fewer facilities. Because a postage stamp rate places a relatively high revenue burden on short distance transactions and could result in an undesirable incentive to construct short distance parallel lines, BPA implemented a short distance exception to the IR demand charge, and continues to utilize the use-of-facilities charges.

WP-85 Wholesale Power and Transmission Rate ROD, WP-85-A-02, at 358. This history demonstrates that BPA preferred to change the FPT mileage and facility rate structure, but was prevented by contract considerations.<sup>4</sup> The same assessment and considerations continue to this day.

When JP06 and Powerex argue that BPA's historical rates are inconsistent with the concept of uniform rates, they miss important distinctions. *See* JP06 Br., BP-14-B-JP06-01, at 16-18; Powerex Br., BP-14-B-PX-01, at 21-22. The FPT and IR rates were offered at a time when Federal power sales contracts included delivery and transmission costs that were recovered through bundled power rates. Bliven *et al.*, BP-14-E-BPA-42, at 15-16. At no time in BPA's history was Federal power delivered using an FPT or IR contract. Thus, the policy of encouraging widespread use of Federal power at uniform transmission rates was not frustrated by

---

<sup>4</sup> Powerex argues that BPA continued to offer FPT contracts as late as the mid-1990s. Powerex Br., BP-14-B-PX-01, at 21, n.73 (citing Transmission Rate Design Study Documentation, BP-14-E-BPA-07A, at 25). These agreements had provisions allowing them to be rolled over (or renewed) prior to 1996. The FPT agreements that Powerex is referring to are to FPT agreements that were rolled over in the mid-1990s. BPA did not offer new FPT contracts in the mid-1990s.

the presence of the non-uniform FPT rate. This fact stands in stark contrast to the current situation, in which Federal power is sold at the generation busbar and delivered using the customer's transmission contract.

JP06 argues that under BPA's pre-1996 segmentation policy, rural customers using the Delivery and Fringe segments paid higher rates. JP06 Br., BP-14-B-JP06-01, at 17. JP06 presents no evidence to support this claim, which is contrary to the evidence on the record in this case. Prior to 1996, the costs of the Fringe and Delivery segments were rolled into bundled power rates. Bliven *et al.*, BP-14-E-BPA-42, at 15-16. There were no differences between power rates for customers in small rural communities and power rates for customers in large urban communities; they all paid the same uniform rate.

Powerex claims that BPA offers a low density discount (LDD) that already protects small public power customers. Powerex Br., BP-14-B-PX-01, at 22. The LDD is specified in section 7(d)(1) of the Northwest Power Act to avoid adverse retail rate impacts for customers with low system densities. 16 U.S.C. § 839e(d). As Powerex correctly notes, for purposes of this statute, system densities are measured based on pole miles of distribution facilities, and the discount is for the utility's investment in non-generation electric plant. Powerex Br., BP-14-B-PX-01, at 22 (citing Power General Rate Schedule Provisions, BP-14-E-BPA-09, at 55-61). However, Powerex makes an unsupported leap in concluding that mitigating the adverse effects of low distribution densities would also compensate small rural customers for lower-voltage transmission costs, assuming, as Powerex argues, such costs were charged directly to these customers. *See* Powerex Br., BP-14-B-PX-01, at 22. The LDD includes no provision for the costs the customer pays to BPA for transmission service; it is constrained to compensating for distribution costs (the utility's non-generation electric plant, not BPA's electric plant). Furthermore, not all customers that would be subject to higher transmission costs under Powerex's proposal are eligible for the LDD. The number of customers exposed to higher transmission costs under Powerex's proposal is considerably higher than the 56 BPA customers that receive the LDD.

### **Draft Decision**

*The achievement of uniform rates is an important consideration in whether to adopt the 34.5 kV bright-line threshold for segmentation in this rate proceeding.*

### **Issue 4.1.3.4**

*Whether the 34.5 kV bright-line threshold complies with the definition of the "Integrated Network" segment, under which the network segment consists of facilities that perform a transmission function.*

### **Parties' Positions**

Powerex argues that the 34.5 kV bright-line threshold sweeps lower-voltage facilities into the Integrated Network segment that are inconsistent with the proposed definition of the Integrated Network. Powerex Br., BP-14-B-PX-01, at 5-10. Powerex argues that these facilities serve a

distribution-like function that benefits particular customers and do not provide a benefit to all users of BPA's integrated transmission system. *Id.*

JP12 argues the bright-line threshold is inconsistent with past definitions of the Integrated Network segment. JP12 Br., BP-14-B-JP12-01, at 8-9.

### **BPA Staff's Position**

The majority of BPA's low-voltage facilities, including the facilities Powerex cites in its initial brief, serve a transmission function. Bliven *et al.*, BP-14-E-BPA-42, at 20-27, 33-34. An integrated network is a network that operates as a single machine to move power in bulk from generation sources to load centers. *Id.* at 24-26. Although not all customers use all the facilities in a network, that does not mean they do not operate as integrated facilities moving wholesale power from sources to load centers. *Id.*

### **Evaluation of Positions**

The Initial Proposal Segmentation Study defines the Integrated Network segment as follows:

The Integrated Network segment is the core of BPA's transmission system. BPA created the Integrated Network segment in its Cost of Service Analysis for the 1981 rate case. The facilities in this segment transmit power to the Delivery segments and directly to wholesale customers, as well as to and from the Intertie segments and other interconnections with adjacent balancing authority areas. They also integrate major system resources directly or in conjunction with BPA's Generation Integration segment. The Integrated Network segment consists of facilities that serve a transmission function, including sub-transmission, from 34.5 kV to 500 kV. (Sub-transmission facilities are lower-voltage facilities that transfer power from BPA's bulk transmission system to retail utility distribution systems, which then deliver power to retail customers.)

The facilities in this segment do not serve distinct functions like the Generation Integration or Southern Intertie segments do. Instead, they provide services and benefits to nearly all of BPA's customers, including users of both Federal and non-Federal power. Therefore, they are treated as integrated facilities for purposes of cost allocation and cost recovery. The benefits of this segment include displacement (local generation serving load instead of remote generation scheduled to serve that load), bulk power transfers, voltage regulation, and increased overall reliability resulting from alternative resource and transmission pathways. BPA plans and operates these facilities on an integrated basis to achieve maximum efficiency on a system-wide basis.

Transmission Segmentation Study, BP-14-E-BPA-06, at 2-3.

Powerex argues that the 34.5 kV bright-line threshold results in rolling distribution-like facilities into the Integrated Network segment, a result that is inconsistent with the definition set forth

above because the Integrated Network is supposed to consist of facilities that serve a transmission function. Powerex Br., BP-14-B-PX-01, at 6-9. Powerex challenges three examples offered by Staff in its rebuttal testimony to illustrate that lower-voltage facilities serve a transmission function: the Mapleton substation, the 34.5 kV line serving the City of Minidoka, and the Alfalfa substation. *Id.* Powerex argues that these facilities serve a non-integrated, distribution-like function because they serve a particular customer's load rather than benefitting all users of the Integrated Network. *Id.*

The disagreement between Powerex and Staff regarding these and similar facilities centers on what constitutes integrated transmission and non-integrated, distribution-like facilities. Powerex's argument that the above-referenced facilities are non-integrated, distribution-like facilities appears to be based on the fact that only particular customers benefit from these facilities rather than all users of the Integrated Network segment. *Id.* at 7-10. For example, in reference to the Mapleton substation, which transmits power to Central Lincoln PUD and Blachly-Lane Cooperatives (the Central Lincoln portion is in the Utility Delivery segment and is not in dispute), Powerex asserts that "this facility is not serving an integrated function; rather, this facility's function appears more consistent with BPA's definition of the Utility Delivery segment noted above, *i.e.*, facilities used by customers to serve their local loads." *Id.* at 8. Powerex makes similar arguments regarding BPA's 34.5 kV line to the city of Minidoka and the Alfalfa substation. *Id.* at 8-9.

On the contrary, however, these facilities serve a transmission function and are properly included in the Integrated Network segment. Bliven *et al.*, BP-14-E-BPA-42, at 22-23. Such conclusion is premised on the type of service being provided by the facility, not the number or identity of customers that benefit from those facilities:

At Mapleton, BPA delivers power to both Central Lincoln PUD and Blachly-Lane Cooperative. BPA's one-line diagram shown in JP12's Exhibit 2 makes the deliveries to each of these customers look very much alike. A 115 kV bus connects to two transformers. One of the transformers steps down the voltage to 12.5 kV for delivery to Central Lincoln. The other transformer steps down the voltage to 34.5 kV for delivery to Blachly-Lane. JP12 argues that we have inappropriately included the 34.5 kV transformer in the Network segment while including the 12.5 kV transformer, performing the same function, in the Delivery segment.

What is not on BPA's one-line diagram is what happens after the power is delivered. The power delivered at 12.5 kV to Central Lincoln travels about 200 feet to a Central Lincoln distribution station that serves the Mapleton community over its distribution lines. The power delivered at 34.5 kV to Blachly-Lane travels 11.5 miles before being stepped down to 12.5 kV for distribution to Blachly's retail customers. The intervening 11.5 miles are not within Blachly's service territory, meaning there are no retail service drops between BPA's Mapleton transformer and Blachly's distribution station. To us, this is a

transmission function, not a distribution function, making 34.5 kV a transmission voltage, while 12.5 kV is a distribution voltage.

*Id.* Similar explanations support Staff’s segmentation of BPA’s 34.5 kV line to the city of Minidoka and the Alfalfa substation. *Id.* at 23. Facilities that serve the City of Seattle perform similar functions as those serving the three utilities that Powerex cites. *Id.* at 25-26. None of the facilities serving Seattle is being disputed, apparently because they are 230 kV facilities. But if the facilities serving Blachly-Lane, Minidoka, and the Alfalfa substation are not integrated under Powerex’s proposition, then the facilities serving Seattle would not be integrated either.

In arguing that the separation between integrated transmission and non-integrated, distribution-like functions is based on the particular customers that benefit from a facility, Powerex misconstrues the definition and purpose of the Integrated Network segment. The Integrated Network segment allows for BPA’s core transmission system to operate as a single machine to move wholesale power in bulk from generation sources to load centers in the Pacific Northwest. *Id.* at 26. Facilities at 34.5, 69, and 115 kV generally serve the same purpose as many of BPA’s higher-voltage facilities—to move power from generation sources to load. *Id.* at 22-27, 33. BPA considers facilities that serve this purpose to serve a transmission function, not a distribution-like function. The fact that some facilities are at lower voltages is a reflection of the size of the load center, rather than of the service being provided. *Id.* at 17. Particular components of an integrated transmission system do not have to be allocated to particular transmission customers in proportion to their direct use or degree of direct benefit, as Powerex suggests, because such balkanizing of the transmission system is inconsistent with the operation of an integrated system as a single machine.

Narrowing the definition of the Integrated Network segment to include only higher-voltage facilities as Powerex and JP12 suggest would likely have a significant impact on BPA’s ability to plan and construct an efficient, cost-effective transmission system to serve its customers in the Pacific Northwest. If BPA were to use a higher bright-line threshold or a narrower definition of the Integrated Network, BPA might well face pressure to construct higher-voltage facilities to serve its transmission customers simply to meet that threshold, thereby increasing costs and rates to all customers. *Id.* at 53-54. BPA’s segmentation policy should not influence planning and construction decisions. *Id.* A broader definition allowing facility costs to be rolled into the Integrated Network without respect to voltage encourages a more efficient, cost-effective transmission system and benefits all of BPA’s customers. *Id.*

While Powerex is correct that Utility Delivery facilities generally benefit a smaller set of customers, that is a general characteristic of the segment, not one of the criteria for determining whether a facility should be in the Utility Delivery or Integrated Network segment. *See* Powerex Br., BP-14-B-PX-01, at 6. BPA’s 34.5 kV facilities predominantly serve a transmission function because they are used to transmit wholesale power from generation resources to load centers in the Pacific Northwest. Bliven *et al.*, BP-14-E-BPA-42, at 22-24, 33-34. Facilities below the 34.5 kV threshold are predominantly distribution-like facilities because they are not necessary for BPA to provide transmission service. Delivery segment facilities “step down” or reduce the voltage from BPA’s transmission facilities to distribution voltages. *Id.* at 18-19.

Therefore, the 34.5 kV bright-line threshold serves as a reasonable delineation between facilities that serve a transmission function and those that serve a distribution-like function.

JP12 argues that the bright-line threshold is inconsistent with past definitions of the Integrated Network segment. JP12 Br., BP-14-B-JP12-01, at 8-9. JP12 argues that, based on pre-1996 definitions, many of the facilities that would be part of the Integrated Network segment under the 34.5 kV bright-line threshold were not considered integrated prior to 1996. *Id.* at 9. As explained in Issue 4.1.3.2, it is incorrect to conclude that facilities excluded from the Integrated Network prior to 1996 were not integrated; such a conclusion is unsupported by evidence on the record. JP12 also argues that Staff does not explain what occurred in 1996 to technically support the conversion of what were then non-integrated facilities into integrated facilities or why the definition of the Integrated Network segment should now include a 34.5 kV or above bright-line threshold. *Id.* The extensive changes that occurred in 1996 are laid out in the evaluation of Issue 4.1.3.1.

### **Draft Decision**

*The 34.5 kV bright-line threshold complies with the definition of the “Integrated Network” segment because facilities at and above that threshold perform transmission functions.*

### **Issue 4.1.3.5**

*Whether the level of analysis presented in this proceeding, when compared to the level of analysis in past segmentation studies, supports a segmentation based on a 34.5 kV bright-line threshold.*

### **Parties’ Positions**

JP12 argues that the 34.5 kV bright-line threshold is inconsistent with past segmentation studies. JP12 Br., BP-14-B-JP12-01, at 9. JP12 cites to the segmentation study from the 1993 rate case, in which BPA used one-line diagrams and power flow studies to determine the type of service or function each facility provided. *Id.* JP12 asserts that Staff did not perform this level of analysis for the segmentation study in this rate period. *Id.* JP12 also argues that Staff did not explain why the methodologies in past segmentations are no longer appropriate and how using a voltage-based bright-line threshold is an adequate substitute, considering the amount of analysis performed for past studies. *Id.*

JP06 and JP12 similarly argue that the 34.5 kV bright-line threshold is “fundamentally inconsistent” with the segmentation of BPA’s transmission rates prior to the non-precedential 1996 Settlement Agreement. JP06 Br., BP-14-B-JP06-01, at 19; JP12 Br., BP-14-B-JP12-01, at 8-9. JP06 argues that Staff failed to explain sufficiently this shift in its approach to segmentation. JP06 Br., BP-14-B-JP06-01, at 19. JP06 contends that an agency is required to explain its determinations in light of seemingly inconsistent factual determinations in earlier proceedings. *Id.* (citing *Humane Society v. Locke*, 626 F.3d 1040, 1053 (9th Cir. 2010)). JP12 argues that many of the facilities that would become part of the Integrated Network segment

under the 34.5 kV bright-line threshold were not considered integrated prior to 1996. JP12 Br., BP-14-B-JP12-01, at 9.

JP12 argues that Staff did not engage in the same level of analysis for determining the costs of facilities that should be included in the Integrated Network segment as it did in determining how those costs should be allocated. *Id.* at 13-15.

MSR argues that Staff's proposal to incorporate all or substantially all of the 1996 study is not supported by evidence demonstrating that there has been insufficient change to warrant a new study. MSR Br., BP-14-B-MS-01, at 9. MSR argues that Staff's refusal to complete a new segmentation study is inconsistent with its obligations to operate the transmission system reliably, fails to provide sufficient documentation to justify rate treatment, and presents a specter of a Balancing Authority without sufficient information about its own system to operate as may be required by the North American Electric Reliability Corporation. *Id.* MSR contends that relying on a 27[sic]-year-old study is inconsistent with current FERC decisions, and that Staff is unable to provide any significant explanation of why no new study is needed despite the significant changes at BPA and in the electric power industry. *Id.* at 10.

### **BPA Staff's Position**

Prior to the 1996 rate case, BPA used power flow studies to determine the operating voltages and ownership of various facilities but did not use them to determine the direction of flow on certain facilities because they represented limited circumstances of direction and magnitude of flows. Bliven *et al.*, BP-14-E-BPA-42, at 34-35. To the extent BPA considered the flow of power, it used meter data instead, because such data encompassed all operating conditions rather than the assumption-based operating conditions inherent in a power flow study. *Id.* at 35. Pre-1996 segmentation studies did not mention meter data because it was rarely used. *Id.* Actual or modeled flow of power was not a consideration for determining the separation between Network and Fringe because the distinction was based on contract use, not actual use or use modeled in a power flow study. *Id.*

The most important factor in the pre-1996 studies was reviewing contracts to determine what points were used to deliver Federal and non-Federal power. *Id.* Based on the points identified in these contracts, BPA would then assign facilities to the Network and Fringe segments. *Id.* As explained in section 4.1.3.1 above, the fundamental industry changes in 1996 changed BPA's segmentation analysis. *Id.* at 16-17.

### **Evaluation of Positions**

JP12 cites to statements from prior segmentation studies to argue that power flow studies were used to determine the type of service or function each facility provided and that this level of analysis is not provided in this rate case. JP12 Br., BP-14-B-JP12-01, at 9. However, the statements from prior segmentation studies regarding the use of power flow studies are not to be read in the manner that JP12 argues. Bliven *et al.*, BP-14-E-BPA-42, at 34-35. In pre-1996 segmentation studies, BPA did not use power flow studies to determine the flow of power on particular facilities to determine their function, because usage was based on contract use, not

actual use or use modeled in a power flow study. *Id.* at 35. Instead, BPA used power flows to assist in determining voltage and facility ownership. *Id.* at 34. Therefore, JP12 errs by reading more into pre-1996 statements about power flow studies than those statements were intended to mean.

JP06's and JP12's charge that Staff did not explain why the methodology used in pre-1996 segmentation studies is no longer appropriate in this rate case is also incorrect. *See* JP06 Br., BP-14-B-JP06-01, at 19; JP12 Br., BP-14-B-JP12-01, at 8-9. The changes that occurred in 1996 that led to the change in segmentation are extensive: unbundled power and transmission rates, open access, functional separation of power and transmission, preference customers diversifying their power sources to include non-Federal power, and comparability. Bliven *et al.*, BP-14-E-BPA-42, at 16-17, 35-37, 39. Prior to 1996, BPA used segmentation to ensure that transmission costs were equitably allocated between Federal and non-Federal power. *Id.* at 39. Under the pre-1996 paradigm, the costs for Federal and non-Federal power were allocated in a two-step process: first the Network was separated from the Fringe and Delivery, and then Network costs were allocated to Federal and non-Federal power based on relative usage. The transmission costs associated with delivering Federal power over the Network were bundled with the costs of the Fringe and Delivery segments into power rates. *Id.* at 16-17, 39. Transmission costs allocated to non-Federal power were recovered through wheeling rates. *Id.* at 15-16.

JP12 argues that many of the facilities that would become part of the Integrated Network segment under the 34.5 kV bright-line threshold were not considered integrated prior to 1996. JP12 Br., BP-14-B-JP12-01, at 9. BPA assumes that JP12's argument does not question the facilities that BPA has segmented to the delivery or intertie segments, because there is no dispute in this proceeding regarding such facilities; the dispute involves facilities that were in the Fringe segment. JP12's statement presumes that facilities that were in the Fringe segment prior to 1996 were not integrated. *Id.* However, pre-1996 Fringe facilities were transmission facilities that were separated from the Network based on one consideration: that such facilities were used almost exclusively to deliver Federal power to load rather than for the wheeling of non-Federal power. Bliven *et al.*, BP-14-E-BPA-42, at 15. This determination was based on contract path rather than whether the facilities were integrated. *Id.* at 35. Thus, there is no basis to claim that former Fringe facilities were not integrated. *See also* Issue 4.1.3.3 above.

In 1996, BPA moved to a policy of open access and functional separation of its power and transmission functions. *Id.* at 16-17, 36-37. Federal preference customers became transmission contract holders and began diversifying their portfolio of resources to include non-Federal power. *Id.* at 16. As a result, the method and manner in which BPA segmented its system needed to change dramatically. *Id.* at 16-17, 36-37. The inclusion of costs associated with Federal power's use of the transmission system in power rates was no longer feasible. *Id.* at 16-17. Today, the bright-line threshold still considers the type of service the facilities provide in determining the proper segmentation. Bliven *et al.*, BP-14-E-BPA-42, at 17, 19, 21-23, 33, 34. However, BPA no longer distinguishes between Federal and non-Federal uses as it did before 1996, since all facilities in the Integrated Network segment can be, and are, used to deliver both Federal and non-Federal power. *Id.* at 16-17. Because the determination of Federal and non-Federal use of each facility is no longer appropriate for segmentation, the analysis of

each facility of the type conducted prior to 1996 is no longer necessary. The bright-line threshold is now applied to distinguish transmission and distribution-like uses.

JP12's assertion that Staff did not describe how a 34.5 kV voltage-based bright-line threshold is an adequate substitute for its pre-1996 analysis is incorrect. *See* JP12 Br., BP-14-B-JP12-01, at 9. Staff's rebuttal testimony fully explains its rationale for proposing a voltage-based bright-line threshold. Bliven *et al.*, BP-14-E-BPA-42, at 29-34. As explained above in Issue 4.1.3.4, the bright-line threshold provides a reasonable delineation between transmission and distribution-like facilities. Analysis of the threshold shows that at least 83 percent of 34.5 kV facilities serve a transmission function. *Id.* at 33-34.

Because conditions have changed, the segmentation based on the bright-line threshold for the proposed BP-14 transmission rates need not depend on any of BPA's past segmentation studies. Segmentation studies from prior cases are informative and helpful in BPA's decision regarding how to segment its transmission system; however, they do not bind BPA with respect to segmentation policy, particularly when current conditions are significantly different from the conditions that existed during prior cases.

JP12 asserts that there is a disparity between the level of analysis Staff performed for network cost allocation and segmentation. JP12 Br., BP-14-B-JP12-01, at 13-15. These are fundamentally different issues driven by very different types of analyses. For cost allocation, Staff considered transmission system planning and evaluated alternative demand tests and other factors relevant to that issue. Transmission Rates Study, BP-14-E-BPA-07, section 4; Fredrickson *et al.*, BP-14-E-BPA-33; Fredrickson *et al.*, BP-14-E-BPA-45. For segmentation, Staff evaluated its proposed segmentation criteria in light of BPA's mission, longstanding transmission policies, and function of facilities. Transmission Segmentation Study, BP-14-E-BPA-06; Transmission Segmentation Study Documentation, BP-14-E-BPA-06A; Messinger *et al.*, BP-14-E-BPA-29; Bliven *et al.*, BP-14-E-BPA-42. The use of the bright-line threshold does not require the increased level of analysis performed for cost allocation issues.

MSR argues that Staff's proposal to incorporate all or substantially all of the 1996 study is not supported by evidence demonstrating that there has been insufficient change to warrant a new study. MSR Br., BP-14-B-MS-01, at 9. MSR states that in the 27 [*sic*] years since the 1996 study was done, the world has changed dramatically. *Id.* MSR asserts that Staff's initial segmentation study simply republishes the 1996 study without any data updates. *Id.* This is not true. The segmentation study presented in this case is a new study, not a repackaging of the 1996 study. Transmission Segmentation Study, BP-14-E-BPA-06; Bliven *et al.*, BP-14-E-BPA-42, at 29. The facilities and associated data are updated to current conditions and reflect facility additions, sales, retirements, and other appropriate changes. *See, e.g.*, Bliven *et al.*, BP-14-E-BPA-42, at 56-58.

### **Draft Decision**

*The level of analysis presented in this proceeding supports a segmentation based on a 34.5 kV bright-line threshold.*

### **Issue 4.1.3.6**

*Whether the 34.5 kV bright-line threshold inappropriately relies on the non-precedential settlement of the 1996 rate case.*

#### **Parties' Positions**

JP06 argues that the 34.5 kV bright-line threshold for segmentation is based exclusively on the segmentation policy adopted in the 1996 rate case, which was the result of a non-precedential settlement. JP06 Br., BP-14-B-JP06-01, at 2-5, 7-12. As a result, JP06 contends, Staff did not perform an adequate study to support its segmentation proposal. *Id.*

JP12 and Powerex also argue that Staff has not supported the 34.5 kV bright-line threshold, and that instead Staff relies upon segmentation policies derived from the 1996 rate case settlement that were intended to be temporary and non-precedential. JP12 Br., BP-14-B-JP12-01, at 3-6; Oral Tr. 273; Powerex Br., BP-14-B-PX-01, at 5, 10-13. Citing Commission precedent, Powerex asserts that it is inappropriate to rely on settlements in litigated proceedings because they are not precedential. *Id.* at 11-12 (citing *Transcontinental Gas Pipe Line Corp.*, 139 FERC ¶ 61,002, at P 63 (2012)). Powerex also argues that Staff has not performed a technical analysis to justify the 34.5 kV bright-line threshold. Powerex Br., BP-14-B-PX-01, at 5.

#### **BPA Staff's Position**

Staff's segmentation study, documentation, and testimony support the Initial Proposal for the bright-line threshold. Bliven *et al.*, BP-14-E-BPA-42, at 29 (citing Transmission Segmentation Study, BP-14-E-BPA-06; Transmission Segmentation Study Documentation, BP-14-E-BPA-06A; Messinger *et al.*, BP-14-E-BPA-29). The analysis Staff presented in the Initial Proposal identified each transmission facility BPA owns, the segment(s) it is assigned to, the total investment for the facility, and the three-year historical O&M costs for the facility. *Id.* Staff fully explained the policy basis of the 34.5 kV bright-line threshold. Bliven *et al.*, BP-14-E-BPA-42.

Staff acknowledged that the 34.5 kV bright-line threshold originated with a non-precedential settlement. *Id.* at 27-28. However, that does not preclude a party to the settlement from making the same proposal in a later rate case. *Id.* The settlement means only that a party cannot rely on the settlement as precedent. *Id.* at 28. Staff did not mention the 1996 rate case settlement in its Initial Proposal because it did not rely on the settlement as precedent in this case. *Id.*

#### **Evaluation of Positions**

JP06, JP12, and Powerex spent a considerable amount of effort in briefs and at oral argument emphasizing that Staff's Initial Proposal relies on the non-precedential settlement from the 1996 rate case. JP06 Br., BP-14-B-JP06-01, at 2-5, 7-12; JP12 Br., BP-14-B-JP12-01, at 3-4; Powerex Br., BP-14-B-PX-01, at 5, 10-13; Oral Tr. 273. In doing so, these parties assert that BPA has failed to support the 34.5 kV bright-line threshold for this rate period.

Although Staff acknowledged that it relied upon the work done in the 1996 case, it did not cite the 1996 settlement, nor its resulting segmentation, as precedent for use of the 34.5 kV bright-line threshold in this case. *See Bliven et al.*, BP-14-E-BPA-42, at 27-28. The 1996 rate case settlement does not preclude Staff from proposing the same segmentation now. More importantly, the record in this case demonstrates that Staff supported the 34.5 kV bright-line threshold based on the policies and facts that exist today.

The Initial Proposal Transmission Segmentation Study, Documentation, and testimony explain the segmentation process, define the segments, and identify each transmission facility BPA owns, the segment(s) it is assigned to, the total investment for that facility, and the three-year historical O&M costs for that facility. Transmission Segmentation Study, BP-14-E-BPA-06; Transmission Segmentation Study Documentation, BP-14-E-BPA-06A; Messinger *et al.*, BP-14-E-BPA-29.

