

**Residential Exchange Program
Settlement Agreement Proceeding (REP-12)**

Initial Proposal

**2012 REP Settlement
Evaluation and Analysis Study**

December 2010

REP-12-E-BPA-01



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REP SETTLEMENT EVALUATION AND ANALYSIS STUDY **TABLE OF CONTENTS**

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COMMONLY USED ACRONYMS AND SHORT FORMS

aMW	average megawatt(s)
ASC	Average System Cost
ASCM	Average System Cost Methodology
BPA	Bonneville Power Administration
CGS	Columbia Generating Station
COE or Corps	U.S. Army Corps of Engineers
Commission or FERC	Federal Energy Regulatory Commission
Corps or COE	U.S. Army Corps of Engineers
COSA	Cost of Service Analysis
COU	consumer-owned utility
Council	Northwest Power and Conservation Council
CRC	Conservation Rate Credit
CY	calendar year (January through December)
DOE	Department of Energy
DSI	direct-service industrial customer or direct-service industry
EN	Energy Northwest, Inc.
EPP	Environmentally Preferred Power
FBS	Federal base system
FCRPS	Federal Columbia River Power System
FCRTS	Federal Columbia River Transmission System
FELCC	firm energy load carrying capability
FERC or Commission	Federal Energy Regulatory Commission
FPS	Firm Power Products and Services (rate)
FY	fiscal year (October through September)
GRSPs	General Rate Schedule Provisions
GWh	gigawatthour
IOU	investor-owned utility
IP	Industrial Firm Power (rate)
IPR	Integrated Program Review
IRP	Integrated Resource Plan
JOA	Joint Operating Agency
JOE	Joint Operating Entity
kW	kilowatt (1000 watts)
kWh	kilowatthour
LRA	Load Reduction Agreement
Mid-C	Mid-Columbia
MW	megawatt (1 million watts)
MWh	megawatthour
NLSL	New Large Single Load
Northwest Power Act	Pacific Northwest Electric Power Planning and Conservation Act
NPV	net present value
NR	New Resource Firm Power (rate)
NWPP	Northwest Power Pool
O&M	operation and maintenance

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
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Integration or Point of Interconnection
PS	BPA Power Services
PSW	Pacific Southwest
PUD	public or people's utility district
RAM	Rate Analysis Model (computer model)
RD	Regional Dialogue
REC	Renewable Energy Certificate
Reclamation or USBR	U.S. Bureau of Reclamation
REP	Residential Exchange Program
ROD	Record of Decision
RPS	Renewable Portfolio Standards
RPSA	Residential Purchase and Sale Agreement
TRL	Total Retail Load
TRM	Tiered Rate Methodology
TS	BPA Transmission Services
UAI	Unauthorized Increase
ULS	Unanticipated Load Service
USBR or Reclamation	U.S. Bureau of Reclamation
VOR	Value of Reserves

1 **PART I THE SETTLEMENT IN ITS CONTEXT**

2 **1. INTRODUCTION**

3
4 It was the best of times, it was the worst of times; it was the age of wisdom, it was the age of
5 foolishness; it was the epoch of belief, it was the epoch of incredulity; it was the season of Light,
6 it was the season of Darkness; it was the spring of hope, it was the winter of despair; we had
7 everything before us, we had nothing before us; we were all going directly to Heaven, we were
8 all going to the Ninth Circuit.

9
10 In *Portland General Elec. Co. v. Bonneville Power Admin.*, 501 F.3d 1009 (9th Cir. 2007)
11 (*PGE*), the Ninth Circuit Court of Appeals held that the 2000 Residential Exchange Program
12 Settlement Agreements (2000 REP Settlement Agreements) executed by BPA and its investor-
13 owned utility customers (IOUs) were inconsistent with the Pacific Northwest Electric Power
14 Planning and Conservation Act (Northwest Power Act). In a companion case, *Golden NW*
15 *Aluminum, Inc. v. Bonneville Power Admin.*, 501 F.3d 1037 (9th Cir. 2007) (*Golden NW*), the
16 Court remanded BPA’s WP-02 power rates on the grounds that BPA improperly allocated the
17 costs of the REP Settlement Agreements, as amended, to BPA’s preference customers. Although
18 the Court’s decision in *Golden NW* addressed only BPA’s WP-02 rates, BPA’s WP-07 wholesale
19 power rates were implicated by the decisions because they contained the same infirmity
20 identified by the Ninth Circuit.

21
22 To respond to the Ninth Circuit’s decisions, BPA revisited its WP-02 and WP-07 rate case
23 assumptions through a comprehensive “Lookback” construct. As explained fully in the 2007
24 Supplemental Wholesale Power Rate Proceeding Administrator’s Final Record of Decision
25 (WP-07 Supplemental ROD), the Lookback construct compared the amounts paid under the REP
26 Settlement Agreements for FY 2002–2008 with the amounts BPA would likely have paid

1 qualifying IOUs under the traditional operation of the REP. The difference between these two
2 amounts, subject to certain specified rules, is generally referred to as the “Lookback Amount.”
3 The total Lookback Amount is composed of six IOU-specific Lookback Amounts. BPA
4 determined that the Lookback Amount would be recovered from the IOUs over time through
5 reductions in future REP benefits and returned to the eligible consumer-owned utilities (COUs),
6 with interest, as credits on their power bills.

7
8 A large number of parties have challenged BPA’s determinations in the WP-07 Supplemental
9 ROD in the Ninth Circuit. Many of the litigants involved in these challenges began meeting with
10 a professional mediator seeking to resolve the many differences among them. The mediation
11 concluded with an agreement in principle that resolved most aspects of the disputes and
12 committed those signing the agreement to negotiate a settlement agreement defining the
13 resolution of all disputed issues.

14
15 In this section 7(i) proceeding, BPA is evaluating and analyzing the proposed Settlement
16 Agreement to determine whether the Administrator should sign the Agreement and commit the
17 agency to abide by its provisions for the term of the Agreement. This Study sets forth BPA
18 Staff’s evaluation and analysis of the Agreement leading to Staff’s recommendation that the
19 Administrator should adopt the settlement and sign the Agreement.

2. BACKGROUND

2.1 The Residential Exchange Program

The Residential Exchange Program (REP) was established in section 5(c) of the Northwest Power Act to provide residential and small-farm customers of Pacific Northwest (regional) utilities a form of access to low-cost Federal power. Under the REP, a participating utility offers to sell power to BPA, and BPA purchases such power from the utility at its respective average system cost (ASC). A utility's ASC is established through a formal ASC review process based on a methodology established by BPA. Coincident with purchasing the power from the utility, BPA sells an equivalent amount of power to the utility at BPA's Priority Firm Power Exchange (PFx) rate. This "exchange" actually transfers no power to or from BPA; rather, it is implemented as an accounting transaction to eliminate real power losses and for administrative ease. The amount of power purchased and sold between BPA and the utility is equal to the utility's qualifying residential and small-farm load. The transaction is reduced to the difference between the amount paid to the utility and the amount paid to BPA, called "REP benefits." The Northwest Power Act requires that all of the REP benefits received by the utility be passed through directly to its residential and small-farm customers.

2.1.1 How REP Benefits Are Determined

ASC is the unit cost of a utility's allowable generation and transmission system as determined by the Administrator through the ASC Review Process, which involves an extensive review of the utility's cost and load data. ASC (expressed in \$/MWh, which is equivalent to mills/kWh) equals a utility's ASC Contract System Cost divided by its ASC Contract System Load. ASC Contract System Cost and ASC Contract System Load are determined by following the prescribed functionalization rules and other requirements established in BPA's 2008 Average System Cost Methodology (2008 ASCM), an administrative rule developed by BPA in

1 consultation with its customers and other stakeholders. The Federal Energy Regulatory
2 Commission (FERC) granted final approval to the 2008 ASCM on September 4, 2009. The
3 Review Processes for individual utilities' ASC filings occur in a separate administrative forum
4 that is not part of BPA's rate proceedings.

5
6 In each rate proceeding, BPA develops a PFx rate pursuant to section 7 of the Northwest Power
7 Act. The PFx rate begins as a rate developed in common with the PF Public (PFp) rate pursuant
8 to section 7(b)(1). At the point in the ratemaking sequence immediately prior to the
9 section 7(b)(2) rate test, the sole distinction between the two PF rates is that customers
10 purchasing under the PFp rate separately acquire the transmission necessary to wheel BPA
11 power to the customers' service territory, whereas the PFx rate includes a transmission wheeling
12 adder to accomplish delivery to the purchaser. In the event the section 7(b)(2) rate test indicates
13 that rate protection should be afforded to BPA's preference customers, the two PF rates diverge.
14 Preference customers' rate protection reduces the PFp rate, while the allocations of cost of the
15 rate protection increase the PFx rate and other rates.

16
17 Once the PFx rate has been established, two of the three necessary elements of the REP have
18 been determined for each rate period. The third element, exchange loads, is based upon
19 qualifying residential and small-farm loads as measured by each utility participating in the REP.
20 Subsequent to each calendar month, each exchanging utility invoices BPA with its exchange load
21 for the month and BPA computes the cost of purchase at the utility's ASC and the revenue from
22 the sale at the PF Exchange rate by multiplying relevant rates by the kilowatthours of invoiced
23 exchange load. The net payment is the utility's REP benefit for the month.

2.1.2 Early Disputes Over the REP

The REP was initially implemented through Residential Purchase and Sale Agreements (RPSAs) and an ASC methodology that were established in 1981. In response to rising costs of the REP, in 1984 BPA revised the 1981 ASCM such that the ASCs for exchanging utilities were reduced by an average of 26 percent. The IOUs disputed most of the changes to the ASCM. In addition, the IOUs have disputed BPA's implementation of the 7(b)(2) rate test in a number of section 7(i) proceedings, especially BPA's 1996 Wholesale Power Rate Proceeding, which reduced REP benefits from around \$200 million in FY 1996 to \$64 million in FY 1998. (FY 1997 REP benefits were increased from expected rate proceeding levels at the direction of Congress.)

2.2 2000 REP Settlement Agreements and WP-02 Rates

Disputes over changes to the 1981 ASCM and the implementation of section 7(b)(2) were a significant subject of consideration by the Comprehensive Review of the Northwest Energy System in 1998. The Comprehensive Review led to the Federal Power Subscription Work Group process and the resulting 1998 Subscription Strategy ROD and contracts. The Subscription Strategy proposed that BPA would offer RPSAs to regional utilities, including the IOUs, to implement the REP for FY 2002–2011. The Strategy also proposed that BPA would offer the IOUs, in the alternative, settlement agreements to resolve disputes arising under BPA's implementation of the REP. All of the region's six IOUs elected to execute the 2000 REP Settlement Agreements.

In the WP-02 rate proceeding, BPA established rates for FY 2002 through 2006 that included the payment of 2000 REP Settlement benefits to the signing IOUs. In addition to the monetary benefits, a power sale at a rate equivalent to the PFp rate was included in the 2000 REP Settlement package of benefits. It was expected that the combination of payments and the below-market power sale would result in 2000 REP Settlement benefits of about \$140 million per year for FY 2002–2006. However, before the WP-02 rates were implemented, the West

1 Coast energy crisis of 2000-2001 caused BPA to revise its rates and the 2000 REP Settlement
2 benefits. BPA entered into Load Reduction Agreements with two IOUs that allowed BPA to
3 monetize the expected power sales to these utilities. The payments to the IOUs were also
4 increased because the 2000 REP Settlement Agreements set REP benefits as the difference
5 between the market price of energy and BPA's PFp rate; thus, as the West Coast energy crisis
6 drove market prices upwards, REP benefits increased. In all, the modifications increased the
7 2000 REP Settlement benefits by more than \$160 million per year, resulting in over \$300 million
8 in total benefits paid each year during FY 2002–2006. Most of these costs fell on BPA's
9 preference customers and their consumers.

11 **2.3 PGE and Golden NW**

12 After the 2000 REP Settlement Agreements had been executed, a number of preference
13 customers and a consortium of their industrial consumers challenged the 2000 REP Settlement
14 Agreements in the Ninth Circuit. In *PGE*, the Court concluded that the 2000 REP Settlement
15 Agreements were contrary to sections 5(c) and 7(b) of the Northwest Power Act. More
16 specifically, the Court invalidated BPA's 2000 REP Settlement Agreements, holding that BPA
17 exceeded its statutory settlement authority under section 2(f) of the Bonneville Project Act and
18 section 9(a) of the Northwest Power Act.

19
20 BPA's WP-02 rates recovered the costs of the 2000 REP Settlement Agreements. After the
21 FERC granted final confirmation and approval to the WP-02 rates, a number of parties
22 challenged the WP-02 rates in the Ninth Circuit. In *Golden NW*, the Court concluded it was not
23 proper for BPA to allocate costs of the 2000 REP Settlement Agreements in excess of the
24 section 7(b)(2) trigger amount to the PFp rate based on BPA's theory that such costs were
25 incurred pursuant to the Administrator's section 2(f) contracting authority and could therefore be

“equitably allocated” pursuant to section 7(g) of the Northwest Power Act. The Court remanded the WP-02 rates to BPA with instructions to set rates “in accordance with this opinion.”

2.4 WP-07 Supplemental Rate Proceeding

BPA responded to the Court’s remand in BPA’s WP-07 Supplemental rate proceeding. In that proceeding, in general, BPA reconstructed the period that the 2000 REP Settlement Agreements were in effect prior to the Court’s rulings, comparing the amounts paid under the 2000 REP Settlement Agreements for FY 2002–2008 (the Lookback period) with the amounts BPA would likely have paid qualifying IOUs under the traditional operation of the REP. In addition, BPA re-examined its Section 7(b)(2) Legal Interpretation and Section 7(b)(2) Implementation Methodology.

In the WP-07 Supplemental proceeding, the Administrator revisited the WP-02 and WP-07 rates charged during the Lookback period, removing the REP Settlement Agreement costs from the rates and supplementing the record as necessary in order to calculate the rightfully due amount of REP benefits the IOUs would have received without the 2000 REP Settlement Agreements. After determining the lawful amount of REP benefits, BPA began returning the resulting overcharges as “credits” to the preference customers for past overpayments, with offsetting “debits” against REP benefits for the IOUs that were overpaid REP benefits under the 2000 REP Settlement Agreements. The Administrator determined that this approach was the most lawful, appropriate, and equitable way to address the Court’s remand in *Golden NW*.

The WP-07 Supplemental proceeding had two central components. First, BPA established rates for FY 2009 that complied with the Court’s order by removing the costs of the 2000 REP Settlement Agreements and replacing them with the costs of REP benefits that survived the 7(b)(2) rate test. Second, to provide an adequate remedy to preference customers overcharged as

1 a result of BPA's prior actions, BPA conducted a Lookback Analysis to determine the amount of
2 REP costs that would have been incurred by BPA had it implemented the traditional REP during
3 the Lookback period instead of implementing the 2000 REP Settlement Agreements with the
4 region's IOUs. Based on that determination, BPA established the amount by which preference
5 customers were overcharged and provided appropriate repayments to preference customers
6 through immediate refunds from collected funds on hand and through ongoing billing credits as
7 funds were reclaimed from the IOUs. In other words, BPA established a means to recover 2000
8 REP Settlement Agreement overpayments through offsets to future REP benefits that would
9 otherwise be payable to the IOUs.

10
11 To properly calculate the amount of REP costs for the Lookback period, BPA reviewed how
12 ASCs would have been established during the Lookback period under the 1984 ASC
13 Methodology, how BPA would have included REP costs in the WP-02 and WP-07 rates, and any
14 adjustments that would have been necessary to more closely track the amount of REP benefits
15 that would have been incurred during that period through implementation of the REP in the
16 absence of the 2000 REP Settlement Agreements. Accordingly, BPA made a number of
17 necessary adjustments to its calculation of the section 7(b)(2) rate test, adjustments that would
18 have been incorporated into the WP-02 and WP-07 rates in the absence of the 2000 REP
19 Settlement Agreements using information available when establishing the final WP-02 and
20 WP-07 rates.

2.5 Current Litigation

Following the extensive WP-07 Supplemental proceeding, BPA issued its Final WP-07 Supplemental ROD on September 22, 2008. In the Final ROD, as noted above, BPA redesigned the Priority Firm rates for FY 2009 to conform to the Court's opinions in *PGE* and *Golden NW*, and established a method for returning to the COUs the improper amounts collected from them under the WP-02 rates and the first two years (FY 2007–2008) of BPA's WP-07 rates. The FY 2009 rates were filed with FERC on September 29, 2008, for confirmation and approval, accompanied by the WP-07 Supplemental ROD and administrative record.

Beginning November 14, 2008, various BPA customers and constituents filed 14 petitions for review with the Ninth Circuit challenging the decisions BPA made in its WP-07 Supplemental ROD. *See Ass'n of Public Agency Customers et al. v. Bonneville Power Admin.*, Nos. 08-74725 *et al.* (APAC). On January 20, 2009, the Court issued an order consolidating all the petitions for review and granting interventions. Petitioner-intervenors' briefs, respondent BPA's brief, respondent-intervenors' briefs, and parties' reply briefs have been filed. The Court granted a motion to stay the consolidated cases while the parties pursue mediation and settlement.

Beginning December 3, 2008, certain BPA customers and state public utility commissions filed seven petitions for review with the Ninth Circuit challenging (i) BPA's "Short-Term Bridge Residential Purchase and Sale Agreement for the Period Fiscal Years 2009-2011 and Regional Dialogue Long-Term Residential Purchase and Sale Agreement for the Period Fiscal Years 2012-2028, Administrator's Final Record of Decision," and (ii) BPA's final "RPSA Templates," which were offered to customers eligible for the REP on September 12, 2008. *See Idaho Public Utilities Commission et al. v. Bonneville Power Administration*, Nos. 08-74927 *et al.* Shortly thereafter, six other petitions for review were filed by various BPA customers and constituents seeking review of the same or substantially the same actions. On January 16, 2009, the Court issued an order consolidating all the petitions for review and granting interventions. Petitioner-

1 intervenors' briefs, respondent BPA's brief, respondent-intervenors' briefs, and parties' reply
2 briefs have been filed. The Court granted a motion to stay the consolidated cases while the
3 parties pursue mediation and settlement.
4

5 On July 16, 2009, FERC granted final approval to BPA's WP-07 Wholesale Power Rates.
6 Within the next 90 days, a number of parties filed petitions for review with the Ninth Circuit
7 challenging BPA's WP-07 rates, BPA's 2008 Section 7(b)(2) Legal Interpretation, and BPA's
8 Section 7(b)(2) Implementation Methodology. *See Avista Corp., et al. v. Bonneville Power*
9 *Admin.*, Nos. 09-73160 *et al.* These petitions involve WP-07 ratemaking issues separate from
10 the Lookback-related issues raised in APAC. The Court granted a motion to stay the
11 consolidated cases while the parties pursue mediation and settlement.
12

13 On July 21, 2009, BPA issued a Record of Decision in BPA's 2010 Wholesale Power and
14 Transmission Rate Proceeding (WP-10), which incorporated certain decisions from BPA's
15 WP-07 Supplemental ROD that are under review in APAC. Five investor-owned utilities filed
16 petitions for review of such decisions to the extent the decisions involved non-ratemaking issues
17 that might be subject to the Ninth Circuit's jurisdiction prior to FERC's final approval of BPA's
18 WP-10 power rates. *See Portland General Electric Co. et al. v. Bonneville Power Admin.*, Ninth
19 Circuit Nos. 09-73288 *et al.* The IOU petitioners acknowledged that the ratemaking issues in the
20 WP-10 rate case would not be timely until FERC granted final confirmation and approval to such
21 rates. The Court granted a motion staying the case.
22

23 On August 6, 2010, FERC granted final confirmation and approval to BPA's WP-10 power and
24 transmission rates. Certain investor-owned utilities, consumer-owned utilities, and a group of
25 industrial customers served by consumer-owned utilities filed petitions for review of the
26 ratemaking decisions underlying the WP-10 rates. *See PacifiCorp et al. v. Bonneville Power*

1 *Admin.*, Nos. 10-73348 *et al.* The petitions for review will likely be consolidated with the
2 petitions for review in *PGE*, Nos. 09-73288 *et al.* The Court granted a motion staying the case.

3
4 In summary, there is currently extensive litigation pending in the Ninth Circuit on issues related
5 to BPA's establishment of its power rates and BPA's implementation of the REP from FY 2002
6 to the present. This litigation creates significant uncertainty for BPA and its customers regarding
7 both retrospective and prospective wholesale power rate levels and REP benefits.

3. HOW 7(b)(2) RATE PROTECTION WORKS

3.1 Ratesetting Steps Occurring Before the 7(b)(2) Rate Test

Although the REP is generally a paper transaction with no real power being exchanged between BPA and the participating utility, as described in section 2.1 above, BPA's ratemaking assumes that the REP comprises an actual exchange of power. BPA's forecast loads are increased by the forecast sales of exchange power, and BPA's forecast of resource generation is equally increased by the forecast purchase of exchange power. BPA's ratemaking calculates the cost of exchange purchases using the ASCs of participating utilities. An equal amount of power is sold to the participating utilities using the same rate, with some adjustments, as used for sales to BPA's preference customers, the PFx rate. However, despite this treatment as an actual power sale, when the ratemaking sequence is complete, the results reflecting the inclusion of the exchange loads and resources are the same as if those exchange loads and resources had been removed (along with the attendant costs and revenues) and replaced with the costs of providing REP benefits. The importance of including the exchange loads and resources in the ratemaking sequence is to determine the proper level of REP benefits and the appropriate cost allocations to all rate classes.

BPA's ratemaking methodology begins with a Cost of Service Analysis (COSA), then implements a series of rate directive adjustments, and finishes with the application of BPA's rate design. See Section 2 of the Power Rate Study, BP-12-E-BPA-01. The COSA divides BPA's power revenue requirement into resource-based cost pools and assigns cost pool responsibility to several load-based rate pools in accordance with generally accepted ratemaking principles and in compliance with statutory directives governing BPA's ratemaking. The rate directive adjustments, including the section 7(b)(2) rate test, modify the costs allocated to rate pools as necessary to ensure that BPA recovers its rate period revenue requirement while following its

1 statutory rate directives. The application of rate design does not change the costs allocated to a
2 rate pool, but defines the parameters used to recover the costs allocated to the rate pool. This
3 ratemaking sequence is programmed into a Microsoft Excel spreadsheet model called the Rate
4 Analysis Model (RAM) for purposes of calculating BPA's requirements power rates.

5
6 Rate pools are groupings of customer classes for cost allocation purposes. The Northwest Power
7 Act established three rate pools. The 7(b) rate pool includes public body, cooperative, and
8 Federal agency sales authorized by section 5(b) of the Northwest Power Act and sales to utilities
9 participating in the REP established in section 5(c). The 7(c) rate pool includes sales to BPA's
10 DSI customers under contracts authorized by section 5(d). The 7(f) rate pool includes all other
11 power BPA sells in the Pacific Northwest (PNW) and outside of the PNW, including sales
12 pursuant to section 5(f).

13
14 The COSA first groups parts of the power revenue requirement into cost pools specified by
15 section 7 of the Northwest Power Act. The cost pools are associated with resource pools
16 (Federal base system (FBS) resources, exchange resources, and new resources) and costs
17 allocated according to section 7(g) of the Northwest Power Act. The COSA then apportions or
18 "allocates" the cost pools among the rate pools based on the priorities of service from resource
19 pools to rate pools provided in section 7 and the principle of cost causation when section 7 does
20 not provide guidance.