Staff provided significant detail regarding how the 34.5 kV bright-line threshold is consistent with BPA's longstanding uniform rates policy, mission, and "most widespread use" requirement. *Bliven et al.*, BP-14-E-BPA-42. Staff also provided a technical explanation showing how the bright-line threshold provides a reasonable delineation between transmission and distribution-like uses on its system today using the 34.5 kV facilities serving the City of Minidoka, Benton Rural Electrical Association, plus Blachly-Lane Cooperative and six other members of PNGC as examples. *Id.* at 22-23, 33-34. Together with JP03's analysis of the 34.5 kV facilities serving PNGC members, the analyses on the record in this case show that at least 83 percent of BPA's 34.5 kV facilities are performing a transmission function. *Bliven et al.*, BP-14-E-BPA-42, at 33; *see also* Scott and Carr, BP-14-E-JP03-03, at 12-13, Attachment 3.

### **Draft Decision**

*The 1996 Rate Case settlement was non-precedential, and it would be inappropriate to rely on the settlement as precedent. That does not, however, preclude BPA or any other party from proposing a segmentation, based on its own merits, that is the same as that adopted in the settlement. The issue in this case is whether the proposal should be adopted based on the justification offered in this case.*

*The 34.5 kV bright-line threshold to distinguish Network Integration facilities from Utility Delivery facilities is supported independent of the non-precedential settlement agreement from the 1996 rate case. The 34.5 kV bright-line threshold is supported based on policies and facts as they exist on BPA's system today.*

### **Issue 4.1.3.7**

*Whether the 34.5 kV bright-line threshold is inconsistent with BPA's Average System Cost Methodology.*

#### **Parties' Positions**

JP12 argues that it is not appropriate for BPA to apply a 34.5 kV bright-line threshold to its facilities when it requires exchanging utilities to use a 115 kV threshold for average system cost purposes. JP12 Br., BP-14-B-JP12-01, at 22. According to JP12, allowing BPA to include facilities at 34.5 kV and above in its transmission cost component while restricting the exchanging utilities to facilities at 115 kV and above is inconsistent and incorrect. *Id.*

JP06 argues that setting the bright-line threshold at 34.5 kV is inconsistent with BPA's Average System Cost Methodology. JP06 Br., BP-14-B-JP06-01, at 7.

Powerex argues that BPA's current Average System Cost Methodology establishes a bright-line threshold of 115 kV to determine transmission expenses and then determines whether facilities serve a transmission function based on FERC's Seven Factor Test. Powerex Br., BP-14-B-PX-01, at 13. Yet, for its own transmission ratemaking purposes, Staff proposes a bright-line threshold substantially lower (at 34.5 kV). *Id.* at 13-14. Powerex claims that Staff makes no effort to explain this inconsistency. *Id.* at 14.

#### **BPA Staff's Position**

Staff states that BPA's Average System Cost Methodology establishes a backstop threshold; only if a filing utility has not performed the required separation of transmission and distribution does the 115 kV threshold govern. Bliven *et al.*, BP-14-E-BPA-42, at 45. Staff notes that it has never applied this backstop to determine any utility's average system cost. *Id.* Staff documented the various voltage levels that different utilities use in their average system cost filings. *Id.* at 45-46. Most of the voltage levels used for average system cost filings are significantly below 115 kV. *Id.* at 46.

#### **Evaluation of Positions**

BPA developed the 2008 Average System Cost Methodology (2008 ASCM) in conjunction with BPA's implementation of the Residential Exchange Program (REP) established by section 5(c) of the Northwest Power Act. 16 U.S.C. § 839c(c)(1), (7). Under the REP a utility may "sell" power to BPA, which BPA must accept, at its "average system cost" (ASC). BPA then simultaneously "sells" to the utility an equivalent amount of power, which the utility must accept, at a rate BPA develops pursuant to section 7 of the Northwest Power Act. *See generally* 16 U.S.C. § 839e(b)(1), (2). In practice, no actual power is exchanged between BPA and the utility. Instead, the two rates are compared, and if the rate at which the utility sells power to BPA (*i.e.*, the utility's ASC) is higher than the rate at which BPA sells power to the utility (*i.e.*, the PF Exchange rate), then the difference is multiplied by the utility's eligible residential and farm load, and converted into a cash payment to the utility. *See CP Nat'l Corp v. Bonneville*

*Power Admin.*, 928 F.2d 905, 907 (9th Cir. 1991). The 2008 ASCM is a BPA-created rule that provides the administrative rules regarding the permissible costs that may be included in a utility's ASC. The sole purpose of the 2008 ASCM is to generate an ASC for use in the voluntary REP.

The 2008 ASCM permits a participating utility to include transmission costs in its ASC calculation. See 2008 ASCM Final Record of Decision at 125-42. To distinguish between transmission facility costs, which are included in ASC, and distribution facility costs, which are not, BPA includes instructions in Endnote i of the 2008 ASCM. Endnote i provides as follows:

If a Utility has a ruling from its Regulatory Body that separates its transmission and distribution lines using the Commission's seven factor test contained in Order 888, as amended by Order 890, and its FERC Form 1 filing is consistent with the Regulatory Body's order, the Utility will include the transmission-related costs and wheeling revenues directly from its FERC Form 1 filing. However, if a Utility is not required to file a FERC Form 1, or it has not received an order from its Regulatory Body separating its lines between transmission and distribution, then it must perform a Direct Analysis on its transmission costs and wheeling revenues. The Direct Analysis must allocate transmission costs and wheeling revenues so that only the costs and revenues of transmission lines rated at 115kV or above are included as transmission. Alternatively, the Direct Analysis may use the Commission's seven factor test for separating transmission and distribution lines to determine the costs attributable to transmission.

In short, Endnote i of the 2008 ASCM offers a utility participating in the REP two methods for determining transmission-related costs. First, if the utility's regulator has approved the separation of the utility's transmission and distribution lines based on the Commission's Seven Factor Test, and the utility submits a FERC Form 1 to BPA based on that separation, BPA will use the transmission data in the FERC Form 1 in establishing the utility's ASC. Second, if a utility (such as a COU) is not required to file a FERC Form 1, or its regulator has not approved separation of its transmission and distribution lines using the Commission's Seven Factor Test, the utility may use either a bright-line test of 115 kV or perform its own analysis using the Commission's Seven Factor Test.

The recognized authority for distinguishing between transmission and distribution facilities for public utility jurisdictional purposes is Order No. 888. *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC STATS. & REGS. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC STATS. & REGS. ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

In Order No. 888, the Commission undertook, among other things, to develop a series of tests that would assist in the determination of which facilities used for unbundled retail wheeling should be considered local distribution facilities subject to the jurisdiction of the state.

Several parties in the case point to Endnote i of the 2008 ASCM as an example of BPA's inconsistent treatment of its segmentation. Specifically, JP12, JP06, and Powerex argue that it is inconsistent for BPA to require exchanging utilities to use a 115 kV threshold for determining network facilities for average system cost purposes under the 2008 ASCM, but then establish a bright-line threshold of 34.5kV for determining its own network facilities. JP12 Br., BP-14-B-JP12-01, at 22; JP06 Br., BP-14-B-JP06-01, at 7; Powerex Br., BP-14-B-PX-01, at 13-14. These arguments, however, are misplaced because the 2008 ASCM contains no *requirement* that exchanging utilities use the 115 kV limit as the voltage for determining network and distribution facilities.

Rather, the ASCM establishes a *backstop* voltage threshold at 115 kV, which is applied *only if* a utility has not separated its facilities between transmission and distribution. Bliven *et al.*, BP-14-E-BPA-42, at 45. The 2008 ASCM fully permits a utility (or its regulators) to make its *own* determination as to the appropriate separation between transmission and other facilities, and applies the 115 kV limits only *if* the utility chooses not to make any separation. *Id.* Thus, there is no internal inconsistency between BPA's choice of segmentation criteria for its system and the functionalization criteria established in the 2008 ASCM. BPA controls the former, but not the latter.

Powerex also contends that BPA uses both the bright-line 115 kV threshold *and* the Commission's Seven Factor Test to determine transmission facilities in the ASCM, but uses neither of these metrics for its own facilities. Powerex Br., BP-14-B-PX-01, at 13-14. Again, Powerex misstates the 2008 ASCM. As noted above by the plain language in the 2008 ASCM, a utility may choose to use *either* the 115 kV threshold *or* its own direct analysis using the Seven Factor Test. Endnote i does not require the utility to use *both*.

Moreover, the 115 kV threshold in the 2008 ASCM is intended to be a *conservative* measure for transmission. Endnote i is structured to incentivize utilities to separate their systems pursuant to the Seven Factor Test. Both the beginning and the end of Endnote i point to the Commission's test for determining a utility's transmission system. If a utility chooses not to do this work, the 115 kV limit serves as a safe, conservative measure of transmission. This higher limit also means that fewer transmission costs would be included in the utility's ASC, lowering the utility's payments under the REP. Thus, the 115 kV limit in Endnote i of the 2008 ASCM is not intended to be an expression by BPA of the "only correct" means of functionalizing a system. Rather, it was a simple, conservative way of demarcating transmission facilities for purposes of determining an ASC when a utility chooses not to segment its system pursuant to the Commission's factors.

Powerex claims that the 34.5 kV bright-line threshold is "substantially lower" than the thresholds used for establishing average system costs. Powerex Br., BP-14-B-PX-01, at 13-14. However, Staff demonstrates that this is not so. Out of the eight utilities that file for average system costs,

three use thresholds of 46 to 50 kV, generally in the same range as Staff’s 34.5 kV threshold; three others use thresholds of 55 to 69 kV, slightly higher than Staff’s threshold; and two use a threshold of 115 kV. Bliven *et al.*, BP-14-E-BPA-42, at 45-46. No utility uses JP12’s proposal of a 116 kV threshold, including Snohomish, a member of JP12. Furthermore, because Snohomish has no facilities between 12.5 kV and 115 kV, it is uncertain what threshold Snohomish would choose if it had 69 kV or 34.5 kV facilities. *See* Bliven *et al.*, BP-14-E-BPA-42, at 46. This leaves only Portland General (57 kV facilities) with facilities between a lower threshold and 115 kV that it, and the Oregon Public Utility Commission, have chosen, with the Commission’s consent, to functionalize to distribution.

JP12 further argues that both BPA and the exchanging utilities should use the same definition of transmission facilities in order to correctly implement the Northwest Power Act. JP12 Br., BP-14-B-JP12-01 at 22. JP12 offers no basis for this assertion. Neither the 2008 ASCM nor sections 5 and 7 of the Northwest Power Act require BPA to develop its transmission rates to exactly “match” the transmission voltages that utilities include in their ASCs. Rather, the 2008 ASCM Record of Decision requires BPA to include “symmetrical” transmission costs in the PF Exchange rate in response to the same issue raised by Snohomish in 2008. 2008 ASCM ROD at 142. BPA has done so in this case (and has been doing so since 2008). BPA includes the costs of transmission facilities, which include facilities at 34.5 kV and above, in the transmission rates that are part of the PF Exchange rate. As noted above, the 34.5 kV threshold is within the range of thresholds used by most of the utilities that participate in the REP.

### **Draft Decision**

*The determinations of which facilities are transmission facilities for purpose of the ASCM are not relevant to segmentation. The 34.5 kV bright-line threshold does not raise a question of inconsistency with BPA’s ASCM. Each utility is allowed to determine its own demarcation between transmission and distribution, and BPA is not required to match a utility’s determination in setting BPA’s power and transmission rates.*

### **Issue 4.1.3.8**

*Whether positions taken by BPA in other forums are relevant to the determination of whether the 34.5 kV bright-line threshold is appropriate for segmentation.*

### **Parties’ Positions**

JP12 and Powerex argue that BPA has taken positions in other forums that are inconsistent with its proposal of a 34.5 kV bright-line threshold for segmentation. JP12 Br., BP-14-B-JP12-01, at 12-13; Powerex Br., BP-14-B-PX-01, at 5, 13-14. JP12 and Powerex cite BPA’s comments in two consolidated Commission rulemaking dockets (Commission Docket Nos. RM12-6-000 and RM12-7-000) in which BPA argued for a BES definition that included a 100 kV voltage threshold with certain inclusions and exemptions. JP12 Br., BP-14-B-JP12-01, at 13; Powerex Br., BP-14-B-PX-01, at 14. JP12 also cites two Commission proceedings involving Puget Sound Energy (Puget) in which BPA protested Puget’s proposed functionalization of 55 kV facilities and above as transmission. JP12 Br., BP-14-B-JP12-01, at 12-13. Powerex

asserts that BPA relies heavily on Commission ratemaking policy to support its proposed 12 NCP cost allocation methodology in this case while eschewing Commission ratemaking policy in the context of segmentation. Powerex Br., BP-14-B-PX-01, at 14-15.

### **BPA Staff's Position**

The Commission has not used the BES definition for ratemaking purposes. Bliven *et al.*, BP-14-E-BPA-42, at 44. Moreover, the fact that lower-voltage transmission facilities may not be BES facilities does not alter the facts that (1) they are integrated with higher-voltage transmission facilities and (2) they contribute to the transfer of bulk power and support the reliability of the integrated system. *Id.*

In the first Puget proceeding before the Commission, Puget proposed to remove all of its 55 kV and most of its 115 kV facilities from its transmission function to keep them from being placed under the control of the regional transmission organization (RTO) that was being considered at that time. *Id.* at 47. BPA protested because it was concerned that facilities that might be important for regional transmission use and control were being excluded from the RTO in a preemptive move without any examination. *Id.* In the second proceeding, Puget sought to move its 115 kV and 55 kV facilities back into the transmission function. *Id.* at 47. BPA protested because Puget provided no evidentiary support for its inclusion of 55 kV facilities in its transmission function. *Id.* at 48. BPA argued that Puget had not provided enough information supporting the appropriateness of the facility shift. *Id.*

Powerex's assertion that Staff relies heavily on Commission ratemaking policy to support its proposed 12 NCP cost allocation methodology while eschewing Commission ratemaking policy in the context of segmentation was raised for the first time in its initial brief. Therefore, Staff did not have an opportunity to address this assertion.

### **Evaluation of Positions**

JP12 and Powerex cite BPA's comments in a Commission rulemaking docket where BPA argued for a BES definition that included a 100 kV voltage threshold with certain inclusions and exemptions. JP12 Br., BP-14-B-JP12-01, at 13; Powerex Br., BP-14-B-PX-01, at 14. JP12 and Powerex argue that BPA has contradicted its 34.5 kV bright-line threshold proposal by commenting that, because of the West's sparse population and long distances between load pockets, utilities in the WECC use higher-voltage facilities to accomplish what is effectively a distribution function. JP12 Br., BP-14-B-JP12-01, at 13; Powerex Br., BP-14-B-PX-01, at 14.

BPA's reference to what generally constitutes a distribution function throughout the western states should not be construed as a definitive statement that BPA's 115 kV and below facilities serve a distribution function. As explained in Issues 4.1.3.2 and 4.1.3.4 above, BPA's analysis shows that the 34.5 kV bright-line threshold accurately delineates between transmission and distribution-like functions on its system.

The BES definition is irrelevant to BPA's transmission segmentation for establishing transmission rates. The BES definition is used to determine the applicability of NERC reliability

standards; BPA has not found any cases where the Commission has used the BES definition for ratesetting purposes for jurisdictional utilities. *Bliven et al.*, BP-14-E-BPA-42, at 44. There are no reported cases applying that definition to jurisdictional utilities for ratemaking purposes since the BES definition became effective in 2007. In fact, the only case that BPA has found that addresses whether the BES definition has any bearing on ratemaking is *Buckeye v. ATSI. Buckeye Power, Inc. v. Am. Transmission Sys., Inc.*, Initial Decision, 142 FERC ¶ 63,007, 2013 WL 240892 (January 11, 2013). While a final order from the Commission has not yet been issued in that case, the administrative law judge has recommended rolling in non-BES facilities into ATSI's network transmission rates. *Id.* at P 494. Finally, in the NOPR issued prior to Order 773, the Commission expressly acknowledged that facilities that fall outside of the definition of bulk electric system are not necessarily local distribution. *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Notice of Proposed Rulemaking, 77 Fed. Reg. 39857 (July 5, 2012) 139 FERC ¶ 61,247, at P 60 n.79 (2012).

JP12 does not explain why the Commission would disclaim jurisdiction of “local distribution” facilities that are lower than its 100 kV threshold in the reliability context yet retain jurisdiction of these same facilities that the Seven Factor Test indicates are not “local distribution” for state jurisdictional purposes. The reconciliation of this distinction is that a particular facility can be a “local distribution” facility for reliability purposes and simultaneously be a “transmission” facility for jurisdictional and ratemaking purposes. Thus, the fact that BPA's comment in the BES reliability context does not match its ratemaking treatment should not be surprising. The comment was offered in a different Commission inquiry where the context was reliability, not ratemaking.

In comments to the Commission, Snohomish stated that “by mandating a 100 kV bright-line test, [the Commission] will improperly classify many 115 kV *distribution* facilities in the Western Interconnection as bulk electric system facilities.” *Revision to Electric Reliability Organization Definition of Bulk Electric System*, Order No. 743, 133 FERC ¶ 61,150 (2010), *order on reh'g*, Order No. 743-A, 134 FERC ¶ 61,210 (2011) (emphasis added). Snohomish was concerned that its own 115 kV facilities would improperly be swept into the BES when Snohomish believed them to be local distribution under the BES definition. Yet, when claiming benefits from BPA under the REP, *see* Issue 4.1.3.7 above, Snohomish claims its 115 kV facilities are transmission facilities. *Bliven et al.*, BP-14-E-BPA-42, at 46.

If consistency between reliability and rates were the controlling factor, as JP12 implies, it would also apply to those, like Snohomish, that take two views of “local distribution.” Under such a rigid paradigm, a utility must either subject its facilities to NERC for reliability jurisdiction or withdraw its transmission facilities from the REP.

JP12 also cites two proceedings before the Commission involving Puget Sound Energy in which BPA intervened and protested Puget's proposed functionalization on the grounds that Puget had not provided sufficient evidence supporting its proposal. JP12 Br., BP-14-B-JP12-01, at 12-13.

BPA's protests in these proceedings do not impugn the 34.5 kV bright-line threshold. In the first proceeding (Commission Docket No. EL02-77-000), Puget proposed to remove all of its 55 kV and most of its 115 kV facilities from its transmission function to keep them from being placed under the control of the regional transmission organization (RTO) that was being considered at that time. Bliven *et al.*, BP-14-E-BPA-42, at 47. BPA protested because it was concerned that facilities that might be important for regional transmission use and control were being excluded from the RTO in a preemptive move without any examination. *Id.* Even assuming that this case is relevant to segmentation (which it is not), BPA's position in the case actually supports its position here: lower-voltage facilities should have remained in Puget's transmission function. *Id.* at 47-48. In fact, in its protest, BPA cited Commission precedent that noted that "while there is no uniform breakout point between transmission and distribution, it appears that utilities account for facilities operated at greater than 30 kV as transmission and that distribution facilities are usually less than 40 kV." Bonneville Power Administration Motion to Intervene and Protest, Commission Docket No. EL02-77-000 (May 17, 2002) (citing Order 888, FERC STATS. & REGS. ¶ 31,036, at 31,981 n.100).

The question in the Puget proceeding was which facilities belonged under the control of an RTO. Puget's action was an effort to prevent the regional entities considering the RTO to assess Puget's facilities. By refunctionalizing the facilities from transmission to distribution prior to a determination of need by the RTO, Puget was creating the potential of gaps in the formation of a reliable and coherent system for the RTO to manage. Ultimately, Puget refunctionalized the facilities to distribution without further protest from BPA. The RTO never formed, so the question of how Puget's facilities interacted with RTO facilities became moot.

In the second proceeding (Commission Docket No. ER12-778-000), after the specter of an RTO had faded, Puget sought to move its 115 kV and 55 kV facilities back into the transmission function. Bliven *et al.*, BP-14-E-BPA-42, at 47; *see also* Bonneville Power Administration Motion to Intervene and Protest, BP-14-E-PX-01-AT07. BPA protested because Puget provided no evidentiary support for its inclusion of 55 kV facilities in its transmission function. Bliven *et al.*, BP-14-E-BPA-42, at 48. Puget's only support for including the 55 kV facilities in its transmission function was that it planned to upgrade these facilities to 115 kV. As a Puget transmission ratepayer, BPA was concerned that Puget had not provided enough information supporting the appropriateness of the facility shift. *Id.* BPA had a responsibility to its ratepayers to ensure that the costs that BPA was paying to Puget were reasonable and justifiable, no different from the responsibility JP12 and Powerex are exercising in this case. The Puget case ended with a settlement that allowed Puget to return its 115 kV and 55 kV facilities to its transmission function. BPA did not oppose this refunctionalization in the final disposition of the case. *Id.*

Powerex also asserts that Staff relied heavily on Commission ratemaking policy to support its proposed 12 NCP cost allocation methodology while eschewing Commission ratemaking policy in the context of segmentation. Powerex Br., BP-14-B-PX-01, at 14-15. In fact Staff's proposed segmentation is consistent with Commission policy. The Commission has demonstrated a consistent policy favoring rolled-in transmission pricing where the system operates as an integrated whole. *California Dept. of Water Resources v. FERC*, 489 F.3d 1029, 1037-38

(9th Cir. 2007). The 34.5 kV bright-line threshold aligns with the Commission’s pricing policy by rolling in BPA’s network transmission facilities.

### **Draft Decision**

*Positions taken by BPA in other contexts are not at issue here and have no bearing on the decision. As set forth above, the evidence in this case supports the adoption of the 34.5 kV bright-line threshold.*

## **4.2 Transmission Revenue Requirement**

### **4.2.1 Introduction**

The transmission and ancillary services rates being established in this case are designed to recover BPA’s costs as set forth in the transmission revenue requirement. BPA determines generation and transmission revenue requirements using separate repayment studies, consistent with the Commission’s 1984 order. *See United States Dep’t of Energy – Bonneville Power Admin.*, 26 FERC ¶ 61,096 (1984). Rates to recover the costs set forth in BPA’s generation revenue requirement are being established in the power portion of the BP-14 case. The costs established in the power portion of the case also include inter-business line costs that one business line charges to the other. For example, Power Services charges Transmission Services for the costs of generation inputs used to provide ancillary services and for the annual costs of the U.S. Army Corps of Engineers and U.S. Bureau of Reclamation transmission facilities that are included in the network and utility delivery segments. Transmission Services establishes ancillary and control area services rates to recover these costs and passes the revenues on to Power Services. For additional information, please see Part 3, Generation Inputs Topics.

Consistent with BPA’s statutory obligations, the transmission revenue requirement establishes the level of revenue required to recover all of BPA’s costs of transmitting electric power, which include the Federal investment in transmission and transmission-supporting facilities; operations and maintenance (O&M) expenses; transmission marketing and scheduling expenses; the cost of generation inputs for ancillary services and reliability; and all other transmission-related costs incurred by the Administrator. Transmission Revenue Requirement Study (Study), BP-14-E-BPA-08, section 1.1.

### **4.2.2 Revenue Requirement Development**

BPA develops its revenue requirement to recover its costs in conformance with its statutory obligations and the financial, accounting, and repayment requirements of the Department of Energy’s Order No. RA 6120.2. *Id.*

BPA calculated its transmission revenue requirement for the FY 2014–2015 rate period using a cost accounting analysis consisting of three components:

- Repayment studies are conducted for each year of the two-year rate period to determine the schedule of amortization payments and to project annual

- interest expense for bonds and appropriations that fund the Federal investment in transmission. Repayment studies include a 35-year repayment period.
- Operating expenses functionalized to transmission and minimum required net revenues (if needed) are projected for each year of the rate period (FY 2014–2015).
  - Annual planned net revenues for risk (PNRR), if any, are determined based on the risks identified, BPA’s cost recovery goals, and risk mitigation measures.

*Id.*

Based on these analyses, BPA sets the transmission revenue requirement at the revenue level necessary to fulfill BPA’s cost recovery requirements. Department of Energy Order No. RA 6120.2 requires that BPA demonstrate the adequacy or inadequacy of its existing rates to recover its costs. BPA conducts a current revenue test to determine whether transmission revenues projected from current rates meet cost recovery requirements for the rate test and repayment periods. If the current revenue test indicates that cost recovery and risk mitigation requirements can be met, BPA can extend current rates. BPA determined that current rates were insufficient to demonstrate cost recovery. *Id.* Accordingly, the current revenue test was not met.

After calculating proposed rates, BPA conducts a revised revenue test to determine the adequacy of the proposed rates. The revised revenue test determines whether projected revenues from proposed rates will meet cost recovery requirements for the rate test and repayment periods. BPA has proposed to increase the transmission rates to ensure cost recovery. The revised revenue test demonstrates that the rates proposed are sufficient to meet cost recovery requirements for the rate test and repayment periods. *Id.*

#### **4.2.3 Assumptions About the Use of Financial Reserves Attributable to Transmission**

In the Initial Proposal, as in the previous four rate cases, BPA proposed to use \$15 million of cash reserves attributable to Transmission Services (generally referred to below as reserves or financial reserves) in each year of the FY 2014–2015 rate period (a total of \$30 million in the two-year rate period) as a funding source for transmission capital programs, rather than using Treasury borrowing authority. This reserve financing assumption is included in the rate period revenue requirements. Homenick *et al.*, BP-14-E-BPA-31, at 6. The use of additional financial reserves attributable to Transmission to mitigate the proposed rate increase is discussed in section 4.2.5.5 below.

#### **4.2.4 Transmission Risk Analysis**

In the 1993 Final Record of Decision, BPA determined that, as a long-term policy, it would set its rates to maintain financial reserves sufficient to achieve at least a 95 percent probability of meeting Treasury payments in full and on time for each two-year rate period. 1993 Final ROD, WP-93-A-02, at 72-73.

The probability of meeting BPA's Treasury payment obligation is the primary measure of BPA's ability to recover its costs. BPA has applied the same risk analysis for the FY 2014–2015 rate period as in the past. Lovell *et al.*, BP-12-E-BPA-32, at 2. To achieve the 95 percent Treasury Payment Probability (TPP), BPA used the following risk mitigation tools:

1. *Starting reserves*: Starting financial reserves include cash and the deferred borrowing balance attributed to the transmission function. Study, section 2.2.1.
2. *Planned Net Revenues for Risk*: PNRR is a component of the revenue requirement that is added to annual expenses. PNRR adds to cash flows so that financial reserves are sufficient to mitigate short-run volatility in costs and revenues and achieve the TPP goal. No PNRR was required to meet the TPP standard in this rate filing. *Id.*
3. *Two-Year Rate Period*: The rates established in this record will be effective for two years. The ability to revise rates after two years, or more frequently if necessary, serves as an important risk mitigation tool. A two-year rate period limits the effects of uncertainty. *Id.* Moreover, BPA retains the right to raise rates during the rate period if necessary.

To quantify risks, BPA used a Monte Carlo simulation method to analyze the effects of uncertainty in costs and revenues on transmission cash flows. The analysis estimated the probability of successful Treasury payment (on time and in full) for both years of the rate period. Successful Treasury payment is deemed to occur when end-of-year Transmission financial reserves, after Treasury payments are made, are sufficient to cover the transmission liquidity reserves requirement of \$20 million. The liquidity reserves threshold is based on the monthly net cash flow patterns and requirements for the transmission function. *Id.* section 2.2.2.

The risk analysis covers the period FY 2013 through FY 2015. This timeframe is used to permit analysis of the change in revenues, costs, and accrual-to-cash adjustments that are expected to occur between the development of the Final Proposal and the end of the rate period. The advantage of this approach is that financial reserves at the start of the FY 2014–2015 rate period may be estimated, thus helping to define the starting conditions for the rate period. *Id.*

The Monte Carlo simulation is conducted in a spreadsheet model that incorporates the effects of risk and risk mitigation to provide an estimate of start-of-year financial reserves for the first year of the rate period and end-of-year financial reserves for each year of the rate period. The estimates of end-of-year financial reserves are used to determine the probability of Treasury payments being made during the rate period. Financial reserve levels at the end of a fiscal year determine whether BPA is able to meet its Treasury payment obligation. *Id.* section 2.2.3. If financial reserves are sufficient to cover working capital requirements at the end of the fiscal year, it can be assumed that the Treasury payment was made in full and on time that fiscal year. *Id.* section 2.2.2.

The transmission risk analysis conducted for this rate case demonstrated that the 95 percent Treasury Payment Probability standard is exceeded for the FY 2014–2015 rate period. *Id.*

section 2.2.4. The risk analysis simulation included the use of \$30 million in reserves attributable to Transmission Services to fund capital projects. *Id.* section 2.2.2. Specific issues raised with respect to the revenue requirement and risk analysis, including issues regarding financial reserves attributable to Transmission Services, are addressed below.

#### **4.2.5 Issues**

##### **Issue 4.2.5.1**

*Whether BPA must use financial reserves attributable to Transmission to offset costs and reduce rates to ensure that rates are established “with a view to encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles.”*

##### **Parties’ Positions**

Iberdrola and ICNU argue that using reserves to offset costs and reduce the proposed rate increase would be consistent with encouraging the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles. Iberdrola Br., BP-14-B-IR-01, at 12; ICNU Br., BP-14-B-IN-01, at 3. JP04 asserts that BPA should apply some of its available transmission reserves to reduce the amount of transmission revenue requirement to be recovered through rates in order to satisfy the statutory requirement that BPA adopt the lowest possible rates consistent with sound business principles. JP04 Br., BP-14-B-JP04-01, at 2. Powerex argues that by proposing to further increase PTP rates when substantial amounts of reserves are available, BPA is not establishing the lowest possible rates, and that BPA has not shown that “‘sound business principles’ require it to both maintain excessive reserve balances and to further increase rates.” Powerex Br., BP-14-B-PX-01, at 34–35.

##### **BPA Staff’s Position**

BPA Staff did not address this issue because it is a legal issue. Homenick *et al.*, BP-14-E-BPA-44, at 21. Staff indicated that it is committed to exploring uses of reserves that would provide long-term benefit to the transmission system, but that BPA is not required to use reserves in any particular manner. *Id.* at 18.

##### **Evaluation of Positions**

Iberdrola argues that “amortizing the over-collection of transmission revenues is consistent with BPA’s directives to set transmission rates at the lowest possible level, consistent with sound business principles.” Iberdrola Br., BP-14-B-IR-01, at 12. ICNU asserts that using excess reserves to offset the proposed rate increase for transmission services “would be consistent with BPA’s mission ‘to encourage the widest possible diversified use of electric power at the lowest possible rates consistent with sound business principles.’” ICNU Br., BP-14-B-IN-01, at 3. Powerex argues that BPA is not establishing the lowest possible rates by proposing to further increase PTP rates when substantial amounts of reserves are available, and that BPA has not shown that “‘sound business principles’ require it to both maintain excessive reserve balances and to further increase rates.” Powerex Br., BP-14-B-PX-01, at 34–35. JP04 asserts that in

order to satisfy the statutory requirement that BPA adopt the lowest possible rates consistent with sound business principles, BPA should apply some of its available transmission reserves to reduce the amount of transmission revenue requirement to be recovered through rates. JP04 Br., BP-14-B-JP04-01, at 2. JP04 also asserts that charging rates that reflect full cost recovery, instead of using reserves to reduce rates, would be “in contravention of BPA’s obligation to ensure that rates are as low as possible consistent with sound business principles.” JP04 Br., BP-14-B-JP04-01, at 17.

Section 9 of the Transmission System Act provides in part that rate schedules for the sales of electric power and for the transmission of non-Federal electric power over the Federal transmission system shall be fixed and established “with a view to encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles.” 16 U.S.C. § 838g. Similarly, section 5 of the Flood Control Act of 1944 provides in part that BPA shall dispose of the power that it markets “in such manner as to encourage the most widespread use thereof at the lowest possible rates to consumers consistent with sound business principles.” 16 U.S.C. § 825s.

Whether BPA’s rates have been set with “a view to encourage the widest possible diversified use ... at the lowest possible rates consistent with sound business principles” “is a matter for BPA to decide, subject to judicial review.” *Bonneville Power Admin.*, 32 FERC ¶ 61,014, at 61,052 (1985). It is not a matter for Federal Energy Regulatory Commission review. *Id.* at 61,057; *see also* 16 U.S.C. § 839e(a)(2).

As noted in the BP-12 Administrator’s Record of Decision, the Ninth Circuit Court of Appeals has found that the responsibility of “encouraging ... the lowest possible rates to consumers” is not a mandate to set the lowest rates possible without regard to any other business or legal principle. 2012 Wholesale Power and Transmission Rate Adjustment Proceeding, Administrator’s Final Record of Decision, BP-12-A-02, at 127. As the Court has explained:

the statutes do not dictate that BPA always charge the lowest possible rates. 16 U.S.C. § 838g directs that rates be set “with a view to encouraging ... the lowest possible rates to consumers....” The words “with a view to encouraging” do not constitute a statutory command that the prices charged to consumers always be the lowest possible. Moreover, nearly every action by BPA has some arguable impact on future rates. If the strict interpretation of the “lowest possible rates” standard [were made] ... the discretion that Congress vested in the Administrator would be eliminated.... In addition, the direction to charge the lowest possible rates is tempered by the addition of the clause “consistent with sound business principles.” 16 U.S.C. § 838g.

*Id.* at 127-28 (quoting *California Energy Comm’n v. Bonneville Power Administration*, 909 F.2d 1298, 1307 (9th Cir. 1990)).

The Ninth Circuit has held that the obligation to operate according to “sound business principles” affords BPA discretion to operate with a business-oriented philosophy. *Public Power Council v.*

*BPA*, 442 F.3d 1204 (9th Cir. 2006) (“*PPC*”); *Association of Pub. Agency Customers, Inc. v. BPA*, 126 F.3d 1158, 1171 (9th Cir. 1997) (“*APAC*”); *Department of Water & Power of the City of Los Angeles v. BPA*, 759 F.2d 683 (9th Cir. 1985) (“*LADWP*”). Congress “has delegated to BPA the discretion to determine ‘how best to further BPA’s business interests consistent with its public mission.’” *Alcoa, Inc. v. Bonneville Power Admin. (Alcoa)*, 698 F.3d 774, 789 (9th Cir. 2012) (quoting *APAC*, 126 F.3d at 1171).

It is not the case that BPA *must* use financial reserves attributable to Transmission in this rate case to reduce rates to satisfy the directive to establish rates “with a view to encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles.” 16 U.S.C. § 838g. The parties’ proposals to use as much as \$100 million or more of reserves to reduce rates would create risk to BPA’s credit rating and higher interest costs and would do nothing for the long-term benefit of the transmission system. Homenick *et al.*, BP-14-E-BPA-44, at 14-21. BPA is capital-constrained and, in today’s political climate, the likelihood of securing additional Federal borrowing is unlikely. As such, the parties’ proposals are not consistent with sound business principles, even if the proposed use of reserves would result in lower rates in the FY 2014–2015 rate period.

In its rebuttal testimony, Staff described several concerns with the parties’ proposals to use significant amounts of reserves. *Id.* at 15-17. Staff persuasively testified that using what would amount to one-third of the agency’s total reserves could very likely be viewed negatively by credit rating agencies, possibly enough for them to downgrade BPA’s credit rating. *Id.* at 15. BPA was downgraded immediately after it filed its BP-12 rates with FERC, “in large part because reserves had declined by 36 percent during 2009 and 2010 (approximately the same proportion that the parties would have us commit to rate relief) and were expected to further decline as a result of the filed rates.” *Id.* Staff explained that the rating agencies judge BPA as a whole and that its credit rating depends on the financial health of the entire agency. *Id.* at 15-16. Therefore, BPA cannot consider reserves attributable to Transmission Services in isolation. Staff also explained the importance of BPA’s credit rating and provided examples of the increase in interest expense that a downgrade could have. *Id.* at 16–17. This unrebutted testimony by BPA’s expert witnesses provides a reasoned and thorough examination of the risks of the parties’ proposals. It demonstrates that it would not be reflective of sound business principles to adopt the proposals to use \$100 million or more of reserves in each year of the rate period to offset costs and reduce rates.

On the other hand, Staff’s testimony demonstrates that rates have been set to recover costs and that there are several other uses of reserves that could have long-term benefits to the transmission system. *Id.* at 2, 19-20. For example, reserves could be used to fund capital investment or to repay Treasury bonds in excess of the payments already planned for the year. *Id.* at 19–20. Either of these uses would increase Treasury borrowing authority and reduce interest expense and would help BPA ensure continuing access to capital. *Id.* at 20. Further, BPA could hold reserves in the Bonneville Fund or invest them in Treasury securities. *Id.* at 19. In both cases the reserves would earn interest, which would offset interest expense and reduce costs, provide support for BPA’s credit ratings, and provide a buffer for unexpected fluctuations in costs. *Id.* Staff also acknowledged that smaller amounts of reserves could be used to reduce rates, possibly

over several rate periods to ease the transition to natural rate levels, while potentially creating less risk of a credit rating downgrade and still leaving reserves available for other purposes. *Id.* at 20-21. This testimony provides reasoned evidence of alternative uses of reserves and their long-term benefits to the transmission system. These long-term benefits demonstrate that a decision to adopt an alternative use of reserves, including using a lesser amount to reduce rates, would be in furtherance of BPA’s business interests consistent with its public mission and would be consistent with sound business principles.

JP04 asserts that the evidence provided in Staff’s rebuttal testimony is speculative and “without quantification or adequate support.” JP04 Br., BP-14-B-JP04-01, at 14-15. JP04 asserts that Staff’s “objections have no reasoned basis.” *Id.* at 17. JP04 also states that failing to use reserves to offset costs in this case is “unjustified and is arbitrary and capricious.” *Id.* at 11. Powerex also asserts that Staff’s testimony is speculative. Powerex Br., BP-14-B-PX-01, at 37. However, Staff has provided persuasive evidence to support its position, as described above. Staff identified the risks of using \$100 million or more of reserves per year of the rate period to offset costs and explained why it was concerned that doing so could lead to a credit rating downgrade. It is not possible to predict with certainty how rating agencies will react. *See Homenick et al.*, BP-14-E-BPA-44, at 15. In light of that uncertainty, Staff provided its expert opinion, based on its observations and knowledge, regarding possible outcomes of the parties’ proposals and of several alternatives. *Id.* at 14-21. Staff has justified and supported its position.

Staff’s testimony provides persuasive evidence that adopting the proposals to use a large amount of reserves, as some parties propose, could have negative impacts on BPA’s credit rating and thus could increase costs for customers overall. As such, using a large amount of reserves to offset costs would not be consistent with sound business principles, even if it would result in lower rates in this rate case. Further, Staff’s testimony discusses alternatives that would provide a benefit to the transmission system and lower overall costs to customers, whether through reduced interest expense or increased income or preservation of Treasury borrowing authority. *See Homenick et al.*, BP-14-E-BPA-44, at 18–21. These benefits could extend over multiple rate periods, rather than only one rate period. *Id.* Therefore, any of these uses reflects sound business judgment in furtherance of BPA’s mission and is consistent with sound business principles.

### **Draft Decision**

*The requirement to establish rates “with a view to encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles” does not require that BPA use reserves attributable to Transmission in this rate case to offset costs and reduce rates.*

### **Issue 4.2.5.2**

*Whether the 95 percent TPP standard is a minimum threshold to satisfy repayment requirements and a maximum threshold to keep rates as low as possible.*

### **Parties' Positions**

JP04 asserts that the TPP standard of 95 percent should not be treated “merely as a floor” and that instead this standard was intended to measure both whether rates are sufficient to meet repayment requirements and whether they are as low as possible consistent with sound business principles. JP04 Br., BP-14-B-JP04-01, at 3-4. JP04 argues that a TPP of 99.9 percent indicates that the rates are higher than permitted by BPA’s statutes. *Id.* at 8.

### **BPA Staff's Position**

Because this issue was raised for the first time in JP04’s initial brief, Staff has not had an opportunity to respond. In general, Staff’s testimony indicated that if TPP is at least 95 percent (that is, Treasury payment was made in both years of the rate period in at least 95 percent of the transmission risk analysis model’s 3,500 games), the TPP standard has been met; and that when TPP meets or exceeds 95 percent, no further action is required. Staff’s testimony also indicated that, if the TPP threshold is met, it has no effect on rates. Lovell *et al.*, BP-14-E-BPA-32, at 2; Homenick *et al.*, BP-14-E-BPA-44, at 3.

### **Evaluation of Positions**

JP04 argues that the 95 percent TPP standard “should not be treated merely as a floor.” JP04 Br., BP-14-B-JP04-01, at 8. JP04 appears to be responding to BPA’s explanation in its rebuttal testimony that “when TPP is below 95 percent, the resulting action is typically to raise it to 95 percent by including sufficient PNRR in the revenue requirement. When TPP meets or exceeds 95 percent, no action is required, and TPP has no effect on rate levels.” Homenick *et al.*, BP-14-E-BPA-44, at 3. As Staff explained:

TPP has no bearing on revenue requirements and, thereby, on rates unless Planned Net Revenue for Risk (PNRR) is included. The basis for BPA to set rates is to recover the costs identified in the Revenue Requirement Study (Study), BP-14-E-BPA-08. Rates are established at the lowest level such that the forecast of total revenues in the rate period will be at least equal to the forecast of total expenses, and the forecast of cash inflow will be at least equal to the total of all cash requirements in the rate period. After rates are calculated and resulting revenues forecast, the risk analysis tests whether sufficient reserves available for risk attributable to Transmission (TS Reserves) are available to meet the 95 percent TPP standard. If TPP is below the 95 percent standard, PNRR is added to the revenue requirement. Since TPP exceeded the 95 percent standard in the Initial Proposal, no PNRR was necessary. There is no other way in which TPP affects the revenue requirement. Consequently, TPP did not cause rates to be higher than

they otherwise would have been. Homenick *et al.*, BP-14-E-BPA-44, at 2 (internal citations omitted).

The Transmission Revenue Requirement Study included a similar explanation, noting that the appropriate amount of PNRR to add to the revenue requirement when TPP is below 95 percent is the amount that is just sufficient to increase TPP until it meets the TPP standard. Study, BP-14-E-BPA-08, at 17. Thus, rates are established at the lowest level that ensures that the revenue requirement is recovered—that the forecast of revenues is at least equal to the forecast of expenses, and the forecast of cash inflow will at least equal cash requirements. Homenick *et al.*, BP-14-E-BPA-44, at 2. The mechanisms for testing rates to ensure that they are adequate to recover the revenue requirement are the current and revised revenue tests. Study, BP-14-E-BPA-08, at 28-30. The only way in which TPP has any impact in this calculation is if TPP is below 95 percent and PNRR must be added to the revenue requirement. Homenick *et al.*, BP-14-E-BPA-44, at 2.

JP04 states that a TPP of 95 percent “is reflective of rates that are consistent with sound business principles and BPA’s ability to meet its statutory mandates.” JP04 Br., BP-14-B-JP04-01, at 8. JP04 apparently refers to section 9 of the Transmission System Act, which provides that rate schedules for the sales of electric power and for the transmission of non-Federal electric power over the Federal transmission system shall be fixed and established “with a view to encourage the widest possible diversified use of electric power at the lowest possible rates to consumers consistent with sound business principles.” 16 U.S.C. § 838g. JP04 argues that the 95 percent standard was intended to measure whether rates are sufficient to meet repayment requirements and whether they are as low as possible consistent with sound business principles. JP04 Br., BP-14-B-JP04-01, at 6.

The 95 percent TPP standard is a policy tool BPA adopted to help ensure that it can make its Treasury payments in full and on time during the rate period. Study, BP-14-E-BPA-08, at 16. It is not a statutory requirement or standard. The fact that it may be exceeded, or, for that matter, may not be met in a particular rate period does not indicate that rates violate BPA’s statutes. *See id.* The TPP standard measures the probability of Treasury repayment; if the 95 percent standard is met, then TPP has no effect on rate levels. Homenick *et al.*, BP-14-E-BPA-44, at 2.

JP04 bases its assertion that the 95 percent standard was intended to measure whether rates are as low as possible consistent with sound business principles on quotes from the Administrator’s Record of Decision from the 1993 Wholesale Power and Transmission rate case (1993 ROD), in which the 95 percent standard was adopted. JP04 Br., BP-14-B-JP04-01, at 6, 8; 1993 ROD, WP-93-A-02, at 72-73.

The 1993 ROD evaluated BPA Staff’s proposal to adopt, consistent with BPA’s Financial Plan, a long-term Treasury payment probability standard of 95 percent for each two-year rate period as a whole (that is, looking at the rate period as one unit of time). 1993 ROD at 69. Parties had proposed a 95 percent average annual standard, in which the average of the probabilities of making full Treasury payment in each year for five years was at least 95 percent. *Id.* at 69, 71. In evaluating the positions, the 1993 ROD demonstrated that “when put in comparable two-year

rate period terms to BPA’s proposed long-term 95 percent standard, the [parties’] average 95 percent proposal results in only a 90 percent standard over a 2-year rate period.” *Id.* at 71. The 1993 ROD also explained that the “long-term certainty of BPA’s continued success of meeting Treasury payments would be significantly diminished under the [parties’] proposal.” *Id.* (quoting testimony at WP-93-E-BPA-20, at 9). Thus, the 1993 ROD evaluated the 95 percent standard against a proposed *lower* standard.

The 1993 ROD explained why the 95 percent standard for each two-year rate period was warranted:

As a matter of policy, the 95 percent probability Treasury payment standard proposed by BPA is fully warranted, rather than the lesser probability standard advocated by the Joint Customers. It reflects consideration and balancing of BPA’s responsibilities to keep rates as low as possible while ensuring its ability to carry out its legally mandated responsibilities required under the Northwest Power Act in a sound and businesslike manner. This necessitates that a very high priority be placed on making Treasury payments in full and on time and is accomplished through the 95 percent long-term Treasury payment probability standard.

*Id.* at 71. The Record of Decision indicates that the lower standard was advocated for by parties that were opposed to any rate increases or additional costs needed to achieve the rate period 95 percent standard. *Id.* at 71-72. These parties essentially argued that the additional Treasury payment certainty achieved by BPA’s proposed standard was not worth the additional cost. *Id.* at 72. The 1993 ROD addressed these arguments, stating:

These arguments speak to the issue discussed earlier of the need to weigh and determine the appropriate balance of BPA maintaining the lowest rates possible while meeting its cost recovery requirements, which includes making its full annual payments to Treasury on time. As discussed above, BPA has weighed these considerations and believes the 95 percent rate period Treasury payment policy is entirely appropriate. The [parties’] proposed lesser standard would significantly reduce the long-term certainty of BPA’s ability to fully recover costs and meet its Treasury payments in full and on time.

*Id.* JP04 quotes the statements regarding the 95 percent TPP standard as “balancing ... BPA’s responsibilities to keep rates as low as possible while ensuring [BPA’s] ability to carry out its legally mandated responsibilities required under the Northwest Power Act in a sound and businesslike manner” and interprets the statements to indicate that the 95 percent TPP standard should not be treated as a floor. JP04 Br., BP-14-B-JP04-01, at 8. This interpretation is not consistent with the context in which the Administrator adopted the 95 percent standard. As described above, certain parties were arguing that the TPP standard should be *lower* than 95 percent. In response, the Administrator described how the 95 percent standard struck an appropriate balancing of BPA’s statutory requirements. The language does not support an

interpretation or conclusion that a calculated TPP *above* 95 percent, even one of 99.9 percent, is not appropriate or, in JP04's words, is "not permitted."

Further, the 1993 ROD demonstrates that the 95 percent TPP standard is a long-term policy that BPA adopted to support Treasury repayment, not to satisfy other statutory provisions. 1993 ROD, WP-93-A-02, at 72. The 1993 ROD described the TPP as a measure of whether rates are adequate to achieve the 95 percent level of assurance of meeting Treasury payments, and it described measures that could be used to increase rates or reduce costs if rates were not adequate:

The most fundamental aspect of the Financial Plan is the long-term policy that BPA will adopt which establishes the level of assurance of meeting Treasury payments that rates must achieve, and the specific elements, or measures, that will be adopted to achieve that level of assurance, *i.e.*, planned net revenues for risk, the cost deferral mechanism, and the [Interim Rate Adjustment]. Once these policies are finally adopted at the conclusion of this rate case, they will be applied in subsequent rate cases, and the adequacy of rate levels will be tested and established consistent with the overall Treasury payment probability standard adopted.

*Id.* The Administrator concluded in the 1993 ROD that "[a]s a long-term policy, BPA will plan to set its rates to maintain financial reserves sufficient to achieve a 95 percent probability of meeting Treasury payments in full and on time for each 2-year rate period." *Id.* Taken as a whole, the statements in the 1993 ROD fully justify adoption of the 95 percent standard as a tool to support Treasury repayment. The statements do not support an interpretation that the 95 percent standard was also intended to be a measure to determine whether rates have been set "with a view to encouraging the widest possible diversified use of electric power at the lowest possible rates ... consistent with sound business principles." 16 U.S.C. § 838g.

The interpretation now advocated by JP04 has not been advocated for by rate case parties nor adopted by BPA in any previous rate case, and BPA has not taken action in any rate case to adjust a TPP that is above the 95 percent standard down to the 95 percent level. *See* 2002 Final Power Rate Proposal Administrator's Record of Decision, WP-02-A-02, Ch. 7; 2002 Supplemental Power Rate Proposal Administrator's Record of Decision, WP-02-A-09, Ch. 4; 2002 Final Transmission Proposal Administrator's Record of Decision, TR-02-A-01, at 22; 2007 Wholesale Power Rate Case Administrator's Record of Decision, WP-07-A-02, at 5-2; 2007 Supplemental Wholesale Power Rate Case Administrator's Record of Decision, WP-07-A-05, at 308; 2010 Wholesale Power and Transmission Rate Adjustment Proceeding Administrator's Record of Decision, WP-10-A-02/TR-10-A-02, at 41-49; 2012 Wholesale Power and Transmission Rate Adjustment Proceeding Administrator's Record of Decision, BP-12-A-02, at 107.

The evidence in the record supports the 95 percent TPP standard as a minimum threshold. The 95 percent standard does not represent a maximum level that should not be exceeded.

## **Draft Decision**

*The 95 percent TPP standard does not represent a maximum level that should not be exceeded. A higher TPP is not inconsistent with BPA’s obligation to establish the lowest possible rates consistent with sound business principles.*

### **Issue 4.2.5.3**

*Whether the TPP calculated in the Initial Proposal indicates that rates are too high.*

### **Parties’ Positions**

Parties argue that a TPP result that is greater than the 95 percent standard means that rates are too high. Iberdrola states that the TPP calculated in the Initial Proposal “causes the transmission rates to be higher than they otherwise would be.” Iberdrola Br., BP-14-B-IR-01, at 10. Powerex argues that a “higher TPP (99.9 percent) virtually guarantees that rates will continue to over-collect the revenue requirement upon which they are based” and that “[u]se of the 95 percent TPP standard to set rates ensures that Transmission Reserve balances will continue to grow.” Powerex Br., BP-14-B-PX-01, at 34, 36. JP04 states that the proposed rates result in a TPP that far exceeds the 95 percent threshold. JP04 Br., BP-14-B-JP04-01, at 3.

### **BPA Staff’s Position**

TPP plays no role in the rate levels unless planned net revenues for risk (PNRR) must be added to the revenue requirement. Homenick *et al.*, BP-14-E-BPA-44, at 2. Since the Initial Proposal revenue requirement did not include PNRR, TPP did not influence the proposed rates. *Id.*

### **Evaluation of Positions**

Parties assert that a TPP result that is higher than the 95 percent standard means that rates are being set too high. Iberdrola Br., BP-14-B-IR-01, at 10; Powerex Br., BP-14-B-PX-01, at 34. Neither Iberdrola nor Powerex offers any support for this contention. The parties’ briefs simply repeat the assertions their witnesses made in testimony without any attempt to address Staff’s rebuttal of their positions. JP04 extends this argument to assert that the 95 percent standard should not be viewed as a minimum standard. JP04 Br., BP-14-B-JP04-01, at 4, 6. This argument is addressed in Issue 4.2.5.2.

The parties may misunderstand how BPA sets its rates and the role that TPP plays. Rates are set to meet two standards. First, the forecast of total revenues must at least equal the forecast of total expenses. Study Documentation, BP-14-E-BPA-08A, Chapter 1.3. Second, the forecast of cash inflow must at least equal the sum of all cash requirements in the rate period. *Id.* Once rates are calculated, the risk analysis tests whether there will be sufficient reserves on hand during the rate period to meet the 95 percent TPP standard. Homenick *et al.*, BP-14-E-BPA-44, at 2. If TPP is below 95 percent, PNRR is added to the revenue requirement until the 95 percent TPP standard is met. *Id.* Simply put, TPP cannot affect proposed rates unless it is so low that

PNRR must be added to the revenue requirement *Id.* The Initial Proposal revenue requirement did not include PNRR. Study, BP-14-E-BPA-08, Table 3. Therefore, the TPP result does not affect the calculated rates.

Powerex does not explain its concern that the high TPP means BPA will over-collect the revenue requirement, and its concern is misplaced. As noted previously, because there was no PNRR in the Initial Proposal, the TPP result does not affect the revenue requirement. Homenick *et al.*, BP-14-E-BPA-44, at 2. The risk analysis, which calculates TPP, estimates only “the probability that financial reserves available for risk at the start of the rate period plus the cash flow during the rate period will be sufficient to meet all cash obligations during the rate period.” Study, BP-14-E-BPA-08, at 18. The risk analysis estimated that reserves available for risk attributable to Transmission would actually decline over the rate period, from \$437.2 million to approximately \$380 million. Study Documentation errata, BP-14-E-BPA-08A-E02, Table 10-3. As a result, the TPP result merely means that the forecast revenues from proposed rates and rate period reserves balances are sufficient to meet cash obligations and nothing more.

### **Draft Decision**

*The TPP result greater than the 95 percent TPP standard does not mean that rates are too high.*

### **Issue 4.2.5.4**

*Whether the Transmission Risk Analysis Model (TRAM) should include the calibration adjustment proposed by Staff to adjust for uncertainty in net revenues.*

### **Parties’ Positions**

JP04 argues that the calibration adjustment used in TRAM arbitrarily lowers the TPP calculation for transmission rates and should be rejected. JP04 Br., BP-14-B-JP04-01, at 18.