21
22 Rate directive adjustments are made to recognize sections 7(a)(1), 7(c)(2), 7(b)(2), and 7(b)(3) of
23 the Northwest Power Act. The first adjustment assures cost recovery by reassigning costs
24 allocated to surplus sales that are not recoverable due to contract provisions setting the rates for
25 the surplus sales. The second adjustment implements section 7(c)(2) by adjusting the costs
26 allocated to the IP rate pool to assure the IP rate is set at the level specified in section 7(c)(2). At
27 this point in the sequence of ratemaking, the PFp rate and the PFx rate are equal except for a

transmission wheeling adder to accomplish delivery to the PFx rate purchaser. In addition, pursuant to section 7(c)(1), the IP rate is equal to the PFp rate plus adjustments for the typical margin specified in section 7(c)(2) and a section 7(c)(3) adjustment for the value of power reserves provided by IP rate purchasers pursuant to section 5(d)(1)(A). The final rate directive adjustments result from the section 7(b)(2) rate test.

3.2 Description of the Rate Test

Section 7(b)(2) of the Northwest Power Act directs BPA to conduct a comparison (called the rate test) of the projected amounts to be charged for general requirements power sold to its public body, cooperative, and Federal agency customers, over the rate period plus the ensuing four years, with the power costs (as measured by rates) to such customers for the same time period if certain assumptions are made. The effect of this rate test is to partially protect BPA's preference and Federal agency customers' wholesale firm power rates from costs resulting from certain provisions of the Northwest Power Act. The rate test can result in a reallocation of costs from the rates of PF Public customers to other BPA power rates. BPA has codified the procedures used to conduct the rate test in the *Implementation Methodology of Section 7(b)(2) of the Pacific Northwest Power Planning and Conservation Act (Implementation Methodology)*, which, in turn, relies on BPA's legal interpretation of section 7(b)(2), as set forth in the *Legal Interpretation of Section 7(b)(2) of the Pacific Northwest Power Planning and Conservation Act (Legal Interpretation)*.

The rate test ensures that preference customers' firm power rates applied to their requirements loads are no higher than rates calculated using specific assumptions that may remove certain effects of the Northwest Power Act. If the 7(b)(2) rate test indicates that rate protection is due to the preference customers, the rate test is said to "trigger." Pursuant to section 7(b)(3), the cost of this rate protection is borne by all other BPA power sales. Some PF purchasers, the preference

1 customers, receive rate protection, while other PF purchasers, the REP participants, pay a portion
2 of the cost of the rate protection. Thus, to allow the cost reallocations due to the rate protection,
3 the PF rate is bifurcated into the PFp rate, which receives the rate protection, and the PFx rate,
4 which does not receive rate protection and bears its allocated share of the rate protection
5 reallocation. In addition, forecast sales under the IP rate, the NR rate, and the FPS rate are also
6 allocated a share of the cost of the rate protection.

7
8 As noted above, the rate test involves the projection and comparison of two sets of wholesale
9 power rates for the general requirements of BPA's preference customers. The two sets of rates
10 are: (1) a set for the rate period and the ensuing four years assuming that section 7(b)(2) is not in
11 effect (*i.e.*, the "projected amounts to be charged for firm power," known as Program Case
12 rates); and (2) a set of rates for the same period taking into account the five assumptions listed in
13 section 7(b)(2) (*i.e.*, the "the power costs for general requirements," known as 7(b)(2) Case
14 rates). Certain specified costs allocated pursuant to section 7(g) of the Northwest Power Act are
15 subtracted from the Program Case rates prior to the rate comparison. Next, each nominal rate is
16 discounted to the beginning of the test period of the relevant rate case. The discounted Program
17 Case rates are averaged, as are the 7(b)(2) Case rates. Both averages are rounded to the nearest
18 hundredth of a mill per kilowatthour for comparison. If the simple average of the discounted
19 Program Case rates is greater than the simple average of the discounted 7(b)(2) Case rates, the
20 rate test triggers. The difference between the average of the discounted Program Case rates and
21 the average of the discounted 7(b)(2) Case rates is used to determine the amount of costs to be
22 reallocated from the PFp rate to other BPA power rates for the rate period.

23 24 **3.3 Reallocation of Rate Protection Costs**

25 In the event the rate test triggers to provide rate protection to BPA's preference customers, the
26 difference between the average of the Program Case rates and the average of the 7(b)(2) Case

1 rates is multiplied by the preference customer loads for the rate period. The resulting dollar
2 amount, the rate protection amount, is allocated as a credit to the PFp rate pool to reduce the PFp
3 rate to the level allowed by the rate test.

4
5 The rate protection amount is also allocated as a cost to all other BPA power sales pursuant to
6 section 7(b)(3). The rate protection amount is allocated on a pro rata energy basis to sales in the
7 PFx rate pool, the IP rate pool, the NR rate pool and firm surplus and secondary energy sales
8 under the FPS rate. As a result of this additional cost allocation, these other rates, except for the
9 market-determined FPS rate, will increase as the PFp rate decreases.

10
11 As a result of the decrease in the PFp rate and section 7(c)(2)'s direction to set the IP rate equal
12 to the PFp rate, the IP rate (exclusive of its allocation of rate protection costs) is lowered to the
13 PFp rate. The cost of linking the IP rate to the PFp rate is a direct result of the rate test and,
14 therefore, none the costs of this linking can be allocated to the PFp rate, as was the case with the
15 linking of the IP rate to the PF rate prior to the rate test. Instead, the cost of linking the two rates
16 is allocated to the PFx rate pool and the NR rate pool. The rate protection cost allocated to the IP
17 rate pool is then reinstated to the IP rate to finalize the costs in the IP rate pool.

18
19 In the WP-07 Supplemental proceeding, BPA implemented a new method of allocating rate
20 protection costs within the PFx rate pool. Prior to the WP-07 Supplemental proceeding, BPA
21 allocated rate protection costs to the PFx rate pool based on energy loads. This had the effect of
22 increasing the single PFx rate, which would often result in disqualifying REP participants whose
23 ASCs would now be less than the modified PFx rate. In the WP-07 Supplemental proceeding,
24 BPA changed the allocator from energy loads to pre-rate test REP benefits, sometimes called
25 Unconstrained Benefits. This change in allocation had the effect of retaining all participants that
26 qualified for the REP prior to the rate test as participants after the rate test. Therefore, BPA was
27 able to spread the REP benefits more broadly across the region without increasing the costs of

1 the REP borne by preference customers. The costs of the REP remain the same under this
2 revised allocation methodology as under the prior allocation methodology, but the amounts paid
3 to each REP participant are different and each REP participant has a different PFx rate.

4
5 With these final reallocations as a result of the rate test completed, all costs are finally allocated
6 and rate designs can be applied to each rate pool to determine the manner in which its allocated
7 costs will be recovered.

8 9 **3.4 The Effect of the Rate Test**

10 As mentioned above, the inclusion of exchange purchases and sales is used to determine the
11 proper level of REP benefits. The 7(b)(2) rate test changes only one of BPA's costs, the cost of
12 the REP. All other BPA costs remain as stated prior to the rate test. In the ratemaking view of
13 the REP, the proper level of benefits is determined by changing the amount of revenue
14 requirement recoverable from the PFx rate pool, which changes the level of the PFx rate and, as
15 a result, the amount of revenue from the PFx rates. The cost of exchange purchases included in
16 rates is not changed by the rate test.

17
18 The proper level of REP benefits is determined by comparing each participant's ASC with its PF
19 Exchange rate and multiplying the difference by each participant's qualified exchange load.
20 Because BPA's rates are set using forecasts of qualified exchange load, the variance between
21 forecast and actual exchange loads can result in a different amount of REP benefits being paid
22 during each rate period compared to the amount expected in the rate proceeding.

23
24 Because the REP is the only BPA cost that changes as a result of the rate test, any change in the
25 outcome of the rate test and the subsequent cost reallocations affects only REP benefits and
26 which rate pools pay for the REP. Thus, the purpose of the rate test is confined solely to

1 defining the amount of REP benefits expected to be paid and the sharing of the costs of the REP
2 by the different rate pools.

4. THE PROPOSED 2012 REP SETTLEMENT

4.1 History of Current Settlement Efforts

The proposed 2012 REP Settlement reflects the efforts of a broad group of BPA customers and other interested parties who, for the better part of three years, have attempted to reach a global settlement over BPA's past and future implementation of the REP. The first round of post-*PGE* settlement discussions began shortly after the Court issued its decisions in *PGE* and *Golden NW*. At that time, BPA commenced a series of meetings with interested parties to discuss BPA's response to the Court's opinions. During these meetings, BPA encouraged representatives of the COUs and IOUs to reach a settlement over the REP to avoid protracted and complicated litigation. Thereafter, a group of IOU and COU representatives, representing the vast majority of regional utilities, engaged in an intensive negotiation effort to find common ground. Ultimately, in November of 2007, the represented parties were able to reach agreement on a non-binding value structure and framework that, in the parties' view, would equitably resolve both past and future disputes over BPA's implementation of the REP. These recommendations, referred to as the November 2007 Recommendations (Recommendations), asked BPA to, among other items, reinstate the REP with the expectation of providing the IOUs between \$200 million and \$220 million annually (in nominal dollars) from FY 2007 through FY 2028. The parties requested that BPA implement the Recommendations in its WP-07 Supplemental proposal.

The parties submitted the Recommendations to BPA just prior to the scheduled initiation of BPA's WP-07 Supplemental rate proceeding. In response, BPA delayed the commencement of the WP-07 Supplemental rate proceeding and met with IOU and COU groups throughout November and December of 2007 in an attempt to determine whether the concepts in the Recommendations could feasibly be implemented. Although progress was being made on developing a construct that would permit Staff to propose an implementation of the Recommendations in rates, time constraints ultimately precluded the parties and Staff from

1 finalizing a resolution that could be proposed in the WP-07 Supplemental rate proceeding. Staff
2 subsequently withdrew from the settlement discussions to focus on completing the initial
3 proposal for the WP-07 Supplemental proceeding. Although some aspects of the
4 Recommendations were considered in developing the initial proposal, Staff was ultimately
5 unable to implement the Recommendations as intended by the parties.

6
7 At the conclusion of the WP-07 Supplemental proceeding in September of 2008, BPA presented
8 its final findings in the WP-07 Supplemental ROD. In the WP-07 Supplemental ROD, BPA
9 determined that the COUs had been overcharged by approximately \$1 billion during the
10 FY 2002–2008 period as a result of the 2000 REP Settlement Agreements. BPA proposed to
11 return these overcharges to the injured COUs with an initial lump-sum cash payment in 2008 and
12 then through future reductions in REP benefit payments to the applicable IOUs. In addition to
13 determining the refunds and overcharges caused by the 2000 REP Settlement Agreements, the
14 WP-07 Supplemental ROD also addressed the Administrator’s final decisions on the appropriate
15 amount of REP benefits to pay the IOUs, and include in rates, for FY 2009. To make these
16 determinations, the Administrator had to address a host of controversial issues related to the
17 section 7(b)(2) rate test.

18
19 Both COUs and IOUs vigorously opposed the decisions BPA reached in the WP-07
20 Supplemental ROD. The COUs and entities supporting the COUs’ positions claimed that BPA
21 had grossly underestimated the IOUs’ refund obligation and that the actual overcharge to COUs
22 for the FY 2002–2008 period was at least \$2 billion. The IOUs, public utility commissions, and
23 ratepayer advocacy groups, in contrast, argued that no refunds were owed at all because the
24 Court did not direct BPA to provide refunds and because the terms of the 2000 REP Settlement
25 Agreements specifically prohibited BPA from recouping REP benefits paid under those
26 agreements. The IOUs and COUs also opposed BPA’s interpretation and implementation of the
27 section 7(b)(2) rate test. It appeared inevitable that the parties would challenge the decisions

1 BPA reached in the WP-07 Supplemental ROD in court. The Administrator, recognizing that
2 endless litigation over BPA's decisions would only perpetuate uncertainty in the region over
3 BPA's rates and the REP, appealed to the parties in the WP-07 Supplemental ROD to not give up
4 on settlement efforts:

5 This has been a very difficult undertaking, fraught with complexity and with large
6 financial stakes. I believe we have done the best we could do to find a legally
7 sustainable and politically equitable solution (in that order) to the challenge
8 provided by the Ninth Circuit. Nevertheless, I would suggest there remains
9 considerable uncertainty for the parties as to how REP issues may evolve in the
10 future. For that reason I continue to urge the parties to work towards a lawful
11 settlement that will provide greater long-term certainty and, because it will be
12 defined by the parties, greater political equity than what any single Administrator,
13 acting within the confines of the law, can provide.

14 WP-07 Supplemental ROD (Conformed), WP-07-A-05, at xx-xxi.

15
16 Following the publication of the WP-07 Supplemental ROD in 2008, BPA and principals from
17 various IOU and COU groups continued to explore the possibility of settlement. Settlement
18 discussions continued through the fall and winter of 2008 and moved into 2009. While these
19 discussions were ongoing, petitions challenging BPA's implementation of the REP were filed
20 with the Ninth Circuit Court of Appeals. These challenges were consolidated into four primary
21 cases: *APAC*, *IPUC*, *Avista*, and *PGE II*. Briefing was set to begin in the *APAC* and *IPUC* cases
22 in August of 2009. As the briefing in *APAC* and *IPUC* moved forward, BPA and representatives
23 for the COUs and IOUs met to discuss the possibility of involving a mediator in the REP
24 settlement discussions. In November of 2009, the parties tentatively agreed to engage a mediator
25 following the completion of the briefing in the *APAC* and *IPUC* cases. Mediation sessions were
26 scheduled to begin in mid-April 2010 and continue until late May 2010.

4.2 The REP Mediation Effort

Mediation on the REP litigation commenced on April 15, 2010, in Portland, Oregon. Leading the mediation sessions was former Federal District Court Judge Layn Phillips, a nationally renowned mediator. Assisting Judge Phillips was former Magistrate Judge Bernard Schneider. Because many of the issues in the mediation would affect the prospective implementation of the REP, the litigants invited regional parties not directly involved in the litigation to participate in the mediation. In total, more than 50 litigants and other parties participated in the mediation. The mediation was scheduled to end in May, but discussions between the parties and the mediator continued through the end of June 2010. Although by the conclusion of these sessions the litigants and parties had not achieved a global settlement, significant progress had been made toward reaching a compromise on all existing claims and the future implementation of the REP. Principals for most of the litigants agreed to continue to work toward a settlement.

In early September 2010, with assistance from the mediator, representatives for a substantial majority of the litigants and other regional parties agreed to a non-binding Agreement in Principle (AIP). The AIP committed the negotiating parties to work in good faith on a final settlement of the REP that adhered to certain terms and conditions outlined in the AIP. *See* FY 2012 REP Settlement Documentation, REP-12-E-BPA-01B. Drafting of the 2012 REP Settlement Agreement began immediately following the parties' execution of the AIP and has continued through mid-December. Participants in that effort have produced a near-final draft of the Agreement. *Id.* The Agreement is currently being reviewed by the principals for the negotiating participants, and is expected to be finalized in early January 2011. Once the agreement is completed, it will be offered to the litigants in the pending cases and to the region's IOUs and COUs.

4.3 Description of the 2012 REP Settlement Terms

4.3.1 Basic Elements

The proposed 2012 REP Settlement would resolve challenges over BPA's implementation of the REP in return for a stream of REP benefits to the IOUs for a term of 17 years. IOU-specific Lookback obligations would be extinguished. The COUs' obligation to pay REP benefits in rates would be limited to the COUs' share of the stream of REP benefits as set forth in the Agreement. The distribution of these REP payments to the IOUs would depend on each IOU's respective ASC and exchange load. The IOUs would continue to file ASCs with BPA pursuant to the 2008 ASCM.

In addition to the stream of REP benefits, the IOUs would receive (i) a percentage of any incremental BPA Renewable Energy Credits (RECs) that might accrue to BPA resources used to serve BPA Tier 1 loads and (ii) the payment of certain outstanding interim payments due under the 2008 Residential Exchange Interim Relief and Standstill Agreements between BPA and four of the IOUs.

The Agreement provides for Refund Amounts to COUs through FY 2019 to allocate the benefits of the Settlement among COUs that paid BPA's rates during FY 2002 through FY 2006 and those that did not. It also requires parties to the Settlement to work together, directly or through associations, to urge the U.S. Congress to pass legislation that would affirm and direct BPA to implement the settlement.

Under the Settlement, BPA would establish rates consistent with the terms of the Settlement for all BPA customers, whether or not they sign the Settlement Agreement. The drafters recognized, however, that parties might challenge BPA's implementation of the Settlement in rates, and that a court might preclude BPA from setting rates and otherwise treating BPA customers that did not execute the Agreement in the same manner as parties to the Settlement. Given this possible

outcome, the drafters included provisions in the Agreement that address how the Settlement would apply to parties if a court rules that parties and non-parties should be treated differently.

4.3.2 REP Benefit Payments to the IOUs

Section 3.1 of the Agreement establishes a schedule of annual REP benefits to be paid to the IOUs in the aggregate (Scheduled Amounts). Scheduled Amounts would increase over time from \$182.1 million in FY 2012 to \$286.1 million in FY 2028. See Table 4.1. The Scheduled Amounts constitute the aggregate REP benefits paid to the IOUs, and included in BPA's rates, under the Settlement. As described more fully in section 4.3.6, this amount may change if BPA is required to set rates differently for COUs that did not sign the Settlement. The Settlement would permit BPA to round its rates such that the difference, if any, between the Scheduled Amounts and the amounts payable to the IOUs is no more than one thousand dollars (\$1000).

4.3.3 Refund Amounts to COUs

Section 3.2 of the Agreement addresses equity issues among the COUs by establishing Refund Amounts to be provided to COUs during the first eight years of the settlement term. For Fiscal Years 2012 through 2019, \$76.538 million per year would be included in REP costs recovered in BPA rates in addition to the Scheduled Amounts paid to the IOUs. The \$76.538 million per year would be returned to BPA customers that purchase power at the PFp rate based on an allocation approach described below.

4.3.4 Inclusion of REP Benefit Costs in Rates

Section 3.3 of the Agreement addresses how the REP benefit costs would be recovered in rates, including the allocation of REP benefit costs to COU parties to the Settlement. BPA would establish rates to recover the Scheduled Amounts plus the COU Refund Amounts (the sum of which is defined as the REP Recovery Amounts in the Agreement), plus any COU REP benefits.

1 The Agreement includes a formula that determines an REP Surcharge Amount, which is the
2 amount of rate protection allocated to the IP and NR rates. This formula effectively scales the
3 rate protection costs allocated to the IP and NR rates for the settlement period to the rate
4 protection costs allocated to the IP and NR rates in the WP-10 rate proceeding. For example, if
5 the REP Recovery Amounts in a given rate period were 10 percent higher than the REP benefit
6 costs in the WP-10 rate proceeding, the rate protection costs allocated to the IP and NR rates
7 would be 10 percent higher on a mills/kWh basis.

8
9 The REP Recovery Amount cost remaining after subtracting the allocation of REP Surcharge
10 Amount to the IP and NR rates is allocated to the IP, NR, and Tier 1 PF rates on a pro rata load
11 share basis. COU parties to the Settlement agree to pay their Allocated Share of the Scheduled
12 Amounts based on the sum of COU parties' TOCAs divided by the sum of all PF customers'
13 TOCAs (TOCA Shares). This TOCA Share approach ensures that the COUs that sign the
14 Settlement only pay in rates their agreed-upon share of the REP benefits payable to the IOUs.
15 Non-settling COUs would receive similar treatment in their rates unless BPA is required to set
16 rates differently for these customers. In that case, the non-settling COUs would pay their TOCA
17 share of whatever REP benefits were allocated to the PFp rate as calculated pursuant to the
18 direction of the court.

19 20 **4.3.5 Allocation of Refund Amounts to COUs**

21 Section 3.4 of the Agreement addresses how the Refund Amounts to COUs described in
22 section 4.3.3 above would be calculated. Fifty percent of the amount (\$38.269 million) would be
23 returned to COUs based on PF-02 customer percentages set forth in the Agreement. See
24 Table 4.2. These customer percentages are equivalent to the percentages BPA established in the
25 WP-10 rate proceeding to allocate the FY 2010–2011 Lookback Credits to the COUs.

1 The other 50 percent of the refund amount would be returned to COUs based on each customer's
2 Tier 1 Customer TOCA Share, which is equal to each COU's TOCA divided by the sum of all
3 COUs' TOCAs. TOCAs are the Tier 1 Cost Allocators established pursuant to BPA's Tiered
4 Rate Methodology (TRM). There are several vintages of TOCAs in the TRM. The Initial
5 Proposal assumes that the TOCAs used to return Refund Amounts would be those used to set
6 rates for a given rate period, not actual TOCAs for Slice/Block customers or adjusted TOCAs for
7 Load Following customers that might be different from TOCAs used to set rates due to load loss
8 during the rate period.

9 10 **4.3.6 Court Determination Related to Allocation of Costs of REP Benefits**

11 Section 3.6 of the Agreement addresses how parties would implement the Settlement if BPA is
12 precluded from setting rates consistent with sections 3.1–3.5 of the Agreement for all customers,
13 regardless of whether or not they are parties to the Settlement. Parties to the Settlement would
14 continue to pay their allocated share of the Scheduled Amounts. Customers that were not parties
15 to the Settlement, if any, would pay the costs of IOU REP benefits BPA determines consistent
16 with the court's ruling (REP Benefit Costs). The REP benefits that BPA would pay the IOUs
17 under this situation would be the sum of these two amounts, which might, in any year, be greater
18 or less than the Scheduled Amounts.

19
20 For example, assume for illustrative purposes that in the FY 2012–2013 rate period, 85 percent
21 of REP costs are recoverable from the PFp rate and the remaining 15 percent from other rates
22 (presumably the IP and NR rates). The COUs in total would be responsible for 85 percent of the
23 \$182.1 million per year of the Scheduled Amounts, or \$154.4 million per year. If the allocated
24 share of the COU parties to the settlement was 90 percent, then BPA would recover from these
25 customers 90 percent of \$154.4 million per year, or \$139.3 million. Further assume that the
26 court determined that BPA's recovery of REP costs from rates other than the PFp rate was

appropriate (or alternatively, that all customers paying such other rates are parties to the settlement), so non-COU customers would be responsible for their 15 percent share, or \$27.3 million per year. Finally, assume that based on the court ruling, BPA determines that COUs that are not parties to the settlement are responsible for REP benefit costs of \$20 million per year rather than the \$15.4 million under the Settlement. Under this example, BPA would owe the IOUs REP benefits of \$139.3 million plus \$27.3 million plus \$20 million, for a total of \$186.6 million per year.

4.3.7 Interim Agreement True-Up Payments to the IOUs

Section 4 of the Agreement states that BPA will, consistent with the provisions of the 2008 Residential Exchange Interim Relief and Standstill Agreements (Contract Nos. 08PB-12438, 08PB-12439, 08PB-12441, 08PB-12442) (“Interim Agreements”), pay the IOUs Interim Agreement True-Up amounts determined by BPA, pursuant to the WP-07 Supplemental ROD and the 2010 BPA Rate Case Wholesale Power Rate Final Proposal: Lookback Recovery and Return (WP-10-FS-BPA-07).

If the Agreement is not challenged, BPA will pay the True-Up amounts 95 calendar days after the effective date of the Agreement (which is the date the BPA Administrator executes the Agreement). If the Agreement is challenged, BPA will pay the True-Up amounts 30 days after a final, non-appealable order by the court that dismisses the challenges or that otherwise upholds the Agreement. If Congress adopts the legislative authorization provided for in section 8 of the Agreement, any IOU with an Interim Agreement may notify BPA in writing that it wants to be paid its Interim Agreement True-Up amount. BPA is to pay the True-Up amount within 30 days of receiving the notice.