### **BPA Staff’s Position**

Without the calibration adjustment, TRAM would underestimate the uncertainty in net revenues when it calculates TPP and would thus overestimate TPP. Lovell *et al.*, BP-14-E-BPA-32, at 6. The calibration adjustment should be applied to correct this modeling error. *Id.* at 5-6.

### **Evaluation of Positions**

JP04 asserts that BPA has persistently underforecast net revenues for FY 2008-2012. JP04 Br., BP-14-B-JP04-01, at 20. JP04 further asserts that “[n]otwithstanding this persistent underforecasting of TS net revenues, BPA erroneously concludes that (i) the risk in forecasting TS net revenues is inadequately reflected in the modeled net revenues, and (ii) the calibration adjustment should be made to reflect otherwise unreflected risk in forecasting TS net revenues.” *Id.*

Staff measures TPP for transmission rates using TRAM. Lovell *et al.*, BP-14-E-BPA-32, at 2-3. Staff included a “calibration adjustment” to TRAM in the risk analysis for the Initial Proposal after Staff’s statistical comparison of historical forecast errors with the variability of TRAM output indicated that TRAM was underestimating the uncertainty or variability in forecast net revenue. *Id.* at 5-6. Underestimation of variability is a significant issue, because the primary function of TRAM is to ensure that the proposed transmission rates are sufficient to meet BPA’s TPP standard. If TRAM underestimates the uncertainty in transmission net revenue, it will overestimate TPP. Homenick *et al.*, BP-12-E-BPA-31, at 11. The calibration adjustment increases the uncertainty in TRAM output to the standard error of rate case forecasts of transmission net revenue for fiscal years 2008 through 2012. Lovell *et al.*, BP-14-E-BPA-32, at 5-7. The calibration adjustment was used in calculating TPP for the BP-12 rates as well. Transmission Revenue Requirement Study Documentation, BP-12-FS-BPA-07A, at 86.

In performing its comparison of historical results to model results, Staff found that the standard deviation for the five differences between forecast and actual net revenues from FY 2008 through FY 2012 is \$49.1 million. Lovell *et al.*, BP-14-E-BPA-32, at 5. This is a large value, implying that about one-third of the forecasts made by this forecasting methodology will have errors of more than \$49.1 million in one direction or the other. Homenick *et al.*, BP-14-E-BPA-44, at 6. The two-year average standard deviation of the uncalibrated TRAM results is \$24.7 million, about half of the five-year standard deviation of \$49.1 million. Lovell *et al.*, BP-14-E-BPA-32, at 6. Thus, without any calibration adjustment, TRAM would capture only about half of the net revenue uncertainty that has been observed in the past five years.

Based on these results, Staff concluded that TRAM is systematically underestimating the variability or uncertainty of net revenues that TRAM simulates. Homenick *et al.*, BP-14-E-BPA-44, at 4. To ensure that the model more accurately reflects the observed actual uncertainty, Staff calculated the ratio between (1) the standard deviation of the difference between actual net revenue and rate case net revenue forecasts for fiscal years 2008 through 2012, and (2) the standard deviation of unadjusted TRAM net revenue results. Staff then applied that ratio to the model results. Lovell *et al.*, BP-14-E-BPA-32, at 6-7. The calibrated modeled net revenues adequately reflect the observed forecast uncertainty. *Id.* at 7. There is no evidence to indicate that capturing significantly less uncertainty than what BPA has observed historically is adequate for purposes of calculating TPP.

JP04 asserts that the calibration adjustment “is unsupported and arbitrarily distorts the TPP calculation.” JP04 Br., BP-14-B-JP04-01, at 7, 18 n.65. JP04 states that “persistent underforecasting net revenues cannot and does not justify the calibration adjustment in TPP calculations that results in an almost doubling of the variability (risk) of overforecasting modeled TS net revenues.” *Id.* at 21-22. JP04 suggests that the calibration adjustment increases the risk of overforecasting net revenue. *Id.* JP04 further asserts that the adjustment

erroneously uses the effects of historically underforecasting net revenues to increase the forecasted likelihood that revenues will be too low in the future. Because TPP measures the percentage of games in which net revenues are

inadequate, almost doubling the standard deviation increases the number of games in which the net revenues and financial reserves will be inadequate.

*Id.* at 22. These assertions misinterpret Staff’s testimony. The adjustment is made not because of persistent underforecasting of net revenues, but because the uncertainty in TRAM’s net revenue output is less than the uncertainty in historical net revenue. Homenick *et al.*, BP-14-E-BPA-44, at 4. The calibration adjustment does not change the likelihood of overforecasts or underforecasts; it increases the magnitude of the forecast errors in either direction. *Id.* The adjustment shifts game result net revenues that were above the mean further above the mean, and game result net revenues that were below the mean further below the mean. *Id.* The calibration adjustment does not increase the forecast likelihood that revenues will be too low in the future, because it does not change the probability of underforecasts or overforecasts. *Id.*

JP04 asserts that the calibration adjustment “had the effect of arbitrarily (i) shifting game result net revenues that were below the mean net revenues even further below the mean (by a factor of almost two), and thereby (ii) lowering the TPP calculation results.” JP04 Br., BP-14-B-JP04-01, at 19. As mentioned above, the calibration adjustment uses the effects of historical forecast errors to adjust the magnitude of both underforecasts and overforecasts, but not the likelihood of either. Homenick *et al.*, BP-14-E-BPA-44, at 4. The calibration does change the distribution of net revenues from TRAM and the TPP calculation; indeed, that is its purpose. *Id.* In doing so, the adjustment ensures that the results of TRAM reflect the uncertainty that has been observed in actual results. The calibration adjustment was reasonably applied to remedy what would otherwise be an underestimation of uncertainty in TRAM, which would cause an overestimation of TPP. The record contains significant evidence to support the calibration adjustment.

JP04 argues that use of the calibration adjustment to increase the uncertainty in TRAM output is inconsistent with “BPA’s expectation of lowered forecast error in TS net revenues.” JP04 Br., BP-14-B-JP04-01, at 22. To support its assertion that BPA expects lower forecast error, JP04 quotes from a pre-rate-case presentation in which BPA identified three causes that contribute to underforecasting of cash flows (and presumably net revenue) and thus to the build-up of financial reserves attributable to Transmission, and described its efforts to address the causes. *Id.* at 23-24.

The first cause was that revenues have been higher than forecast; Staff indicated that the forecast variance has been decreasing and revenues were expected to be “relatively close to forecasts in the future.” *Id.* at 23. The second cause was that transmission credits associated with large generator interconnection agreements have been lower than forecast; Staff indicated that it was “looking at risk analysis” as a way to improve forecasts of these credits. *Id.* The third cause was that interest expense has been lower than forecast; Staff said it was “exploring revisions to forecast assumptions and methodologies.” *Id.* at 24.

These efforts may reduce the magnitude of forecast errors generally; however, they may not reduce the inconsistency or variability of the errors. Homenick *et al.*, BP-14-E-BPA-44, at 9. JP04 claims that Staff’s testimony attempted to dismiss these efforts by “erroneously” characterizing them as “‘hopes of lower forecast errors’ and as an indication that BPA is

‘exploring some ways to reduce the magnitude of forecast errors.’” JP04 Br., BP-14-B-JP04-01, at 24. However, it would not be prudent to assume, without any evidence, that the efforts will be successful and that forecast error and uncertainty will no longer be underestimated in TRAM. Homenick *et al.*, BP-14-E-BPA-44, at 9.

The purpose of the risk analysis and TPP standard is to ensure that rates are set high enough so that there is at least a 95 percent probability that the financial reserves available for risk attributable to a business line will be sufficient to cover the cash obligations associated with that business line in each two-year rate period. *Id.* The evidence in the record shows that the risk analysis has not fully captured the uncertainty that has been observed in the last five years of historical data. Lovell *et al.*, BP-14-E-BPA-32, at 6. The evidence does not demonstrate that forecast error and uncertainty going forward will be reduced from what has been observed in the last five years. It would be contrary to the purpose of the TPP standard to assume that these steps would be successful until there is evidence to that effect. The calibration adjustment is still necessary.

JP04 also argues that the calibration adjustment lowers TPP and therefore can increase the transmission revenue requirement. JP04 Br., BP-14-B-JP04-01, at 25. The calibration adjustment does lower TPP; in the current circumstances (modeled net revenue uncertainty in TRAM results is about half the magnitude of historically observed net revenue uncertainty, and therefore modeled uncertainty may underestimate risk) it is intended to do so. Homenick *et al.*, BP-14-E-BPA-44, at 7. The calibrated TPP is still over 99 percent, so any reduction to TPP due to the calibration adjustment is extremely small. The TPP result is well above BPA’s standard of 95 percent, so no PNRR was added to the transmission revenue requirement. Lovell *et al.*, BP-14-E-BPA-32, at 7. The calibration adjustment did not increase either the transmission revenue requirement or transmission rates.

JP04 states that Staff “argues that because the magnitude of the underforecasting of TS net revenues has varied, the persistency of the underforecasting error should be ignored, and appears to argue, without support, that correction for bias in forecasts can only be made if the underforecasting error has been uniform in each year.” JP04 Br., BP-14-B-JP04-01, at 25. JP04 states that these arguments ignore the persistency of the historical underforecasting error and do not justify a “failure to discern a bias ... and correct for it.” *Id.* These statements misinterpret Staff’s testimony.

Staff explains, persuasively and in detail, that the calibration adjustment is intended and necessary in this rate case to correct an underestimation of net revenue uncertainty in TRAM. *See Lovell et al.*, BP-14-E-BPA-32, at 5-7; Homenick *et al.*, BP-14-E-BPA-44, at 3-9. The “persistency” of underforecasts is not the issue addressed by the calibration adjustment, as JP04 claims. *See JP04 Br.*, BP-14-B-JP04-01, at 25. The adjustment addresses variability in the magnitude of forecast error, not the direction. Homenick *et al.*, BP-14-E-BPA-44, at 3-4. The evidence in the record demonstrates that the unadjusted uncertainty in TRAM’s output is smaller than the uncertainty in forecasts inferred from historical data, that this underrepresentation of uncertainty can bias TPP calculations upward, and that an upward bias would weaken the TPP standard. *Id.* at 6-9. The evidence demonstrates that Staff observed significantly more

variability—approximately twice as much—in historical observed forecast error than in TRAM results. Lovell *et al.*, BP-14-E-BPA-32, at 5-6. Because actual forecast error variability has been observed to be twice as large as the variability in TRAM results, Staff reasonably concluded that TRAM underestimates the uncertainty in transmission net revenue. *Id.*

When there is a significant difference between the results of a model that is used for forecasting and the most recent actual data, it is important to acknowledge and address the difference. Homenick *et al.*, BP-14-E-BPA-44, at 5. As the evidence in the record demonstrates, the calibration adjustment does precisely that by increasing the standard deviation of the net revenue in each run of TRAM, without changing whether or not the net revenue is above or below the mean (that is, it does not introduce a bias or cause net revenue to be higher or lower). Lovell *et al.*, BP-14-E-BPA-32, at 6-7. The evidence demonstrates that the calibration adjustment is a reasonable and appropriate approach to remedying the underestimation of the uncertainty in Transmission Services net revenue.

### **Draft Decision**

*TRAM should include the calibration adjustment to adjust for uncertainty in net revenues.*

### **Issue 4.2.5.5**

*Whether agency financial reserves attributable to Transmission Services in excess of the amount needed to support a 95 percent TPP should be used to mitigate the proposed transmission rate increase.*

### **Parties' Positions**

Multiple parties argued that financial reserves attributable to Transmission that are in excess of the amount needed to support a TPP of 95 percent should be used to mitigate the proposed rate increase. Without specifying an amount, Powerex argues that reserves should be used to offset the costs of rate increases associated with changing the segmentation methodology to move “distribution-like facilities” into the Network segment, to temporarily reduce the increase in Utility Delivery Charge rates, and to reduce the overall rate increase. Powerex Br., BP-14-B-PX-01, at 36. ICNU also does not specify an amount but urges BPA to use excess reserves to offset the proposed rate increase for transmission services. ICNU Br., BP-14-B-IN-01, at 3. Iberdrola advocates the use of \$100 million per year from reserves to offset the revenue requirement. Iberdrola Br., BP-14-B-IR-01, at 12-13. JP04 argues that BPA should adopt its “Case 5,” which would have BPA commit \$140 million per year of reserves to reduce rates. JP04 Br., BP-14-B-JP04-01, at 13-14. In its brief MSR argues that reserves should be drawn down to “a more reasonable amount, such as \$100 million,” with the amounts above that used to reduce transmission rates and fund infrastructure investments. MSR Br., BP-14-B-MS-01, at 15. In oral argument, however, MSR appears to back away from the use of reserves for rate relief and implied that it might support using reserves for the benefit of the transmission system. Oral Tr. 345. WPAG suggests that BPA try to balance short-term rate relief with long-term

business needs by using small, though unspecified, amounts of reserves. WPAG Br., BP-14-B-WG-01, at 35.

### **BPA Staff's Position**

BPA is committed to using financial reserves attributable to Transmission for the long-term benefit of the transmission system but is not required to use them in any particular way. Homenick *et al.*, BP-14-E-BPA-44, at 18. Staff identified three potential uses for reserves: holding funds in the Bonneville Fund for unexpected needs and to support BPA's credit rating, using reserve funds for capital investment, or using reserve funds to mitigate part of the rate increase. *See generally id.* at 18-21.

### **Evaluation of Positions**

Several parties argue that BPA's reserves attributable to Transmission have accumulated to the degree that BPA has reserves in excess of what it needs for risk mitigation and TPP support. Iberdrola Br., BP-14-B-IR-01, at 10-12; JP04 Br., BP-14-B-JP04-01, at 2; MSR Br., BP-14-B-MS-01, at 15; Powerex Br., BP-14-B-PX-01, 32-33; ICNU Br., BP-14-B-IN-01, at 2-3.

Several parties further argue that BPA should use significant amounts of reserves (for example, \$100 million per year or more) to offset costs and reduce rates. Citing the Transmission System Act, Iberdrola, Powerex, and JP04 argue that reserves should be used so that rates are as low as possible consistent with sound business principles, and Powerex and JP04 make a legal argument that failing to use reserves to offset rates in this case would be in contravention of the Transmission System Act. Iberdrola Br., BP-14-B-IR-01, at 12; Powerex Br., BP-14-B-PX-01, at 34; JP04 Br., BP-14-B-JP04-01, at 2, 17; all citing 16 U.S.C. 838g. Iberdrola also argues that using reserves to reduce rates is necessary to return an over-collection of revenues to customers in a timely manner—that is, that excess reserves belong to customers. Iberdrola Br., BP-14-B-IR-01, at 12. ICNU explains that lower rates would provide a substantial economic benefit to the region during the rate period, “which is of critical importance during this time of sluggish economic recovery.” ICNU Br., BP-14-B-IN-01, at 4.

The parties' legal arguments are addressed in section 4.2.5.1 above. In response to the argument that reserves belong to customers and should be returned to them in a timely manner, the parties have no right to any accumulation of reserves that may occur. Customers have paid rates that they agreed to in settlements of every rate case since 1996 and that have been approved by the Federal Energy Regulatory Commission. Homenick *et al.*, BP-14-E-BPA-44, at 17-18. These rates do not contain any mechanism requiring that any revenues in excess of costs be paid to customers. *Id.* at 18. Moreover, embedded in BPA's origins was the understanding that any accumulation of reserves would be put to use for the long-term benefit of the system and, ultimately, ratepayers. Under BPA's original repayment methodology, all revenues in excess of costs that contributed to reserves were used for incremental repayment of the Federal investment. *Id.*

Staff has indicated that it is committed to exploring uses of reserves for the long-term benefit of the transmission system but that BPA is not obligated to use accumulated reserves in any

particular way. *Id.* at 18. Some of the uses Staff described are already providing benefits; for example, for the last several rate cases BPA has planned to use \$15 million per year of reserves for capital investment and is continuing that plan for the FY 2014–2015 rate period. BPA’s Access to Capital strategy plans to continue the use of \$15 million per year of reserves to finance Transmission capital investment over the next decade. *Id.* at 19. Further, BPA earns interest income on the full expected value of cash reserves. *Id.* at 18. This interest income is incorporated into annual transmission revenue requirements and thus reduces transmission rates. *Id.*

Iberdrola, MSR, and JP04 would have BPA commit a substantial majority of its financial reserves to immediate rate relief in FY 2014–2015. These proposals are short-sighted. Each proposal would lower transmission’s financial reserves to approximately \$100–\$150 million and produce a TPP level at or very near the 95 percent standard. All of them would leave little or no reserves available for other uses in the FY 2014–2015 rate period or in future rate periods. *Id.* at 14. Using reserves at this level to avoid a rate increase today could result in a larger average rate increase in the next rate period, without any means of mitigating it. *Id.* at 15. It would also create risk to BPA’s credit rating, as described in Staff’s testimony and as discussed above. *Id.* at 15-17; *see also supra* section 4.2.5.1.

A course of action that could provide more benefits with potentially less risk is to use a smaller amount of reserves to mitigate but not eliminate the rate increase. Homenick *et al.*, BP-14-E-BPA-44, at 20-21. After years of transmission rate case settlements, often with no rate increase, a 13 percent average increase for the next rate period may sound shocking. This rate increase can be tempered by applying mitigation across all rate classes, as WPAG suggests. WPAG Br., BP-14-B-WG-01, at 35–36. Using smaller amounts of reserves could allow BPA to gain some of the benefits of other uses of reserves, such as preserving some reserves for future capital investment. As ICNU noted, lower rates would provide a substantial economic benefit to the region during the rate period as the economy slowly recovers. ICNU Br., BP-14-B-IN-01, at 4. Using smaller amounts of reserves may also pose lower risk of a credit rating downgrade. Homenick *et al.*, BP-14-E-BPA-44, at 20-21.

To balance the important but competing objectives of reducing the level of the rate increase but maintaining credit ratings, the use of reserves to lower rates should be limited to \$20 million per year for the FY 2014–2015 rate period (in addition to the \$15 million per year for capital investment already reflected in rates). Using this amount of reserves would provide a degree of rate relief, may pose less risk of a credit rating downgrade than a higher amount, and could preserve some financial reserves for other beneficial uses. Using \$20 million of reserves per year to offset costs and reduce rates for the FY 2014–2015 rate period reflects sound business judgment in furtherance of BPA’s public mission. In order to provide the benefit to all customers, the reserves will be applied as an offset to the general revenue requirement to reduce all transmission rates.

While the figure of \$20 million per year was chosen in part because it may present lower risk of a credit rating downgrade than use of a greater amount, the potential for a downgrade and increased interest expense is a serious concern that deserves more regional discussion during the

upcoming rate period. The ratings are a primary factor determining the interest rate on all BPA-backed bonds that are publicly issued and sold by third parties. *Id.* at 16. A downgrade could significantly increase the interest cost associated with bonds for investments such as the transmission facilities under BPA’s transmission lease-purchase program or the Energy Northwest net-billed nuclear projects. *Id.* As Staff explained:

The magnitude of the impact would depend on the final credit rating and how much more investors would demand in interest rates for BPA-backed bonds due to the lower credit rating. If investors require an increase in interest rates of 50 basis points, BPA’s total interest expense could increase by approximately \$10 million a year, while a 150-basis-point premium could increase BPA’s interest expense by approximately \$30 million per year.

*Id.*

Each rating agency has a different methodology, and each gives different weighting to different factors. Homenick *et al.*, BP-14-E-BPA-44, at 17. Thus, the likelihood of a downgrade is difficult to predict. However, all of the rating agencies are concerned about the amount of reserves available for risk (which they term “unrestricted cash on hand”). *Id.* BPA’s rating was downgraded by Moody’s immediately after BPA’s BP-12 rates were filed with the Federal Energy Regulatory Commission. *Id.* at 15. This downgrade occurred in large part because reserves had declined by 36 percent during 2009 and 2010 and were expected to further decline as a result of the filed rates. *Id.* If the rating agencies were to downgrade BPA again, the result would be higher interest expense for the non-Federal debt backed by BPA, which would affect both Transmission Services and Power Services. *Id.* at 17.

JP04 challenges Staff’s testimony regarding the risk of a credit rating downgrade. JP04’s assertions regarding whether Staff has supported its position are discussed in section 4.2.5.1. JP04 also asserts that “BPA fails to explain why ... BPA’s credit rating is not adversely affected when it raises its TPP to equal 95 percent through the use of PNR.” JP04 Br., BP-14-B-JP04-01, at 15 n.51. Staff did not address that scenario’s impact on BPA’s credit rating because PNR has not been added to the proposed transmission or power rates. Regardless, adding PNR to the revenue requirement effectively raises rates to increase revenues. Homenick *et al.*, BP-14-E-BPA-44, at 2. This action *augments* financial reserves instead of diminishing them. Study, BP-14-E-BPA-08, at 17. Nothing in the record indicates that the rating agencies would be concerned with increasing financial reserves due to the addition of PNR. In fact, because those reserves provide security for non-Federal financing of capital investments, the reverse seems more likely—rating agencies would likely have a positive view of increasing reserves. *See id.*

JP04 also argues that BPA has “singled out transmission financial reserves for its undocumented concern,” implying that it believes Staff should have raised similar concerns about the level of Power financial reserves. JP04 Br., BP-14-B-JP04-01, at 15 n.54. Staff discussed only the ratings impacts of proposed diminution of transmission reserves because no parties proposed planned diminution of power reserves. In addition, Staff noted that power rates include a Cost Recovery Adjustment Clause to increase rates if needed, and a Dividend Distribution Clause. Homenick *et al.*, BP-14-E-BPA-44, at 17–18. These clauses result in power rate surcharges or reductions if reserves attributable to Power will be below \$0 or above \$750 million (as indicated

by near-term forecasts of accumulated net revenue). Lovell *et al.*, BP-14-E-BPA-15, at 29-30, 34-35. Thus, power rates already include a mechanism that is the equivalent of a reduction. No parties proposed changes to these thresholds or the uses of Power reserves. Therefore, Staff did not address them further.

Some parties suggest using reserves to offset increases in certain rates only. JP23 suggests using reserves to offset increases to PTP rates resulting from the adoption of a 12 CP cost allocation methodology, as long as any other rate increases over 20 percent (that is, the proposed increase to the Utility Delivery Charge) are also offset. JP23 Br., BP-14-B-JP23-01, at 18 n.57. Powerex suggests using reserves to offset increases associated with adoption of a different segmentation methodology or to temporarily offset the proposed increase in the Utility Delivery Charge. Powerex Br., BP-14-B-PX-01, at 36. JP23's and Powerex's proposals regarding use of reserves associated with the 12 CP cost allocation methodology and a different segmentation methodology appear to apply only if their proposals concerning cost allocation and segmentation are adopted. As discussed in sections 4.1 and 4.3.1, respectively, these proposals were not adopted. Powerex's proposal with respect to the Utility Delivery Charge is discussed in section 4.3.2.

### **Draft Decision**

*Agency financial reserves attributable to Transmission Services in excess of the amount needed to support a 95 percent Treasury Payment Probability will be used to mitigate the proposed rate increase in the amount of \$20 million per year to offset the general revenue requirement and reduce the level of the rate increase.*

## **4.3 Transmission Rate Design**

BPA's transmission rate design process involves determining the overall costs of the transmission system, allocating those costs among transmission customers, and calculating the proposed transmission rates for BPA's wholesale transmission products and services for FY 2014 and 2015. The Transmission Rates Study, BP-14-E-BPA-07, includes the results of this process and demonstrates that the rates for BPA's wholesale transmission services for FY 2014–2015 have been developed consistent with BPA's statutory and contractual obligations and will recover the transmission revenue requirement.

This section of the Draft ROD addresses transmission rate design issues raised by the parties, including network segment cost allocation, utility delivery service, allocation of BPA's share of the costs of the Eastern Intertie, the proposal to directly assign costs of certain reliability compliance activities, and the billing factor for SCD service for NT customers.

In the Initial Proposal, Staff proposed to use the customer's load on the hour of the customer's monthly peak as the billing factor for NT service and utility delivery service. Bogdon *et al.*, BP-14-E-BPA-30, at 4, 9. In response to testimony by JP03 and WPAG that this billing factor resulted in disparate rate impacts among customers, Staff changed its position in rebuttal testimony to support retaining the current billing factor for these services, which is the

customer's load on the hour of the monthly transmission system peak. Bogdon *et al.*, BP-14-E-BPA-43, at 4, 16; Scott and Carr, BP-14-E-JP03-02, at 28-29; Saleba *et al.*, BP-14-E-WG-01, at 36. JP23, JP03, and WPAG support Staff's position on rebuttal, and no other party has opposed this proposal. JP23 Br., BP-14-B-JP23-01, at 20; JP03 Br., BP-14-B-JP03-01, at 22; WPAG Br., BP-14-B-WG-01, at 30.

#### **4.3.1 Network Segment Cost Allocation**

##### **Issue 4.3.1.1**

*Whether BPA should allocate costs to PTP and IR customers based on contract demand when it allocates costs to NT customers based on peak load.*

##### **Parties' Positions**

JP11 argues that BPA should not treat load and contract demand as comparable bases for cost allocation purposes because, although BPA bases its cost allocation largely on its system planning, BPA does not treat contract demand and load the same for purposes of system planning. JP11 Br., BP-14-B-JP11-01, at 6-7. JP11 also argues that allocating costs to PTP customers based on contract demand and to NT customers based on load does not result in equitable rates between customer classes and therefore does not meet the equitable allocation requirement of section 10 of the Transmission System Act. *Id.* at 11-12. JP11 proposes that BPA allocate costs to all customers on the basis of usage, which JP11 argues is consistent with BPA's system planning objectives. *Id.* at 2, 6-9.

Powerex agrees with JP11 but recommends as an alternative to JP11's proposal that BPA "maintain its current cost allocation" factor for this rate period until BPA designs a different methodology that considers BPA's planning, operating, and segmentation approaches. Powerex Br., BP-14-B-PX-01, at 29, 32.

WPAG argues that JP11's proposal is a departure from Commission guidance and fails to consider the flexibility of PTP service, which makes PTP service comparable to NT service and justifies treating contract demand and load as equivalent. WPAG Br., BP-14-B-WG-01, at 28-30.

##### **BPA Staff's Position**

Staff based its proposed cost allocation on BPA's system planning approach, which reflects BPA's obligation to plan the system to satisfy its customers' contractual rights. Fredrickson *et al.*, BP-14-E-BPA-33, at 4-5. Contract demand for PTP and IR customers and network load for NT customers define the customer's rights and BPA's planning obligation. *Id.* Staff disagreed that costs should be allocated to PTP and IR service on the basis of usage, because BPA plans the system to flexibly meet contract demands under a range of system conditions. Fredrickson *et al.*, BP-14-E-BPA-45, at 17-23.

## **Evaluation of Positions**

JP11 states that it “agrees with Staff on the importance of examining BPA’s system planning” to assess the drivers behind transmission system investment and states that it regards Staff’s testimony about BPA planning as thorough and credible. JP11 Br., BP-14-B-JP11-01, at 6. Otherwise, however, JP11 disagrees with Staff’s position. JP11 argues extensively that contract demand and load are “fundamentally different” and, therefore, not a common basis for cost allocation purposes. *Id.* at 9. JP11 maintains that using two different approaches for cost allocation is “grossly inequitable and unfair,” because PTP customers end up bearing a disproportionate share of the costs. *Id.* at 10.

At the core of JP11’s cost allocation arguments is JP11’s position that allocating costs to PTP and IR contract demand is inconsistent with the assumptions used in BPA’s planning studies (which JP11 claims are based on usage). *Id.* at 6-7, 9-10, 13. Therefore, JP11 asserts, allocating costs to PTP and IR customers based on contract demand is inconsistent with cost causation. *Id.* JP11 proposes that BPA allocate costs to PTP and IR customers based on usage. *Id.*

BPA’s planning for IR and PTP service is not based solely on usage. BPA incurs costs based on its obligation to plan the system to satisfy its customers’ contractual rights. Fredrickson *et al.*, BP-14-E-BPA-33, at 5. BPA’s planning obligation for PTP and IR service is based on contract demand, which is the amount of capacity the customer has reserved to deliver energy from points of receipt to points of delivery. *Id.* at 4. Since PTP service is flexible (the customer has the right to resell, assign, and redirect transmission service during hours when its contract demand exceeds its needs), BPA’s planning obligation is to ensure that it has sufficient capacity for customers to flexibly use their reserved capacities consistent with their contracts. *Id.*; Fredrickson *et al.*, BP-14-E-BPA-45, at 17, 24-27.

For NT service, on the other hand, BPA’s planning obligation is “load based,” and BPA must plan the transmission system to serve each NT customer’s peak loads and forecast load growth from the customer’s designated network resources. Fredrickson *et al.*, BP-14-E-BPA-33, at 4. NT customers do not have the same flexibilities to resell, assign, and redirect their service as PTP customers. Fredrickson *et al.*, BP-14-E-BPA-45, at 27.

JP11 argues that contract demand and load are not equivalent, because contract demand “defines a customer’s rights to use the transmission system,” while load “represents a customer’s usage of the transmission system.” JP11 Br., BP-14-B-JP11-01, at 9-10. In fact, load does define the NT customer’s rights to use the system. NT customers have the right to use their designated resources to serve their network load; they cannot resell, assign or redirect any capacity they are not using. Fredrickson *et al.*, BP-14-E-BPA-33, at 4-5; Fredrickson *et al.*, BP-14-E-BPA-45, at 27. NT customers are allocated costs and billed based on their peak demands, but use that amount of transmission only during their monthly peak hour, whereas PTP customers have the right to use their contract demand during all hours.

JP11’s main objection is that for purposes of its planning studies, BPA does not assume that all customers’ contract demands will be utilized at the same time, all the time. JP11 Br., BP-14-B-JP11-01, at 6, 9-10. Therefore, JP11 argues, it is inconsistent with cost causation to allocate

costs to contract demand as if BPA did make this planning assumption. *Id.* JP11 is correct that BPA’s planning studies do not assume that all contract demands will be utilized at the same time, all the time. Fredrickson *et al.*, BP-14-E-BPA-45, at 18. Critically, however, BPA’s planning studies ensure that there is sufficient capacity available for PTP customers to use their contract demands.

When BPA performs its planning studies, BPA does not know which contract demands will be used or the amount that each contract demand will be used at any given time (as explained above, not all contract demands are used at the same time). *Id.* at 14, 17-20. BPA studies the most stressful system conditions (*e.g.*, higher wind generation during the outage of critical transmission facilities) to ensure that the system is capable of meeting demands during those conditions. *Id.* at 14. In addition, BPA’s Available Transfer Capability and Available Flowgate Capability methodologies, which account for contract demands, ensure that BPA does not make additional transmission sales that would impair the reliability of the system, including BPA’s ability to meet contract demands. *Id.* at 21-22. Therefore, BPA’s system is normally capable of serving the contract demand during any hour of the month that the customer chooses to utilize its full contract demand to serve load and transmit generation, or resell or assign to third parties (capacity may not be available during transmission congestion events, such as an unplanned transmission outage).

JP11 challenges Staff’s “assumption that PTP transmission service offers greater value because of the customer’s ability to resell and redirect the product.” JP11 Br., BP-14-B-JP11-01, at 13. JP11 offers evidence that PTP customers use only 66 percent of their contract demand during BPA’s monthly system peak and argues that this percentage indicates that it would be “inappropriate” to allocate costs to PTP customers “as if they were using 100 percent of their contract demand.” *Id.* JP11 derives its figure from the monthly transmission system peak data. *Id.* However, these data are determined based on generation and metered flow into BPA’s system, not on metered load or transmission schedules (which would reflect PTP usage). *See* Fredrickson *et al.*, BP-14-E-BPA-33, at 14. Therefore, they do not accurately reflect PTP usage of the system.

JP11 also argues that Staff’s cost allocation proposal “violates” BPA’s “own stated principles” regarding cost causation. JP11 Br., BP-14-B-JP11-01, at 11. JP11 cites a pre-rate-case workshop presentation that included the statement “Cost causation – allocate costs to customers based on proportionate use.” *Id.* JP11 has taken this statement out of context. The workshop presentation lists the general ratemaking principles suggested by BPA Staff and some customers to use for consideration of cost allocation methodologies for the Initial Proposal. The principles are proposals, not “stated principles.” In any case, contract demand is a valid measure of use by PTP customers.

Staff testified that “[t]he underlying theory of cost causation is that costs incurred to benefit a class of service should be allocated to the rates paid by customers for that service.” Fredrickson *et al.*, BP-14-E-BPA-33, at 3. The “benefit” is the customer class’s rights to use the transmission system. How customers use the system is defined by their transmission contracts. For NT service, the use is defined by load. *Id.* at 5. For PTP service, the use is defined by contract

demand, whether it is used to serve load or to transmit generation to third parties, or is resold, assigned, or redirected to new points of receipt or delivery. *Id.*; Fredrickson *et al.*, BP-14-E-BPA-45, at 26-27.

JP11 makes statements about cost causation that are similar to Staff's testimony. In response to a data request, JP11 stated that allocation of costs to PTP customers on the basis of contract demand would adhere to the principle of cost causation if "it can be demonstrated that BPA plans its transmission system on the basis of contract demand versus actual observed level of usage." BPA Cross Examination Exhibit, BP-14-E-BPA-53, at 27. The record demonstrates that BPA considers contract demand for its transmission planning. Fredrickson *et al.*, BP-14-E-BPA-45, at 17-23. Since BPA uses power flow studies in which generation and load must balance each other, BPA studies several generation dispatch scenarios in which different combinations of generation (which are associated with different contracts, including PTP and IR contracts) are dispatched to serve the load. *Id.* at 19-20. The power flow studies model the representative ways that contract demands may be used. *Id.* at 4, 18. By JP11's own admission, BPA's proposal satisfies the cost causation principle.

To support its position that the rates are not equitable, JP11 applied the PTP and NT rate to two entities with the same load. JP11 Br., BP-14-B-JP11-01, at 11-12. JP11 asserts that the NT customer fares considerably better than the PTP customer because its costs are lower. *Id.* Therefore, JP11 argues, allocating costs to contract demand and load is inequitable. *Id.* at 12. JP11's argument does not account for the PTP customer's rights to deliver power to points of delivery off its system (as stated above, NT customers may serve only their designated load) and to resell, assign, and redirect during the hours when its contract demand exceeds its load. These rights allow the PTP customer to reduce its costs. The evidence indicates that PTP customers significantly utilize these rights. Fredrickson *et al.*, BP-14-E-BPA-45, at 27. One customer that takes advantage of these rights is Snohomish County Public Utility District No. 1, one of the JP11 parties. *See Saleba et al.*, BP-14-E-WG-04, at 14-15; Carr and Scott, BP-14-E-JP03-03, at 44-45.

JP11 also maintains that Staff's proposal to allocate costs to NT service based on load during average conditions (a load forecast with a 50 percent probability of occurring), and to PTP service based on contract demand, results in PTP customers subsidizing NT customers. JP11 Br., BP-14-B-JP11-01, at 12. It is appropriate to allocate costs to NT service based on average conditions. First, allocating costs to NT service based on average conditions is consistent with the load forecast that BPA uses for transmission system planning. Fredrickson *et al.*, BP-14-E-BPA-33, at 8; Fredrickson *et al.*, BP-14-E-BPA-45, at 35. Second, a load forecast based on average conditions reflects NT customers' rights to use the system and BPA's planning obligation during the rate period because these load conditions are more likely to occur during the rate period. Fredrickson *et al.*, BP-14-E-BPA-45, at 36.

JP11 argues that the rates are inequitable as between customer classes and therefore "run afoul" of the equitable allocation standard in section 10 of the Transmission System Act, 16 U.S.C. § 838(h). JP11 Br., BP-14-B-JP11-01, at 12. JP11 avers that section 10 requires BPA "to

equitably allocate the cost of the Federal transmission system between transmission customers.”  
*Id.*

As discussed below, the 12 NCP method does equitably allocate costs as between customer classes. Moreover, JP11 mischaracterizes the equitable allocation requirement. Section 10 of the Transmission System Act specifies that the costs of the Federal transmission system shall be equitably allocated between *Federal and non-Federal power* utilizing the Federal transmission system. 16 U.S.C. § 838h. It does not apply more broadly to an equitable allocation of costs generally as between customer classes. The proposed rates meet the equitable allocation requirement. Bliven *et al.*, BP-14-E-BPA-42, at 39. PTP and NT customers utilize BPA’s system to transmit Federal and non-Federal power. All PTP service is charged the same rate, regardless of the type of power transmitted. Similarly, all NT service is charged the same rate, regardless of the type of power transmitted. Neither Federal nor non-Federal power is advantaged. *Id.*

As for Powerex’s proposal to maintain the current cost allocation factor as an alternative to allocating costs based on usage, presumably Powerex refers to the 1 NCP proposal advanced in its direct testimony. *See* Opatrny, BP-14-E-PX-01, at 28-29. The 1 NCP method is inconsistent with BPA’s planning approach because it does not account for any off-peak conditions that are considered in BPA’s transmission planning (see discussion at Issue 4.3.1.4).

Finally, although BPA is not bound by Commission precedent, it should be noted that Staff’s proposal to treat contract demand as the equivalent to peak load for cost allocation purposes is consistent with the Commission’s guidance in Order No. 888. Fredrickson *et al.*, BP-14-E-BPA-45, at 23. In that order, the Commission said that

[F]irm point-to-point customers can reassign and resell unused portions of their reserved firm capacity to third parties. With flexible firm and non-firm point-to-point transmission service, the transmission provider must make firm point-to-point transmission capacity available to the customer regardless of its load characteristics or use.

The flexibility and reassignment rights of [PTP] transmission service requires the transmission provider to hold the firm contract capacity available regardless of the customer’s load characteristics or its actual use. In other words, a transmission provider’s *obligation to plan* for, and its ability to use, a transmission customer’s reserved capacity *is clearly defined by that customer’s contract reservation*. For that reason, *it is appropriate to consider a firm reservation as the equivalent of load for cost allocation and planning purposes*.

*Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, FERC STATS. & REGS. ¶ 31,036, 61 Fed. Reg. 21,540, at 21,600 (1996) (emphasis added).

## **Draft Decision**

*Because contract demand for PTP and IR service and load for NT service define the customers' rights to use the system and BPA's planning obligation, it is appropriate to allocate costs to PTP and IR service based on contract demand and to NT service based on peak load.*

### **Issue 4.3.1.2**

*Whether operations, administrative salaries, internal support, information technology, and Scheduling, System Control and Dispatch Service (SCD) costs are directly related to transmission facility investment and, if not, whether BPA should allocate these costs on the basis of contract demand and load.*

### **Parties' Positions**

JP11 asserts that “only one-third of BPA’s transmission revenue requirement is directly related to transmission facility investment” and argues that only these costs are the subject of BPA’s planning criteria and should be allocated on that basis. JP11 Br., BP-14-B-JP11-01, at 10. JP11 alleges that two-thirds of costs are related to non-investment costs, which JP11 claims include costs related to operations, administrative salaries, internal support, and information technology (IT). *Id.* at 10-11. JP11 argues that BPA has not justified its proposal to allocate these “non-investment” costs and SCD costs to contract demand and load. *Id.*

### **BPA Staff's Position**

Staff did not specifically address this issue, but proposed to allocate all costs based on BPA’s planning obligations, which results in an allocation based on contract demand for PTP and IR service and load for NT service. Messinger *et al.*, BP-14-E-BPA-29, at 3; Fredrickson *et al.*, BP-14-E-BPA-33, at 5. Staff also proposed to allocate SCD costs using the same allocation factors as are used for the Network segment. Transmission Rates Study, BP-14-E-BPA-07, at 38-39.

### **Evaluation of Positions**

JP11 argues that Staff’s justification for allocating costs on the basis of contract demand and load applies only to the costs “directly related” to transmission facility investment. JP11 Br., BP-14-B-JP11-01, at 10. JP11 asserts that the majority of Network segment costs are not “directly related” to transmission facility investment, and thus that Staff did not support its proposal to allocate these “non-investment” costs based on contract demand and load. *Id.* at 10-11. Although JP11 does not explain which costs are “directly related” to transmission facility investment, it excludes costs for operations, administrative salaries, internal support, IT, and SCD. *Id.* JP11 does not state the basis on which the non-transmission investment and SCD costs should be allocated.

In fact, however, these costs are directly related to transmission facility investment. The operational, administrative, internal support, IT, and SCD services help to maintain the reliability

of the transmission system, administer BPA's tariff, provide transmission service, and otherwise meet BPA's planning obligations for PTP, IR, and NT service, all of which are critical for maintaining BPA's transmission facility investments.

JP11 questions the "public policy justification" for allocating operations and personnel costs based on contract demand and load and also asks why PTP customers should pay administrative salaries, internal support, IT, and SCD costs based upon contract demand while NT customers pay based on load. *Id.* at 11. As described in Issue 4.3.1.1, contract demand and load are equivalent for cost allocation purposes: both reflect a customer's right to use the system and BPA's planning obligation. Since the operations, administrative salaries, internal support, IT, and SCD costs are incurred to maintain BPA's transmission facility investment and ensure that BPA meets its planning obligations for PTP, IR, and NT service, it is consistent with cost causation to allocate these costs based on contract demand and load.

### **Draft Decision**

*Operations, administrative salaries, internal support, IT, and SCD costs are directly related to maintaining BPA's transmission facility investment and necessary to meet BPA's planning obligations for PTP, IR, and NT service. Therefore, BPA will allocate these costs on the basis of contract demand and load.*

### **Issue 4.3.1.3**

*Whether the evidence in the record supports the conclusion that BPA plans certain parts of the transmission system to meet demands on a coincident peak basis.*

### **Parties' Positions**

JP23 argues that BPA "plans [the system] to meet area non-coincident peak loads, but at the same time plans other parts of the transmission system to meet coincidental peak loads." JP23 Br., BP-14-B-JP23-01, at 13. JP23 concludes that BPA "could just as easily construct an argument that, based on the way Bonneville plans its system, a coincident peak cost allocation methodology, 12 CP, is appropriate for the agency." *Id.* at 14.

### **BPA Staff's Position**

BPA does not consider any coincident peak assumptions in its transmission system planning. Fredrickson *et al.*, BP-14-E-BPA-45, at 6-7.

### **Evaluation of Positions**

JP23 relies on BPA's response to a data request for its assertion that BPA plans parts of the system to meet coincident peak loads. JP23 Br., BP-14-B-JP23-01, at 13, referring to Data Request Response WG-BPA-21. The data request asked whether the "transmission lines and facilities that are used to serve load in more than one planning area" are designed "to meet the sum of all the non-coincident peak loads of all the customers in all of the planning areas that are

served by those lines and facilities.” Scott and Carr, BP-14-E-JP03-02, at 12-13, citing Data Request Response WG-BPA-21.

In response to the data request, Staff stated that BPA does not design the transmission lines and facilities that are located in more than one planning area to meet the sum of all of the non-coincident peak loads of all the customers in all of the planning areas served by those lines and facilities. *Id.* at 12, citing Data Request Response WG-BPA-21. Staff elaborated on its response in rebuttal testimony, stating that BPA designs the system as a whole (that is, all the lines and facilities connected to all of the planning areas) to serve the expected range of forecast non-coincident peak demand levels and critical system conditions within each planning area. Fredrickson *et al.*, BP-14-E-BPA-45, at 6-7.

Some parties interpreted Staff’s response that BPA plans the system “as a whole” to indicate that BPA considers coincident peaks for planning parts of the system. Scott and Carr, BP-14-E-JP03-02, at 12; Saven *et al.*, BP-14-E-JP14-01, at 3-4; Saleba *et al.*, BP-14-E-WG-01, at 32-33. WPAG interpreted the response to indicate that BPA considers load diversity and claimed that this meant that BPA considered coincident peak demands. Saleba *et al.*, BP-14-E-WG-01, at 33. On the contrary, BPA does not design the system to meet the loads during the hour that total load on BPA’s transmission system is highest. Fredrickson *et al.*, BP-14-E-BPA-45, at 6-7. BPA does not explicitly consider diversified loads or make diversity adjustments to reflect load assumptions coincident with forecast monthly or annual BPA system peaks. *Id.* at 7. BPA’s planning approach automatically factors in seasonal diversity of load, as well as generation patterns, because BPA’s planning studies reflect the fact that utilities experience peak loads in different months. *Id.* at 8.

The record does not support JP23’s assertion that BPA plans parts of its system to meet coincident peaks. Staff’s response to the data request indicates that BPA plans each part of the system so that it is capable of meeting the non-coincident demands placed upon that part of the system, not the demands coincident with BPA’s system peak. Fredrickson *et al.*, BP-14-E-BPA-33, at 8-9, 12, 15; Fredrickson *et al.*, BP-14-E-BPA-45, at 6-11, 17-18. JP23, WPAG, and JP11 acknowledge that BPA considers non-coincident peak assumptions for transmission planning. JP23 Br., BP-14-B-JP23-01, at 13; WPAG Br., BP-14-B-WG-01, at 22; JP11 Br., BP-14-B-JP11-01, at 7-8.

### **Draft Decision**

*The record does not support the conclusion that BPA plans certain parts of its system to meet coincident peak demands.*

#### **Issue 4.3.1.4**

*Whether BPA should allocate costs to NT load under the 12 CP method, because the Commission uses the 12 CP method for jurisdictional utilities, or under a non-coincident peak method.*

#### **Parties' Positions**

JP23 argues that BPA should not base cost allocation on its planning approach but instead should presume that a coincident peak method (specifically, the 12 CP method) is appropriate because the Commission presumes that the 12 CP method is appropriate for jurisdictional utilities. JP23 Br., BP-14-B-JP23-01, at 13.

WPAG and JP23 argue that the Commission determines which coincident peak methodology is appropriate for a utility by applying three tests (referred to as the peak ratio tests) to measure the flatness of a utility's demand curve throughout the year and by considering a utility's other "operating realities," which include system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments. WPAG Br., BP-14-B-WG-01, at 18-19; JP23 Br., BP-14-B-JP23-01, at 10-11. WPAG and JP23 assert that application of Commission cost allocation guidance to BPA's system indicates that BPA should use the 12 CP method. WPAG Br., BP-14-B-WG-01, at 19-21; JP23 Br., BP-14-B-JP23-01, at 11-12.

Powerex and JP11 maintain that BPA should not consider the results of the Commission's peak ratio tests because BPA is different from the utility systems at issue in the Commission's cases in that 80 percent of BPA's sales are based on contract demand. Powerex Br., BP-14-B-PX-01, at 30-31; JP11 Br., BP-14-B-JP11-01, at 4-5, 10. Powerex argues that the high amount of contract demand skews the tests results in favor of allocating costs on the basis of 12 months. Powerex Br., BP-14-B-PX-01, at 30-31 (citing Opatrny, BP-14-E-PX-01-E01, at 38). JP11 also asserts that, unlike the utilities considered in the Commission's tests, BPA does not have native load. JP11 Br., BP-14-B-JP11-01, at 5.

#### **BPA Staff's Position**

BPA incurs costs based on its transmission planning. Fredrickson *et al.*, BP-14-E-BPA-33, at 3-4; Fredrickson *et al.*, BP-14-E-BPA-45, at 2. BPA's planning studies use non-coincident peak load data because BPA's transmission system covers a geographically diverse territory in which loads peak at different times throughout the year. Fredrickson *et al.*, BP-14-E-BPA-33, at 8-9. BPA applies mandatory NERC transmission planning standard TPL-001-0.1, which requires BPA to plan to meet all demands over a range of system conditions, by planning the system to serve each customer's non-coincident peak demand. *Id.* at 9. Because BPA uses non-coincident peak load data in its planning studies, allocating costs using a non-coincident peak method is reasonable. *Id.* at 3-4; Fredrickson *et al.*, BP-14-E-BPA-45, at 2.

To determine the number of months on which to base the non-coincident peak allocation, Staff considered when load and energy transfers (the transmission of energy over BPA's system to adjacent transmission systems) on BPA's system peak throughout the year and when BPA schedules maintenance and outages. Fredrickson *et al.*, BP-14-E-BPA-33, at 8-11. Staff also conducted the Commission's peak ratio tests and considered the test results as additional support for allocating costs on the basis of 12 months. In rebuttal testimony, Staff acknowledged that the peak ratio tests apply when choosing among coincident peak methodologies but may not apply directly to the determination of which non-coincident peak methodology a utility should use. Fredrickson *et al.*, BP-14-E-BPA-45, at 5.

### **Evaluation of Positions**

JP23's position is that "[t]he Commission has used planning to decide between 12 CP and other *coincident* peak methodologies, but it has not used planning to justify a move from 12 CP or any other coincident peak methodology to a non-coincident peak methodology." JP23 Br., BP-14-B-JP23-01, at 13 (emphasis in original). JP23 argues that it is "improper" for BPA "to use planning as a reason to move from 12 CP, the rebuttable presumption cost allocation methodology, to a 12 NCP methodology." *Id.*

Commission guidance indicates that planning is an important criterion for choosing a cost allocation methodology because it is an indicator of cost causation. Fredrickson *et al.*, BP-14-E-BPA-45, at 2. Staff is not aware of any Commission guidance addressing the merits of a non-coincident peak methodology or the factors that should be considered when choosing between a coincident and non-coincident peak methodology. *Id.* at 3. Staff believes that the Commission favors coincident peak methods because of a presumption that utilities plan their systems to meet coincident peak demands. *Id.* Staff is not aware of any cases in which the presumption was rebutted. *Id.*

In Order No. 888, the Commission reaffirmed the 12 CP method because "the majority of utilities plan their systems to meet their twelve monthly peaks." Order No. 888, 61 Fed. Reg. at 21,599. The Commission has explained that "the underlying theory" for the frequent use of the coincident peak method "is that the size of the utility's plant is in large part determined by the capacity which must be made available to accommodate peak loads." *Louisiana Power & Light Co.*, 14 FERC ¶ 61,075, at 61,127 (1981). The Commission has stated:

A utility builds its bulk power facilities, *i.e.*, generating units and transmission lines, to meet the maximum or peak demand of its firm customers. Because the utility incurs the cost of these facilities to meet the peak demand of its firm customers, those customers should pay for the facilities. The peak responsibility method accomplishes this by allocating the cost of the facilities among the firm customers in the same proportion as each customer's demand bears to the system peak.

*Louisiana Pub. Serv. Commission v. Entergy Corp.*, 106 FERC ¶ 61,228, at P 61 (2004), *order denying reh'g*, 111 FERC ¶ 61,080 (2005). Planning to meet coincident peaks entails using coincident peak assumptions in the planning studies. *See generally Re Kentucky Utilities Co.*,

Opinion No. 116, 15 FERC ¶ 61,002, *reh'g denied*, Opinion No. 116-A, 15 FERC ¶ 61,222, at 61,504-07 (1981). Therefore, the Commission's affirmation of the 12 CP method is based on a presumption that utilities use coincident peak assumptions in their planning studies.

BPA is not a jurisdictional utility and is not required to follow Commission precedent. Moreover, the Commission does not require jurisdictional utilities to use a coincident peak method if the utility demonstrates that another method is consistent with its transmission planning approach. Order No. 888, 61 Fed. Reg. at 21,599; *see also* Order No. 888-A, 62 Fed. Reg. 12,274. 12,321 (1997), stating "utilities are free to propose ... an alternative to the use of the 12-month rolling average in the load ratio share calculation, *subject to demonstrating that such alternative is consistent with the utility's transmission system planning...*" (emphasis added). The Commission has also stated that:

nothing would foreclose the utility "from showing in another case that a cost allocation method other than peak responsibility more appropriately reflects the operating and planning realities of its transmission system."

*Re American Electric Power Serv. Corp.*, 44 FERC ¶ 61,206, at 61,749 (1988), citing *Kentucky Utilities Co.*, 15 FERC ¶ 61,002, *reh'g denied*, 15 FERC ¶ 61,222. Further, the Commission has noted that planning documents that showed that the utility did not use system peak demand data in planning its transmission system would tend to support the position that the utility does not plan its system to meet its coincident peaks. *Kentucky Utilities Co.*, 15 FERC ¶ 61,222 at 61,506 n.15.

The record in this proceeding demonstrates that BPA does not use coincident peak assumptions for transmission planning. Fredrickson *et al.*, BP-14-E-BPA-33, at 9; Fredrickson *et al.*, BP-14-E-BPA-45, at 6-7, 9. BPA's planning approach, therefore, is different from the Commission's presumed planning approach. BPA's planning approach supports a non-coincident peak cost allocation method because BPA plans the system to meet its customers' non-coincident peaks.

WPAG argues that the Commission's peak ratio tests and consideration of operational factors are not contemplated to "ever produce an outcome where a utility would use anything other than a coincidental peak allocation method, or even that such an alternative to a coincidental peak method would be appropriate." WPAG Br., BP-14-B-WG-01, at 23. WPAG maintains that the Commission has approved the 12 CP method for utilities that are similar to BPA. *Id.* at 20-22. WPAG concludes that "it is clear" that BPA should use a 12 CP method. *Id.* at 21.

The Commission's peak ratio tests and consideration of operational factors are applied to utilities that use coincident peak planning assumptions. The Commission considers a coincident peak methodology appropriate for utilities that use this type of planning assumption. As indicated at Issue 4.3.1.3, BPA does not use coincident peak planning assumptions. Therefore, the tests and factors are not evidence that BPA plans its system to meet its coincident peaks or that BPA should use a coincident peak methodology.

The Commission uses the tests and factors to determine the number of months on which to base a coincident peak methodology (e.g., 3 or 12 months). See *Golden Spread Electric Coop. et al. v. Southwestern Pub. Serv. Co.*, 123 FERC ¶ 61,047, at P 75-76 (2008). The peak ratio tests compare the utility's coincident peak demand (native load, NT load, PTP contract demand, and legacy contract rights) during the utility's peak months to the coincident peak demand during the off-peak months. *Id.* See also *Fredrickson et al.*, BP-14-E-BPA-33, at 12-13. A flat demand curve supports the use of the 12 CP method. *Golden Spread Electric Coop.* 123 FERC ¶ 61,047, at P 76. The Commission considers the utility's operating realities as additional support for allocating costs on the basis of 12 months. *Id.* at P 75.