1 The IOUs with Interim Agreements and the respective Interim Agreement True-Up principal
2 amounts are stated in Table 4.5. Simple interest will accrue from April 2, 2008, through the date
3 the true-up payment is made, with interest of 1.76 percent per year. If all Interim Agreement
4 True-Up amounts were paid in September 2013, the total interest amount would be
5 approximately \$6.5 million, and the total principal plus interest amount would be approximately
6 \$88.1 million.

8 **4.3.8 Treatment of Environmental Attributes**

9 Section 5 and Exhibit C of the Agreement address how possible future environmental attributes
10 associated with the resources used to serve BPA Tier 1 load would be shared with the IOUs. The
11 Agreement provides that 14 percent of Transferable Renewable Energy Certificates (RECs) and
12 14 percent of Carbon Credits would be transferred to or would be valued and the value paid to
13 the IOUs. Transferable RECs are RECs that may in the future accrue to the resources used to
14 serve BPA Tier 1 load. Transferable RECs do not include the RECs associated with existing
15 Tier 1 renewable projects, which are listed in Exhibit C of the Agreement. Carbon Credits are
16 defined as Environmental Attributes consisting of greenhouse gas emission credits, certificates,
17 or similar instruments.

18
19 In order for 14 percent of the RECs and Carbon Credits to be transferred to the IOUs, COU
20 parties to the Settlement would agree to replace the current Exhibit H of their Contract High
21 Water Mark (CHWM) contracts with the revised Exhibit H in the Agreement. BPA would also
22 offer Exhibit H of the Agreement to any COU that is not a party to the Settlement. If COUs that
23 are not parties to the Settlement did not agree to replace their current CHWM Exhibit H with the
24 Agreement Exhibit H, BPA would use its ratemaking authority as provided in section 9 of the
25 current Exhibit H to determine and factor in the value or costs of RECs that were transferred to
26 such COUs.

4.3.9 Allocation of REP Benefits to IOUs

Section 6 of the Agreement addresses the allocation of the REP Settlement benefits among the IOUs. Section 6.1 describes the calculation that is performed to determine each IOU's respective share of the Scheduled Amount discussed above. REP Settlement benefits, for the most part, would be allocated in the same manner as REP benefits under the traditional REP. IOUs' ASCs would be determined in accordance with the 2008 ASCM. The IOUs' ASCs would also be compared to BPA-generated utility-specific PFX rates to determine the individual utility REP benefit amounts. Whether a particular IOU would be eligible to receive REP benefits would continue to depend on the relationship between the utility's ASC and BPA's rates. Section 6.1.2 of the Agreement discusses the adjustments that would be made to the formula values in Section 6.1.1 in the unlikely event not all of the Scheduled Amounts were disbursed to the IOUs.

Section 6.2 of the Settlement addresses an equity issue among the IOUs by establishing a reallocation of rate protection amounts among the IOUs to achieve a particular allocation of REP benefits. The reason for this specific allocation is because of the manner and method BPA used to recover Lookback Amounts from the IOUs during the FY 2009–2011 period. Although the IOUs dispute the existence and level of the Lookback Amounts BPA established in its WP-07 Supplemental and WP-10 proceedings, they recognize that between FY 2009 and FY 2011, they have differentially experienced the effects of the setoffs that BPA has made to their REP benefit payments. In addition, although Idaho Power received no REP benefits and therefore incurred no Lookback setoffs in FY 2009 through FY 2011, it would realize a substantial benefit under the 2012 REP Settlement because both the disputed deemer obligation asserted by BPA stemming from its 1981 RPSA and its Lookback obligation established in the WP-07 Supplemental and WP-10 proceedings would be extinguished.

1 In consideration of these equity issues among the IOUs, the Agreement specifies an approach to
2 reallocate the costs of rate protection among the IOUs and calls for BPA to develop PFX rates
3 that would result in the IOUs receiving REP benefits consistent with the Settlement. Although
4 the adjustment is included in establishing the PFX rates, each IOU's REP benefits ultimately
5 would be determined for each rate period based on its ASC, its PFX rate, and its contract
6 exchange load. Each IOU's PFX rate would be based in part on the IOU-specific adjustment
7 established in the Agreement. The following describes the IOU reallocation in the draft
8 Agreement as of mid-December 2010.

9
10 Step 1 of the reallocation is an initial calculation of the amount of REP benefits each IOU would
11 receive if the section 7(b)(2) rate test did not trigger (IOU-Specific Unconstrained Benefit
12 Amounts). These amounts are equal to the difference between each IOU's ASC and the base
13 PFX rate (the unbifurcated PF rate plus a transmission adder) times its contract exchange load.
14 This step is equivalent to the ratemaking step BPA currently performs to determine the gross cost
15 of the REP prior to the application of the section 7(b)(2) rate test.

16
17 In step 2, a Constrained Total Benefit Ratio would be calculated for each Fiscal Year of the
18 Exchange Period by dividing the aggregate REP benefits for each year by the sum of all IOU-
19 Specific Unconstrained Benefit Amounts for the respective year derived in step 1. This ratio
20 would then be multiplied by each IOU-Specific Unconstrained Benefit Amount to determine
21 IOU-specific interim REP benefits. In effect, this calculation would proportionally reduce each
22 IOU's Unconstrained Amount so that the resulting total amount of REP benefits would be equal
23 to the Scheduled Amounts described in section 4.3.2 above. This step is equivalent to the
24 ratemaking step BPA currently performs to determine the net costs of the REP after application
25 of the section 7(b)(2) rate test.

Both steps 1 and 2 model BPA's current ratesetting methodology for PFx rates using different terminology. See Section 5 of this Study for additional discussion of the ratemaking steps BPA would perform to implement the Settlement.

In step 3, IOU-specific reductions would be made to the IOU-specific interim REP benefits for Avista, Idaho Power, PacifiCorp, and PGE. These annual adjustment amounts would be determined by establishing an initial adjustment balance and a maximum annual reduction for each of the four IOUs. The initial balances (Initial IOU-specific Adjustment Amounts) and the maximum annual reductions (Maximum IOU Annual Adjustment Amounts) are specified in the Agreement. Tables 4.3 and Table 4.4 show the Initial IOU-specific Adjustment Amounts and Maximum IOU Annual Adjustment Amounts specified in the mid-December draft of the Agreement. The IOU-specific Adjustment Amounts would be reduced over time by annual adjustment amounts until the Initial IOU-specific Adjustment Amounts, plus interest compounded annually at 3 percent on unpaid balances, were extinguished. The annual reduction for a given IOU is limited to the lesser of (i) the outstanding IOU-specific Adjustment Amount balance, (ii) the Maximum IOU Annual Adjustment Amount in Table 4.4, or (iii) the amount that would reduce an IOU's REP benefits for the year to zero.

In step 4, the IOU-specific reductions for each IOU determined in step 3 would be allocated to other IOUs. Idaho Power's reductions would be allocated to Avista, NorthWestern, PacifiCorp, PGE, and Puget. Avista and PacifiCorp's reductions would be allocated to NorthWestern, PGE, and Puget. PGE's reductions would be allocated to NorthWestern and Puget. In each reallocation, the receiving IOU would get an amount equal to its IOU-Specific Unconstrained Benefit Amount divided by the sum of the IOU-specific Unconstrained Benefit Amounts for all IOUs receiving a reallocation from a given IOU. For example, the reduction for Avista would be allocated to NorthWestern, PGE, and Puget based on each of the receiving IOU's share of the

1 sum of the three IOU-Specific Unconstrained Benefit Amounts. At the completion of step 4, the
2 total REP benefits for all IOUs would remain equal to the REP benefits in section 4.3.2 above.

3
4 The Agreement specifies that BPA would set rates such that the results of step 4 would be
5 produced after the application of each IOU's ASC, PFx rate, and exchange load. BPA's
6 implementation methodology would implement steps 1 and 2 in a similar manner as currently
7 used for PFx rates; a pro rata allocation of the costs of rate protection among both IOU and COU
8 REP participants plus a pro rata allocation of Refund Amounts to IOU REP participants. The
9 reallocations of steps 3 and 4 would take the form of a reallocation of the costs of rate protection
10 to the IOUs in the development of the utilities' specific PFx rates. Once the allocations of the
11 costs of rate protection and costs of the Refund Amounts were established, the amounts allocated
12 to each utility would be specified as a utility-specific REP Surcharge, which would then be
13 added to the utility's base PFx rate to determine each IOU's utility-specific PFx rate. This would
14 allow the steps specified in the Agreement to be incorporated into the development of the PFx
15 rate with very few ratemaking modifications.

16 **5. IMPLEMENTING THE 2012 REP SETTLEMENT IN RATEMAKING**

17 18 **5.1 Ratesetting Pursuant to the Settlement**

19 As described in section 3.1 above, BPA's ratesetting consists of three major steps: the COSA
20 step, the rate directives step, and the rate design step. Ratesetting under the Settlement affects
21 only a portion of the rate directives step. The ratesetting process is unchanged prior to the
22 7(b)(2) rate test.

23
24 As described in sections 3.2 and 3.4 above, the purpose of the rate test is to calculate the level of
25 rate protection due to preference customers pursuant to section 7(b)(2) of the Northwest Power
26 Act. At the point in the rates modeling after the section 7(c) rate directives have been completed,

1 the Settlement proposes a new set of rate calculations. This new set of rate calculations
2 effectively implements the section 7(b)(2) rate test through alternative calculations that provide
3 preference customers with an amount of rate protection based on the amount of IOU REP
4 benefits specified in the Settlement, any COU REP benefits for qualified REP participants, and
5 section 7(b)(3) adjustments to the IP and NR rates as specified in the REP Settlement.

6
7 The REP Settlement ratesetting begins with total IOU REP benefits as specified in the 2012 REP
8 Settlement Agreement, called Scheduled Amounts. Added to the Scheduled Amount for each
9 year is an additional amount of REP benefits, also specified in the Agreement, known as the
10 Refund Amount. The Refund Amounts are considered REP benefits because they are subject to
11 the amount of rate protection afforded to the PFp rate. The Refund Amounts, however, are not
12 paid to the IOUs, but instead are credited back to preference customers in the form of a credit on
13 their power bills.

14
15 The REP Settlement rate modeling first calculates the Unconstrained Benefits, which are the
16 REP benefits that would be paid if there was no PFp rate protection. In such circumstance, the
17 REP benefits for each exchanging utility would be equal to its ASC minus its appropriate Base
18 PFx rate multiplied by its qualified exchange load. These Unconstrained Benefits are then used
19 to calculate total COU REP benefits under the REP Settlement. A ratio is calculated by dividing
20 (i) the Scheduled Amounts plus any Refund Amounts by (ii) the total Unconstrained Benefits for
21 IOUs. This ratio is then multiplied by total Unconstrained Benefits for COUs to derive total
22 COU REP benefits.

23
24 The total rate protection provided to preference customers under Settlement ratemaking is
25 composed of two parts. With the Unconstrained Benefits and the total IOU and COU REP
26 benefits determined, the first amount of rate protection due to preference customers is calculated
27 as the sum of Unconstrained Benefits minus the sum of REP benefits. The cost of this first part

1 of rate protection is allocated entirely to the PFx rate pool. The cost of the second part of rate
2 protection to be allocated to the IP and NR rate pools is calculated later. Settlement ratemaking
3 allocates this first amount of rate protection to individual REP participants using the same
4 process used in non-settlement ratemaking, a pro rata allocation based on each participant's
5 Unconstrained Benefits. Settlement ratemaking next allocates the cost of providing Refund
6 Amounts to IOUs in the same pro rata manner. Settlement ratemaking then calculates utility-
7 specific REP Surcharges to be added to the appropriate Base PFx rates to produce utility-specific
8 PFx rates. After the utility-specific PFx rates are calculated, the utility-specific REP benefits are
9 calculated and summed. At this point, the total annual utility-specific REP benefits for IOUs are
10 equal to the Scheduled Amount for each year.

11
12 The second part of rate protection is calculated and allocated to the IP and NR rate pools. This
13 second part of rate protection is equal to the REP Surcharge included in the IP and NR rates.
14 The REP Surcharge is determined by multiplying the total REP benefit costs determined above
15 (Scheduled Amounts plus COU REP benefits) by a scalar specified in the proposed REP
16 Settlement. The scalar is calculated by dividing the WP-10 7(b)(3) Supplemental Rate Charge
17 included in the IP and NR rates by the total REP benefit costs included in WP-10 rates. This
18 REP Surcharge, when multiplied by the expected sales under the IP and NR rate schedules, will
19 produce an amount of dollars comprising the second amount of rate protection. The second
20 amount of rate protection is subtracted from the total IOU and COU benefits to yield a residual
21 amount of REP benefits that are allocated to the PFp, IP, and NR rate pools on a pro rata load
22 basis.

23
24 After the IP and NR adjustment, the now-lower PFp rate and the now-higher IP rate must again
25 be adjusted to maintain the proper 7(c)(2) rate directive cost relationship. For this second IP-PF
26 Link calculation, monthly/diurnal PFp energy rates are determined, and the IP rate is set equal to
27 the flat PFp rate plus the net Industrial Margin plus the REP Surcharge.

1
2 One further adjustment is made to recognize that each IOU has differing levels of setoffs in
3 repaying its Lookback Amounts. This adjustment is accomplished through reallocations of the
4 cost of rate protection allocated to the IOUs. The Agreement specifies a maximum annual
5 adjustment amount for three IOUs and a separate adjustment for Idaho Power. These
6 adjustments reduce the initial amount of REP benefits that each IOU would receive and allocate
7 this reduction to other IOUs. Once all of the adjustments are allocated, the cost of rate protection
8 initially allocated to each IOU is recomputed to account for this adjustment. The adjusted
9 allocations of the cost of rate protection are added to the allocation of the cost of Refund
10 Amounts to compute each IOU's final PFx rate.

11
12 Once these steps are complete, the ratemaking process continues to the rate design step in the
13 same manner as with no settlement. The Settlement does not affect the rate design step.

14 15 **5.2 Comparing the Rate Test with the Settlement**

16 A comparison of the development of rates under the Settlement and without a settlement reveals
17 only a few changes. Under the Settlement, the amount of rate protection included in the PFp rate
18 is calculated using specific formulas rather than relying on the disputed rate test. The allocation
19 of the cost of rate protection is also determined according to specific formulas. Finally, the
20 allocation of the 7(c)(2) adjustments after the rate protection has been applied is somewhat
21 different. Other aspects of ratemaking are unchanged by the Settlement.

22
23 Under the Settlement, rate protection is afforded to preference customers. The amount of rate
24 protection is calculated in the manner prescribed by the REP Settlement. In the same manner as
25 with no settlement, the rate protection reduces the costs allocated to the PFp rate applicable to
26 preference customers. The cost of this rate protection is reallocated to all other power sales, with

1 the exception of surplus sales. Two PF rates are the result of this reallocation: the PFp rate,
2 which receives the rate protection, and the PFx rate, which does not receive rate protection and
3 bears its allocated share of the rate protection reallocation. The cost of rate protection continues
4 to be collected through REP surcharges applied to non-PFp sales. An additional calculation is
5 performed when determining utility-specific REP surcharges for IOUs that assigns the cost of the
6 Refund Amounts in the rate determination rather than through the current use of separate setoffs
7 to the REP benefits paid to the IOUs.

11 **5.3 Summarizing the PFp Rate**

12 Under the Settlement, the PFp rate has been lowered from the level prior to the application of
13 rate protection included in the PFx rates. It has also been lowered by the amount of REP benefits
14 recoverable through the REP Surcharges in the IP and NR rates. It has then been somewhat
15 increased to relink the IP and PFp rates. After these adjustments, the final amount of costs
16 allocated to the PFp rate pool is complete and the ratesetting process proceeds to setting rates
17 pursuant to the Tiered Rate Methodology.

19 **5.4 Summarizing the PFx Rate**

20 Under the Settlement, the PFx rates are set to produce the Scheduled Amounts for the IOUs.
21 This is accomplished through the allocation of the cost of rate protection provided to the PFp rate
22 and the cost of providing Refund Amounts. The PFx rates for COUs participating in the REP are
23 set in the same manner except that the costs of the Refund Amounts are not allocated to the COU
24 participants. Finally, the rate protection costs allocated to the IOUs is reallocated to provide a
25 reallocation of REP benefits that recognizes that each IOU has differing levels of setoffs in
26 repaying its Lookback Amounts.

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5.5 Summarizing the IP and NR Rates

Under the Settlement, the IP and NR rates have been adjusted upwards by application of the REP Surcharge, which are section 7(b)(3) allocations of the cost of rate protection. The IP rate is then relinked with the PFp rate pursuant to section 7(c)(2).

PART II ANALYSIS AND EVALUATION OF THE 2012 REP SETTLEMENT

6. ANALYZING THE SETTLEMENT

6.1 Introduction

The 2012 REP Settlement Agreement reflects a compromise by a substantial majority of BPA's customers and most of the participants in the litigation on outstanding REP-related issues. It was developed after extensive negotiations by representatives of COU customers, IOU customers, public utility commissions, and ratepayer advocacy groups. Many of these entities signed the AIP and are expected to sign the 2012 REP Settlement once it is completed. These parties have informed the Administrator of their development of a proposed Settlement. The Administrator has requested that BPA Staff analyze and evaluate the proposed Settlement to develop a record to allow him to determine whether the Settlement is both reasonable and consistent with law and, if adopted, could be used to set rates consistent with its terms.

Although Staff firmly believes that settlement of the existing REP litigation is in the interest of all BPA ratepayers, the Administrator must ensure that the terms and conditions in the 2012 REP Settlement are reasonable and comply with all relevant statutory provisions. The purpose of this part of the Study is to present this analysis and evaluation.

Part II of the Study is divided into five sections. After this overview of the criteria and methodologies Staff is using to evaluate the proposed Settlement, sections 7–9 describe the development of inputs for the analysis. Section 7 presents a summary of the issues in the pending litigation that Staff is considering in its scenario analysis. Section 8 describes the near-term and long-term assumptions Staff is using to develop ASC forecasts for the FY 2012–2032 period. Section 9 describes the assumptions Staff is considering in the long-term forecasts of

1 BPA's costs and revenues. Section 10 describes the results of the analysis that develops a series
2 of REP benefits under a variety of scenarios. Finally, Section 11 describes the rationale for
3 Staff's evaluation and recommendation that the Administrator adopt the 2012 REP Settlement.
4

5 **6.2 Overview of Methodology Used to Analyze the 2012 REP Settlement** 6 **Agreement**

7 As noted in section 4 of this Study, the proposed 2012 REP Settlement would resolve existing
8 and future challenges to BPA's implementation of the REP for a term of 27 years, from FY 2002
9 through FY 2028. Beginning in FY 2012, BPA would not perform the traditional section 7(b)(2)
10 rate test in its rate cases. Instead, the Settlement (developed in the context of numerous 7(b)(2)
11 rate test scenarios) would determine the amount of REP payments to the IOUs and,
12 concomitantly, the amount of rate protection afforded to the COUs. REP payments to IOUs
13 under the proposed Settlement would begin in FY 2012 at approximately \$182 million per year
14 and gradually increase over 17 years to about \$286 million by FY 2028. In addition, Refund
15 Amounts of \$76.5 million per year would start in FY 2012 and run for eight years. Finally, it is
16 expected that COUs may participate in the REP, when eligible, resulting in additional REP
17 payments. All of these payments under the Settlement must be allowable under section 7(b)(2).
18

19 The protection and payments under the proposed Settlement are well defined and can be
20 computed without much interpretation. The REP payments to the IOUs are defined by a
21 schedule, as are the Refund Amounts paid to the COUs. However, before the Administrator can
22 make these payments and perform his obligations in the proposed Settlement, Staff believes that
23 the Settlement must have a clear and direct connection to the protections and requirements set
24 forth in the Northwest Power Act. To that end, Staff has approached the analysis of the 2012
25 REP Settlement by comparing the protections and requirements set forth in the Settlement with
26 protections and requirements that would be reasonably expected in absence of the Settlement.
27

1 To analyze the protections and requirements set forth in the Settlement, Staff developed a set of
2 potential future streams of results based on an examination of the major variables that would
3 affect the amount of rate protection and REP payments. In addition, Staff developed a set of
4 potential future streams of results based on an examination of the issues in litigation that would
5 affect the amount of rate protection and REP payments. To accomplish this analysis, Staff used
6 two separate rate models.

8 **6.3 Rate Models Used to Analyze the 2012 REP Settlement Agreement**

9 Staff modified the existing RAM2012 to examine the effect of different resolutions of issues in
10 litigation on the amount of rate protection provided by section 7(b)(2) and the amount of REP
11 benefits that would be paid after application of the 7(b)(2) alternatives. RAM2012 is the detailed
12 rate model being used to calculate rates in the concurrent BP-12 rate proceeding. RAM2012 has
13 the capability of developing rates based on either the proposed Settlement or the 7(b)(2) rate test.
14 In fact, RAM2012 is the model that would be used to set rates using the 7(b)(2) rate test should
15 the Administrator decide not to adopt the Settlement. However, RAM2012 in its current state
16 cannot be used as the sole model for analyzing the Settlement. RAM2012 is limited to
17 calculating rates for only the FY 2012–2013 rate period. Although work is under way that would
18 allow RAM2012 to perform rate calculations for an extended period (currently envisioned to be
19 20 years), this work is not expected to be completed until after the end of both the REP-12 and
20 BP-12 proceedings.

21
22 To address the need for a long-term analysis of the Settlement, Staff has developed a long-term
23 rate forecast model to produce estimates of rate protection amounts and REP benefits in the
24 absence of settlement. This new model projects rates, including rate protection amounts and
25 REP benefits, for the full 17-year term of the proposed Settlement. This new model is a scaled-
26 down version of RAM2012. It performs many of the same functions as RAM2012 in the

1 portions of the ratesetting process necessary to analyze the Settlement. The new model develops
2 energy allocation factors in the same manner as RAM2012. The new model allocates costs and
3 credits to rate pools in the same manner as RAM2012. The new model links the IP rate to the PF
4 rate in a simplified form as used in RAM2012; the new model uses annual data only, so it cannot
5 independently calculate a flat annual PF rate for use in the 7(c)(2) linking process. Most
6 important, the new model performs the 7(b)(2) rate test, and consequent 7(b)(3) reallocations, in
7 essentially the same manner as RAM2012; different formulas are used to compress the rate-
8 period-plus-four-year features of the rate test into a one-dimensional approach rather than the
9 two-dimensional approach used in RAM2012.

10
11 There are a few notable differences between the new long-term model and RAM 2012. The
12 long-term model is an annual model; it does not calculate rates based on a two-year rate period
13 as in RAM2012. Thus, the rate test in the long-term model is based on each year plus the four
14 subsequent years. This will create only minor differences compared to RAM2012. Also, the
15 long-term model calculates only average energy rates for different rate classes; RAM2012 can
16 calculate monthly and diurnal rates and apply the effects of the demand rate to the energy rates.
17 Finally, the long-term model does not calculate tiered rates, whereas RAM2012 implements the
18 Tiered Rate Methodology. The lack of tiered rates has only one effect on this analysis: the rate
19 for COUs participating in the REP is based on Tier 1 costs and loads; the long-term model
20 forecasts the costs and loads associated with expected service at Tier 2 rates and removes them
21 from the PFx rate for COUs. The assumptions Staff used to develop inputs for the long-term
22 model, including Staff's projected estimates of future ASCs, PF rates, and exchange loads, are
23 discussed in sections 8 and 9 of this Study.

24
25 Once the long-term model was operational, Staff also incorporated the ability to compute REP
26 benefits and rate protection amounts under a variety of different litigation scenarios. Staff
27 recognizes that the level of future REP benefits could be influenced by the outcome of the

1 pending litigation. To model these impacts on future REP benefits, Staff designed the long-term
2 model to produce rate protection and REP benefits under differing section 7(b)(2) assumptions in
3 the same manner as in RAM2012.