The underlying theory for the Commission's peak ratio tests and consideration of operating realities is that coincident peak demands during off-peak months are in part responsible for the utility's fixed costs. See *Union Elec. Co. v. F.E.R.C.*, 890 F.2d 1193, 1198-99 (D.C. Cir. 1989); see generally *Re Carolina Power & Light Co.*, 4 FERC ¶ 61107, at 61,230 (1978). If demand during off-peak months is high relative to demand during peak months, the Commission will allocate costs based on the 12 monthly coincident peaks (the 12 CP method). *Id.* On the other hand, demand significantly greater during a single month or season suggests that the demand during the peak months is largely responsible for the utility's fixed costs, and the Commission will allocate costs based on those peak months (e.g., 3 CP method). See *Illinois Power Co.*, 11 FERC ¶ 63,040, at 65,248 (1980); see also *Golden Spread Electric Coop.*, 123 FERC ¶ 61,047, at P 75-76. The parties do not cite any decisions in which the Commission uses the tests as a basis to reject proposed alternatives to the coincident peak method (e.g., a non-coincident peak method) or considers facts similar to the evidence in this record. Nor is BPA aware of any such decisions.

Staff applied the peak ratio tests using two sets of data: (1) NT coincident peak load and PTP and IR contract demand; and (2) monthly transmission peak load, which represented all system flows during the peak hour of the month, including load served under NT, PTP and IR contracts. *Fredrickson et al.*, BP-14-E-BPA-33, at 13-14. Both tests were within the range that indicates a flat demand. *Id.* at 14-15. Staff concluded that the flat demand supported allocating costs to NT customers on the basis of 12 months. *Id.* at 15. However, since BPA's planning approach supported a non-coincident peak methodology, Staff argued that the test results supported the 12 NCP method, rather than the 12 CP method. *Id.*

In rebuttal testimony, Staff acknowledged that the peak ratio tests apply when choosing among coincident peak methods, but "may not apply directly to the determination of which non-coincident peak methodology a utility should use." *Fredrickson et al.*, BP-14-E-BPA-45, at 5. Staff stated that the tests were "additional support" for allocating costs on the basis of 12 months, but that the primary consideration "was that the [non-coincident] demands on BPA's system peak at different times throughout the year and that BPA schedules maintenance and outages during off-peak periods when demands are lower." *Id.* at 6. Staff concluded that the test results "are consistent with this conclusion, even though they are not directly applicable to an NCP allocation methodology." *Id.*

Powerex and JP11 argue that the Commission’s peak ratio tests do not apply to BPA because BPA is different from the utilities that the Commission has used the tests for. Powerex Br., BP-14-B-PX-01, at 30-31; JP11 Br., BP-14-B-JP11-01, at 4-5.

The peak ratio tests do not indicate that BPA should use the 12 CP method, but for a different reason than is argued by Powerex and JP11. As explained above, the Commission presumes that utilities use coincident peak data for transmission planning and, therefore, its guidance is in the context of a coincident peak planning approach. BPA’s planning approach, on the other hand, is different from the Commission’s presumed approach because BPA uses non-coincident peak data for transmission planning.

WPAG and JP23 assert that BPA’s system and transmission planning is similar to the planning performed by other utilities that use the 12 CP method; however, neither party offers evidence to support these contentions. See WPAG Br., BP-14-B-WG-01, at 20-21; JP23 Br., BP-14-B-JP23-01, at 14. WPAG analyzes Staff’s testimony on scheduled maintenance, system demand, unscheduled outages, diversity, and energy transfers and argues that Commission precedent has considered “similar” factors to support the 12 CP method. WPAG Br., BP-14-B-WG-01, at 20-21. Contrary to WPAG’s arguments, however, Staff’s consideration of the factors is not similar to the Commission’s consideration of the factors. Staff’s testimony analyzed these factors from the context of a non-coincident peak planning approach. In the cases that WPAG cites for support, the Commission considered the factors based on a coincident peak planning approach.

For example, WPAG compares Staff’s testimony on BPA’s system demand to a proceeding in which the Commission considered a utility’s system demand and “generally adopted” the 12 CP method because it was “reasonably reflective” of the customer’s peak demand patterns “which give rise to capacity (demand) related cost.” WPAG Br., BP-14-B-WG-01, at 20 (citing *Central Illinois Public Service Co.*, 14 FERC ¶ 63,047, at 65,132 (1981)). In the order WPAG cites, the Administrative Law Judge stated that the utility “presumably build[s] the capacity necessary to serve their peak requirements” and then evaluated all of the utility’s operating realities — the monthly peak hour relationships using the peak ratio tests, scheduled maintenance, reserve capacity, short term sales and interchange transactions — from the context of this coincident peak planning presumption. *Central Illinois*, 14 FERC ¶ 63,047 at 65,132-36. Staff’s testimony about BPA’s system demand, however, discusses non-coincident peak demand patterns, not coincident peak demand. Fredrickson *et al.*, BP-14-E-BPA-33, at 8-9. See also Snohomish Cross Examination Exhibit, BP-14-E-SN-07-V06, at 27-29. The case is not comparable.

WPAG also compares Staff’s testimony on energy transfers to the Commission’s affirmation of the 12 CP method for utilities that plan to meet 12 monthly non-coincident peaks. WPAG Br., BP-14-B-WG-01, at 21. Staff’s testimony on energy transfers, however, referred to the highest loading conditions on particular flowgates and transmission paths, not the loading coincident with BPA’s system peak. Fredrickson *et al.*, BP-14-E-BPA-33, at 9-11. See also Snohomish Cross Examination Exhibit, BP-14-E-SN-07-V06, at 30-31.

As explained above, JP23's position is that BPA should presume that the 12 CP method is appropriate because it is the Commission's presumed cost allocation method. JP23 Br., BP-14-B-JP23-01, at 13. JP23 maintains that BPA's compliance with reliability standards and the diversity of BPA's system do not rebut the 12 CP presumption. *Id.* at 14. JP23 argues that "[o]ther major transmission providers in the Northwest must comply with reliability standards and have diverse loads, yet all major transmission providers in the Northwest use the 12 CP methodology." *Id.* BPA recognizes that other transmission providers are required to comply with reliability standards and have diverse systems; however, no party has offered evidence in the record indicating whether other transmission providers apply the reliability standards and plan similarly to BPA. Moreover, as stated above, BPA's planning approach is different from the Commission's presumed planning approach.

The peak ratio test evidence is not directly applicable for a non-coincident peak method. Staff applied the tests using coincident peak data, and there is no evidence applying the tests using non-coincident demand data. Thus, Staff's test results are not directly applicable for a non-coincident peak methodology. Further, it is not clear that the Commission would apply the tests to analyze a non-coincident peak methodology if a utility presented evidence to demonstrate that it planned its system to meet the non-coincident peaks. The Commission has not applied the tests in all cost allocation cases. In at least one case, the Commission approved an alternative cost allocation method (a member load ratio calculation) without applying the tests, despite the Commission's staff supporting the 12 CP method. *American Electric Power Serv. Corp.*, 44 FERC ¶ 61,206, at 61,749 (1988).

### **Draft Decision**

*BPA's planning approach, which uses non-coincident peak data, is different from the Commission's presumed planning approach for the 12 CP method. Because BPA plans the system to meet non-coincident demands as one of its factors to plan the system, its planning approach supports a non-coincident peak method, not a coincident peak method. BPA will allocate costs to NT service using a non-coincident peak methodology.*

### **Issue 4.3.1.5**

*Whether a non-coincident peak cost allocation method is inconsistent with the pro forma tariff.*

### **Parties' Positions**

WPAG argues that because BPA has voluntarily filed its tariff with the Commission and is seeking reciprocity status, allocating costs without regard to how the Commission would allocate transmission costs would upset the *pro forma* tariff "balance" between the terms and conditions of the various transmission services and the allocation of costs between such services "to the detriment of BPA's NT customers and to the benefit of BPA's PTP customers." WPAG Br., BP-14-B-WG-01, at 17-18. WPAG and JP23 argue that 12 CP is the Commission's general standard for cost allocation for the *pro forma* tariff. WPAG Br., BP-14-B-WG-01, at 18; JP23 Br., BP-14-B-JP23-01, at 9.

JP11 believes that BPA does not need to adopt the 12 CP method to “achieve reciprocity so long as the methodology it selects is either comparable to FERC’s standard or required to meet the law.” JP11 Br., BP-14-B-JP11-01, at 2-4.

### **BPA Staff’s Position**

Staff does not specifically address this issue, but believes that a non-coincident peak method (the 12 NCP method) is consistent with Commission guidance in Order No. 888 that a cost allocation method should reflect a utility’s transmission planning approach. Fredrickson *et al.*, BP-14-E-BPA-45, at 2-3.

### **Evaluation of Positions**

JP11 appears to assert that a condition of the Commission’s approval of BPA’s tariff as an acceptable reciprocity tariff is that BPA’s allocation methodology is comparable to the Commission’s ratemaking standards or, if not comparable, is necessary to meet the other statutes that apply to BPA. JP11 Br., BP-14-B-JP11-01, at 2-4. The conditions for reciprocity status are outside the scope of the rate proceeding and are not a rate issue. The Commission’s review of BPA’s rates does not include examining whether the rates are consistent with the Commission’s requirements for jurisdictional utilities.

WPAG appears to assert that any cost allocation method other than the 12 CP method (for example, the 12 NCP method Staff proposed) upsets the balance between the terms and conditions in the *pro forma* tariff and the costs allocated to PTP and NT service. *See* WPAG Br., BP-14-B-WG-01, 17-18. This assertion is incorrect. The Commission permits jurisdictional utilities to propose alternative cost allocation methods if the alternative is consistent with the utility’s transmission planning approach (see discussion at Issue 4.3.1.4). The Commission is open to other cost allocation methods and has never said that a certain method is needed to be consistent with the *pro forma* tariff.

WPAG also makes general assertions that imply that BPA has disregarded the Commission’s guidance on cost allocation (“For BPA to establish terms and conditions of transmission service that are consistent with the *pro forma*, and then allocate transmission costs without regard to how FERC would allocate transmission costs....”). WPAG Br., BP-14-B-WG-01, at 17. Again, BPA is not bound to follow Commission guidance. Nevertheless, BPA has considered Commission guidance in depth and believes that the 12 NCP method is consistent with that guidance.

### **Draft Decision**

*BPA’s reciprocity status is not a rate case issue. The record does not support a conclusion that a non-coincident peak method is inconsistent with the pro forma tariff or BPA’s tariff.*

### **Issue 4.3.1.6**

*Whether Staff's proposal for a non-coincident peak methodology gives too much weight to the non-coincident peak load forecast assumption in BPA's planning studies.*

### **Parties' Positions**

WPAG and JP23 argue that BPA's support for the 12 NCP proposal overemphasizes the non-coincident peak load forecast assumption in BPA's planning studies. WPAG Br., BP-14-B-WG-01, at 22; JP23 Br., BP-14-B-JP23-01, at 13. WPAG claims that the non-coincident peak load forecast assumption is one factor among many to consider for transmission cost allocation. WPAG Br., BP-14-B-WG-01, at 22. WPAG argues that this one factor does not outweigh all of the other factors (*e.g.*, BPA's operating realities and peak ratio tests) that support the 12 CP method. *Id.* at 24.

### **BPA Staff's Position**

BPA plans the system to meet each customer's forecast peak demand, which includes the customer's load and the transmission of energy over BPA's system to adjacent transmission systems (energy transfers). Fredrickson *et al.*, BP-14-E-BPA-33, at 9-10. The use of the non-coincident peak load forecast assumption in BPA's planning studies is Staff's primary consideration supporting a non-coincident peak methodology. Fredrickson *et al.*, BP-14-E-BPA-45, at 6.

### **Evaluation of Positions**

WPAG argues that the 12 NCP method "gives an [undue] amount of weight to a single factor," the non-coincident peak load forecast assumption in BPA's planning studies. WPAG Br., BP-14-B-WG-01, at 25. WPAG asserts that if the choice of a cost allocation method were entirely dependent upon the load assumption used by the utility for its transmission planning, the Commission "could simply declare that transmission cost allocation is an exclusive function of the type of load forecast used [for transmission planning] and that would be the end of the matter." *Id.* at 22.

WPAG diminishes the importance that the planning load assumption plays in the Commission's guidance on cost allocation. As explained at Issue 4.3.1.4, the Commission's endorsement of the 12 CP method is based on a presumption that utilities use coincident peak assumptions for transmission planning. *See* Order. No. 888, 61 Fed. Reg. at 21,599; Order No. 888-A, 62 Fed. Reg. at 12,321; *Kentucky Utilities Co.*, Opinion No. 116-A, 15 FERC ¶ 61,222, at 61,504-61,507. Thus, even under Commission guidance, the load assumption is a critical factor in transmission cost allocation.

WPAG claims that BPA has not demonstrated that "its reliance on seasonal non-coincidental rather than coincidental peak loads," for transmission planning "is a primary cost driver on BPA's system." WPAG Br., BP-14-B-WG-01, at 23. Because facilities needed to mitigate potential system problems within BPA's ten-year planning horizon would be the same if BPA used coincident rather than non-coincident load assumptions, WPAG believes that the "only

impact” that the use of non-coincident as opposed to coincident loads has is on the timing of transmission reinforcements or upgrades. *Id.* at 23-24. WPAG argues that timing “is not immutable” because timing is also impacted by the professional judgment of BPA’s system planners. *Id.* at 25.

Therefore, WPAG claims, the “chief distinction” between the non-coincident and coincident load assumptions is not a matter of what costs are incurred, but “*a matter of when* those costs are incurred.” *Id.* at 24 (emphasis in original). WPAG does not believe that the timing difference between the two load assumptions “overwhelms all of the other evidence and factors that indicate that BPA should use 12 CP for cost allocation.” *Id.*

The chief distinction is not timing, but which assumption BPA uses to plan the system. The design of BPA’s system and the timing for reinforcements and the costs BPA incurs are impacted by the non-coincident, not the coincident, peak load forecasts and energy transfer assumptions. Fredrickson *et al.*, BP-14-E-BPA-33, at 9-10; Fredrickson *et al.*, BP-14-E-BPA-45, at 9. While it is true that BPA might incur similar costs if BPA used coincident peak assumptions for transmission planning, this does not indicate that BPA actually incurs costs to meet the coincident peaks. Further, as described at Issue 4.3.1.4, all of the other factors do not support the 12 CP method. WPAG’s comparison of Commission guidance to Staff’s testimony does not indicate that BPA should use the 12 CP method.

A core function of BPA’s transmission planning is to ensure that the transmission system is capable of reliably serving the customers’ demands, including their loads, over a range of system conditions. BPA’s planning does not exclusively examine the non-coincident peak loads, but analyzes the system’s ability to serve those loads under a range of conditions, including the dispatch of the generation on the system, seasonal ambient temperatures, and outage of critical transmission facilities. Fredrickson *et al.*, BP-14-E-BPA-33, at 8-12; Fredrickson *et al.*, BP-14-E-BPA-45, at 6-11, 17-18. These factors are considered in relation to serving the load. Thus, the customers’ non-coincident peak load forecasts are the main driver of the costs BPA incurs to provide reliable load service, and a non-coincident peak cost allocation method does not give that forecast assumption too much weight.

WPAG and JP23 argue that the rate differential between 12 NCP and 12 CP is significant for NT customers. WPAG Br., BP-14-B-WG-01, at 25; JP23 Br., BP-14-B-JP23-01, at 17-18. WPAG also argues that NT customers have paid “noticeably more” for transmission service since 1996 and that “[a]fter 17 years it is time to put an end to this improper cost shift.” WPAG Br., BP-14-B-WG-01, at 25. There has been no improper cost shift. Since BPA has adopted the OATT, BPA’s rate levels for the Network segment (as well as other rate levels) have been set through the Administrator’s adoption of largely uncontested settlements with the transmission customers. Fredrickson *et al.*, BP-14-E-BPA-33, at 1-3. The question for this proceeding is not whether NT customers are paying more than they would under a different methodology, but whether the allocation of costs to them is appropriate. It is.

## **Draft Decision**

*Serving the customers' non-coincident loads is a core function of BPA's transmission planning and a key driver of the costs BPA incurs. A non-coincident peak method does not overemphasize the role of non-coincident peaks in BPA's planning approach.*

### **Issue 4.3.1.7**

*Whether BPA should allocate costs to NT service on the basis of two, three, or twelve months.*

### **Parties' Positions**

Although JP11 regards Staff's description of BPA's planning approach as thorough and credible, JP11 disagrees with the conclusion that the use of 12 months for the cost allocation proposal is consistent with BPA's planning approach. JP11 Br., BP-14-B-JP11-01, at 6-9. JP11 argues that BPA's planning approach focuses more on two or three seasonal peaks, which indicates that costs should be allocated using the 2 or 3 NCP method. *Id.* at 9. Powerex agrees with JP11's suggested cost allocation methodology. Powerex Br., BP-14-B-PX-01, at 31-32.

WPAG and JP23 support allocating costs on the basis of 12 months but disagree that cost allocation should be on a non-coincident peak basis. WPAG Br., BP-14-B-WG-01, at 17; JP23 Br., BP-14-B-JP23-01, at 12.

### **BPA Staff's Position**

Staff proposed allocating costs to NT service on the basis of 12 months because BPA plans the transmission system to meet demands under a range of system conditions throughout the year. Fredrickson *et al.*, BP-14-E-BPA-33, at 8-12; Fredrickson *et al.*, BP-14-E-BPA-45, at 11-17. Staff explained that BPA's transmission system covers a geographically diverse territory and, as a result, BPA's load and energy transfers (the transmission of energy over BPA's system to adjacent transmission systems) peak throughout the year, not during a single month or season. Fredrickson *et al.*, BP-14-E-BPA-33, at 8-11. Staff also considered the system's ability to reliably meet demands during the outage of critical transmission facilities and the scheduling of maintenance and outages during off-peak periods. *Id.* at 11. These factors support allocating costs using 12 months. *Id.*

### **Evaluation of Positions**

JP11 states that BPA uses Western Electricity Coordinating Council (WECC) base cases representing winter and summer peak and spring off-peak loading conditions and concludes that BPA's system planning focuses on two or three seasonal peaks rather than on 12 monthly peaks. JP11 Br., BP-14-B-JP11-01, 7-9. JP11 argues that this justifies allocating costs based on the customer's peak in the winter peak case (the winter season), the summer peak case (the summer season), and the spring off-peak case (the spring season), which JP11 refers to as the 3 NCP method. *Id.* at 8-9. The 2 NCP method includes the customer's peak in the winter and summer peak cases only. *Id.*

While JP11 is correct that BPA’s planning studies use seasonal WECC base cases that incorporate the customer’s highest non-coincident demand for the season, JP11’s emphasis on the two or three seasonal peaks does not account for the impact that off-peak periods have on BPA’s costs. Fredrickson *et al.*, BP-14-E-BPA-33, at 12; Fredrickson *et al.*, BP-14-E-BPA-45, at 17. Potential system deficiencies occur at times when loads are typically lower. Fredrickson *et al.*, BP-14-E-BPA-45, at 13, 16. BPA uses at least one off-peak base case, which represents spring or early summer off-peak load and system conditions. *Id.* at 14. BPA does not explicitly use a fall off-peak case, but these conditions are nonetheless captured by BPA’s planning studies, because the spring or early summer off-peak conditions adequately represent the highest stresses on the system during all off-peak periods. *Id.* The off-peak conditions impact the costs BPA incurs. *Id.* For example, the higher ambient temperatures during the summer reduce the transfer capability of the system and result in potential thermal overload problems during off-peak summer load levels that may require a corrective action plan. *Id.* at 6, 14.

JP11’s proposal also overlooks the impact that transmission facility or generation outages have on BPA’s ability to meet demands. Fredrickson *et al.*, BP-14-E-BPA-33, at 11. Outages affect the availability of transmission capacity to serve load and transmit energy off-system. *Id.* In order to mitigate the impact that outages may have on BPA’s ability to serve load during the peak periods, BPA schedules a large amount of transmission line maintenance work and plans its transmission outages for periods when load and energy transfers are lower. *Id.* at 12. The transfer capability (which is reduced by scheduled transmission outages) available to serve load during off-peak periods is not significantly different than the transfer capability available to serve load during summer and winter peak conditions. *See generally* Fredrickson *et al.*, BP-14-E-BPA-45, at 16-17.

A 2 NCP method does not reflect any off-peak conditions, and a 3 NCP method reflects only one, the spring off-peak condition. However, BPA reinforces or upgrades the transmission system to mitigate the potential system deficiencies that may occur during all of the off-peak conditions. Fredrickson *et al.*, BP-14-E-BPA-33, at 12; Fredrickson *et al.*, BP-14-E-BPA-45, at 14, 16. Therefore, it is important to consider all of the off-peak periods when allocating costs. The 12 NCP method does this.

JP11 also argues that the 12 NCP proposal “assumes that transmission system peak usage during each month of [the] year contributes equally to the overall cost of building and constructing a reliable transmission system.” JP11 Br., BP-14-B-JP11-01, at 7. Powerex similarly argues that “[u]se of twelve monthly peaks considers each month equally, and thus is appropriate [only] where NT customers have relatively flat loads.” Powerex Br., BP-14-B-PX-01, at 30. The 12 NCP proposal does not assume that the cost impact is the same for all months. Instead, it assumes that meeting the customer’s demands during the peak and off-peak months impacts the costs BPA incurs. This assumption is correct.

In addition, although BPA is not bound by Commission precedent and the Commission’s guidance on the peak ratio tests and operating realities is not directly applicable for a non-coincident methodology (see discussion at Issue 4.3.1.4), it should be noted that the

Commission’s standard for allocating costs on the basis of 12 months does not assume that the load during each month of the year causes the utility to incur the same amount of costs. Rather, the Commission compares the relationship between peak and off-peak demands to determine whether the off-peak demands are, in part, responsible for the utility’s fixed costs. Thus, the Commission determines whether the off-peak periods impact the costs the utility incurs, not whether the cost impact is the same during all months.

WPAG states that JP11 “summarily rejects the results of FERC’s peak ratio tests on the basis that it does not believe they apply to BPA’s system” and “completely ignores the operational factors that FERC requires utilities to consider.” WPAG Br., BP-14-B-WG-01, at 27. WPAG argues that application of the Commission’s guidance to BPA “leads to the undeniable conclusion” that BPA should use the 12 CP method. *Id.* WPAG states that JP11 “argues that the standard industry metrics that produce [the 12 CP] conclusion must be wrong (but without providing any authority or precedent to support that position).” *Id.* at 27-28. Although the 12 CP method may not be the “undeniable conclusion” when applying the Commission’s guidance (see discussion at Issue 4.3.1.4), WPAG is correct that JP11’s proposal does not account for the full range of BPA’s operating realities.

### **Draft Decision**

*BPA plans the transmission system and incurs costs to meet its customer’s non-coincident demands throughout the year, not only during the customer’s peak hour of the spring, winter, or summer months. Accordingly, BPA will use a non-coincident peak methodology (as discussed at Issue 4.3.1.4) and allocate costs to NT service on the basis of 12 months.*

### **Issue 4.3.1.8**

*Whether BPA should credit short-term and non-firm PTP sales revenue to PTP, IR, and NT service based on the contribution of each service to excess capacity on the system.*

### **Parties’ Positions**

JP11 argues that the capacity that BPA sells as short-term and non-firm PTP service is unused capacity that has been built into the system for PTP, IR, and NT service (which JP11 calls “excess”). JP11 Br., BP-14-B-JP11-01, at 14. JP11 proposes that BPA credit short-term and non-firm PTP sales revenue between PTP, IR, and NT services. *Id.* at 13-15.

WPAG argues that JP11’s proposal is outside generally accepted practice in which short-term sales are credited against the total revenue requirement for the entire network, even when utilities use the 12 CP method. WPAG Br., BP-14-B-WG-01, at 29-30.

### **BPA Staff’s Position**

JP11’s proposal is not credible because it lacks support, a rationale, or analysis. Fredrickson *et al.*, BP-14-E-BPA-45, at 39. JP11’s proposal is not consistent with the standard Commission

methodology or with standard revenue crediting methodology used when cost allocation is based on contract demand for PTP service and load for NT service. *Id.* at 40.

### **Evaluation of Positions**

The premise of JP11’s argument is that its 2 or 3 NCP proposal (with costs allocated based on usage) or the 1 NCP method (with costs allocated based on contract demand for PTP and IR service and 1 NCP load for NT service) reflects the amount of excess capacity that BPA has built into the system for each customer class. JP11 Br., BP-14-B-JP11-01, at 14. Thus, under the 1, 2, or 3 NCP methods, JP11 argues, PTP, IR, and NT customers should share equally in the revenue credits for short-term firm and non-firm PTP sales. *Id.* JP11 states that the revenue credits for the other cost allocation methods build from this premise. *Id.* at 14-16. JP11 argues that under the 12 CP method, the NT customer class does not receive any revenue credits for short-term and non-firm PTP sales, because NT customers “only pay for the capacity they use” and “[do] not share in the cost of excess capacity built into the system to meet extreme loading conditions they may place on the system.” *Id.* at 14.

JP11 assumes that its 2 or 3 NCP proposal or the 1 NCP method is the appropriate cost allocation method for BPA. For the reasons described at Issues 4.3.1.1 and 4.3.1.4, JP11’s assumption is incorrect. Allocating costs to PTP and IR customers based on usage under the 2 or 3 NCP proposal does not reflect the customers’ rights to use the system or BPA’s planning obligation. Allocating costs on the basis of 1, 2 or 3 peaks does not account for the impact that off-peak conditions have on the costs BPA incurs. As a result, it is inappropriate to use the 1, 2, or 3 NCP method as the starting point from which the allocation amounts for the other cost allocation methods are calculated. In addition, as explained at Issue 4.3.1.1, BPA plans the system to meet average loading conditions, not extreme loading conditions.

Although BPA is not bound by Commission precedent when setting rates, it should be noted that JP11’s crediting proposal is not consistent with the standard revenue crediting methodology used by the Commission in conjunction with allocating costs to PTP service based on contract demand and to NT service based on a 12 CP methodology. *See* Fredrickson *et al.*, BP-14-E-BPA-45, at 40; WPAG Br., BP-14-B-WG-01, at 29-30. The standard Commission methodology is to credit the transmission revenue requirement for the short-term revenues prior to allocating the costs to PTP and NT service. Fredrickson *et al.*, BP-14-E-BPA-45, at 40; WPAG Br., BP-14-B-WG-01, at 29.

### **Draft Decision**

*BPA will not adopt the short-term and non-firm revenue crediting alternative to BPA’s proposal.*

#### **4.3.2 Utility Delivery Service**

The utility delivery charge is a rate for the delivery of power to utility customers over the utility delivery segment, which includes substations and other transmission facilities that deliver power at voltages below 34.5 kV. Transmission Rates Study, BP-14-E-BPA-07, at 77. Settlement of

the transmission rate cases for the last several rate periods resulted in a utility delivery charge that did not fully recover the costs of the utility delivery segment. Bogdon *et al.*, BP-14-E-BPA-30, at 10. Staff proposed to increase the charge by 25 percent for FY 2014–2015 to move the rate toward full cost recovery, even though the charge still would not fully recover the costs of the segment. *Id.* at 10-11; Bogdon *et al.*, BP-14-E-BPA-43, at 16.

Utility delivery customers argue that the proposed increase is too high and would result in rate shock. These customers propose transitioning the utility delivery charge to full cost recovery over the next three to five rate periods. Non-utility delivery customers argue that a 25 percent increase is too low and recommend that BPA adopt a rate that fully recovers the costs of the utility delivery segment. The contested issues related to utility delivery service are addressed in the discussion that follows.