4 5 **6.4 Overview of the Settlement Analysis**

6 RAM2012 is used in the analysis to produce near-term results and is used as the basis for
7 calibrating the long-term model. From these scenarios, parties can see the projected near-term
8 and long-term quantitative impacts on future REP benefits of a number of different litigation
9 positions. Among other scenarios Staff considered in the analysis are a BPA best-case scenario
10 (BPA reference case), an IOU best-case scenario (IOU Best Case), and a COU best-case scenario
11 (COU Best Case). The litigated issues Staff considered in this analysis are discussed in
12 section 7, and the effects these issues have on future REP benefits are described in section 10.

13
14 In addition to the analysis of the litigation positions, the analysis considers other factors that
15 could affect the future amounts of rate protection and REP benefits. Both are affected by such
16 things as changes in costs, loads, and other revenues. The factors considered can affect the
17 ASCs used as the price of BPA's purchases from REP participants. The factors can likewise
18 affect the PF rates used as the price of BPA's sales to REP participants. While any factor that
19 could affect rates could produce a change in rate protection and REP benefits, the factors can be
20 grouped into those that would cause ASCs to grow faster than BPA's rates and those that would
21 cause BPA's rates to grow faster than ASCs.

22
23 If ASCs grow faster than BPA's rates, the increased spread between the two rates produces more
24 rate protection and mitigates the increase in REP benefits that would otherwise occur as ASCs
25 increase. If BPA's rates grow faster than ASCs, the decreased spread between the two rates
26 produces less rate protection and mitigates the decrease in REP benefits that would otherwise

1 occur as BPA's rates increase. Factors that tend to equally increase or decrease ASCs and
2 BPA's rates produce offsetting effects on rate protection and REP benefits. Thus, Staff's
3 analysis focuses on factors that produce opposite or disproportionate effects between ASCs and
4 BPA rates. The analysis builds a high-ASC, low-BPA case and a low-ASC, high-BPA case to be
5 representative of the variety of factors that can affect the two rates. The factors that affect ASCs
6 are addressed primarily in section 8; the factors that affect BPA rates are addressed in section 9.

7. DESCRIPTION OF ISSUES IN LITIGATION

7.1 Introduction

This section examines issues that have been raised in current litigation with regard to BPA's response to the *PGE* and *Golden NW* decisions, including BPA's determination of rate protection and REP benefits. This section is not an exhaustive list of issues; instead, the issues examined in this section represent the most significant issues that have been identified in the current litigation to date. This section of the Study focuses on the effect of these issues on the determination of either the Lookback Amounts, or rate protection and REP benefits. Based on BPA's RODs for the WP-07 Supplemental rate proceeding and the WP-10 rate proceeding, three issues have been added to the issues currently before the Court.

This section does not address the merits or demerits of the parties' positions on any legal issues. Rather, this Study simply notes that litigants have raised, or most likely will raise, these issues before the Court. This Study also addresses the impact on REP benefits if the Court were to resolve an issue contrary to BPA's previous determinations. The following is a brief summary of the issues currently being litigated in Court.

7.2 Lookback Issues

Following the issuance of the *PGE*, *Golden NW*, and *Snohomish* decisions, BPA performed an analysis, referred to as the "Lookback," to determine whether BPA had overcharged the COUs during the WP-02 rate period (*i.e.*, FY 2002–2006) and the first two years of the WP-07 rate period (*i.e.*, FY 2007–2008). BPA's Lookback approach compared the payments the IOUs received, or would have received, under the 2000 REP Settlement Agreements with the amount of REP benefits the IOUs would have received under the traditional implementation of the REP pursuant to sections 5(c) and 7(b) of the Northwest Power Act. IOUs that received more in REP

benefits under the 2000 REP Settlement Agreement than allowed by sections 5(c) and 7(b)(2) of the Act were assessed a refund obligation known as a “Lookback Amount.” BPA decided to recover the Lookback Amounts from the IOUs by withholding future benefits owed to the IOUs under the REP and issuing refunds to the injured COUs.

In the WP-07 Supplemental ROD, BPA determined that the COUs had been overcharged by approximately \$1.002 billion during the FY 2002–2008 period. This amount was subsequently revised to \$985.2 million as a result of the settlement of the Avista deemer account. *See* Lookback Recovery and Return, WP-10-FS-07, at 3. To return these overcharges to the injured COUs, BPA proposed to provide the COUs with an initial lump-sum cash payment in 2008 and then return the remaining overcharges through future reductions to REP benefit payments of applicable IOUs. By the end of FY 2011, a total of \$587 million in Lookback Amount payments, including interest, will have been paid back to COUs. *See* FY 2012–2013 Lookback Recovery and Return Study, REP-12-E-BPA-03 at 6; Table 2. Approximately \$398 million of the original \$985.2 million remains outstanding. *Id.*

Parties to the WP-07 Supplemental rate proceeding disputed many of BPA’s Lookback-related decisions. BPA’s decisions were appealed to the Ninth Circuit Court of Appeals and have been fully briefed in the *APAC* and *IPUC* cases. *See* Section 3. The following subsections summarize the parties’ respective litigation positions regarding BPA’s Lookback-related determinations. These descriptions are not intended to be legal evaluations of the parties’ positions and should be read as Staff’s understanding of the relevant issues for purposes of analyzing the Settlement. For a comprehensive review of the parties’ legal positions, please refer to the litigants’ briefs, which are included in the Study Documentation.

7.2.1 No Lookback Proposition

7.2.1.1 Invalidity Clause

The IOUs argue that no Lookback Amounts are owed to COUs because the 2000 REP Settlement Agreements included an “Invalidity Clause.” In the Invalidity Clause, the IOUs allege that BPA agreed to forgo recovery of past settlement payments if the settlement agreements were deemed “unlawful, void, or unenforceable” by the Court. IOU *IPUC* Br. at 1. The IOUs allege that BPA’s Lookback construct violates the Invalidity Clause because it recovers past payments made under the 2000 REP Settlement Agreement through prospective reductions in REP benefit payments made under Northwest Power Act section 5(c). The IOUs also contend that enforcing the Invalidity Clause is consistent with the Court’s opinions in *PGE* and *Golden NW* because neither decision declared the 2000 REP Settlement Agreements to be void in their entirety. *Id.* at 32–39. The IOUs believe the Invalidity Clause was severable from the illegal portions of the 2000 REP Settlement and should be enforced in accordance with its terms. *Id.* at 29–32; *see also* IOU *APAC* Br. at 32, OPUC *APAC* Br. at 34; CUB *IPUC* Br. at 12.

If the IOUs were to prevail on their argument that the Invalidity Clause is enforceable as of the date of the Court’s ruling (May 4, 2007), Staff assumes that the \$237.6 million in FY 2002–2006 Lookback Amounts recovered from the IOUs in FY 2009–2011, and paid to the COUs, would have to be returned to the IOUs. Staff also assumes that the remaining portions of the Lookback Amount would not be recoverable.

7.2.1.2 Retroactive Rulemaking and Ratemaking

The OPUC argues that BPA’s Lookback proposal is faulty because it comprises retroactive rulemaking. OPUC *APAC* Br. at 12–15. The OPUC contends that the Lookback is a retroactive rule because it revises BPA’s previously established rulemaking (in this case, the WP-02 rates). *Id.* at 15–16. The OPUC contends that because BPA does not have express statutory authority to

engage in retroactive rulemaking, the Lookback proposal is unlawful. *Id.* at 19; *see also* OPUC APAC Reply Br. at 7.

The IPUC similarly argues that BPA's Lookback proposal violates the general prohibition against retroactive ratemaking. IPUC APAC Br. at 21–24. The IPUC contends that BPA does not have express statutory authority to engage in retroactive ratemaking, and therefore, there is no basis for BPA to conduct the Lookback. *Id.* at 24–31; *see also* IPUC APAC Reply Br. at 2.

If either the OPUC or IPUC were to prevail on its argument, Staff assumes that the \$237.6 million in Lookback Amounts that BPA has already collected from the IOUs, and paid to the COUs, would have to be returned to the IOUs. Staff also assumes that the remaining portions of the Lookback Amount would not be recoverable.

If refunds to the IOUs were required, BPA would need to decide how to fund those refunds. They could be paid for by simply raising rates to the COUs, or perhaps by recovering the credits that the COUs have received on their power bills in FY 2009–2011.

In this case, because the WP-07 power rates had not yet received final approval from FERC, they would not be affected by a ruling in favor of retroactive ratemaking. Hence, while the Lookback Amount up to that point in time would be extinguished, and the \$237.6 million of REP benefits recovered from the IOUs would need to be returned, a small Lookback Amount of \$55 million for FY 2007–2008 would remain. This amount results from the settlement payments paid to Avista and PacifiCorp that exceeded their reconstructed REP benefits. *See* FY 2002–2008 Lookback Study, WP-07-FS-BPA-08, at 282.

7.2.1.3 LRAs Separate and Unchallenged

Under the 2000 REP Settlement Agreements, BPA provided the IOUs access to approximately 1900 aMW of benefits for the FY 2002–2006 period. Of this amount, 900 aMW of benefits were to be provided as financial payments and 1,000 aMW were to be provided as power, which could, however, be converted to financial payments by election of the customer. The 1,000 aMW of power sales were to be provided through actual power deliveries under the terms of a Block Firm Power Sale Agreement, which was attached to the 2000 REP Settlement Agreements as Exhibit A.

In 2001, extremely low water in the Federal hydrosystem, an extremely tight power supply on the West Coast, and extremely high and volatile wholesale market prices for power combined to portend a 250 percent or higher increase in BPA’s power rates for FY 2002–2006. BPA concluded the most effective response to these circumstances was to reduce its costs by reducing its reliance on the high-priced electricity market. BPA therefore developed a three-pronged Load Reduction Program that involved conservation by consumers, reductions in power purchases from BPA by utilities, and load curtailments by the DSIs. One element of the Load Reduction Program involved BPA purchasing back approximately 620 aMW of power it was contractually obligated to provide to PacifiCorp and Puget for five years (the “Load Reduction Agreements” or “LRAs”). The Load Reduction Program proved tremendously successful, reducing a potential 250 percent (or higher) rate increase to only 46 percent. The LRAs with PacifiCorp and Puget were not challenged within 90 days, as required by the jurisdictional provisions of the Northwest Power Act.

Because no timely challenges were filed against the LRAs, BPA proposed to allow PacifiCorp and Puget to retain the value of the LRAs when constructing the Lookback in the WP-07 Supplemental rate proceeding. *See* BPA APAC Br. at 78. However, BPA did not entirely exclude the LRAs from the Lookback calculation. Instead, BPA allowed PacifiCorp and Puget

1 to retain the greater of their LRA payments or their revised REP benefits as determined in the
2 Lookback, but not both. *Id.* at 78–80. This treatment of the LRA payments in BPA’s Lookback
3 proposal, referred to as “protecting” the LRA payments, had the effect of increasing PacifiCorp’s
4 and Puget’s respective Lookback Amounts.

5
6 PacifiCorp and Puget oppose BPA’s decision to include the LRA payments in the Lookback
7 calculation. IOU APAC Br. at 46–47. They contend that BPA should not have adopted the
8 “greater than, but not both” methodology but instead should have completely removed the LRA
9 payments from the Lookback calculation. *Id.*

10
11 If PacifiCorp and Puget were to prevail on this argument, Staff assumes that BPA would have to
12 remove the LRA payments from BPA’s Lookback calculations. This adjustment would have the
13 effect of reducing PacifiCorp’s Lookback Amount by approximately \$15.7 million and Puget’s
14 Lookback Amount by approximately \$262 million. *See* IOU APAC Br. at 47. *See* Table 7.1.

15 16 **7.2.1.4 Exclusion of Power Sales**

17 As noted above, the 2000 REP Settlement Agreements provided the IOUs with both cash
18 payments and a firm power sale. When considering the amount of REP benefits the IOUs
19 received under the 2000 REP Settlement Agreements, BPA included the market value of the
20 power sold to PGE and the actual financial payments to Avista and Idaho Power that monetized
21 what would have been a power sale.

22
23 The IOUs allege that BPA improperly included in the Lookback calculation the value of the
24 power BPA sold to the IOUs under the 2000 REP Settlement Agreements. *See* IOU APAC Br.
25 at 37-45. The IOUs contend that the power sales made under the 2000 REP Settlement
26 Agreements were separate power sales made under section 5(b) of the Northwest Power Act and,

1 therefore, were not invalidated by the Court’s decisions in *PGE* and *Golden NW*. *Id.* at 42–45.
2 The IOUs also argue that the COUs’ rates were not adversely impacted by these sales because
3 BPA would have sold the power to other parties at the same rate regardless of the settlement.
4 *Id.* at 41, 44–45.

5
6 If the IOUs were to prevail on this argument, Staff assumes that BPA would have to remove the
7 value of the power sales from the Lookback calculation for Avista, PGE, and Idaho Power. This
8 adjustment would have the effect of reducing Avista’s, Idaho Power’s, and PGE’s FY 2002–
9 2006 Lookback Amounts by the value attributed to the power sales and used in the calculation of
10 these utilities’ Lookback Amounts, or approximately \$26.3 million, \$33.3 million, and
11 \$144.2 million, respectively, prior to bringing the Lookback Amounts to 2009 dollars. *See IOU*
12 *APAC Br.* at 40, 45.

14 **7.2.1.5 Combined Effect of IOU Positions**

15 The combined effect of the IOU and related party positions is to reduce the initial FY 2002–2006
16 Lookback Amounts established for each IOU to zero. To analyze the REP Settlement, in one
17 scenario Staff assumes that the \$237.6 million in Lookback Amount refunds that BPA has
18 already collected from the IOUs, and paid to the COUs, would have to be returned to the IOUs.
19 Staff also assumes that the remaining portions of the Lookback Amount would not be
20 recoverable. *See Section 10..4.1.*

22 **7.2.2 Large Lookback Proposition**

23 **7.2.2.1 Use WP-02 Determinations**

24 In *Golden NW*, the Court remanded BPA’s WP-02 power rates to BPA with instructions “to set
25 rates in accordance with this opinion.” Upon remand, BPA had to determine whether the
26 existing record was sufficient to reset rates. In order to correct overcharges to the COUs’ rates,

1 BPA determined to, in simple terms, compare the benefits the IOUs received under the 2000
2 REP Settlement Agreements with the REP benefits the IOUs would have received in the absence
3 of the settlement and under the traditional implementation of the REP, referred to as
4 reconstructed REP benefits. The difference would be recovered from the IOUs and refunded to
5 the injured COUs. REP benefits are determined by comparing an IOU's ASC with BPA's PFX
6 rate, and then multiplying the difference by the utility's exchange load. The WP-02 record,
7 however, included IOUs' ASCs and exchange loads that were not reviewed for accuracy and
8 appropriateness, and included a PFX rate that relied on faulty market price and load data.
9 Consequently, BPA reopened the WP-02 record to correct known errors and supply adequate
10 ASC and exchange load information.

11
12 APAC argues that, in reopening the WP-02 record, BPA violated the rule against retroactive
13 ratemaking, violated the rule prohibiting retroactive rulemaking, and exceeded the scope of the
14 Court's mandate. APAC claims that BPA should have simply relied on the existing WP-02
15 record to determine the reconstructed REP benefits due the IOUs in the absence of the 2000 REP
16 Settlements. APAC claims that BPA exceeded the scope of the Court's mandate and violated the
17 rules prohibiting retroactive ratemaking and rulemaking when BPA reopened the final rate
18 determinations made in the WP-02 ROD, updated the rates with different load and market price
19 assumptions, and revised the Section 7(b)(2) Implementation Methodology and Legal
20 Interpretation retroactively. APAC APAC Br. at 56.

21
22 If APAC were to prevail on this argument, Staff assumes that BPA would have to determine the
23 IOUs' reconstructed REP benefits using the PFX rate developed in the original WP-02 rate
24 proceeding. Under this scenario, the IOUs' reconstructed REP benefits for FY 2002–2006
25 would average \$47 million per year, an \$87 million reduction from the reconstructed average of
26 \$134 million. The IOUs' Lookback Amounts would then be \$929.3 million, if calculated the

1 same way as in the WP-07 Supplemental proceeding -- an increase of \$183.1 million. See Table
2 7.2.

3
4 Similarly, the total Lookback Amount would be \$1,941 million under the WP-02 determinations
5 of REP benefits when combined with the assumption of void LRAs, and \$772 million if the
6 WP-02 determinations are combined with the assumption that the LRAs are valid and separate.
7 All of these amounts are larger than the original Lookback Amount of \$746 million.

8 9 **7.2.2.2 LRAs Voided**

10 This issue is related to the issue discussed in section 7.2.1.3. In the WP-07 Supplemental
11 proceeding, BPA treated the LRAs as valid and binding contracts. As a result, BPA concluded
12 that the LRA payments to PacifiCorp and Puget would be “protected” payments that were not
13 subject to recovery as part of their Lookback Amounts. BPA explained that the LRAs were
14 contracts with PacifiCorp and Puget where BPA purchased power back from these utilities to
15 limit BPA’s exposure to volatile energy prices during the West Coast energy crisis of 2001.
16 BPA further explained that petitions to review the LRAs, which only challenged the reduction of
17 risk provision of the LRAs, were dismissed as moot.

18
19 APAC and Tillamook argue that the LRAs simply amended the 2000 REP Settlement
20 Agreements to monetize as cash payments certain physical power deliveries required only by the
21 REP Settlement Agreements. They state that despite the fact that the physical power deliveries
22 required under the 2000 REP Settlement Agreements were later found by the Court to be
23 unlawful, BPA elected to treat the cash payments required by the LRAs as binding obligations in
24 the WP-07 Supplemental proceeding. They note that BPA further determined that the LRA
25 payments would be “protected” against the section 7(b)(2) rate test and, ultimately, exempted
26 from repayment to preference customers. APAC and Tillamook assert that BPA’s refusal to

1 include the LRA payments in the amount to be refunded to its preference customers is unlawful
2 both because the LRAs were part and parcel of the REP Settlement Agreements held to be illegal
3 and void, and because the LRA payments were charged to the preference customers in violation
4 of the section 7(b)(2) rate test. APAC APAC Br. at 25, 28; APAC APAC Reply Br. at 28;
5 Tillamook APAC Br. at 28; Tillamook APAC Reply Br. at 10.

6
7 If APAC and Tillamook were to prevail on this argument, Staff assumes that BPA would have to
8 include the value of the LRAs in the Lookback Amount calculation. As a result of this
9 adjustment, PacifiCorp's Lookback Amount would increase from \$203.5 million to
10 \$660.3 million and Puget's Lookback Amount would increase from \$262.2 million to
11 \$562.6 million. See Table 7.3.

12 13 **7.2.2.3 Certainty of Repayment of Lookback**

14 Under the Lookback Approach, BPA determined that the COUs had been overcharged
15 approximately \$1.002 billion in rates, subsequently revised to \$985.2 million due to the Avista
16 deemer settlement, as a result of the 2000 REP Settlement Agreements. To refund this amount to
17 the injured COUs, BPA developed a comprehensive Lookback Recovery and Return Proposal
18 (Lookback Recovery Proposal) in the WP-07 Supplemental rate proceeding. Under the
19 Lookback Recovery Proposal, BPA provided COUs an initial cash payment of approximately
20 \$256 million, which refunded all overcharges to COUs in the PF-07 rates charged in FY 2007–
21 2008. It was further decided that the remaining \$767 million in outstanding refunds, referred to
22 as the Lookback Amount, would be recovered from the IOUs through reductions in prospective
23 IOU REP benefits, which would in turn be provided to the COUs as credits on their power bills.
24 A goal was established to recover the overpayments from the IOUs and return all overcharges to
25 the COUs within seven years (by FY 2015). Interest is paid on the outstanding Lookback
26 Amount balances.

1
2 BPA's Lookback recovery method is not a rigid formula. Instead, in each rate proceeding BPA
3 balances the interests of the COUs, which are entitled to refunds, with the interests of the
4 residential and small-farm consumers of the IOUs, who are the beneficiaries of the REP.
5 Whether and to what extent refunds are provided in a given rate period are determined by the
6 Administrator based on the facts in the given case. For FY 2009, the Administrator decided to
7 withhold from the IOUs sufficient REP benefits to meet the seven-year goal, provided that no
8 IOU received less than 50 percent of the utility's lawfully due REP benefits. For FY 2010–2011,
9 the Administrator determined that sufficient progress had been made in returning the Lookback
10 Amounts and that it would be reasonable to retain the 50 percent threshold for the WP-10 rate
11 period.
12

13 APAC and Tillamook argue that BPA acted unlawfully in the WP-07 Supplemental rate
14 proceeding by adopting a repayment scheme that defers repayment of the Lookback Amounts to
15 the COUs far into the future in order to allow BPA to maintain substantial and additional REP
16 payments to the IOUs. They claim BPA has failed to respond to this Court's order in *Golden*
17 *NW*, and to fulfill its statutory duties to recoup and repay monies unlawfully paid to the IOUs
18 and illegally charged preference customers. Specifically, Tillamook and APAC argue that
19 BPA's establishment of a seven-year goal for repayment and recoupment of costs from the
20 IOUs' prospective REP benefits does not provide sufficient certainty of repayment; that one IOU
21 may not participate in the REP and thus would not have REP benefits to offset for its share of the
22 Lookback Amount; that BPA's approach does not guarantee that the customers who paid the
23 illegal rates will receive refunds; and that higher interest should be applied to the Lookback
24 Amounts. APAC APAC Br. at 32; APAC APAC Reply Br. at 22; Tillamook APAC Br. at 46.
25

26 If APAC and were to prevail on this argument, Staff assumes that BPA would have to accelerate
27 the recovery and return of the Lookback Amounts to the affected COUs. The effect of this

outcome on future REP benefits depends on the remaining level of Lookback Amount and the projected amount of future REP benefits.

7.2.2.4 Combined Effect of COU Positions

The combined effect of the COU and related party positions is to increase the combined Lookback Amounts established for each IOU to \$1,941 million. *See* Table 7.2. To analyze the Settlement, Staff produced analyses using two different assumptions on how quickly the Lookback Amounts would be recovered from the IOUs. One analysis assumes BPA continues the 50 percent rule established in the WP-07 Supplemental ROD that limits the Lookback Amount recovered in any year to no more than 50 percent of the REP benefits for that year. The second analysis assumes that the Lookback Amounts would be recovered from the IOUs, and paid to the COUs, as much as necessary to effect repayment of the IOUs' outstanding Lookback Amount balances by the end of FY 2015, or as soon thereafter as possible. The 50 percent rule is removed and REP benefits are allowed to fall to zero if necessary to accomplish repayment to COUs. *See* Section 10.4.3.