#### **Issue 4.3.2.1**

*Whether cost causation principles require BPA to increase the utility delivery charge to the level necessary for the charge to fully recover the FY 2014–2015 utility delivery costs.*

#### **Parties' Positions**

Iberdrola and Powerex argue that cost causation principles dictate that BPA set the FY 2014–2015 utility delivery charge to fully recover the costs of the utility delivery segment. Iberdrola Br., BP-14-B-IR-01, at 7-8, 10; Powerex Br., BP-14-B-PX-01, at 27.

JP03 and WPAG argue that increasing the utility delivery charge to fully recover the costs of the utility delivery segment would result in rate shock. *See* JP03 Br., BP-14-B-JP03-01, at 20-21; WPAG Br., BP-14-B-WG-01, at 34.

#### **BPA Staff's Position**

Increasing the utility delivery charge to fully recover the costs of the utility delivery segment would result in rate shock. Bogdon *et al.*, BP-14-E-BPA-30, at 10-11; Bogdon *et al.*, BP-14-E-BPA-43, at 16. Staff recommends increasing the utility delivery charge by 25 percent to balance cost causation principles with the avoidance of significant rate shock. *Id.*

#### **Evaluation of Positions**

Iberdrola and Powerex argue that cost causation principles dictate that BPA adopt a utility delivery charge that fully recovers all utility delivery costs. Iberdrola Br., BP-14-B-IR-01, at 6-8; Powerex Br., BP-14-B-PX-01, at 27. These customers point out that non-utility delivery customers do not use utility delivery facilities and do not cause BPA to incur utility delivery costs. *Id.* Iberdrola and Powerex argue that non-utility delivery customers have been paying utility delivery costs for at least 12 years, and possibly longer. *Id.*

BPA would have to increase the utility delivery charge by approximately 84 percent to fully recover the utility delivery costs for FY 2014–2015. Bogdon *et al.*, BP-14-E-BPA-43 at 15. Staff and utility delivery customers are concerned that such an increase would result in rate shock. Bogdon *et al.*, BP-14-E-BPA-30, at 10-11; Scott and Carr, BP-14-E-JP03-3 at 5-6; WPAG Br., BP-14-B-WG-01, at 34. Staff’s proposal would result in recovering approximately \$2.56 million in utility delivery costs through the rates that apply to the other segments. Transmission Rates Study Documentation, BP-14-E-BPA-07A, at 6. This represents approximately 0.2 percent of the total transmission revenue requirement in the Initial Proposal. *See id.* at 1.

All parties acknowledge that the utility delivery charge in the last several rate periods was the product of negotiated settlements rather than decisions made in fully litigated proceedings. Iberdrola Br., BP-14-B-IR-01, at 6, 8-9; Powerex Br., BP-14-B-PX-01, at 26. Although these settlements have led to a lengthy period of relative transmission rate stability, they also have contributed to the current under-recovery by the utility delivery charge. Bogdon *et al.*, BP-14-E-BPA-30, at 10. After this lengthy period, it would be unfair to impose an 84 percent increase in the utility delivery charge in one rate period. Although cost causation is an important principle, avoidance of rate shock is as well. As explained in the discussion of Issue 4.3.2.2, the ratemaking discretion provided in BPA’s statutes guides the establishment of the utility delivery charge in this proceeding.

Iberdrola argues that adopting an 84 percent increase would not result in rate shock, because most utility delivery customers also buy Federal power from BPA, and utility delivery charges are only a small percentage of the combined power and transmission bill. Iberdrola Br., BP-14-B-IR-01, at 7. Under Iberdrola’s approach, however, any increase in transmission rates would be insignificant to a customer that purchases Federal power, because power costs greatly exceed transmission costs. Bogdon *et al.*, BP-14-E-BPA-43, at 10-11. No transmission rate increase could ever result in rate shock.

Iberdrola’s analysis indicates that in many cases utility delivery costs are more than a third of a customer’s transmission bill (*e.g.*, Bandon, Bonners Ferry, Cascade Locks, Coulee Dam, Drain, Milton, Minidoka, Steilacoom, and Troy). *See* Bogdon *et al.*, BP-14-E-BPA-43, Attachment 1. WPAG points out that the utility delivery charge impacts some of BPA’s smallest customers, which are least equipped to handle large rate increases. WPAG Br., BP-14-B-WG-01, at 32. The evidence demonstrates that increasing the utility delivery charge by 84 percent would have significant enough impacts on utility delivery customers to warrant balancing cost causation with concerns about rate shock. No other customer group faces an increase close to that for any transmission rate in the FY 2014–2015 rate period.

Iberdrola objects to the “inequitable treatment” among customers due to “marked differences” in BPA’s approach to cost causation for preference customers and for non-Federal VER transmission customers. Iberdrola Br., BP-14-B-IR-01, at 8, 9. Iberdrola states that BPA has been “permitting this [utility delivery] subsidy” for 12 years, and that it is representative of a pattern of BPA decisionmaking that shifts preference customer costs to integrated network transmission customers but directly assigns to VERs any costs that are arguably related to VERs.

*Id.* Iberdrola cites the costs of certain resources under the VERBS rate and the Wind Integration Team costs as examples of expenses that “benefit network transmission customers generally” but that BPA assigns to VERs. *Id.*

The “subsidy” that Iberdrola says BPA “permitted” for 12 years was the product of uncontested settlements by rate case parties in every rate case during that period. Likewise, in this proceeding the treatment of resources under the VERBS rate and of the Wind Integration Team costs was resolved through a settlement that was adopted after Iberdrola’s initial brief was filed. Administrator’s Record of Decision on Settlement Proposal for Generation Inputs and Transmission, Ancillary, and Control Area Services Rates, BP-14-A-01, at 14. BPA’s decisionmaking associated with these settlements does not reflect discriminatory or other forms of inequitable treatment, but reflects an appreciation for regional resolution of the otherwise divisive issues that would be involved.

Iberdrola and Powerex also argue that setting a utility delivery rate lower than the full cost of service may inhibit utility delivery facility sales. Iberdrola Br., BP-14-B-IR-01, at 9; Powerex Br., BP-14-B-PX-01, at 28. BPA’s policy goal of selling its utility delivery facilities is an important consideration in setting the utility delivery charge. Bogdon *et al.*, BP-14-E-BPA-30, at 11. Increasing the charge by 84 percent would send a very strong price signal to encourage customers to purchase the remaining facilities. The record shows, however, that BPA has sold a large number of substations without setting a utility delivery rate that fully recovers its costs. Bogdon *et al.*, BP-14-E-BPA-43, at 16. Furthermore, as JP03 and WPAG point out, the utility delivery rate is but one of many issues that affect BPA’s ability to sell utility delivery facilities; other issues, such as the cost and age of the facilities, are also very important. WPAG Br., BP-14-B-WG-01, at 32-33; JP03 Br., BP-14-B-JP03-01, at 21. These points suggest that BPA can effectively promote the purchase of the facilities without increasing the utility delivery charge to a level that would result in rate shock.

Powerex recommends that BPA increase the utility delivery rate to full cost recovery and use transmission financial reserves to mitigate the rate impact. Powerex Br., BP-14-B-PX-01, at 25, 27. Powerex would require utility delivery customers to “replenish” the financial reserves in the future. *Id.* As discussed in section 4.2, financial reserves are being applied to reduce the general transmission revenue requirement and to reduce transmission rates overall. Reserves are not being targeted to reduce any one particular rate. Although Powerex’s proposal acknowledges the potential impacts associated with increasing the utility delivery charge to full cost recovery, the mechanism for “replenishment” of the reserves remains unclear, and the record contains no evidence to support adoption of a particular mechanism. Staff expresses concern that utility delivery customers could still experience rate shock under Powerex’s proposal, and Powerex acknowledges that BPA would have to structure the terms of replenishment to avoid that result. Bogdon *et al.*, BP-14-E-BPA-43, at 15; Powerex Br., BP-14-B-PX-01, at 27. BPA is reluctant to adopt a rate mitigation proposal that has not been developed on the record, particularly when there are concerns that it might not address the problems at hand. *See* Scott and Carr, BP-14-E-JP03-03, at 7 (expressing concern about the “circularity” of Powerex’s proposal).

Although it is important to set a utility delivery rate that begins transitioning that rate to complete cost recovery, the recommendation to set the rate to fully recover the utility delivery costs fails to properly recognize the potential impacts on utility delivery customers. Appropriately resolving the FY 2014–2015 utility delivery charge requires striking a balance between cost causation, avoidance of rate shock, and furtherance of BPA’s policies promoting the purchase of utility delivery facilities by utility delivery customers.

### **Draft Decision**

*Cost causation principles do not require BPA to increase the utility delivery charge to the level necessary for the charge to fully recover the FY 2014–2015 utility delivery costs.*

### **Issue 4.3.2.2**

*Whether section 9 of the Transmission System Act requires BPA to increase the utility delivery charge to the level necessary for the charge to fully recover the FY 2014–2015 utility delivery costs.*

### **Parties’ Positions**

Powerex argues that setting a utility delivery charge that does not fully recover utility delivery costs “is inconsistent with BPA’s statutory mandate under section 9 of the Transmission System Act to establish the lowest possible rates consistent with sound business principles” because it results in higher rates for BPA’s other transmission customers. Powerex Br., BP-14-B-PX-01, at 27.

### **BPA Staff’s Position**

This is a legal issue that Staff did not address in its testimony.

### **Evaluation of Positions**

Powerex cites *Pacific Northwest Generating Coop. v. Department of Energy*, 580 F.3d 792, 820-21 (9th Cir. 2009), in support of its argument regarding section 9 of the Transmission System Act. *Id.* Powerex states that the *PNGC* court held that “because a monetary payment to certain direct service industrial customers would have resulted in higher rates for all other BPA power customers, such payment was inconsistent with BPA’s mandate under section 9 of the Transmission System Act to provide power at the lowest possible rates to customers consistent with sound business principles.” *Id.* n.96.

Powerex’s argument is misplaced. Section 4.2 of this Draft ROD describes in detail how courts have interpreted section 9 of the Transmission System Act. The standard is not a mandate to set the lowest rates possible without regard to any other business or legal principle. *See* Draft ROD, section 4.2; *see also* BP-12 Final ROD, BP-12-A-02, at 127-28 (quoting *California Energy Comm’n v. Bonneville Power Admin.*, 909 F.2d 1298, 1307-08 (9th Cir. 1990)). Congress “has delegated to BPA the discretion to determine ‘how best to further BPA’s business interests

consistent with its public mission.” *Alcoa, Inc. v. Bonneville Power Admin.*, 698 F.3d 774, 789 (9th Cir. 2012).

Powerex suggests that section 9 of the Transmission System Act requires BPA to apportion costs and benefits solely based on cost causation. *See* Powerex Br., BP-14-B-PX-01, at 27. This is contrary to the plain language and the courts’ interpretations of the statute. *See* Draft ROD section 4.2; *see also* *Public Power Council v. BPA*, 442 F.3d 1204 (9th Cir. 2006). Nothing in section 9 restricts BPA to any particular rate design methodology or theory or requires setting rates based on strict cost causation principles. *See* *Pac. Power & Light Co. v. Duncan*, 499 F. Supp. 672, 683 (D. Or. 1980); *accord* *City of Santa Clara, Cal. v. Andrus*, 572 F.2d 660 (9th Cir. 1978). Section 9 provides BPA the ratemaking discretion to rely on generally accepted ratemaking principles to further its mission and business objectives. *Id.* As explained in the previous section, setting the FY 2014–2015 utility delivery charge involves balancing the interests between a rate increase that reflects cost causation and one that avoids significant rate shock.

In the *PNGC* case cited by Powerex, BPA effectively supplied the DSI power at a cost below both the market rate and the DSI power rates established pursuant to section 7(c) of the Northwest Power Act. *PNGC*, 580 F.3d at 807-08. The court found that BPA had no existing legal obligation to supply that power, had “voluntarily agreed to forgo revenues” by offering the power below the market rate or the statutory rate, and that BPA had not explained how its actions were consistent with a business-oriented philosophy. *Id.* at 820, 823. That case is distinguishable from this issue in the following ways. First, BPA has existing contractual obligations to provide service to utility delivery customers. Second, BPA’s statutes do not include specific requirements that govern the rates for utility delivery customers. BPA is charged with setting overall transmission rates that recover its costs. Third, avoiding significant rate shock is a generally accepted ratemaking principle in the utility business, and setting a utility delivery charge that avoids rate shock is consistent with a business-oriented philosophy. *Bogdon et al.*, BP-14-E-BPA-30, at 11; *Finley et al.*, BP-14-E-JP11-01, at 13. Powerex’s proposal to apply financial reserves to address the potential impact of increasing the utility delivery charge by 84 percent recognizes that avoiding rate shock is consistent with a business-oriented philosophy. Powerex Br., BP-14-B-PX-01, at 27-28. The fact that Powerex and Staff have proposed different approaches to addressing the potential impacts of such an increase highlights the fact that decisions such as these appropriately are left to the Administrator’s ratemaking discretion.

### **Draft Decision**

*Section 9 of the Transmission System Act does not require BPA to increase the utility delivery charge to the level necessary for the charge to fully recover the FY 2014–2015 utility delivery costs.*

### **Issue 4.3.2.3**

*Whether BPA should increase the utility delivery charge by 25 percent for FY 2014–2015 or begin a series of gradual increases to transition the rate to full cost recovery in three to five rate periods*

#### **Parties' Positions**

JP03 proposes that BPA should increase the utility delivery charge at the overall rate of increase of rates for the network segment for the next three rate periods. JP03 Br., BP-14-B-JP03-01, at 21-22.

WPAG proposes that BPA should increase the utility delivery charge by 9.2 percent over five rate periods to transition the charge to full cost recovery in ten years. WPAG Br., BP-14-B-WG-01, at 34; Saleba *et al.*, BP-14-E-WG-02, at 19.

#### **BPA Staff's Position**

Staff proposed increasing the utility delivery charge by 25 percent for FY 2014–2015. Bogdon *et al.*, BP-14-E-BPA-30, at 10-11.

#### **Evaluation of Positions**

JP03 argues that increasing the utility delivery charge at the same rate as the network segment for the next six years would give both BPA and utility delivery customers a reasonable means of addressing utility delivery facilities without unfairly subjecting those customers to rate shock. JP03 Br., BP-14-B-JP03-01, at 21-22. WPAG makes similar arguments in favor of its proposal. WPAG Br., BP-14-B-WG-01, at 33-34.

As an initial matter, in this proceeding BPA is setting rates for the FY 2014–2015 rate period only. Even if BPA were inclined to address the utility delivery charge for several rate periods, however, the record provides little support for adopting JP03's or WPAG's proposals, which, as explained below, place too little emphasis on cost causation.

It is unclear in JP03's proposal when, if ever, the utility delivery charge would fully recover utility delivery costs. *See* JP03 Br., BP-14-B-JP03-01, at 21-22; *see* Scott and Carr, BP-14-E-JP03-02, at 27-28. The degree to which the utility delivery rate would recover the utility delivery costs would depend entirely on unknown changes in network rates and utility delivery costs over the next six years. JP03 also did not address the potential outcomes at the end of the six-year period or the actions BPA should take at that point. JP03 appears to focus almost exclusively on minimizing the rate increase for utility delivery customers in the FY 2014–2015 rate period.

WPAG proposes a plan to bring the utility delivery charge to a level at which it will achieve full cost recovery, but WPAG proposes a rate increase for FY 2014–2015 that is significantly lower

than the increase in some other rates. *See* WPAG Br., BP-14-B-WG-01, at 33-34. This places too little emphasis on cost causation and the eventual elimination of the cost shift to other customers. Both WPAG and JP03 seem to rely on the assumption that the utility delivery charge under-recovery results in a *de minimis* cost shift that should cause little concern. *See id.*; JP03 Br., BP-14-B-JP03-01, at 21-22. JP03 argues that its proposal to increase the utility delivery charge by the amount of the network rate increase is a fair one for BPA and its customers. JP03 Br., BP-14-B-JP03-01, at 21-22. Powerex and Iberdrola maintain that any shift of utility delivery costs is unfair. Powerex Br., BP-14-B-PX-01, at 27; Iberdrola Br., BP-14-B-IR-01, at 7-8. Given the evidence of the cost shift created by the under-recovery by the utility delivery charge and the opposition of some customers that bear the under-recovery, it would be difficult to justify increasing the charge less than or equal to the increase in the network rate. The utility delivery charge is not increasing to the level necessary to fully recover the utility delivery costs for FY 2014–2015, but the rate needs to begin an aggressive transition to full cost recovery in this rate period. Bogdon *et al.*, BP-14-E-BPA-43, at 11. JP03’s and WPAG’s proposals do not go far enough in that direction.

JP03 argues that Staff’s proposal for a 25 percent rate increase would “unfairly penalize” utility delivery customers for the settlement of the past several rate cases and the sale of utility delivery facilities in recent years. JP03 Br., BP-14-B-JP03-01, at 20. This is an argument that it would be unfair for utility delivery customers to bear a larger portion of their cost of service than they have had to bear in the past. The evidence demonstrates, however, that the utility delivery charge would under-recover the costs of the segment even with a 25 percent increase and that other customers pay those costs. Bogdon *et al.*, BP-14-E-BPA-30, at 10. BPA is not penalizing utility delivery customers by requiring them to pay more of the costs of providing service to them. Bogdon *et al.*, BP-14-E-BPA-43, at 12.

JP03 also argues that a 25 percent rate increase would result in rate shock. JP03 Br., BP-14-B-JP03-01, at 20, 22. WPAG describes “adverse impacts” to some of BPA’s smallest preference customers. WPAG Br., BP-14-B-WG-01 at 32; Saleba *et al.*, BP-14-E-WG-02, at 17-19. Although 25 percent is a significant increase, the record does not demonstrate that the increase is so high or that the impacts will be so great that this increase alone will result in significant rate shock. JP03 and WPAG suggest that rate shock must be evaluated in terms of the magnitude of the increase at issue relative to the increases in other rates in the proceeding. Scott and Carr, BP-14-E-JP03-03, at 5; Saleba *et al.*, BP-14-E-WG-02, at 16. The rate increase meets this test as well; a 25 percent increase for the utility delivery charge is at the upper end of the range for all proposed transmission rate increases for the rate period. WPAG Br., BP-14-B-WG-01, at 32. This does not constitute rate shock, particularly given that the rate will still under-recover the segment’s costs even with a 25 percent increase.

JP03 and WPAG provide evidence regarding the cumulative impact of all transmission rate changes for certain utility delivery customers in FY 2014–2015. Scott and Carr, BP-14-E-JP03-03, at 4-5; Saleba *et al.*, BP-14-E-WG-02, at 17. Reducing the rate increase for utility delivery customers is not the appropriate means of addressing cumulative rate impacts. As described in section 4.2 of the Draft ROD, the use of financial reserves will reduce the overall increase and address those impacts. Draft ROD, section 4.2. The price signal for the utility

delivery charge should create additional incentive to purchase utility delivery facilities and avoid the utility delivery charge altogether. Bogdon *et al.*, BP-14-E-BPA-30, at 11-12; Bogdon *et al.*, BP-14-E-BPA-43, at 16.

WPAG predicts two undesirable outcomes if BPA adopts Staff's proposal: (1) due to significant non-financial issues affecting some utility delivery facilities, customers served by those facilities will be unable to immediately buy them, which makes a higher price signal ineffective; or (2) BPA will be overwhelmed by and unable to timely respond to the volume of customer interest in purchasing utility delivery facilities, and customers that want to purchase the facilities will have to pay the utility delivery charge while they wait. WPAG Br., BP-14-B-WG-01, at 33-34.

Although the sale of specific utility delivery facilities is not an issue in this proceeding, it is true that in the past non-financial issues have complicated the discussions regarding the sale of some of those facilities. However, WPAG's concern is based on the assumption that it would be inappropriate for utility delivery customers to pay a rate that reflects the true cost of service. BPA is not increasing the rate to achieve full cost recovery for FY 2014–2015 due to concerns about rate shock, but there is nothing inappropriate about utility delivery customers paying the full costs of the facilities that serve those customers.

With respect to WPAG's second point, that customers will be unable to purchase delivery facilities they wish to purchase, BPA wants to encourage interest in purchasing utility delivery facilities. Adopting a relatively smaller rate increase for utility delivery customers because of concerns about the potential for significant customer interest in purchasing utility delivery facilities runs counter to this policy.

The utility delivery charge should increase by more than the average transmission rate increase in this proceeding in order to begin an aggressive transition to full cost recovery, but at the same time, utility delivery customers should not be faced with an 84 percent rate increase all at once. Draft ROD, Issues 4.3.2.1–4.3.2.2; Bogdon *et al.*, BP-14-E-BPA-43, at 16. The utility delivery charge for FY 2014–2015 also should encourage the purchase of low-voltage facilities. Staff's proposal appears to be best tailored to achieving these results and strikes an appropriate balance for the utility delivery charge for FY 2014–2015.

### **Draft Decision**

*Staff's proposal to increase the utility delivery charge by 25 percent for FY 2014–2015 is appropriate and will be adopted. BPA will continue to encourage the purchase of low-voltage facilities during the rate period.*

#### **Issue 4.3.2.4**

*Whether BPA should allocate to all other transmission segments the FY 2014–2015 utility delivery costs that are not recovered through the utility delivery charge.*

#### **Parties' Positions**

Iberdrola recommends allocating to NT customers the utility delivery costs that are not recovered through the utility delivery charge. Iberdrola Br., BP-14-B-IR-01, at 9.

#### **BPA Staff's Position**

Staff recommends allocating the utility delivery costs that are not recovered through the utility delivery charge to all other segments based on net plant investment. Bogdon *et al.*, BP-14-E-BPA-43, at 14.

#### **Evaluation of Positions**

In the Initial Proposal, Staff recommended allocating the utility delivery costs that are not recovered through the utility delivery charge to the Network segment. Transmission Rates Study, BP-14-E-BPA-07, at 79. Staff changed its position in rebuttal testimony in response to concerns expressed by Powerex. Bogdon *et al.*, BP-14-E-BPA-43, at 14. In its rebuttal testimony, Staff reasoned that allocating the costs to all other segments was more equitable, because none of the other segments benefit from the utility delivery facilities, and therefore no segment should bear the entire cost. *Id.* In addition, allocating the utility delivery costs to all other segments based on net plant investment is consistent with the treatment of DSI Delivery costs and the Eastern Intertie surplus. *Id.*

Iberdrola recommends that BPA allocate the utility delivery costs that are not recovered through the utility delivery charge to NT customers only. Iberdrola Br., BP-14-B-IR-01, at 9-10.

Iberdrola points out that only one utility delivery customer is not an NT customer, so allocating the under-recovery to NT customers would keep the shift of costs “within that class.” *Id.* at 10.

Although all utility delivery customers except one are NT customers, not all NT customers are utility delivery customers. Bogdon *et al.*, BP-14-E-BPA-30, at 9; Transmission Rates Study Documentation, BP-14-E-BPA-07A, at 66-72, 81. Iberdrola’s proposal would require non-utility delivery customers taking NT service to bear a disproportionate share of utility costs, even though those customers are included in the class of integrated network customers that Iberdrola seeks to protect.

Staff’s recommendation is the most equitable and is consistent with the allocation of the excess costs and revenues from other segments. Bogdon *et al.*, BP-14-E-BPA-43, at 14.

## **Draft Decision**

*BPA will allocate the utility delivery costs that are not recovered through the utility delivery charge to all other segments based on net plant investment.*

### **4.3.3 Eastern Intertie**

#### **Issue 4.3.3.1**

*Whether BPA should eliminate the Eastern Intertie segment and roll the costs of BPA's share of Eastern Intertie capacity into the Integrated Network.*

#### **Parties' Positions**

JP10 states that the Eastern Intertie is a separate segment, and rolling it into the Network would be inconsistent with BPA's longstanding segmentation methodology. JP10 Br., BP-14-B-JP10-01, at 3. JP10 adds that rolling in the Eastern Intertie would unfairly transfer costs and risks to the Network customers without providing any benefits. *Id.* at 6.

RNP argues that the Eastern Intertie is not a true intertie but is an artificial segmentation that operates as an integrated part of BPA's transmission system. Nevertheless, customers must pay the Montana Intertie (IM) rate in addition to BPA's network rate to schedule energy over the Eastern Intertie to some other point on BPA's system. Therefore, BPA should roll the Eastern Intertie into the Network. RNP Br., BP-14-B-RN-01, at 60.

#### **BPA Staff's Position**

Staff proposes no change to the current Townsend-Garrison Transmission (TGT), IM, and Eastern Intertie (IE) rates. Metcalf *et al.*, BP-14-E-BPA-35, at 2. However, Staff remains willing to consider roll-in of BPA's Eastern Intertie capacity. *Id.*

#### **Evaluation of Positions**

The Eastern Intertie is radial to BPA's Integrated Network. As JP10 testified, "[t]he Eastern Intertie itself is connected to, but does not function as part of, the [Integrated] Network. . . ." Baker *et al.*, BP-14-E-JP10-01, at 3. Further, the Eastern Intertie is used primarily for transmission of Colstrip generation under the Montana Intertie Agreement. Metcalf *et al.*, BP-14-E-BPA-46, at 9. This service is provided to only five parties. Metcalf *et al.*, BP-14-E-BPA-35, at 2. Only 16 MW of BPA's Eastern Intertie westbound capacity has been sold on a long-term basis, and that was for transmission of Colstrip generation. Metcalf *et al.*, BP-14-E-BPA-46, at 10. There are no requests in BPA's Eastern Intertie transmission queue. JP10 Br., BP-14-B-JP10-01, at 4. Use of the Eastern Intertie does not include long-term transmission of other generation. These factors indicate that the Eastern Intertie should remain a separate

segment. Metcalf *et al.*, BP-14-E-BPA-35, at 6. As discussed below, other reasons to roll in BPA's Eastern Intertie capacity have not been established.

### **Draft Decision**

*BPA will not roll in its share of Eastern Intertie capacity.*

### **Issue 4.3.3.2**

*Whether roll-in of BPA's share of Eastern Intertie capacity would encourage development of renewable generation in the Pacific Northwest.*

### **Parties' Positions**

JP10 cites the absence of transmission service requests in BPA's Eastern Intertie transmission service queue. JP10 Br., BP-14-B-JP10-01, at 4. JP10 argues that "leaving aside transmission costs, Montana wind is already competitive with the Columbia Gorge wind on a cost basis." *Id.* at 8. JP10 further argues that given its evidence of the levelized cost of wind generation, the IM-14 rate "is not likely to have an actual or substantial impact on an entity's decision to invest in Eastern Montana projects over Columbia Gorge projects." *Id.* at 9.

RNP argues that eliminating the IM rate would help BPA to fulfill its responsibility under the Northwest Power Act to encourage development of renewable energy resources. RNP Br., BP-14-B-RN-01, at 62.

### **BPA Staff's Position**

Staff testified that the National Renewable Energy Laboratory (NREL) has identified areas of high-quality wind resources within the Pacific Northwest as defined in Northwest Power Act section 3(14)(B), and that wind generation in such areas could reach the Eastern Intertie through transmission service from a local transmission provider. Metcalf *et al.*, BP-14-E-BPA-46, at 4-5. Staff testified that eliminating the IM rate would reduce transmission costs for utilities wishing to acquire that generation. Metcalf *et al.*, BP-14-E-BPA-35, at 3.

### **Evaluation of Positions**

There is up to 9,000 MW of wind generation potential in Montana. *See* Metcalf *et al.*, BP-14-E-BPA-35, at 4. There is also significant wind generation potential within BPA's service area east of the Continental Divide. Metcalf *et al.*, BP-14-E-BPA-46, at 4-5; Williams and Yourkowski, BP-14-E-RN-03, at 4.