7.3 7(b)(2) Issues

7.3.1 Treatment of Conservation

7.3.1.1 General Requirements Same in Both Cases

In the WP-07 Supplemental proceeding, BPA described its treatment of conservation in the 7(b)(2) rate test. BPA initially included all of its conservation costs in the Program Case revenue requirement. BPA's acquired conservation reduces preference customers' requirements. Next, BPA excluded all conservation costs from the Program Case because section 7(b)(2) prescribes the Program Case as "exclusive of amounts charged such customers under subsection (g) for the costs of conservation ...". 16 U.S.C. § 839e(b)(2). There is no similar requirement to remove such costs from the 7(b)(2) Case. In the 7(b)(2) Case, "[t]he initial loads that will be used in the

1 7(b)(2) case will be the same as those used in the program case, except they will not include
2 estimates of programmatic conservation savings.” 1984 Section 7(b)(2) Implementation
3 Methodology, Section V.1. Because conservation resources are included in the resource stack
4 used to serve remaining loads if needed, these resources could not have already reduced loads in
5 the 7(b)(2) Case. To remove the effects of conservation from the 7(b)(2) Case, the 7(b)(2)
6 Customer loads were increased by an amount of load equal to the conservation savings BPA
7 assumed in the Program Case. This adjustment ensured that conservation resources were given
8 their full and intended effect when selected from the resource stack under section 7(b)(2)(D)(i).
9
10 Cowlitz and APAC argue that increasing preference customers’ general requirements by BPA’s
11 estimate of conservation savings conflicts with the Northwest Power Act because it is contrary to
12 the definition of “general requirements” in the Act. Cowlitz APAC Br. at 32–46; APAC APAC
13 Br. at 52–54. They state that the definition, in section 7(b)(4), specifically defines the term
14 “general requirements” as preference customers’ “electric power purchased from [BPA] under
15 § 5(b), exclusive of any new large single load.” They argue that power *not purchased* because of
16 conservation is *not* “power purchased.” Cowlitz and APAC note that section 3(9) of the Act
17 defines “electric power” as “electric peaking capacity, electric energy, or both.” They argue that
18 BPA’s approach is inconsistent with the definition of “general requirements” in BPA’s Legal
19 Interpretation. They claim that Congress addressed the one and only change BPA should make
20 to “general requirements” between the Program Case and 7(b)(2) Case, and the only permissible
21 difference is set forth in the first assumption, which requires BPA to add to the general
22 requirements only DSI loads. In summary, Cowlitz and APAC argue that had Congress wanted
23 load-changing assumptions in the 7(b)(2) Case other than the required addition of certain DSI
24 loads, it would have specified them. They argue that Congress did not, and BPA had no
25 authority to modify the section 7(b)(2) assumptions adopted by Congress so as to increase
26 preference customers’ “general requirements.”
27

1 The IOUs argue that BPA must not increase the combined general requirements of PF Preference
2 rate customers in the 7(b)(2) Case by an amount equal to conservation load reduction, but rather
3 must include all conservation costs in the section 7(b)(2) Case. IOU Br., WP-07-B-JP6-01,
4 at 27. The IOUs argue that BPA's proposed 7(b)(2) Legal Interpretation must be revised to
5 exclude conservation as an available resource in the 7(b)(2)(D) resource stack. *Id.* at 97. The
6 IOUs argue that BPA's proposed treatment of conservation is contrary to five provisions of the
7 Northwest Power Act. *Id.* at 51. The IOUs contend that BPA must adopt an interpretation that
8 comports with the five statutory provisions they describe. *Id.*

9
10
11 If APAC and the PPC were to prevail on this argument, Staff assumes that the conservation
12 adjustment to 7(b)(2) Customers' loads in the 7(b)(2) Case would be removed and loads would
13 be consistent with Program Case preference customer plus DSI loads. *See* Section 10.4.5. If the
14 IOUs were to prevail on this argument, Staff assumes that the conservation adjustment to 7(b)(2)
15 Customers' loads in the 7(b)(2) Case would be removed and loads would be consistent with
16 Program Case preference customer plus DSI loads, plus the Program Case conservation costs
17 would be included in the 7(b)(2) Case revenue requirement. *See* Section 10.4.6.

18 19 **7.3.2 7(b)(2) Repayment Study**

20 BPA develops different revenue requirements, based on different repayment studies, for the
21 Program Case and the 7(b)(2) Case. One is incorporated into the total Program Case revenue
22 requirement, and the other is incorporated into the total revenue requirement developed
23 specifically for the 7(b)(2) Case, based on the relevant assumptions that guide the two respective
24 Cases. In each Case, BPA's outstanding debt and appropriation repayment obligations are
25 considered; however, for the 7(b)(2) Case repayment study, conservation repayment obligations
26 are removed because the resources are considered to not have been acquired. Instead, the

conservation is included in the resource stack and the cost of the repayment obligation is included in the cost of the resource specified in the stack.

BPA's preference customers argue an alternative repayment study is contrary to the 1984 Legal Interpretation and the 1984 Implementation Methodology, which provide that only changes required by the five 7(b)(2) assumptions may be reflected in the 7(b)(2) Case. Cowlitz APAC Br. at 47–49. Assuming that BPA might lawfully create an alternative 7(b)(2) repayment study, Cowlitz states BPA cannot as a matter of law base that study on an arbitrarily truncated set of revenue requirements. Cowlitz argues BPA must base any alternative repayment study on the full revenue requirements of the 7(b)(2) Case, including the revenue requirements of all resources necessary to meet the general requirements of preference customers.

If Cowlitz were to prevail on this argument, BPA Staff assumes that BPA would have to remove the effects of the separate repayment study from the 7(b)(2) Case COSA and replace those costs with the equivalent costs from the Program Case COSA. *See* Section 10.4.7.

7.3.3 Treatment of Mid-Columbia Resources

Section 7(b)(2)(D) of the Act requires BPA to assume that Federal base system ("FBS") resources are used first to meet the COUs' requirements loads in the 7(b)(2) Case. If there are "remaining" COU requirements loads, BPA must assume that all resources that would have been required to meet these loads were (i) purchased from such COU customers by the Administrator under NWPA section 6, or (ii) not committed to load under NWPA section 5(b). In addition, these must be the least expensive resources owned or purchased by COUs. Therefore, these two types of resources are stacked in order of cost, and the least expensive resources are acquired from the resource stack to meet COU loads in the 7(b)(2) Case as needed. If the resource stack is

1 insufficient to meet COU loads, any additional needed resources are obtained at the average cost
2 of all other new resources acquired by the Administrator.

3
4 Section 7(b)(2)(D)(ii) of the Act provides that resources owned or purchased by COUs but “not
5 committed to load pursuant to section 839c(b) [NWPAA section 5(b)]” can be used to meet
6 remaining COU requirements in the 7(b)(2) Case. 16 U.S.C. § 839e(b)(2)(D)(ii). Non-
7 committed resources are eligible to meet COU loads in the 7(b)(2) Case; committed resources
8 are not eligible to meet COU loads in the 7(b)(2) Case. Thus, first, only resources “not
9 committed to load pursuant to [NWPAA section 5(b)]” can be used to meet remaining COU
10 requirements in the 7(b)(2) Case. Second, resources can be committed to load pursuant to
11 section 5(b) only by COUs or IOUs. Therefore, only resources not committed to load by COUs
12 and IOUs pursuant to section 5(b) can be used to meet COU requirements in the 7(b)(2) Case.

13
14 BPA’s preference customers note that under section 7(b)(2)(D), “resources owned or purchased
15 by public bodies or cooperatives” are available in the 7(b)(2) Case if they are “not committed to
16 load pursuant to section 5(b).” 16 U.S.C. § 839e(b)(2)(D). Cowlitz APAC Br. at 49–58.

17 Cowlitz notes that the Act defines “resources” as “electric power, including the actual or planned
18 electric power *capability* of generating facilities.” 16 U.S.C. § 839e(b)(2)(D) (emphasis added).

19 Cowlitz states that therefore a generator’s capability is a “resource” for purposes of
20 section 7(b)(2)(D). Cowlitz then argues that under section 5(b)(1)(A), a generator’s *capability*
21 can only be committed to serve the load of the generator’s owner (*i.e.*, “the capability of such
22 entity’s firm ... resources used ... to serve its firm load in the region.”). 16 U.S.C.

23 § 839c(b)(1)(A). Cowlitz concludes that under these statutory provisions, the capability of non-
24 Federal resources, including the capability of the Mid-Columbia resources, cannot be
25 “committed to load pursuant to section 5(b)” unless their capability is committed to the load of
26 the resource owner.

1 If the preference customers were to prevail on this argument, Staff assumes that BPA would have
2 to include Mid-Columbia resources in the resource stack to the extent that such resources are not
3 committed to serving COU loads. See Section 10.4.8.

4 5 **7.4 7(b)(3) Issues**

6 Section 7(b)(2) of the Northwest Power Act directs BPA to conduct, after July 1, 1985, a
7 comparison of the projected amounts to be charged its preference and Federal agency customers
8 for their general requirements with the costs of power for the general requirements of those
9 customers if certain assumptions are made. 16 U.S.C. § 839e(b)(2). The effect of this
10 comparison is to protect BPA's preference and Federal agency customers' wholesale firm power
11 rates from certain costs resulting from the provisions of the Northwest Power Act. The rate test
12 can result in a reallocation of costs from the general requirements loads of preference and
13 Federal agency customers to other BPA loads.

14
15 Section 7(b)(3) of the Northwest Power Act governs the reallocation of costs in the event the
16 section 7(b)(2) rate test triggers. Section 7(b)(3) provides that "[a]ny amounts not charged to
17 public body, cooperative, and Federal agency customers by reason of paragraph (2) of this
18 subsection shall be recovered through supplemental rate charges for all other power sold by the
19 Administrator to all customers." 16 U.S.C. § 839e(b)(3). In other words, if the rate test triggers,
20 the trigger amount must be allocated away from preference customers' power sales priced under
21 section 7(b) and reallocated to other power sales, including sales to utilities participating in the
22 REP. These costs increase the PFx rate, which is the rate at which BPA sells power to utilities
23 participating in the REP. When the PFx rate increases, the difference between that rate and the
24 utility's ASC rate decreases, resulting in a reduction of REP benefits paid to the utility.

7.4.1 Allocation of Rate Protection to Surplus Power Sales

In the section 7(b)(2) rate test, if the Program Case exceeds the 7(b)(2) Case in the 7(b)(2) rate test, the rate test is said to “trigger.” The difference between the two cases is called the “trigger amount” or “7(b)(3) allocation amount.” If there is a trigger amount, section 7(b)(3) of the Northwest Power Act prescribes the manner in which the trigger amount is allocated. Section 7(b)(3) provides, in pertinent part, that “[a]ny amounts not charged to public body, cooperative, and Federal agency customers by reason of paragraph 2 of this subsection shall be recovered *through supplemental rate charges for all other power sold by the Administrator to all customers.*” 16 U.S.C. § 839e(b)(3) (emphasis added). The trigger amount is to be recovered from “*all other power sold by the Administrator to all customers,*” *id.* (emphasis added), which includes secondary power sales at the FPS rate.

Section 7(b)(3) appears unambiguous to BPA. In its WP-07 ROD, BPA decided to recover part of the trigger amount from BPA’s forecast surplus power sales on a going-forward basis, beginning with rates being established for FY 2009. Such recovery is accomplished on a ratemaking basis through the incorporation of a 7(b)(3) Supplemental Rate Charge in the FPS rate schedule. BPA decided that no 7(b)(3) supplemental rate charge was necessary to accomplish such recovery from the surplus sales to Slice customers. The 7(b)(3) Supplemental Rate Charge is separately stated in the PF Exchange, IP, NR, and FPS rate schedules, but will not require a minimum price or charge for FPS transactions.

The preference customers argue that a 7(b)(3) allocation to surplus power sales would offset revenues that would have otherwise been credited to the wholesale power rates charged to BPA’s preference customers with a result, in economic terms, of placing back into preference customers’ wholesale power rates the costs that were supposedly removed by operation of section 7(b)(2). Cowlitz WP-07S Br. at 43–47. They state that section 7(b)(3) does not direct BPA to “allocate” the trigger amount to other power rates, but to “recover” the amounts from

1 “other” power sales. They criticize an “allocation,” wherein the rates would remain the same but
2 the allocation would only cause the surplus revenue credit to decrease or a surplus revenue
3 deficit to increase. They assert that allocating the trigger amount to the FPS rates, with the “net
4 effect” of shrinking the secondary revenues credit and raising the PFp rate, is contrary to the
5 section 7(b)(2) statutory guarantee.

6
7 If the preference customers were to prevail on this argument, Staff assumes that BPA would
8 remove the 7(b)(3) allocation to surplus sales in the ratesetting process. *See* Section 10.4.9.

9 10 **7.4.2 Treatment of Secondary Energy Credit**

11 BPA believes that all surplus sales should be reflected in the cost reallocations pursuant to
12 section 7(b)(3). There is no difference in the section 7(b)(3) reallocations regardless of whether
13 BPA assumes the sale of surplus power is to the market or to the Slice customers. BPA receives
14 the same amount of forecast revenue whether the surplus is sold in the market and credited to
15 rates or sold to the Slice customers at the Slice rate. BPA properly reflects sales of surplus
16 power associated with the Slice product in the section 7(b)(3) cost reallocations. BPA does not
17 add an explicit 7(b)(3) Supplemental Rate Charge on the Slice sale of surplus power because the
18 effect of the 7(b)(3) allocation to the sale is incorporated into the PFp rate paid by Slice
19 customers. In calculating the amount included in the PFp rate, BPA reduces the secondary
20 revenue credit in the Program Case for the 7(b)(3) allocation, but does not reduce the secondary
21 credit in the 7(b)(2) Case.

22
23 The IOUs state that BPA, in performing the section 7(b)(3) reallocations, does not assess a
24 7(b)(3) Supplemental Rate Charge on the surplus power associated with the Slice product sold to
25 Slice customers under the Slice rate and understates the 7(b)(3) allocation to the Slice surplus
26 power.

1
2 If the IOUs were to prevail on this argument, Staff assumes that BPA would have to adjust the
3 secondary revenue credit in the 7(b)(2) Case to use the same reduced secondary revenue credit as
4 used in the Program Case. See Section 10.4.10.
5

6 **7.5 Additional Issues Subject to Litigation**

7 **7.5.1 7(b)(2) Accounting and Financing Treatment of Conservation Costs**

8 In the WP-07 Supplemental ROD, historical and projected capitalized conservation costs were
9 amortized and financed over a 15-year period for the 7(b)(2) Case resource stack. The first-year
10 historically expensed costs were treated as deferred charges amortized and financed over a
11 one-year to useful-life period. In the WP-07 Supplemental ROD, the first-year expense cost was
12 deferred over seven years. This approach mitigated the first-year rate shock associated with the
13 large number of programmatic conservation resources being selected from the resource stack in
14 the first year of the five-year period. The financing parameters will be assessed in each BPA rate
15 case depending on the number of conservation resources drawn from the stack and the
16 then-current accounting practices for conservation costs. Conservation investments that have
17 been fully amortized (FY 1998 and prior years) are considered obsolete resources that are not
18 available to serve 7(b)(2) Customer loads in the 7(b)(2) Case.
19

20 PPC disagrees with BPA's treatment of financing conservation resources available to serve
21 preference customer load in the 7(b)(2) Case. PPC contends the manner in which conservation is
22 acquired in the 7(b)(2) Case is fundamentally different than the Program Case. PPC states that
23 BPA must determine how the Joint Operating Agency in the 7(b)(2) Case would finance a very
24 large resource brought on to meet load, and argues that standard industry practice for financing
25 such a resource is to capitalize all costs of such a resource and amortize those costs over the
26 useful life of the resource.

1
2 The OPUC argues that BPA's approach of deferring the historical expensed portions of BPA's
3 conservation programs and financing these costs over five years should be rejected. The OPUC
4 believes that proposals that avoid the front-loading of costs are contrary to current utility
5 practice.

6
7 The IOUs argue that BPA's financing and accounting treatment for conservation costs in the
8 7(b)(2) rate test is incorrect. The IOUs' primary argument is that BPA should not have increased
9 the 7(b)(2) Case loads for conservation savings that did not occur. However, if conservation
10 should be in the resource stack and there should be a load adjustment, the IOUs argue that
11 conservation costs should be expensed in the year the costs are incurred.

12
13 If the PPC were to prevail on this argument, Staff assumes that BPA would have to capitalize all
14 costs of the conservation resources included in the resource stack and recover the costs over the
15 useful life of the resources. If the OPUC were to prevail on this argument, and the IOUs were to
16 prevail on their alternative argument, Staff assumes that BPA would have to expense all costs of
17 the conservation resources in the resource stack and recover costs in the first year the resource is
18 selected from the stack.

19 20 **7.5.2 Discounting of the Stream of 7(b)(2) Rate Projections**

21 In the 1984 7(b)(2) Implementation Methodology, BPA decided that after calculating the stream
22 of annual rates in the Program and 7(b)(2) Cases, it would be appropriate to discount the rates to
23 the beginning of the rate test period before averaging the rate streams to perform the 7(b)(2) rate
24 test. The statutory directive to include four years beyond the rate period is to ensure that the rate
25 period 7(b)(2) rate test trigger in one rate case is similar to the rate test triggers in later rate cases,
26 all else being equal, by discounting rate period anomalies through the inclusion of more

1 normalized forecast years. This has the effect of reducing the weighting of an anomalous rate
2 period difference between the Program Case and the 7(b)(2) Case. BPA uses the forecast long-
3 term interest rate on Federal debt for this discounting. In establishing the discounting
4 methodology and use of the long-term interest rate, BPA stated “[i]t is logical to use BPA’s
5 borrowing rate, since BPA could theoretically borrow the money in the test year to reimburse the
6 7(b)(2) customers for the five-year section 7(b)(2) rate test differential. The value to BPA of
7 money over time is thus the economically correct value for the rate differential over time.”
8 Melton and Armstrong, b2-84-E-BPA-01, at 35-36. Also, smoothing the within-rate-case annual
9 data is not necessarily a meaningful criterion; nor is minimizing the differences between the rate
10 test period average difference and the annual differences between the Program Case and 7(b)(2)
11 Case rates.

12
13 APAC argues the methodology BPA uses to perform the present value calculation and the
14 averaging in the 7(b)(2) rate test distorts the rate test results in future years. APAC WP-10 Br.
15 at 13. APAC further argues that the trigger calculation should be based on an inflation
16 adjustment internal to the data for BPA costs and ASC levels. APAC claims this methodology
17 better smoothes the annual trigger data while minimizing the difference between the annual
18 values and the combined trigger.

19
20 The IOUs support BPA’s position, but offer an alternative if a change in discount rates is
21 warranted. The IOUs argue that if any change is to be made from using the long-term interest
22 rates, it should be to use BPA’s capital investment decision rate.

23
24 If APAC were to prevail on this argument, Staff assumes that BPA would use the current
25 inflation rate forecast as discount factors in the rate discounting. If the IOUs were to prevail on
26 this argument, Staff assumes that BPA would use its current investment decision rate forecast for
27 the rate discounting. See Sections 10.5.3 and 10.5.4.

7.5.3 Including All Acquired Conservation in the Resource Stack

Section 7(b)(2)(D) of the Northwest Power Act directs that any additional resources necessary to serve 7(b)(2) Customer load after FBS resources have been completely used should be the least expensive resources owned or purchased by public bodies or cooperatives if such resources (i) have been acquired by BPA pursuant to section 6 of the Act, or (ii) not committed to load pursuant to section 5(b) of the Act. To model this provision, a resource stack is established for the 7(b)(2) Case that contains resources meeting the requirements of section 7(b)(2)(D). In BPA's construction of this resource stack, certain conservation acquisitions are excluded because some acquisitions of conservation have not already reduced customers' general requirements in the Program Case and therefore should not adjust customers' general requirements in the 7(b)(2) Case. See Section 7.3.1.1 for additional discussion on the interaction between conservation and general requirements.

The IOUs argue that the exclusion of the conservation acquisitions from the resource stack is inappropriate. Notwithstanding their primary argument regarding the treatment of conservation in the 7(b)(2) Case, they argue that if conservation is included in the resource stack, all of the conservation acquisitions should be included because all of the conservation resources meet the 7(b)(2)(D) definition.

If the IOUs were to prevail on this argument, Staff assumes that all of the conservation acquisitions, including the amount currently excluded, would be included in the 7(b)(2) Case resource stack and 7(b)(2) Customer loads would be adjusted for the full amount of the acquisitions.

7.6 RPSA Issues

7.6.1 Deemer Treatment

Section 5(c) of the Northwest Power Act established the REP as a “purchase and exchange sale” by and between BPA and an exchanging utility. See 16 U.S.C. §§ 839c(c)(1) and (2). Although the language and structure of section 5(c) is couched in terms of an actual power exchange (with BPA selling power to the exchanging utility at the PFx rate and purchasing an equivalent amount of power from the exchanging utility at the utility’s ASC), BPA has implemented the REP as a monetary transaction since its inception in 1981. In this monetary transaction, BPA pays the exchanging utility based on the difference between the PFx rate and the utility’s ASC.

Nevertheless, because REP benefits are derived by comparing the rate levels charged by each party for its hypothetical sale of power to the other, the benefits (or economic value of the exchange) could flow from an exchanging utility to BPA in the event the utility’s ASC (the rate “paid” by BPA) is lower than BPA’s PFx rate. However, Congress appears to have contemplated such a circumstance and provided exchanging utilities with a limited statutory right to terminate their RPSAs in the event a utility’s ASC falls below the PFx rate due to application of section 7(b)(3) of the Act. 16 U.S.C. §§ 839c(c)(4), 839e(b)(3).

7.6.1.1 Past Deemer Treatment

The 1981 RPSAs, in addition to providing for termination or suspension of the Agreement consistent with the above-referenced statutory right, included a provision that gave an exchanging utility the option, in lieu of invoking its termination or suspension right, to have its ASC “deemed equal” to the PFx rate. This allowed the exchanging utility to avoid paying money to BPA. Notwithstanding this deemed equalization of the two rates, the provision also provided that during the period any such election was in effect, BPA would “debit to a separate account the net exchange payment to Bonneville, if any, that would have been required of the Utility if the Utility had not made such election and shall credit to that account any exchange

1 payments that would have been made.” The debit calculated by this provision of the 1981
2 RPSA accumulated whenever the utility’s ASC was less than BPA’s PF Exchange rate. These
3 debits would accrue in a “deemer account” maintained by BPA. Under the terms of the 1981
4 RPSA, the utility was required to extinguish its deemer account balance before it could receive
5 any REP payments from BPA. A utility could pay off its deemer balance either by making cash
6 payments to BPA or by allowing BPA to reduce the utility’s REP benefit payments when its
7 ASC rose above the PFx rate.

8
9 Between 1984 and 1993, Idaho Power accrued a deemer balance of approximately \$91 million.
10 Idaho Power subsequently terminated its participation in the REP. Upon termination, Idaho
11 Power agreed that its outstanding deemer balance would accrue interest. Between 1993 and
12 October 2000, Idaho Power’s deemer balance grew to approximately \$158 million. Idaho Power
13 and BPA then entered the 2000 REP Settlement Agreement, wherein BPA and Idaho Power
14 agreed to hold the deemer balance “in abeyance” during the term of that agreement.

15
16 Idaho Power and the Idaho Public Utilities Commission (IPUC) vigorously oppose BPA’s
17 decision to recover the outstanding deemer balances accrued under the 1981 RPSA. Idaho
18 Power and the IPUC argue that BPA has not articulated a “cost or power planning purpose” for
19 recovering the outstanding deemer against future ratepayers of Idaho Power. IPUC *IPUC Br.*
20 at 43.

21
22 If Idaho Power and the IPUC were to prevail on this argument, Staff assumes that BPA would
23 have to cease collecting deemer balances from Idaho Power. Because Idaho Power was not
24 eligible to receive REP benefits in the Lookback period (FY 2002–2006), the WP-07 rate period
25 (FY 2007–2009), or the WP-10 rate period (FY 2010–2011), no retroactive adjustments to Idaho
26 Power’s REP benefits would be necessary if Idaho Power were to succeed in its challenge.
27 Prospectively, however, BPA expects Idaho Power to become eligible to receive REP benefits

beginning in FY 2012. If Idaho Power's historic deemer balance is extinguished or otherwise unrecoverable, Staff assumes that Idaho Power would receive its full allocation REP benefits beginning in FY 2012, subject to setoffs to recover Idaho Power's Lookback Amount, and continuing through the end of the evaluation period (*i.e.*, FY 2028).