At a 40 percent capacity factor, roll-in of the Eastern Intertie would reduce transmission costs on the Eastern Intertie by over \$2/MWh. Williams and Yourkowski, BP-14-E-RN-03, at 6. However, the levelized cost of wind generation nationally ranges between \$77/MWh and \$112/MWh. Baker *et al.*, BP-14-E-JP10-02, at 3. Given the high cost of wind generation, the cost of transmission at the IM rate is only a small component of the delivered cost of eastern

Montana wind generation. Without some comparison of the costs of Montana and Columbia Gorge wind generation (including consideration of the benefits of the higher capacity factor and favorable seasonal and diurnal shape of Montana generation) and of the costs of transmitting generation in each area to the BPA network, it appears that roll-in would not encourage development of wind generation in Montana to any significant degree.

### **Draft Decision**

*Based on the evidence in the record, roll-in of BPA’s Eastern Intertie capacity would not encourage development of renewable generation in the Pacific Northwest.*

### **Issue 4.3.3.3**

*Whether roll-in of BPA’s share of Eastern Intertie capacity would be consistent with sound business principles.*

### **Parties’ Positions**

JP10 argues that transmission customers of Montana wind generation could default on their Network Open Season (NOS) obligations, which, if BPA has rolled the Eastern Intertie into the Network, would leave BPA’s other transmission customers with stranded costs, and BPA’s NOS reforms have not been shown to protect existing ratepayers. JP10 Br., BP-14-B-JP10-01, at 11-12. JP10 also argues that “BPA staff has not adequately considered the risk that importing wind generation from Montana would exacerbate oversupply conditions and create additional costs for the Northwest utilities and consumers.” *Id.* at 14.

WPAG argues that because of BPA’s diminishing amount of Treasury borrowing authority and its failure to use lease-financing in Montana, BPA would have to rely on customer financing for incremental rate projects in Montana. Such financing would require credits to the customers to repay the loans, thus increasing network rates to make up for lost revenues. WPAG Br., BP-14-B-WG-01, at 38-39. WPAG argues that the interplay between customer financing and an incremental rate must be better understood before any decision is made to roll in Eastern Intertie costs. *Id.* at 39.

WPAG argues that BPA Staff’s testimony “takes the short view” of the potential for Montana wind to add to BPA’s oversupply problem, and argues that BPA should undertake a “comprehensive prospective review” of the cost risks before deciding to roll in BPA’s Eastern Intertie capacity. WPAG Br., BP-14-B-WG-01, at 41.

RNP argues that because roll-in would encourage additional use of the Eastern Intertie, roll-in would be consistent with sound business principles. RNP Br., BP-14-B-RN-01, at 62.

### **BPA Staff’s Position**

Staff testified that if BPA’s Eastern Intertie capacity became part of the Network, there could be increased demand for short-term firm and non-firm transmission service at the rolled-in Network

rate. Metcalf *et al.*, BP-14-E-BPA-46, at 6. Issues concerning Network Open Season and incremental rates should be raised in other forums. *Id.* at 7-9.

### **Evaluation of Positions**

Only 184 MW of westbound capacity is available on the Eastern Intertie. Metcalf *et al.*, BP-14-E-BPA-46, at 11. BPA Staff's testimony that new facilities to transmit additional generation would take several years to build, and RNP's testimony to the same effect, do not estimate the amount or likelihood of new service. *See id.*; Williams and Yourkowski, BP-14-E-RN-03, at 7. Thus, it is possible that a significant additional amount of the remaining wind generation potential in Montana could find its way to BPA's transmission system. WPAG Br., BP-14-B-WG-01, at 43. Because Montana wind generation is envisioned to serve incremental Oregon and Washington RPS requirements in 2020 and 2025, there could be several thousand megawatts of new Montana wind generation accessing BPA's transmission system, which could result in significant cost impacts. WPAG Br., BP-14-B-WG-01, at 41 and 42, n.12; *see also* Metcalf *et al.*, BP-14-E-BPA-35, at 3, 5.

JP10 and WPAG have also raised concerns about whether the Network Open Season (NOS) reforms and incremental rates would sufficiently protect existing network customers. JP10 Br., BP-14-B-JP10-01, at 11-12; WPAG Br., BP-14-B-WG-01, at 39. These issues should be considered in other forums.

### **Draft Decision**

*There is a significant risk of additional costs from roll-in of BPA's Eastern Intertie capacity that has not been refuted. Because of that risk, it has not been demonstrated that roll-in would be consistent with sound business principles.*

### **Issue 4.3.3.4**

*Whether roll-in of BPA's Eastern Intertie capacity would be a precedent supporting roll-in of other segments.*

### **Parties' Positions**

JP10 argues that BPA Staff has not adequately assessed the risk of Eastern Intertie roll-in as a precedent for roll-in of other segments, notably the Southern Intertie and any generation interconnection facilities that otherwise would be directly assigned. JP10 Br., BP-14-B-JP10-01, at 12-13.

WPAG argues that roll-in of BPA's Eastern Intertie capacity on the basis that it would help Northwest resources overcome a competitive disadvantage would also support roll-in of the Southern Intertie. WPAG Br., BP-14-B-WG-01, at 37.

RNP argues that "(1) there are sufficient differences between BPA's share of the Eastern Intertie and other true interties; (2) there is insufficient evidence of any similarities between BPA's share

of the Eastern Intertie and the Southern Intertie; and (3) any other concerns about precedent are purely speculative and not supported by the record in this proceeding.” RNP Br., BP-14-B-RN-01, at 62.

### **BPA Staff’s Position**

BPA’s capacity on the Eastern Intertie is not a generation interconnection facility, and its use differs from the Southern Intertie. Metcalf *et al.*, BP-14-E-BPA-46, at 9-11. In addition, roll-in of BPA’s Eastern Intertie capacity would increase network rates between 0.02 percent and 0.195 percent, whereas roll-in of the Southern Intertie would increase rates by approximately 15 percent, a far greater increase. Metcalf *et al.*, BP-14-E-BPA-35, at 6. Staff prefers having a settlement on the issue of whether roll-in of the Eastern Intertie would be a precedent for Southern Intertie roll-in. *Id.* at 11.

### **Evaluation of Positions**

Because no changes are being made to the TGT, IM, and IE rates, this issue is moot. However, because this issue is appropriate for future segmentation workshops that may be held, a brief discussion is appropriate. BPA Staff, JP10, and WPAG are concerned about the precedent that roll-in of BPA’s Eastern Intertie capacity would have for roll-in of the Southern Intertie, and JP10 is concerned about the precedent for roll-in of generation interconnection facilities that would otherwise be directly assigned. However, there are significant distinctions between the Eastern Intertie and the Southern Intertie. Rolling in the Southern Intertie would have a much greater rate impact. Metcalf *et al.*, BP-14-E-BPA-35, at 10. The Southern Intertie is used for interregional transfers in both directions, while the Eastern Intertie is used for deliveries in one direction only, primarily for Colstrip generation. Metcalf *et al.*, BP-14-E-BPA-46, at 10. These factors may be sufficient to distinguish roll-in of BPA’s Eastern Intertie capacity from Southern Intertie roll-in.

With respect to Eastern Intertie roll-in being a precedent for generator interconnection facility roll-in, JP10 argued that the Eastern Intertie is essentially a generator interconnection facility, and roll-in would open the door to arguments that other generation interconnection facilities should also be rolled into network rates. JP10 Br., BP-14-B-JP10-01, at 13. JP10 is free to raise this issue in workshops that BPA may hold to discuss the circumstances under which it might roll additional facilities into the Integrated Network.

### **Draft Decision**

*It cannot be determined on this record whether roll-in of the Eastern Intertie would be a precedent for roll-in of the Southern Intertie. In the upcoming segmentation workshops BPA will consider the circumstances under which it might roll additional facilities into the Integrated Network.*

#### **4.3.4 NERC/WECC Costs**

##### **Issue 4.3.4.1**

*Whether BPA should directly assign the projected costs of reliability compliance activities it performs pursuant to agreements it has with certain customers.*

##### **Parties' Positions**

JP04 focuses on agreements under which BPA has agreed to assume certain reliability compliance responsibilities for specific customers related to customer-owned transmission facilities. JP04 Br., BP-14-B-JP04-01, at 26-27. JP04 recommends that BPA directly assign to the individual customers the projected costs of the activities performed by BPA pursuant to these agreements. *Id.* at 26.

##### **BPA Staff's Position**

Staff opposes JP04's recommendation. Bogdon *et al.*, BP-14-E-BPA-43, at 26. Staff believes that BPA's agreements reflect commitments to continue reliability-related activities that BPA was already performing for certain customers before mandatory reliability standards took effect. *Id.* at 18. Any additional costs that BPA incurs related to these agreements are minimal. *Id.* at 25.

##### **Evaluation of Positions**

JP04 maintains that BPA should directly assign the costs of BPA's actions under its reliability-related agreements, because those actions benefit only the customers that are the parties to the agreements. JP04 Br., BP-14-B-JP04-01, at 28. BPA's agreements fall into two primary categories: (1) "transmission operator" agreements, under which BPA has agreed to register with NERC as the transmission operator for the customer facilities and to assume legal responsibility for complying with the reliability standards that apply to the transmission operator; and (2) "delegation agreements," which make BPA contractually responsible to the customer for compliance with certain standards that apply to load-serving entities and distribution providers. Bogdon *et al.*, BP-14-E-BPA-43, at 19. Under the delegation agreements, the customer retains the ultimate legal responsibility for demonstrating compliance to WECC and NERC. *Id.*

As an initial matter, it is incorrect that the only customers that benefit from these agreements are the customers that signed the agreements. *Id.* at 25. The agreements promote operational efficiency and reliability compliance, which benefit all users of the regional transmission system. *Id.* at 18, 25. In addition, BPA was performing many reliability-related activities for the parties to these agreements before the mandatory reliability standards were adopted. *Id.* at 18-19. The agreements capture BPA's commitment to continuing those actions. *Id.* BPA was not charging individual customers for any costs of its actions prior to the adoption of mandatory reliability standards, and signing these agreements did not change that arrangement.

JP04 lists certain activities that it alleges BPA “may perform” under the agreements. JP04 Br., BP-14-B-JP04-01, at 27 n.102; Oral Tr. 170 (reciting the same list of activities). JP04 appears uncertain as to which activities BPA undertakes under these agreements, but the activities that JP04 lists appear to be the primary source of the “projected costs” that JP04 suggests BPA directly assign. Holland *et al.*, BP-14-E-JP04-01, at 21; *see also* Bogdon *et al.*, BP-14-E-BPA-43, at 17.

Staff is in the best position to know which reliability-related compliance activities BPA performs, and Staff testified that BPA was not performing most of the activities that JP04 lists. *Id.* at 21-22. Staff likely would be spending just as much time on reliability compliance issues without the agreements, and any “additional” costs incurred specifically for these agreements relate to staff time and administrative expense. *Id.* at 25. Based on Staff’s testimony, any costs attributable specifically to these agreements appear limited. *Id.*

JP04 expresses the specific concern that BPA may be liable for monetary sanctions for actions taken under the agreements. Oral Tr. 175. JP04 also argues that BPA may receive a “much larger penalty” than the counterparty to the agreement due to BPA’s ability to pay such fines. JP04 Br., BP-14-B-JP04-01, at 27 n.103. The record demonstrates that BPA has not paid any sanctions or other amounts under the agreements and provides no basis to conclude that there are any such costs to directly assign. Bogdon *et al.*, BP-14-E-BPA-43, at 22. JP04’s argument about the potential for larger penalties is speculation, and it suggests that JP04’s real focus is BPA’s decision to enter into these agreements, which is not an issue in this proceeding.

The only evidence that demonstrates that there are any costs related to these agreements is Staff’s testimony about staff time and administrative costs related to compliance responsibilities. *Id.* at 25. Staff believes these costs are minimal. *Id.* The record provides no basis to conclude that BPA is incurring significant costs due to these agreements. BPA spends staff time and administrative costs on specific issues for almost every transmission customer, and no other customers have been directly assigned those costs. *Id.* at 24.

JP04 argues that the absence of evidence is due to Staff’s unwillingness to provide information in discovery. JP04 Br., BP-14-B-JP04-01, at 29 n.105. JP04 pointed out in testimony, its brief, and at oral argument that Staff objected to some of its data requests. *Id.*; Holland *et al.*, BP-14-E-JP04-01, at 24; Oral Tr. 172-73. JP04 suggests that it has been denied its procedural rights under section 7(i) of the Northwest Power Act as a result. JP04 Br., BP-14-B-JP04-01, at 29 n.105. The record shows that Staff objected to some of JP04’s data requests on the basis that they sought information that is outside the scope of this proceeding. *See* BP-14-E-PC-01. The record also shows, however, that Staff responded to most of JP04’s data requests notwithstanding the objection. *Id.* Moreover, JP04 did not move to compel production of any additional response from Staff, and BPA’s responses to JP04’s data requests were admitted into the record without objection. BP-14-HOO-40. JP04 has received all the process that the Northwest Power Act requires.

**Draft Decision**

*BPA will not directly assign the costs of reliability compliance activities performed by BPA on behalf of individual customers.*

#### **4.3.5 Billing Factor for Scheduling, System Control, and Dispatch Service Rate**

##### **Issue 4.3.5.1**

*Whether BPA should retain the existing SCD billing factor for NT customers and establish a separate SCD rate for those customers.*

##### **Parties' Positions**

JP03 opposes the Initial Proposal's use of a customer's highest hourly load during the month for the billing factor for SCD service for NT customers. JP03 Br., BP-14-B-JP03-01, at 22. JP03 recommends retaining the existing billing factor, which is the customer's network load on the hour of the monthly transmission system peak, or a coincident peak billing factor. *Id.*

##### **BPA Staff's Position**

Although Staff's Initial Proposal used a customer's highest hourly load during the month for the billing factor for SCD service for NT customers, Staff changed its position in response to parties' direct testimony. BP-14-E-SN-07-V10, at 36. Staff now supports retaining the existing billing factor. *Id.* Staff also recommends, however, establishing a separate SCD rate for NT customers to ensure that changing the billing factor for NT customers does not result in increasing the SCD rate for all customers. *Id.*

##### **Evaluation of Positions**

In the Initial Proposal, Staff proposed to use a customer's highest hourly load during the month (NCP) as the billing factor for NT service, utility delivery service, and SCD service for NT customers. Bogdon *et al.*, BP-14-E-BPA-30, at 4, 9; Transmission, Ancillary and Control Area Service Rate Schedules and General Rate Schedule Provisions, BP-14-E-BPA-10, at 42. JP03 and WPAG submitted direct testimony regarding the disparate impacts the proposed billing factor would have on NT and utility delivery customers, but there was relatively little discussion of the SCD billing factor. Scott and Carr, BP-14-E-JP03-02, at 25, 28-29; Saleba *et al.*, BP-14-E-WG-01, at 35-40. Staff's rebuttal testimony likewise focused on billing factors for NT service and utility delivery service. *See* Bogdon *et al.*, BP-14-E-BPA-43, at 4, 16. Staff supported retaining the existing billing factors for those services, but Staff did not take a position on the SCD billing factor for NT customers. *Id.*

In response to a data request on Staff's rebuttal testimony submitted by Tacoma Power, Staff said that it supports retaining the existing billing factor (CP) for SCD service. *See* BP-14-E-SN-07-V10, at 36. No party has objected to retaining the existing billing factor for SCD service for NT customers.

In the Initial Proposal, one SCD rate applied to all long-term transmission service. Transmission Rates Study, BP-14-E-BPA-07, at 74. Staff calculated that rate by dividing the SCD revenue requirement by the sum of the SCD sales forecasts for all transmission services. *Id.* at 73-74.

Thus, each transmission service was allocated a portion of the SCD revenue requirement equal to its proportion of the sales forecasts.

The SCD sales forecast for NT customers in the Initial Proposal was based on a 12 NCP load forecast. Transmission Rates Study Documentation, BP-14-E-BPA-07A, at 9, 19. Thus, NT customers were allocated a portion of the SCD revenue requirement on the basis of the 12 NCP load forecast. *See id.* at 19. The 12 NCP billing factor proposed by Staff fully recovered this allocated amount of the SCD revenue requirement from NT customers. *Id.*

Because a 12 NCP load forecast allocates more costs to NT service than a 12 CP forecast would, the use of 12 CP for both the NT sales forecast and the NT billing factor would allocate fewer costs to NT service and raise the SCD rate for all other customers. *See id.* at 9; *see* BP-14-E-SN-07-V10, at 36. The purpose of adopting a CP billing factor for NT service, however, is to avoid disparate impacts on NT customers, not to lower costs to those customers. By calculating a separate SCD rate for NT customers, BPA can allocate those customers their share of the SCD revenue requirement based on the 12 NCP load forecast while using the existing 12 CP billing factor to avoid disparate impacts. *See* BP-14-E-SN-07-V10, at 36. This approach prevents any impacts to other customer classes.

#### **Draft Decision**

*BPA will retain the existing (BP-12) SCD billing factor for NT customers and establish a separate SCD rate for those customers.*

**This page intentionally left blank.**

## 5.0 PARTICIPANT COMMENTS

### 5.1 Introduction

This chapter summarizes and evaluates the comments of participants in BPA’s BP-14 rate case. As defined in BPA’s procedures for conducting rate proceedings, “participants” are persons and organizations that comment on BPA’s rate proposal but do not take part in the formal hearing process with the responsibilities of “parties.” Parties to the case file testimony and briefs and thus are not allowed to submit comments as participants. Participant comments are part of the official record of the rate proceeding and are considered when the Administrator makes his final decisions.

On November 8, 2012, BPA published in the Federal Register a Notice of “Fiscal Year (FY) 2014–2015 Proposed Power and Transmission Rate Adjustments; Public Hearing and Opportunities for Public Review and Comment.” 77 Fed. Reg. 66966 (2012). The Federal Register notice may be viewed on the BPA Web site under Finance & Rates, Rate Cases, BP-14 Rate Case, FRN & Rate Schedules. The Federal Register notice set a deadline of February 15, 2013, for participant comments.

Springfield Utility Board (Springfield) and Canby Utility (Canby) submitted comments as participants (comment numbers BP14120009 and BP14120011). Both these utilities are BPA customers and are members of the Public Power Council (PPC), which represents publicly owned utilities in BPA rate cases both as a party and as a member of several joint parties. As stated in the Federal Register notice, “BPA customers whose rates are subject to this proceeding, or their affiliated customer groups, may not submit participant comments.” 77 Fed. Reg. 66966, 66969 (2012). Moreover, Springfield and Canby did not file general comments in the proceeding. Instead, they commented on technical matters that are issues in the rate case and have been heavily litigated by the parties to the case. Their comments addressed BPA’s proposal for cost allocation of Network Segment costs and the average rate increase for transmission service to BPA’s NT customers.

If Springfield and Canby were allowed to use the participant comment process to address substantive issues, rate case parties with opposing views would be placed at a disadvantage, as they would have no opportunity to question the utilities’ positions and offer rebuttal and refutation. Springfield and Canby cannot escape the duties of a rate case party by using the participant comment process as a means of subverting the due process of rate case parties. Therefore, Springfield Utility Board and Canby Utility may not file participant comments, and their comments will not be addressed in this Draft Record of Decision.

Including the above comments, BPA received 12 comments through the participant comment process. Summaries of the participant comments, and BPA’s draft responses, are provided below.

## 5.2 Participant Comments

**Comment.** Participant Christopher Calder requested that BPA not spend any more money on wind power projects, contending that BPA could find “better carbon free energy solutions.” He also stated that “high energy prices = high food prices.” BP14120003.

**Response.** This comment addresses issues that are outside the scope of the rate proceeding. To address the comment briefly, however, it should be noted that BPA does not own resources. Therefore, BPA does not purchase resources, including wind projects, but instead markets the output of the resources (the power produced). In its Resource Program BPA determines the types of resources to acquire. BPA Staff develops the Resource Program analyses and recommendations to be consistent with the Northwest Power and Conservation Council’s most recent Power Plan. BPA recently released its 2013 Resource Program, which shows that BPA will not need to acquire any resources for use during the next rate period. If BPA did decide to acquire the output of a major resource, BPA would conduct a formal public process as required by the Northwest Power Act.

As to the effect on rates, as noted in the Federal Register notice BPA published for the BP-14 rate proceeding and in section 1.2.1 of this Draft Record of Decision, BPA determines its spending levels—the costs on which power and transmission rates are based—in the Integrated Program Review process. This process is separate from the rate proceeding, and material related to the Administrator’s decisions on cost and spending levels is excluded from the official record of the rate proceeding. 77 Fed. Reg. 66966, 66967 (2012). As noted below and in Draft ROD section 2.1, BPA is aware of the potential impacts of its rate increases. BPA strives to minimize its rate increases while ensuring it has the funds to meet its many statutory obligations.

**Comment.** Several participants (self-identified as Dupree, Janet Young, Anderson, and DeBiddle (two comments)) in the Port Angeles city utility service territory stated that a BPA rate increase would be a hardship for them. BP14120004, BP14120005, BP14120006, BP14120007, BP14120008. These commenters cited regional unemployment levels and the general economic situation as well as their own financial situations. Participant Jacqueline Larsen stated that BPA Staff’s Initial Proposal rate increase is excessive and would harm consumers, businesses, and non-profit agencies. BP14120015.

**Response.** This issue is addressed in section 2.1. BPA is mindful of, and has taken into account, the impact its rates have on its wholesale power and transmission customers; at the same time, BPA must recover its costs and make necessary investments to protect the value of the Federal Columbia River Power System for current and future power consumers. BPA notes here that it sells wholesale power and transmission services. It does not have control over how the utilities that buy its products and services recover their costs from consumers in retail rates. BPA hopes that consumers will learn as much as possible about their local utility’s cost structure, take part in public processes held by their utility, and let their utility know how cost increases affect them.

**Comment.** The Governor of Montana filed participant comments stating that BPA should aid the development and expansion of renewable energy in Montana by removing the Montana

intertie “pancake” rate. The Governor stated that eliminating the rate pancake for the Montana Intertie could boost the development of wind resources in Montana, providing much-needed jobs and local government revenues for rural Montana. BP14120010.

**Response.** This issue has been litigated in the rate case and is addressed in Draft ROD section 4.3.3.

**Comment.** Participant Charles Pace stated that setting February 15, 2013, as a final date for participants to submit written comments and “extraordinary” limits on the scope of the BP-14 proceeding violate the procedural requirements in the Northwest Power Act and limit BPA’s ability to develop a full and complete record. Dr. Pace commented that limits on participant opportunities in the rate proceeding are “repugnant on their face to the declaration of purpose by the 96th Congress to allow the public at large” to participate in developing “regional plans and programs related to energy conservation, renewable resources, other resource, and protecting, mitigation, and enhancing fish and wildlife resources.” Dr. Pace implies that, because participants are not able to “address the propriety, e.g., of costs and methodologies” deemed to be outside the scope of the rate case, the Record of Decision “will not meet the requirements of the Administrative Procedure Act, 5 U.S.C. 701-06.” BP14120013.

**Response.** Setting a reasonable limit on the time for submitting participant comments (as the February 15 limit is) does not violate the procedural requirements of the Northwest Power Act. Dr. Pace’s underlying concern appears to be that BPA denied participants procedural protections when it set the date for public comment before the filing of parties’ direct and rebuttal cases, cross examination, and filing of briefs. The Northwest Power Act requires the Administrator to publish notice of the “proposed rates” in the Federal Register. 16 U.S.C. § 8393(i)(1). The Act requires the hearing officer to conduct a hearing to “receive public comment in the form of written and oral presentation of views, data, questions and argument related to *such proposed rates.*” 16 USC §8393(i)(2) (*italics added*). That is, the public has the right to respond to BPA’s proposal.

BPA filed its Initial Proposal on November 8, 2012, more than three months before the date set for the end of receipt of public comments. As a result, all participants had adequate opportunity to review and comment on BPA’s rate proposal. That said, BPA will consider moving the date for participant comments to after the filing of the parties’ direct cases in the future.

Dr. Pace also states that the limitation on the scope of the rate proceeding denied both parties and participants their rights under the Northwest Power Act to comment on “the development of regional plans and programs related to energy conservation, renewable resources, other resource, and protecting, mitigation, and enhancing fish and wildlife resources.” 16 U.S.C. § 839(3). In addition, Dr. Pace states, “the restrictions on participants’ ability to develop the record, and the limitations on all parties’ ability to address the propriety, e.g., of costs and methodologies” violates the Administrative Procedures Act. The contention that Northwest Power Act or the Administrative Procedures Act mandates that parties and participants are entitled to address regional plans, energy conservation programs, renewable resources, enhancing fish and wildlife resources, and program costs within a rate case is misplaced. As stated in the Federal Register

notice, these programs are not addressed in the rate case, which is the forum where BPA's rates are established. BPA conducts separate public processes to address the issues Dr. Pace raises. The mere fact that BPA is conducting a rate case does not open the door to allow parties or participants to address any matter that they wish. The Administrator must be allowed to exercise the discretion necessary to establish the scope of the proceeding in order to allow the proceeding to be conducted in an orderly and timely manner. The fact that certain matters are deemed to be outside the scope of a rate proceeding does not deprive parties or participants of the opportunity to comment on such matters. BPA conducts a number of other forums wherein regional plans, conservation, and fish and wildlife mitigation, along with many other matters, are discussed in separate public forums. The fact that those matters are determined by the Administrator to be outside the scope of the rate case does not prevent Dr. Pace or any other person or entity from commenting on these matters in those other forums; nor does such determination violate the Northwest Power Act or Administrative Procedures Act.

**Comment.** Participant Cherie A. Kidd stated that BPA Staff's Initial Proposal would have "disproportionate impacts on the Port Angeles community." She stated that the 12 non-coincident peak method for allocating costs to NT customers "would cause an estimated increase in our transmission rates of up to an alarming 30%." She asked that BPA retain what she calls "its current 12 coincident peak allocation and bill calculation methodology." As an alternative, she suggested that BPA "include in the new calculation method a means to mitigate a disproportionate impact on a single community." BP14120014.

**Response.** This issue was litigated in the rate case and is addressed in Draft ROD section 4.3.1.

## **6.0 NATIONAL ENVIRONMENTAL POLICY ACT ANALYSIS**

BPA is in the process of assessing the potential environmental effects that could result from implementation of the FY 2014–2015 proposed power and transmission rate adjustment, consistent with the National Environmental Policy Act (NEPA). The NEPA analysis is conducted separately from the formal rate process. No comments concerning NEPA compliance and/or potential environmental effects of the proposal were received during the participant comment period for the rate proceeding. As discussed in the Federal Register notice for the BP-14 power and transmission rate proposal, 77 Fed. Reg. 66966, 66969 (2012), this proposal appears to fall within the scope of the Market-Driven Alternative that was evaluated in BPA’s Business Plan Final Environmental Impact Statement, DOE/EIS-0183, June 1995 (Business Plan EIS) and adopted in the August 1995 Business Plan ROD. Accordingly, BPA expects to tier its decision under NEPA to the Business Plan EIS and ROD. BPA will complete its NEPA process and issue its NEPA ROD or other appropriate final NEPA documentation concerning the proposal when it issues its Final Record of Decision for the BP-14 rate proceeding.