7.6.1.2 Existing Provision

The "deemer" account concept was carried forward by BPA in the 2008 and subsequent RPSAs in the form of a Payment Balancing Account. Whenever a utility's ASC is less than BPA's then-current PFx rate during the term of the 2008 and subsequent RPSA, the payment that would otherwise be owed BPA is tracked by BPA and added to the balancing account. If there is a balance in the balancing account and the ASC is greater than the applicable PFx rate, BPA makes no cash payments but applies the amount that would have been paid in order to reduce the account balance. The utility resumes the receipt of exchange payments from BPA when there is no longer an amount in the balancing account, or the utility makes payments to BPA to bring the balance in the balancing account to zero.

The IPUC and Idaho Power argue that Congress enacted the REP for the purpose of providing rate relief to residential and small-farm consumers of the IOUs by providing IOUs access to lower-cost Federal power, thereby promoting wholesale rate parity between BPA's preference customers and eligible IOU customers. IPUC *IPUC Br.* at 21–28. The IPUC and Idaho Power argue that the REP should be implemented in a manner that allows benefits to be provided only to utilities' residential consumers, not through a deemer mechanism that effectively allows payments to be made to BPA. *Id.* at 31. The IPUC and Idaho Power propose that the deemer provision should be stricken in its entirety, and replaced with provisions that permit an exchanging utility to suspend participation in the REP when the utility's ASC is lower than the PFx rate, and to resume participation when the circumstances reverse. *Id.*

1
2 If the IPUC and Idaho Power were to prevail on this argument, Staff assumes that BPA would
3 remove the Payment Balancing Account provision from the 2008 and subsequent RPSAs. Under
4 this scenario, an exchanging utility would have no risk of losing future REP benefits if its ASC
5 fell below BPA's PFX rate.
6

7 **7.6.2 Exit/Reentry of REP Participants**

8 Section 5(c)(1) of the Northwest Power Act provides that BPA shall enter into an exchange
9 transaction whenever an exchanging utility offers to sell power to BPA at the utility's average
10 system cost. 16 U.S.C. § 839c(c)(1). The Act further provides that an exchanging utility may
11 terminate an exchange transaction "upon reasonable terms and conditions agreed to by the
12 Administrator and such utility prior to such termination" in the event that the 7(b)(2) rate test
13 triggers and additional costs are allocated to the PFX rate, causing that rate to exceed the average
14 system cost of power sold by an exchanging utility to BPA. 16 U.S.C. § 839c(c)(4). The effect
15 of this termination provision is to relieve the exchanging utility from buying higher-priced BPA
16 power and selling to BPA its own lower-cost power, but only in the case where the 7(b)(2) rate
17 test trigger is the cause of PFX rate exceeding the utility's ASC. The statute does not expressly
18 provide for termination of an exchange transaction in the event the PFX rate exceeds a utility's
19 ASC due to an increase in the PFX rate caused by something other than the 7(b)(2) rate test
20 triggering.
21

22 The IPUC and OPUC allege that sections 1 and 11 of the 2008 RPSAs are unlawful in requiring
23 utilities to agree to a single long-term contract as a condition for participating in the REP, which
24 impermissibly and unreasonably restricts utilities' rights to enter and exit residential exchange
25 transactions and make new offers for new residential exchange transactions. IPUC *IPUC Br.*
26 *at 34–37*; OPUC *IPUC Br. at 10–16*. The IPUC and OPUC argue that because the Northwest

1 Power Act allows utilities to offer to sell power to BPA to begin the exchange, utilities should be
2 able to determine the period of time the exchange will exist. IPUC *IPUC* Br. at 34; OPUC *IPUC*
3 Br. at 7.
4

5 If the IPUC and OPUC were to prevail on this argument, Staff assumes that BPA would revise
6 the terms of the 2008 RPSA to permit exchanging utilities to exit and enter the exchange. If the
7 provision restricting exiting and reentry into the REP is removed, an exchanging utility would
8 have the ability to exit the exchange whenever its ASC fell below BPA's PFx rate, thereby
9 avoiding an assessment of a Payment Balance Account obligation (*i.e.*, deemer balance). The
10 impact on REP benefits of this outcome is similar to the result discussed above in section 7.6.1.
11
12

8. AVERAGE SYSTEM COST FORECASTS

8.1 Introduction

This section of the Study presents BPA Staff's FY 2012–2032 forecasts of average system costs (ASCs) and residential and small-farm (REP) Exchange Loads for the six investor-owned utilities (IOUs) and three consumer-owned utilities (COUs) currently participating in the REP. The ASCs discussed in this section were determined pursuant to BPA's 2008 Average System Cost Methodology (2008 ASCM), as approved by FERC in September of 2009. This portion of the Study is comprised of the following sections:

- Section 8.2 provides an overview of the ASC determination process under the 2008 ASCM.
- Section 8.3 describes the initial calculations BPA Staff performs to determine a utility's Base Period ASC and Exchange Load. In this case, the Base Period is CY 2009.
- Section 8.4 describes the process and assumptions BPA Staff uses to escalate the Base Period ASCs to and through the Exchange Period (FY 2012–2013). The Exchange Period ASCs are determined in the ASC Review Process and are reported for each utility in the 2012–2013 ASC Draft Reports, as published on November 19, 2010.
- Section 8.5 describes the processes and assumptions BPA Staff uses to escalate the Base Period ASCs to and through the Long-Term Period (FY 2014–2032). Included in this section is a discussion of the Long-Term ASC Forecast Model (LTAFM) BPA Staff developed to forecast ASCs for the Long-Term Period. In the LTAFM, new resource additions to meet future load growth for all forecast years following the Exchange Period are met with individual utilities' resource forecasts as published in each utility's most recent Integrated Resource Program (IRP) report. The IRP new resource additions are incorporated into the LTAFM.

- Section 8.6 describes the process for inputting ASCs into the Long-Term Rate Model (LTRM).
- Section 8.7 describes the assumptions and analysis used to develop the online data, cost, and operating characteristics for “generic” new resources that could be used in the LTAFM.
- Section 8.8 discusses the Renewable Portfolio Standards and effect on the LTAFM.
- Section 8.9 discusses the Load Forecast for each utility.
- Section 8.10 discusses the New Resource additions for each utility.

8.2 Overview of Average System Cost Determination Process

In its simplest form, ASC is calculated by dividing a utility’s allowable resource costs and credits (referred to as Contract System Cost) by the utility’s allowable system load (referred to as Contract System Load). The resulting quotient is the utility’s ASC. Whether a cost or credit may be included in Contract System Cost, or a load in Contract System Load, is determined pursuant to the rules in the 2008 ASCM.

Under the 2008 ASCM, ASCs are developed in a two-step process. First, a “Base Period” ASC is calculated for each utility. In this case, the Base Period is CY 2009. For all utilities, the Base Period ASC is calculated by populating BPA’s 2008 ASC Appendix 1 template, an Excel-based computer model, with financial, load, and resource cost data. For the IOUs, this data is drawn largely from the IOUs’ 2009 FERC Form 1 filings. For the COUs, the data is based on each individual utility’s 2009 annual financial report. At the end of this first step, all of the utility’s costs are functionalized between Production, Transmission, and Distribution/Other to determine the exchangeable Production and Transmission costs. Once the exchangeable costs and loads are determined, a 2009 Base Period ASC (\$/MWh) for each utility is established.

1 In step two, the Base Period ASC is escalated for each utility to the midpoint of the applicable
2 exchange period. In this case, the applicable exchange period is FY 2012–2013. This escalation
3 is accomplished by inputting the utility’s Base Period ASC data into the ASC Forecast Model.
4 The ASC Forecast Model is an Excel-based model that escalates certain categories of costs and
5 credits in the utility’s Appendix 1 by a set of escalators defined in the 2008 ASCM. The ASC
6 that is produced following application of the ASC Forecast Model is referred to as the Exchange
7 Period ASC. The Exchange Period ASC is compared to BPA’s PF Exchange rate to determine
8 the utility’s REP benefits.

9
10 The first two steps described above generate forecast ASCs for exchanging utilities up to and
11 through the Exchange Period (FY 2012–2013). In this Study, however, BPA needs to forecast
12 ASCs for all utilities for the Long-Term Period (FY 2014–2032). In order to forecast ASCs for
13 this period, a third step is added to the forecasting of ASCs. In this third step, BPA Staff uses the
14 ASC Forecast Model described above and makes certain adjustments to the model to project the
15 utility’s ASC out to FY 2032. The revised ASC Forecast Model is referred to as the Long-Term
16 ASC Forecast Model or LTAFM. The assumptions BPA Staff used to develop the LTAFM are
17 discussed in sections 8.5 through 8.9.

18 19 **8.3 Determination of the 2009 Base Period ASC**

20 The Base Period ASCs used in this Study were obtained directly from the Draft ASC Reports
21 BPA issued on November 19, 2010. Table 8.3.1 below shows the 2009 Base Period ASC for
22 each utility.

Table 8.3.1
2009 Base Period Average System Cost
(Dollars per megawatt hour)

Avista	56.04
Idaho Power	47.33
NorthWestern	58.31
PacifiCorp	58.70
Portland General	68.92
Puget Sound Energy	70.61
Clark	53.87
Franklin	35.67
Snohomish	47.99

*See FY 2012 REP Settlement Documentation, REP-12-E-BPA-01A,
FY 2012–2013 Draft ASC Report for each of the exchanging utilities.*

The Appendix 1 workbook used to calculate the Base Year ASC consists of a series of seven Schedules and other supporting worksheets that present the data necessary to calculate a utility's ASC. The Schedules and supporting worksheets are as follows:

1. Schedule 1 – Plant Investment/Rate Base
2. Schedule 1A – Cash Working Capital Calculation
3. Schedule 2 – Capital Structure and Rate of Return
4. Schedule 3 – Expenses
5. Schedule 3A – Taxes
6. Schedule 3B – Other Included Items
7. Schedule 4 – Average System Cost
8. Purchased Power and Sales for Resale
9. Load Forecast
10. Distribution Loss Calculation
11. Distribution of Salaries and Wages
12. Labor Ratios

13. New Resources – Individual and Grouped

14. Materiality – Individual and Grouped

15. New Large Single Loads

16. Tiered Rates Above Rate Period High Water Mark (RHWM) ASC Calculation

(for COUs only)

8.3.1 Schedule 1 – Plant Investment/Rate Base

Schedule 1 of the Appendix 1 establishes the utility's rate base. The rate base computation begins with a determination of the gross electric plant-in-service for intangible, general, production, transmission, and distribution plant.

For exchanging IOUs that provide electric and natural gas services, only the portion of common plant allocated to electric service is included. For COUs that provide electric, water, and fiber-optic or other such services, financial statements are reviewed to ensure that only plant and expenses related to electric service is included. These values (and all subsequent values) are entered into the Appendix 1 as line items based on the FERC Uniform System of Accounts. Because most financial systems used by COUs have the FERC account structure built in, the COUs can also prepare plant and expense reports based on the FERC Uniform System of Accounts. Each line item (generally Account or groups of Accounts) is functionalized to Production, Transmission, and/or Distribution/Other in accordance with the 2008 ASCM. See 18 C.F.R. Pt. 301, Tbl. 1.

The net electric plant-in-service is determined next by subtracting the functionalized depreciation and amortization reserves from gross plant-in-service.

1 Total Rate Base is determined by incorporating the following adjustments to Net Plant-in-
2 Service: Cash Working Capital (calculated in Schedule 1A), Utility Plant, Property and
3 Investments, Current and Accrued Assets, Deferred Debits, Current and Accrued Liabilities, and
4 Deferred Credits.

6 **8.3.2 Schedule 1A – Cash Working Capital**

7 Cash working capital is an estimate of investor-supplied cash used to finance operating costs
8 during the time lag before revenues are collected. This approach (cash) ignores the lag in
9 recovery of non-cash costs of service (depreciation), deferred taxes, and other items. The cash
10 working capital concept is widely used by state commissions and is the basic premise of the
11 FERC's proposed working capital formula. The purpose of working capital is to compensate a
12 utility for funds used in day-to-day operations.¹

13
14 Cash working capital is a ratemaking convention that is not included in the FERC Uniform
15 System of Accounts, but is a part of all electric utility rate filings as a component of rate base.
16 To determine the allowable amount of cash working capital in rate base for a utility, the 2008
17 ASCM allows one-eighth of the functionalized costs of total production expenses, transmission
18 expenses, and administrative and general expenses, less purchased power, fuel costs, and public
19 purpose charges into rate base. Cash working capital is not functionalized *per se*. Instead, the
20 cash working capital values shown on Schedule 1A are the functionalized value of each
21 component. *See* 18 C.F.R. § 301, End. f.

23 **8.3.3 Schedule 2 – Capital Structure and Rate of Return**

24 Schedule 2 calculates the utility's rate of return, which is applied to the rate base developed in
25 Schedule 1.

¹ James C. Bonbright *et al.*, *Principles of Public Utility Rates*, 244 (2d ed. 1988).

1
2 The 2008 ASCM requires IOUs to use the weighted cost of capital (WCC) from their most recent
3 state commission rate order. The return on equity (ROE) used in the WCC calculation is grossed
4 up for Federal income taxes at the marginal Federal income tax rate using the formula described
5 in Endnote b of the 2008 ASCM. *See* 18 C.F.R. § 301, End. b.

6
7 The 2008 ASCM requires COUs to use a rate of return equal to the COU's weighted cost of debt.
8 *Id.*

9 10 **8.3.4 Schedule 3 – Expenses**

11 This schedule represents operations and maintenance expenses for the production, transmission,
12 and distribution functions of the utility. Each line item on Schedule 3 is functionalized as
13 described in Table 1 of the 2008 ASCM. Also included in Schedule 3 are additional utility
14 expenses associated with customer accounts, sales, administrative and general expense,
15 conservation program expense, and depreciation and amortization. The sum of the items in
16 Schedule 3 is the Total Operating Expenses for the utility.

17 18 **8.3.5 Schedule 3A – Taxes**

19 This schedule presents the taxes paid by the utility during the Base Period. Federal and state
20 income taxes, franchise fees, regulatory fees, and city/county taxes are accounted for in this
21 schedule but are functionalized to Distribution/Other and therefore not included in ASC. Federal
22 and state employment taxes are functionalized by the Labor ratio, while property taxes are
23 functionalized by the PTDG ratio. *See* 18 C.F.R. Pt. 301, Tbl. 1. COUs are allowed to include
24 state taxes paid “in-lieu” of property taxes. Taxes and fees for each state listed are grouped
25 together and entered as “combined” line items for Appendix 1 purposes. *See* 18 C.F.R. § 301,
26 End. c.

Federal income taxes are included in ASC and are calculated, as applicable, in Schedule 2, *Capital Structure and Rate of Return*. See 18 C.F.R. § 301, End. b.

8.3.6 Schedule 3B – Other Included Items

This schedule includes revenues from the disposition of plant, sales for resale, and other revenues, including electric revenues and revenues from transmission of electricity for others (wheeling). The revenues in this schedule are deducted from the total costs of each utility in Schedule 4, Average System Cost.

8.3.7 Schedule 4 – Average System Cost (\$/MWh)

This schedule summarizes the cost information calculated in Schedules 2 through 3B: Capital Structure and Rate of Return, Expenses, Taxes, and Other Included Items. This schedule also identifies the Contract System Cost and Contract System Load, as defined below, and calculates the utility's Base Period ASC (\$/MWh).

8.3.8 Three-Year Purchased Power and Sales for Resale

This schedule presents the detailed values by FERC statistical classification code² of the utility's purchased power and sales for resale for the Base Period and two previous years. Purchased Power is an Account on Schedule 3, Expenses, and includes all power purchased by the utility. Sales for Resale is an Account on Schedule 3B, Other Included Items, and includes power sales to purchasers other than retail consumers. The purpose of this schedule is to calculate the percentage price spread between the utility's average cost of short-term purchased power and

² Please refer to the FERC Form 1, pages 310–311, for Sales for Resale, and pages 326–327, for Purchased Power, for identification of the classification codes.

1 sales for resale. *See* 18 C.F.R. § 301.4.(b) The price spread is used in the ASC Forecast Model,
2 which is discussed later in this document.

3 4 **8.3.9 Load Forecast**

5 Each utility is required to provide an eight-year forecast (FY 2010–2017) of its total retail load,
6 as measured at the meter, and its qualifying residential and small-farm retail load, as measured at
7 the retail meter. The total retail and residential and small-farm load forecasts are adjusted for
8 distribution losses and NLSLs when appropriate. The resulting load forecasts are the Contract
9 System Load forecast and Exchange Load forecast, respectively. This load forecast is also used
10 in the ASC Forecast Model.

11
12 For the COUs only, the Exchange Period forecast loads (FY 2012–2013) are the load forecasts as
13 determined by BPA under the Tiered Rate Methodology. The COUs provide the remaining six-
14 year forecasts of their total retail load, as measured at the meter, and their qualifying residential
15 and small-farm retail load, as measured at the retail meter.

16 17 **8.3.10 Distribution Loss Calculation**

18 Each utility is required to provide a current distribution loss study as described in Endnote e of
19 the 2008 ASCM. *See* 18 C.F.R. § 301, End. e. The total retail and residential and small-farm
20 load forecasts are adjusted for distribution losses (and NLSLs when appropriate).

21 22 **8.3.11 Distribution of Salaries and Wages**

23 This schedule presents the salary and wage information that is used to determine the Labor ratio,
24 shown on the Ratios schedule. The data is taken directly from Page 354 of the FERC Form 1,
25 which functionalizes utility total salary and wage costs into the components shown on the
26 schedule. It includes salaries and wages from relevant operations and maintenance of the electric

1 plant. For COUs, comparable information comes from the detailed salary and wage data of the
2 utility's financial system.

4 **8.3.12 Ratios**

5 This schedule develops the various ratios used to functionalize costs and revenues on other
6 Schedules of the Appendix 1 and ASC Forecast Model. Six ratios are calculated on this
7 schedule: labor, general plant (GP), production, transmission, distribution (PTD), production,
8 transmission, distribution and general plant (PTDG), transmission and distribution (TD), and
9 maintenance of general plant (GPM). Ratios determined in this schedule are used to allocate
10 costs on other schedules of the Appendix 1 and ASC Forecast Model. *See* 18 C.F.R. Pt. 301,
11 Tbl. 1

13 **8.3.13 Exchange Period Major Resource Additions – Individual and Grouped**

14 The 2008 ASCM allows a utility's ASC to adjust during the Exchange Period to reflect the
15 addition or loss of a major resource(s), subject to a materiality threshold of 2.5 percent. That is,
16 in order to be included in the calculation of the utility's Exchange Period ASC, the addition or
17 loss of a major resource must result in a 2.5 percent increase or decrease in the utility's Base
18 Period ASC. Major resources include production or generating resources, transmission lines,
19 long-term purchased power contracts, pollution controls and environmental compliance upgrades
20 related to generating resources, transmission resources or contracts, hydro relicensing costs and
21 fees, and plant rehabilitation investments. *See* 18 C.F.R. § 301.4(c)(3)(i)-(vii). These schedules
22 are used in the ASC Forecast Model.

24 Utilities are required to provide forecasts of major resource additions, retirements and sales,
25 along with the associated costs, with their ASC Filings. Utilities may include in their major
26 resource forecasts all resources that are planned to begin or cease commercial operation from the

end of the Base Period (December 31, 2009) to the end of the Exchange Period (September 30, 2013). *Id.*

8.3.14 Exchange Period Major Materiality – Individual and Grouped

These schedules determine the effects of major resource additions or reductions on a utility's Exchange Period ASC. For major resources that are expected to be on line, sold, or retired prior to the start of the Exchange Period, BPA projects the costs of the resource forward to the midpoint of the Exchange Period. For resources that are expected to be on line, sold, or retired during the Exchange Period, BPA calculates the cost as if the major resource change occurred at the midpoint of the Exchange Period.

Each resource meeting the minimum materiality threshold of 0.5 percent may be entered individually in the "New Resources-Individual" tab. Resources that do not meet the 2.5 percent materiality requirement independently may be grouped together with other resources within "New Resources – Grouped" to meet the 2.5 percent materiality requirement. The grouping and timing of materiality for new resource additions is discussed in section 8.4.2 of this document. These schedules are used in the ASC Forecast Model.

8.3.15 New Large Single Loads and Above-High Water Mark Load

This schedule calculates the cost of resources in an amount sufficient to serve any New Large Single Loads (NLSLs), which BPA must exclude from the utility's ASC pursuant to the Northwest Power Act, section 5(c)(7). An NLSL is any load associated with a new facility, an existing facility, or an expansion of an existing facility which was not contracted for or committed to (CF/CT) prior to September 1, 1979, and which will result in an increase in power requirements of ten average megawatts (aMW) or more in any consecutive 12-month period. 16 U.S.C. § 839a(13)(A)-(B). By law, BPA must exclude from a utility's ASC the load associated

1 with an NLSL and an amount of resource costs sufficient to serve such NLSL. *See* 16 U.S.C.
2 § 839c(c)(7)(A). To determine the amount of resource costs to exclude from a utility's ASC,
3 BPA follows the methodology described in Endnote d of the 2008 ASCM. *See* 18 C.F.R. § 301,
4 End. d.

5
6 The fully allocated cost of resources plus transmission in an amount sufficient to serve NLSLs
7 that is developed on this schedule is used in Schedule 4.

8 9 **8.3.16 Tiered Rates**

10 All exchanging COUs have the right to purchase power at BPA's Tier 1 rate by executing a
11 Contract High Water Mark (CHWM) contract with BPA. By signing a CHWM contract, COUs
12 agree to limit the resources they will exchange in the REP. Under the CHWM contract, the COU
13 agrees to not include in its ASC the cost of resources necessary to serve the COU's Above-Rate
14 Period High Water Mark (RHWM) load. The CHWM contracts require the cost of serving
15 Above-RHWM loads to be calculated using a methodology similar to Endnote d of the 2008
16 ASCM.

17
18 This schedule is used to determine the amount of Tier 1 load purchased from BPA and comes
19 from BPA's Power Rates and Implementation Group (PFR). For background information and
20 details, see Chapter 3 of the Power Rates Study, BP-12-E-BPA-01.

21 22 **8.3.17 Contract System Cost**

23 Contract System Cost is the utility's cost for production and transmission resources, including
24 power purchases and conservation measures. Contract System Cost is calculated by adding the
25 functionalized Production and Transmission costs less revenue credits. Contract System Cost
26 does not include the cost of resources in an amount sufficient to serve any NLSLs of the utility.

Contract System Cost is the numerator in the ASC calculation. Table 8.3.2 shows the 2009 Base Period Contract System Cost for each utility.

Table 8.3.2
2009 Base Year Contract System Cost
(Dollars)

Avista	525,768,148
Idaho Power	661,614,029
Northwestern	354,465,565
PacifiCorp	1,239,331,429
Portland General	1,220,326,129
Puget Sound Energy	1,622,598,719
Clark	254,099,355
Franklin	36,915,438
Snohomish	341,468,092

See FY 2012 REP Settlement Documentation, REP-12-E-BPA-01A,
FY 2012–2013 Draft ASC Report for each of the exchanging utilities.

8.3.18 Contract System Load

Contract System Load (MWh) is the denominator in the ASC calculation and equals the utility's total retail sales, minus any NLSLs, plus distribution losses. Distribution loss factors will vary for each utility due to the size, age and population density of the system. The 2008 ASCM includes distribution losses in the Contract System Load. Table 8.3.3 shows the 2009 Base Period Contract System Load for each utility.

Table 8.3.3
2009 Base Year Contract System Load
(MWh)

Avista	9,382,688
Idaho Power	13,979,604
Northwestern	6,078,493
PacifiCorp	21,112,995
Portland General	17,706,495
Puget Sound Energy	22,979,451
Clark	4,716,985
Franklin	1,035,043
Snohomish	7,115,588

*See FY 2012 REP Settlement Documentation, REP-12-E-BPA-01A,
FY 2012–2013 Draft ASC Report for each of the exchanging utilities.*

8.3.19 PacifiCorp Inter-Jurisdictional Cost Allocation

Calculation of PacifiCorp’s ASC involves consideration of a unique inter-jurisdictional allocation issue. The 2008 ASCM states that a single ASC will be used for each utility’s entire regional load. PacifiCorp operates both inside and outside the Pacific Northwest (PNW). PacifiCorp’s FERC Form 1 is based on its total system costs, and therefore adjustments must be made to determine the portion of costs used to serve retail load within the region. To perform this adjustment, PacifiCorp’s total utility cost data from the FERC Form 1 is entered into the 2008 ASC Appendix 1, and then allocated based on the Inter-Jurisdictional Cost Allocation Protocol (JCAP) developed jointly by most of PacifiCorp’s state commissions. Only the costs and revenues allocated to the PNW are included in PacifiCorp’s ASC.

8.4 Determination of the Exchange Period ASCs for FY 2012–2013

Once the Base Period ASC is calculated, BPA Staff uses the ASC Forecast Model to escalate the Base Period ASC forward to the midpoint of the Exchange Period, which in this case is October 1, 2012. The ASC Forecast Model uses Global Insight’s forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses; BPA’s forecast of market prices

for purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA's forecast of natural gas prices; and BPA's estimates of the rates it will charge for its PF and other products. The ASC Forecast process is described in greater detail in the sections that follow.

8.4.1 Escalation to Exchange Period (FY 2012–2013)

Table 8.4.1 shows the annual escalation rates used in the ASC Forecast Model through FY 2013.

Table 8.4.1
Escalation Rates and Price Forecasts

Cost Item	Escalation Code	2010	2011	2012	2013
No Escalation	CONSTANT	0.00%	0.00%	0.00%	0.00%
Distribution Plant	CD	0.90%	1.70%	2.10%	2.70%
Inflation	INF	1.07%	1.48%	1.50%	1.65%
Wages	WAGES	1.70%	2.00%	2.50%	2.70%
Steam Fuel - (Coal)	COAL	-12.10%	0.60%	1.00%	1.90%
Steam Operations	SOPS	2.30%	2.90%	2.90%	2.50%
Steam Maintenance	SMN	0.40%	1.60%	2.40%	2.60%
Nuclear Fuel	NFUEL	0.00%	0.00%	0.00%	0.00%
Nuclear Operations	NOPS	1.70%	2.50%	2.50%	2.30%
Nuclear Maintenance	NMN	1.50%	2.10%	2.30%	2.30%
Hydro Operations	HOPS	2.70%	3.20%	2.70%	2.20%
Hydro Maintenance	HMN	0.20%	1.60%	2.50%	2.60%
Natural Gas	NATGAS	10.89%	-4.69%	14.36%	12.72%
Other Operations	OOPS	3.00%	3.70%	3.30%	2.80%
Other Maintenance	OMN	0.10%	1.30%	2.20%	2.30%
Transmission Operations	TOPS	1.90%	2.60%	2.60%	2.50%
Transmission Maintenance	TMN	0.60%	1.80%	2.30%	2.20%
Distribution Operations	DOPS	1.50%	2.10%	2.40%	2.30%
Distributions Maintenance	DMN	1.10%	2.00%	2.30%	2.20%
Customer Accounts	CACNT	1.50%	1.80%	2.30%	2.20%
Customer Service	CSERV	1.40%	2.10%	2.20%	2.00%
Customer Sales	CSALES	1.40%	2.10%	2.50%	2.40%
Administrative and General	A&G	2.30%	2.50%	2.90%	3.00%
Blank	ADDER	0.00%	0.00%	0.00%	0.00%

8.4.2 Major Resource Additions, Reductions, and Materiality Thresholds

Under the 2008 ASCM, a utility's ASC is allowed to change during the Exchange Period when major new power or transmission contracts become effective or major new resource additions come on line, or are terminated, and are used to meet the utility's retail load. These additions or reductions will affect costs. Additions may include new production resource investments; new

1 generating resource investments; new transmission investments; long-term generating contracts;
2 pollution control and environmental compliance investments relating to generating resources,
3 transmission resources, or contracts; hydro relicensing costs and fees; and plant rehabilitation
4 investments. *See* 18 C.F.R. § 301.4(c)(4). Changes to an ASC, however, are limited to instances
5 where the cost impact of the new resource passes a materiality threshold of an increase in ASC
6 of 2.5 percent or greater. For the purpose of the ASC forecast, BPA assumed that any resource
7 additions, or reductions, that parties indicated would be occurring during the Exchange Period
8 would become commercially operational on the forecast on-line date.

9
10 All major new resources included in an ASC calculation prior to the start of the Exchange Period
11 are projected forward to the midpoint of the Exchange Period. For each major new resource
12 addition forecast to come on line during the Exchange Period, BPA calculates the ASC with the
13 new resource at the midpoint of the Exchange Period.

14 15 **8.4.3 Ratios**

16 To calculate Exchange Period ASCs, functionalization ratios are developed for each year using
17 the escalated plant and expense values. These functionalization ratios are then applied to the
18 escalated values to determine costs to include in ASC.

19 20 **8.4.4 Schedule 1 – Plant Investment/Rate Base Forecast**

21 **8.4.4.1 Production and Transmission Plant**

22 Gross production and transmission plant are held constant through the end of the Exchange
23 Period, unless there are production plant or transmission plant resource additions. In such case, a
24 new ASC is calculated including the plant addition, as described above. *See* Section 8.4.2.

8.4.4.2 Forecast Distribution Plant-Related Costs

Distribution plant is used to calculate some of the functionalization ratios used in the calculation of a utility's ASC. Therefore, BPA Staff escalates the Base Period average per-MWh cost of distribution plant forward to the midpoint of the Exchange Period, and uses the escalated average cost times the MWh of load growth to determine the distribution plant-related cost of meeting load growth since the Base Period. This cost is then included in the ratios used to forecast the Exchange Period ASCs.

8.4.4.3 Forecast General Plant-Related Costs

To escalate General Plant-related costs, BPA Staff first calculates the ratio of base period general plant to the sum of base period production, transmission, and distribution plant. BPA staff then applies this base period ratio to the sum of the forecast gross costs of production, transmission, and distribution plant to develop the forecast gross general plant.

8.4.4.4 Forecast Depreciation and Amortization Reserves

The forecast functionalized depreciation and amortization reserves are increased annually by the amount of annual depreciation and amortization expense.

8.4.5 Schedule 1A – Cash Working Capital Forecast

Forecast cash working capital is calculated using the same method as the 2009 Base Period value, except that BPA Staff uses the projected component values.

8.4.6 Schedule 2 – Capital Structure and Rate of Return Forecast

The rate of return is held constant at the 2009 Base Period value through the end of the Exchange Period.

8.4.7 Schedule 3 – Expense Forecast

All expense items in Schedule 3 are escalated using the escalation factors assigned to the particular expense item as set forth in the 2008 ASCM, with the following exceptions:

- Short-term purchased power expense is calculated as described in Sections 8.4.9, 8.4.11, and 8.4.12.
- The public purpose charge is escalated at the utility's rate of load growth.
- Depreciation and amortization expense is increased for new plant additions, as described in Section 8.4.7.1.
- Operations and maintenance expense and fuel expense are escalated annually per the ASCM and increased for any additional O&M and fuel associated with new plant additions.

8.4.7.1 Depreciation and Amortization Expense Forecast

Depreciation and amortization expense for each account is forecast to be constant, except for additional depreciation expenses associated with the following:

- new plant additions;
- new distribution plant additions associated with load growth (the amount of the depreciation expense addition is equal to the additional gross distribution plant times the ratio of the 2009 distribution depreciation expense to the 2009 gross distribution plant);
- new general plant additions (the amount of the depreciation expense addition is equal to the additional gross general plant times the ratio of the 2009 general plant depreciation expense to the 2009 gross general plant).

8.4.8 Schedule 3A – Forecast of Taxes

Property-related taxes are held constant throughout the forecast period unless there are property taxes identified with major resource additions. Labor-related taxes are escalated using the wages escalator.

8.4.9 Schedule 3B – Forecast of Revenue Credits and Other Items

With the exception of wheeling revenues and Sales for Resale Revenues, all revenue and other credits are held constant at the Base Period amounts.

The ASC Forecast Model distinguishes between long-term and short-term sales for resale and assumes that the quantity of long-term and intermediate-term firm sales is constant through the Exchange Period and that revenue from these types of sales escalates at the rate of inflation.

The quantity of short-term sales is forecast to be constant into the future unless a utility's forecast resource additions exceed the utility's forecast load growth requirements and reduce short-term purchased power to zero. In such case, the surplus energy is sold off-system at the forecast short-term sales for resale price as determined by BPA. See Section 8.4.12.

Wheeling revenues are held constant unless there are new transmission additions. The increase in wheeling revenues resulting from new transmission resource additions equals:

$$\text{(Wheeling revenues (before additions) / net transmission plant (before additions))} \times \text{new transmission additions.}$$

8.4.10 Load Forecast

8.4.10.1 Forecast Contract System Load and Exchange Load

Each utility was required to provide a forecast of its Contract System Load, NLSL, and associated Exchange Load, as well as a current distribution loss study as described in Endnote e of the 2008 ASCM, with its 2009 ASC Filing. The load forecast for Contract System Load and Exchange Load starts with the Base Period and extends through FY 2017.

1
2 For the IOUs, this Study used the Contract System Load forecasts provided by the utilities in
3 their ASC submittals through the Exchange Period. For the COUs, BPA used the total retail load
4 forecasts provided by BPA's load forecasting group.

5
6 For the Exchange Load forecasts through the end of the Exchange Period, BPA Staff used the
7 forecasts provided by the utilities. For the COUs, the total Exchange Load was reduced each
8 year by each COU's Tier 1 percentage to determine the forecasts of exchange load that the COUs
9 could invoice BPA, per the TRM.

10 11 **8.4.11 Forecast Methodology for Meeting Load Growth**

12 All forecast load growth will first be met by new resource additions. If the power provided by
13 the new resources is less than the total forecast load growth, the remaining load growth will be
14 met with market purchases priced at the utility's forecast short-term purchased power price. In
15 the event the power provided by a new resource exceeds the utility's forecast load growth, the
16 amount of short-term purchases is reduced by the excess. If short-term purchases are reduced to
17 zero, any remaining excess power is sold as surplus power into the market and priced at the
18 utility's forecast sales for resale price as determined by BPA in section 8.4.12.

19 20 **8.4.12 Treatment of Sales for Resale and Power Purchases**

21 The ASC Forecast Model distinguishes between long-term and short-term purchased power. In
22 the FERC Form 1, utilities separate purchased power and sales for resale by the type and length
23 of the purchase and also report any adjustments. The COUs were required to provide detailed
24 information on their long-term, intermediate-term, and short-term purchased power costs and
25 sales for resale revenues.

1 BPA escalated the long-term and intermediate-term (as defined by FERC) firm purchased power
2 costs and sales for resale revenues at the rate of inflation.

3
4 For short-term purchases and sales for resale revenues, the short-term purchases and sales for
5 resale revenues for the Base Period were used as starting values. Each utility's ASC was
6 adjusted to reflect new plant additions and used a utility-specific forecast for the (1) price of
7 purchased power and (2) sales for resale price, to value purchased power expenses and sales for
8 resale revenue to be included in the Exchange Period ASC.

9
10 BPA used each utility's historic three-year weighted spread between short-term purchased power
11 price and sales for resale price (the price spread) to determine that utility's forecast relationship
12 between forecast short-term purchased power and sales for resale prices to calculate the
13 Exchange Period ASCs.

14
15 To forecast a utility's short-term purchased power and sales for resale price, BPA first calculated
16 the midpoint of the utility's 2009 average short-term purchased power and sales for resale price.
17 BPA then escalated the midpoint at the same rate as BPA's market price forecast. The price
18 spread was then applied to the forecast midpoint to determine the forecast purchased power and
19 sales for resale prices.

20 Forecast purchase price = Escalated midpoint price $\times$ (1 + price spread)

21 Forecast sales price = Escalated midpoint price $\times$ (1 – price spread)

22 23 **8.4.13 New Large Single Loads**

24 NLSL is any load associated with a new facility, an existing facility or an expansion of an
25 existing facility that was not contracted for or committed to (CF/CT) prior to September 1, 1979,

1 and which will result in an increase in power requirements of ten average megawatts (aMW) or
2 more in any consecutive 12-month period. 16 U.S.C. § 839a(13)(A)-(B).

3
4 Section 5(c)(7)(A) of the Northwest Power Act directs BPA to exclude from ASC the “cost of
5 additional resources in an amount sufficient to serve any new large single load [NLSL] of the
6 utility.” 16 U.S.C. § 839c(c)(7)(A). To implement this provision, BPA developed Endnote d of
7 the 2008 ASCM. In general, Endnote d identifies three methods for excluding from ASC the
8 cost of resources sufficient to serve a utility’s NLSL. First, the unit cost of any resources
9 dedicated to serve the NLSL are excluded. Second, if dedicated resources are not used to serve
10 NLSLs, or the MWh of dedicated resources is less than the NLSL MWh, the unit cost of any
11 purchases of NR power from BPA will be excluded. Finally, to the extent that the MWh of
12 dedicated resources and NR purchases are less than the NLSL MWh, the fully allocated unit cost
13 of all resources and long-term purchases that were not contracted for or committed to load as of
14 September 1, 1979 will be excluded. See 18 C.F.R. § 301, End. d for detailed description. To
15 date, no IOU serves NLSLs with dedicated resources or purchases power from BPA at the NR
16 rate, so all NLSL resource cost exclusions are based on the fully allocated cost method of
17 Endnote d.

18
19 NLSL determinations are not made in the ASC review process. Instead, they are identified and
20 made through a separate process conducted by BPA’s NLSL Staff, which is tasked specifically
21 with this responsibility. Although NLSLs are determined in another forum, BPA must establish
22 the removal of the costs of serving any potential NLSLs pursuant to the requirements in
23 Endnote d(1)-(3) of the 2008 ASCM in the Draft and Final ASC Reports. Parties to the ASC
24 Review Processes must also be allowed an opportunity to review and comment on BPA Staff’s
25 calculation.

1 During review of utilities' ASC Filings for the FY 2012–2013 ASC Exchange Period, several
2 large utility loads were indentified at Idaho Power, PacifiCorp, and Portland General that could
3 meet the statutory definition of an NLSL. BPA's NLSL Staff is currently evaluating whether
4 these loads meet the statutory criteria for NLSLs. As of the publication of the 2009 Draft ASC
5 Reports, BPA's NLSL Staff had not completed its evaluation. Therefore, a rebuttable
6 presumption was made for the 2009 Draft ASC Reports that the large loads identified in the ASC
7 Review Process are NLSLs for purposes of calculating ASC. To protect the confidentiality of
8 the potential NLSLs, the loads for each utility were grouped and not individually identified.

9
10 The utility may rebut this presumption with information that establishes either: (1) the identified
11 load did not exceed 10 aMW in a 12-month period; or (2) the load is fully or partially protected
12 under the "contracted for or committed to" exemption in the Northwest Power Act. The Final
13 ASC Report will adjust the utility's ASC to reflect BPA's final NLSL determinations.

14
15 For purposes of this LTAFM, each of the large loads identified as potential NLSLs in the 2009
16 Draft ASC Reports will be treated as an NLSL through FY 2032. The MWh associated with
17 each NLSL will remain constant and will be removed from each utility's total retail load. The
18 cost of resources in an amount sufficient to serve these potential NLSLs will be removed from
19 each utility's allowable production and transmission costs using the NLSL worksheets of the
20 LTAFM described in section 8.3.15 above. Costs of resources in an amount sufficient to serve
21 NLSLs are escalated through FY 2032. When new resources are added for a utility in the
22 LTAFM, they are also included in the NLSL worksheets to determine NLSL resource costs.

23 24 **8.4.14 Rate Period High Water Mark ASC Calculation under the Tiered Rate** 25 **Methodology**

26 Exchanging COUs receive power from BPA under CHWM Contracts. By signing the CHWM
27 Contract, a utility agrees to limit the resources it will exchange in the REP. Under the 2008 ASC

Methodology, COUs that execute CHWM Contracts are not allowed to include in their ASCs the cost of resources used to meet their Above-Rate Period High Water Mark (RHWM) loads.

CHWM Contracts require that the cost of resources used to meet Above-RHWM loads be calculated using a methodology similar to the methodology that determines the cost of resources used to serve NLSLs. This methodology is contained in Endnote (d) of the 2008 ASCM.

During the FY 2012–2013 ASC Review Process, BPA used the following method to determine the ASC of a COU that is participating in the REP.

- $$\text{RHWM ASC} = \frac{\text{Contract System Cost} - \text{NewRes\$}}{\text{Contract System Load} - \text{NewResMWh}}$$
- NewRes\$ is the forecast cost of resources used to serve a customer's Above-RHWM Load. The costs included in NewRes\$ will be determined using a methodology similar to Appendix 1, Endnote d of BPA's 2008 ASC Methodology and as described below.
- NewResMWh is the forecast generation from resources used to serve a customer's Above-RHWM Load. For the Draft ASC Report, the NewResMWh was set equal to the customer's Above-RHWM Load.
- For calculating both NewRes\$ and NewResMWh, Existing Resources for CHWMs specified in Attachment C, Column D of the Tiered Rate Methodology (see TRM-12S-A-03, September 2009, Attachment C) and purchases of power at Tier 1 rates from BPA are excluded.

The following considerations are used in calculating the cost of serving Above-RHWM Loads using Endnote d of the 2008 ASCM:

- Types of resources to serve Above-RHWM Loads may be different from those resources used in the NLSL resource cost calculation and will be recognized in calculating RHWM ASC.
- Total output of new resources may exceed Above-RHWM Load; the RHWM ASC does not specify removal of costs associated with this excess.

To calculate RHWM ASC, BPA adjusted Contract System Cost as follows:

- Set NewResMWh equal to Above-RHWM Load.
- NewRes\$ = NewResMWh times Fully Allocated Cost (calculated using Endnote d).
- If output of material new resources fails to meet Above-RHWM Load, meet deficit with short-term (ST) market purchases at utility-specific market price. ST purchases are not allowed in the calculation of the cost to serve NLSLs.
- If output of new resources exceeds Above-RHWM Load, reduce ST market purchases by excess to the extent possible in Contract System Cost calculation.
- Sell any remaining surplus at utility-specific Sales for Resale price in the Contract System Cost calculation.

8.4.15 Forecast Contract System Cost, Contract System Load, and Average System Cost

8.4.15.1 Contract System Cost Forecasts

For the IOUs and COUs, the ASC Forecast Model calculates Contract System Cost as follows:

$$\begin{aligned}
 \text{Exchange Cost}_{2009} = & \sum \text{Rate Base Accounts} \times (1 + \text{escalator}_{(\text{by account})}) \times \text{ROR (w/ Federal} \\
 & \text{Income Tax Factor)} \\
 & + (\sum \text{Expense Accounts}_{(\text{by account})}) \times (1 + \text{escalator}_{(\text{by account})}) \\
 & + \text{Wholesale Purchase Expense}_{2009} \\
 & - \text{Wholesale Sales for Resale Revenue Credit}_{2009} \\
 & + \text{Cost of Load Growth} \\
 & - \text{New Large Single Load Cost}
 \end{aligned}$$

The COU forecasts do not include the Federal income tax calculation.

Please see REP-12-E-BPA-02A, Tables E-5, E-6, and E-7 Documentation for Forecast Contract System Costs, Loads and Average System Costs for the Rate Period through FY 2017.

8.5 Determination of the Forecast ASCs for FY 2014–2032

To calculate ASCs for the Long-Term Period (FY 2014–2032), BPA Staff used the same methods and ASC Forecast Model as were used to escalate costs and revenues from the Base Period to the Exchange Period, except for the revisions described in the following section.

8.5.1 Escalation from the End of the Exchange Period through the End of the Long-Term Period (FY 2014–2032)

Through FY 2017, all of the Global Insight escalators, natural gas and market prices escalators, and BPA PF rates are the same as those used to determine the Exchange Period ASCs, and the ASCs used for the out years for the 7(b)(2) rate test (FY 2014–2017). The global insight escalations were used for FY 2018. For FY 2019 through FY 2032, the annual escalation rate for each Global Insight escalator in the ASC Forecast Model is set equal to the FY 2019 escalation rate.

BPA’s Power Policy Analysis group provided a natural gas price forecast for the FY 2018–2030 period, and was increased by 3 percent annually for the FY 2031 to FY 2032 period. Electric market prices are increased by 3 percent annually for FY 2018-2032.

Table 2.5 in the Documentation shows the escalation rates through FY 2032.

8.5.2 Plant Investment/Rate Base Forecast

New resource additions for the FY 2014–2028 period were based on each utility’s most recent Integrated Resource Plan (IRP) or similar document, the Northwest Power and Conservation

Council's Sixth Power Plan (NPCC Plan), and other sources. The analysis is described in greater detail in sections 8.7, 8.8, and 8.9. All resource additions are included at the midpoint of the fiscal year they are projected to come on line. Depreciation and amortization reserves are held constant at the FY 2014 level for the Long-Term Period. BPA assumes that the utilities will refurbish or replace existing resources. Most of the utilities did not identify the cost of maintaining or replacing existing resources in the IRPs. BPA chose to represent the cost of refurbishing or replacing existing resources as equal to the annual depreciation and amortization costs. In effect, this holds the depreciation and amortization reserves constant.

8.5.3 Load Forecast

8.5.3.1 Forecast Contract System Load and REP Exchange Load

The IOUs' FY 2018–2032 Contract System Load forecasts are based on the load information provided in each IOU's IRP. This load forecast is described in greater detail in section 8.10.

For the COUs, BPA Staff used the total retail load forecast through FY 2029 provided by BPA's Load Forecast group. For FY 2030–2032, COU loads were escalated at the rate of growth from FY 2028–2029.

To develop the FY 2018–2032 REP Exchange Load forecast for the IOUs, BPA Staff calculated the ratio of Exchange Load to total retail load for FY 2017. These ratios were then applied to the individual IOU's total retail load forecast for FY 2018–2032.

For the COU REP Exchange Load forecast, BPA used the same method to forecast exchange loads that was used for the IOUs, with one additional step. For the COUs, Total REP Exchange Load was reduced each year by each COU's Tier 1 percentage to determine the forecast of exchange load that the COUs could invoice BPA, as required by the TRM.

8.6 ASC Inputs into the Long-Term Rate Model (LTRM)

The cost, revenue, and load values from the Long-Term ASC Forecast Model are used to provide the ASC inputs for the Long-Term Rate Model (LTRM). The LTRM uses these inputs to generate ASCs and REP benefits under the various scenarios.

The first step in generating the ASC inputs is to run the ASC Forecast Model, including all new resources scheduled to come on line prior to the start of the Exchange Period. The resulting costs, revenues, and loads data are then used to generate the inputs used in the LTRM. The costs and revenues are selected for the Base Period (CY 2009), and for FY 2012 through FY 2032 at the midpoint (April 1) of each fiscal year.

8.6.1 Escalators

Once the input data has been calculated, escalators are calculated using the input values. The escalators for FY 2012 equal the FY 2012 values divided by the CY 2009 values. The escalators for FY 2013–2032 equal the values for the current fiscal year divided by the values for the previous fiscal year.

For example, the FY 2013 escalator for Production Rate Base equals the Production Rate Base value for FY 2013 divided by the Production Rate Base value for FY 2012.

8.6.2 Forecast Values

With the exception of short term purchases and sales, Tier 1 purchases, and the NLSL/Above RHWB items discussed below, the forecast revenue and expense items are calculated as:

Current FY Value = [Previous FY Value × (1 + escalator)] +

Current FY New Resource Addition

8.6.3 Short-Term Purchases and Sales

Short-term purchases quantity and expense and short-term sales quantity and revenue are calculated exactly the same as in the Long-Term ASC Forecast Model. Any forecast load growth not met with new resources is met with market purchases priced at the utility's forecast short-term purchased power price. In the event the power provided by a new resource exceeds the utility's forecast load growth, the amount of short-term purchases is reduced by the excess. If short-term purchases are reduced to zero, any remaining excess power is sold as surplus power into the market and priced at the utility's forecast sales for resale price as discussed in section 8.4.12.

8.6.4 Tier 1 Purchases

For FY 2012 and FY 2013, Tier 1 purchase expense equals the LTAFM value.

For FY 2014–2032, Tier 1 purchase expense is calculated as:

$\text{Tier 1 purchase expense 2 years prior} \times (\text{Current average PF rate} / \text{average PF rate 2 years prior}).$

For example, the Tier 1 purchase expense for FY 2014 equals the Tier 1 purchase expense for FY 2012 times (FY 2014 average PF rate / FY 2012 average PF rate). The annual Lookback credit equals the ASC Forecast Model value. For all fiscal years, net Tier 1 purchase expense equals Tier 1 purchase expense less the Lookback credit.

8.6.5 NLSL/Above-RHWM Cost Components

For each fiscal year, the NLSL/Above-RHWM production rate base equals the input value from the LTAFM plus the cumulative new resource rate base additions up to that fiscal year. As in the LTAFM, if the output of material new resources fails to meet Above-RHWM Load, the deficit is met with short-term market purchases at utility-specific market prices. Above-RHWM ASC is

1 calculated the same as discussed in section 8.4.14. Contract System Cost is calculated the same
2 as discussed in Section 8.4.15.1.

3 4 **8.7 New Resource Addition for FY 2014–2032**

5 New resource additions used in the Long-Term ASC Forecast Model are based on review and
6 analysis of each utility’s integrated resource plan. The individual IRPs guided the timing,
7 quantity, and resource type added for each utility. However, for the resources added in the
8 LTAFM, a set of 14 “generic” resources were developed and used when a utility IRP indicated
9 that a new resource was added. Cost and operating characteristics for 14 “generic” new
10 resources were based largely on Appendix I the Northwest Power and Conservation Council’s
11 Sixth Power Plan (NPCC Plan), except where noted.

12
13 This section describes the assumptions and analysis used to develop the online date, cost, and
14 operating characteristics for fourteen “generic” new resources that could be used in the LTAFM.
15 The resources discussed in this section are based on information provided in the Appendix I of
16 the NPCC Plan with the following exceptions. First, Appendix I calculates resource costs in real,
17 levelized 2006 dollars. Because the LTAFM calculates ASCs in nominal dollars for each year of
18 the Long-Term Period, the data was converted using the NPCC’s MicroFin model (used by the
19 NPCC to develop the real, levelized values) so that the first-year costs for each resource could be
20 calculated in nominal dollars. Appendix I of the NPCC Plan also reports transmission costs and
21 losses as a single value, also in real, levelized \$/MWh. The LTAFM separates transmission costs
22 and losses and requires transmission costs in nominal \$/kW/year. MicroFin was also used to
23 convert transmission costs. For resource capacity factors, BPA Staff relied on the Appendix I
24 values except for combined and single-cycle combustion turbines. For these resources, BPA

Staff relied on the capacity factors from the California Energy Commission.³ The cost and heat content of coal was based on the weighted average of 19 coal plants owned by exchanging utilities. See Table 2.9 of the Documentation.

8.7.1 Global Parameters and Definitions Used in Determining Reference Plant Costs

8.7.1.1 Conventions

Price Year: The price year from which future changes in costs are calculated is 2009.

Year Dollars: Costs are expressed in nominal dollars.

Technology Base Year: The technology base year from which future changes in technology are calculated is 2009.

Project Scope: The scope of resource cost estimates includes the cost of project development, construction, and operation, integration costs for variable resources, and the cost and losses of transmission to the wholesale receiving point of a load-serving entity.

Total Plant Cost: Capital costs⁴ are expressed in overnight (instantaneous) Total Plant Costs. “Total Plant Costs” are the sum of direct and indirect engineering, procurement, and construction (EPC) costs, plus owner’s costs. Owner’s costs include non-EPC costs incurred by the project developer, such as permits and licenses, land and right-of-way acquisition, project development costs, legal fees, owner’s engineering, project, and construction management staff, startup costs, site infrastructure (transmission, road, water, rail, waste water disposal, etc.), taxes, spares,

³ California Energy Commission, Comparative Costs of California Central Station Electricity Generation Technologies, December 2007, at 19.

⁴ The capital cost estimates for the reference power plants are based on the Northwest Power and Conservation Council’s Sixth Power Plan (except where noted).

furnishings, and working capital. Not included in Total Plant Cost are financing costs, escalation incurred during construction, and interest incurred during construction (IDC).

8.7.1.2 Project Financing

Power plants are assumed to be constructed by investor-owned utilities and consumer-owned utilities. Each of these entities uses different project financing mechanisms.

Plant investment costs are calculated using the spreadsheet model used to calculate resources capital cost and the annual revenue requirements for the various resources. Depreciation is assumed to be straight-line over the life of the plant.

The financing parameter values used are shown in Table 8.7.1.

Table 8.7.1

**Financing and Other Common Parameter Assumptions
(Values are nominal unless stated)**

	Municipal/ PUD	Investor-Owned Utility
Federal Income Tax Rate		35%
Federal Investment Tax Credit		See Incentives
FIT Recovery Period		See Incentives
State Income Tax Rate		5.0%
Property Tax	1.4%	1.4%
Insurance	0.25%	0.25%
Development	100%	50%
Construction	100%	50%
Term	100%	50%
Debt interest –Development	5.1%	7.1%
Debt interest – Construction	5.1%	7.1%
Debt interest – Term	5.1%	7.1%
Return on Equity – Development		10.2%
Return on Equity – Construction		10.2%
Return on Equity – Term		10.2%

8.7.1.3 Project Costs

- All costs are escalated from the nominal Base Period 2009 dollars to the resource's on-line date.
- Total project investment is calculated for the selected year of construction using the estimated total plant cost, plant capacity, cost escalation factors, construction cash flow estimates, and the construction financing of the selected type of project developer.
- Annual capital-related costs (debt interest, debt principal, return on equity, recovery of equity, and state and federal taxes) are calculated for the total project investment using the long-term financing characteristics and tax obligations of the selected type of developer.
- Annual property tax and insurance payments are calculated based on the plant value.

- Annual energy production is calculated based on plant capacity and capacity factor.
- Annual fixed fuel costs are calculated based on escalated fixed fuel costs and plant capacity. Annual variable fuel costs are based on escalated variable fuel costs, heat rate, and energy production.
- Annual fixed O&M costs are calculated based on escalated fixed O&M costs and plant capacity. Annual variable O&M costs are based on escalated variable O&M costs and energy production.
- Annual transmission costs are calculated based on plant capacity and escalated unit transmission costs. Integration costs are calculated based on forecast integration costs and energy production.
- The value of transmission losses is calculated based on total annual costs and the transmission loss factor.

8.7.1.4 Escalation Rates

The LTAFM uses Global Insight’s CY 2014–2018 forecast of cost increases for capital costs and fuel (except natural gas), O&M, and G&A expenses (to escalate these items for the CY 2019–2032 period, the escalation rates from CY 2019 are used); BPA’s forecast of market prices for purchases to meet load growth and to estimate short-term and non-firm power purchase costs and sales revenues; BPA’s forecast of natural gas prices; and BPA’s estimates of the rates it will charge for its PF and other products. The escalators are shown in Table 8.7.2.

Table 8.7.2

Escalation Rates for Various ASC Forecast Model Components

	CY 10	CY 11	CY 12	CY 13	CY 14	CY 15	CY 16	CY 17	CY 18	CY 19–28
Capital	1.3%	1.6%	1.7%	2.3%	2.7%	3.0%	2.1%	1.9%	2.1%	2.3%
Variable O&M	1.6%	2.5%	2.8%	2.6%	3.1%	2.5%	1.8%	1.4%	1.4%	1.4%
Fixed O&M	1.6%	2.5%	2.8%	2.6%	3.1%	2.5%	1.8%	1.4%	1.4%	1.4%
Natural Gas	10.7%	−4.7%	14.4%	12.7%	4.3%	3.7%	4.1%	1.9%	3.9%	3.9%
Inflation	1.1%	1.5%	1.5%	1.7%	1.8%	1.7%	1.7%	1.8%	1.8%	1.8%
Transmission	1.0%	1.8%	2.4%	3.0%	3.3%	3.1%	1.9%	1.8%	2.0%	2.3%
Steam Fuel	−12.1%	0.6%	1.0%	1.9%	1.9%	1.8%	1.8%	1.7%	1.7%	1.7%

8.7.1.5 General Forecasts

Transmission

The common point of reference for the costs of generating resources and energy efficiency measures is the wholesale delivery point to local load-serving entities (*e.g.*, the substations interconnecting local utilities to the regional transmission network). The costs and losses of transmission from the point of generating project interconnection to the wholesale point of delivery are included in estimated generating resource cost.

The cost of resources serving local loads (*e.g.*, Oregon and Washington resources serving Oregon and Washington loads) includes local (in-region) transmission costs and losses. The cost of resources serving remote loads (*e.g.*, Wyoming resources serving Idaho, Oregon, and Washington loads) includes the estimated cost and losses of needed long-distance transmission.

Local Transmission Costs and Losses

Local transmission costs are based on the 2010 Bonneville Power Administration Transmission and Ancillary Service Rate Schedules (BPA 2009). The representative local transmission cost is an approximation of the long-term firm point-to-point service (PTP) rate plus required Ancillary Services and Control Area Services (ACS) rates (scheduling system control and dispatch, reactive supply and voltage control, regulation and frequency response, spinning reserve, and supplemental reserve). The estimated fixed component is \$17/kW/yr, and the variable component is \$1.00/MWh (2009 dollars). The estimated cost of regulation and load-following required to integrate variable generation is separately included, as described in the following section. Local transmission losses are assumed to be 1.9 percent (BPA 2008, Schedule 9).

Transmission to Access Remote Resources

PacifiCorp is the only utility that specifically identified long-haul wind resources in its IRP. PacifiCorp did not identify the points of delivery or points of receipt for long-haul resources in its IRP, so the assumption used in this Study is that the long-haul wind resources are located in Wyoming and the power is received by PacifiCorp in Southern Idaho. The cost and losses associated with long-distance transmission to access remote resources is based upon the NPCC Plan estimates of actual proposed new long-distance transmission alignments serving the resource areas of interest (Appendix I, Table I-3). Table I-24 of Appendix I shows the estimated transmission cost and losses in real, levelized \$/MWh for the Wyoming-Southern Idaho route. Table I-3 is the source for the 2.5 percent transmission loss factor for the Wyoming-to-Southern Idaho route used for long-haul wind in the LTAFM. To develop the \$126.56/kW/year used for transmission costs, the NPCC's MicroFin model (Version 15.01 with Scenario AddIn) was used to develop the estimated first-year costs of the line, \$119.64/kW/year in 2006 dollars. This value was escalated to 2009 dollars using the GDP escalator of 1.0578 for 2006 to 2009 to arrive at \$126.56/kW/year cost of transmission used in the ASC Forecast Model. See Table 1.1.a of the

Documentation for results of the MicroFin model for this calculation. See Appendix I of the NPCC Plan for a greater discussion of transmission costs and the MicroFin model.

Integration Cost for Variable Resources

The cost of providing balancing services for wind resources is based on Table I-5 of Appendix I, which shows balancing costs of \$8.85/MWh for 2010. The 2010 balancing cost was reduced to 2009 dollars using the GDP escalator to arrive at the \$8.67/MWh used in the LTAFM.

8.7.1.6 Capacity Factors

The capacity factor of a power plant is the ratio of the actual output of a power plant over a period of time to its output if it had operated at full nameplate capacity the entire time.

Table 8.7.3 provides the plant capacity factor for each of the reference resources, and Table 8.7.4 provides the adjusted plant capacity factor for each of the reference resources to reflect the transmission losses of energy delivered to the utilities system.

**Table 8.7.3
Plant Capacity Factor**

Resource Type	Capacity Factor	Source
Coal Super Critical PC	93.0%	NPCC Plan
CCCT	60.0%	CEC (2007)
Biomass	80.0%	NPCC Plan
Wind	32.0%	NPCC Plan
Long Haul wind	38.0%	NPCC Plan
Peaker Heavy-duty (Frame)	46.0%	CEC (2007)
Landfill gas	85.0%	NPCC Plan
Geothermal	90.0%	NPCC Plan
Solar CST	35.5%	NPCC Plan
Waste Heat Energy Recovery Cogeneration	80.0%	NPCC Plan
CCCT - Duct Firing	60.0%	CEC (2007)
SCCT - LMS100	5.0%	CEC (2007)
Purchase Power	100.0%	
Hydro	50.0%	NPCC Plan

Table 8.7.4
Capacity Factor (less losses)

Resource Type	Capacity Factor	Trans Loss Factor	Capacity Factor (less losses)
Coal Super Critical PC	93.0%	8.0%	85.6%
CCCT	60.0%	1.9%	58.9%
Biomass	80.0%	1.9%	78.5%
Wind	32.0%	1.9%	31.4%
Long Haul wind	38.0%	5.0%	36.1%
Peaker Heavy-duty (Frame)	46.0%	1.9%	45.1%
Landfill gas	85.0%	1.9%	83.4%
Geothermal	90.0%	1.9%	88.3%
Solar CST	35.5%	1.9%	34.8%
Waste Heat Energy Recovery Cogeneration	80.0%	1.9%	78.5%
CCCT - Duct Firing	60.0%	1.9%	58.9%
SCCT - LMS100	5.0%	1.9%	4.9%
Purchase Power	100.0%	1.9%	98.1%
Hydro	50.0%	1.9%	49.1%

8.7.1.7 Fuel Costs, Purchase Power Expenses & REC Costs

Coal

Coal costs (\$/ton) and heat content values (Btu/lb) were based on the 2009 weighted average for the nineteen coal-fired power plants operated by exchanging utilities (individual coal plant data from 2009 FERC Form 1). Support for this calculation is shown in Table 2.9 of the documentation.

Natural Gas

Natural gas price (\$/MMBtu) is the same gas price as used in the BP-12 rate case. This study does assume the inclusion of incremental transportation costs of \$0.73 / MMBtu (\$2006)⁵.

⁵ Fuel Price Forecasting Model – West-Side Firm Utility Gas Price, Sixth Power Plan Appendix A: Fuel Price Forecast, Table A6-71a.

8.7.2 Assumptions for Reference Plants

The descriptions below are taken largely from, or are direct quotes from, Appendix I of the NPCC's Sixth Power Plan. Tables for each reference plant shown below are included in the Documentation Appendix B, beginning on page 6-9.

8.7.2.1 Landfill Gas Energy Recovery

A landfill gas energy recovery plant uses the methane content of the gas produced as a result of the decomposition of landfill contents to generate electric power. The complete recovery system includes an array of collection wells, collection piping, gas cleanup equipment, and one or more generator sets, usually using reciprocating engines. Typically, the gas collection system is installed as a requirement of landfill operation, and the raw gas sold to the operator of the power plant.

Reference Plant:

The reference plant consists of two 1.6-MW reciprocating engine generating units fueled by landfill gas. The scope includes gas processing equipment, engine-generator sets, powerhouse and maintenance structure, and power generation site infrastructure.

Fuel:

A typical business arrangement is for the power plant operator to purchase the raw landfill gas from the landfill operator. The landfill operator is responsible for installing and operating the well field and collection system.

1 **Heat rate:**

2 The heat rate of the reference plant is 10,060 Btu/kWh. The assumed heat content of the gas is
3 841,000 Btu/Mcf.⁶

4
5 **Unit Commitment Parameters:**

6 Landfill gas energy recovery plants operate as must-run units at an annual capacity factor of
7 85 percent.

8
9 **Development and Construction Schedule, Cash Flows:**

10 Development and construction schedule and cash flow assumptions for a landfill gas energy
11 recovery plant are those assumed for reciprocating-engine power plants:

12
13 **Development** (feasibility study, permitting, geophysical assessment, preliminary engineering):
14 18 months, 3 percent of total plant cost.

15
16 **Early Construction** (final engineering, major equipment order, site preparation): 9 months,
17 9 percent of total plant cost.

18
19 **Committed Construction** (delivery of major equipment, completion of construction and
20 testing): 6 months, 88 percent of total plant cost.

21
22 **Operating and maintenance costs:**

23 Fixed O&M cost for landfill gas energy recovery is \$26/kW/yr and variable O&M cost is
24 \$19/MWh.

⁶ Energy Information Agency – Average Heat Content of Selected Biomass Fuels , August 2010.

1 **Economic Life:**

2 The economic life of a landfill gas energy recovery plant is assumed to be 20 years, limited by
3 the operating life of a reciprocating-engine generator and the productive life of a typical landfill.
4

5 **8.7.2.2 Biomass (Woody Residue Power Plants)**

6 Woody residue includes mill residues, logging slash, urban construction and demolition debris,
7 urban forest and landscaping debris, unmerchantable products of commercial forest management
8 and ecosystem restoration, and woody energy crops. Conventional steam-electric plants with or
9 without CHP will be the chief technology for electricity generation using woody residue in the
10 near term.
11

12 **Reference Plant:**

13 The reference Greenfield plant is a 25-MW (nominal) fluidized-bed steam-electric plant with a
14 full condensing steam turbine-generator. The plant is provided with mechanical draft condenser
15 cooling. Selective non-catalytic NO_x reduction, cyclones, and fabric filters are employed for air
16 emission control. The plant consists largely of new equipment. The fuel supply consists largely
17 of forest thinning and restoration residues within a 50 to 75-mile radius, augmented by mill,
18 logging, and urban wood residues.
19

20 **Fuel:**

21 The fuel supply consists of various proportions of mill residues, logging slash, and forest
22 thinning residues. The delivered cost of these is assumed to be as follows:

23 Mill residues: \$1.33/MMBtu

24 Logging slash: \$3.00/MMBtu

25 Forest thinning: \$3.30/MMBtu

The fuel supply of the Greenfield plant consists largely of forest thinning residues, supplemented with limited quantities of mill residue and logging slash with a net cost of \$3.00/MMBtu.

Heat rate:

The heat rate of the standalone plant is 15,500 Btu/kWh.

Unit Commitment Parameters:

Woody residue steam-electric plants are assumed to operate as must-run units at an annual capacity factor of 80 percent.

Total Plant Cost:

The Greenfield plant representing longer-term marginal development conditions is estimated to cost \$4,000/kW (net) installed capacity.

Development and Construction Schedule, Cash Flows:

Development and construction schedule and cash flow assumptions are as follows:

Development (feasibility study, permitting, geophysical assessment, preliminary engineering): 24 months, 2 percent of total plant cost.

Early Construction (final engineering, major equipment order, site preparation): 12 months, 45 percent of total plant cost.

Committed Construction (delivery of major equipment, completion of construction and testing): 12 months, 53 percent of total plant cost.

1 **Operating and maintenance costs:**

2 The estimated operating and maintenance costs for the reference Greenfield plant are
3 \$180/kW/yr fixed and \$3.70/MWh variable.
4

5 **Value of steam sales:**

6 Extracted 150-psi saturated steam is assumed to be valued at \$5.00/1000 lb., based on Port of
7 Port Angeles (2009).
8

9 **Economic Life:**

10 A new steam-electric plant can operate for 30 years or more.
11

12 **8.7.2.3 Geothermal**

13 Depending on resource temperature, flashed-steam or binary-cycle geothermal technologies
14 could be used with the liquid-dominated hydrothermal resources of the Pacific Northwest.
15

16 **Reference Plant:**

17 The reference plant is a 40-MW (nominal) binary-cycle plant comprised of three 13-MW (net)
18 units. The plant is assumed to use closed-loop organic Rankine-cycle technology suitable for
19 low geothermal fluid temperatures. The plant includes production and injection wells,
20 geothermal fluid piping, power block, cooling towers, step-up transformers, switchgear and
21 interconnection facilities, and security, control, and maintenance facilities. Wet cooling,
22 resulting in higher plant efficiency, greater productivity, and lower cost, would likely be used at
23 sites with sufficient water. Dry cooling could be employed at sites with insufficient cooling
24 water availability, at additional cost and some sacrifice in efficiency and productivity.

1
2 **Unit Commitment Parameters:**

3 Geothermal plants are assumed to operate as must-run units.
4

5 **Capacity Factor:** The average capacity factor over the life of the facility is assumed to be
6 90 percent.
7

8 **Heat Rate:** The average annual full load heat rate is 28,500 Btu/kWh, typical of an ORC binary
9 plant operating on 300°F geothermal fluid.
10

11 **Total Plant Cost:**

12 The total plant cost of the reference geothermal plant is \$4,800/kW installed capacity. This
13 estimate is based on a sample of one reported as-built plant cost and 12 preconstruction
14 estimates, including one estimate consisting of low and high bound costs.
15

16 **Operating and Maintenance Cost:**

17 Estimated operating and maintenance costs for the reference plant are \$175/kW/yr fixed plus
18 \$4.50/MWh variable.
19

20 **Economic Life:**

21 The economic life of a geothermal plant is assumed to be 30 years, limited by well field viability
22 and equipment life.
23

8.7.2.4 Hydropower

Reference Plant:

Because of the diversity of remaining hydropower development opportunities, no single plant configuration is representative of the remaining development opportunities. Cost and performance assumptions were based on the characteristics of recently developed proposed hydropower plants in the WECC.

Unit Commitment Parameters:

Hydropower plants are assumed to operate as must-run units.

Capacity Factor: The average capacity factor over the life of the facility is assumed to be 50 percent. This is based on the average of the reported energy production of a sample of 15 recently developed and proposed hydropower plants in the WECC (49.4 percent), rounded to 50 percent.

Total Plant Cost:

The representative cost of \$3,000/kW is the rounded capacity-weighted, escalation-adjusted average cost of eight “committed” (recently completed or under construction) projects.

Development and Construction Schedule, Cash Flows:

The development and construction schedule and cash flow assumptions for a typical small hydropower plant are as follows:

Development (issuance of preliminary permit to receipt of FERC license and selection of EPC contractor): 48 months, 12 percent of total plant cost.

1 **Construction** (site preparation, construction, and commissioning): 24 months, 88 percent of total
2 plant cost.

3
4 **Operating and Maintenance Cost:**

5 Operating and maintenance costs are assumed to be 3 percent of overnight capital cost. The
6 variable component is small and is included in the fixed O&M estimate.

7
8 **Economic Life:**

9 The economic life of a small hydropower plant is assumed to be 30 years, limited by major
10 equipment life.

11
12 **8.7.2.5 Concentrating Solar Thermal Power Plant**

13 Parabolic-trough concentrating solar thermal power plants are a commercially proven technology
14 with over 20 years of operating history. Existing plants use a synthetic oil primary heat transfer
15 fluid and a supplementary natural gas boiler in the secondary water heat transfer loop for output
16 stabilization and extended operation into the evening hours. Future plants are expected to benefit
17 from higher collector efficiencies, higher operating temperatures (providing higher thermal
18 efficiency and more economical storage), and economies of production.

19
20 **Reference Plant:**

21 The reference plant is a 100-MW dry-cooled parabolic-trough concentrating solar thermal plant
22 located in east-central Nevada in the vicinity of Ely. Power would be delivered to southern
23 Idaho via the north segment of the proposed Southwest Intertie Project and then to the Boardman
24 area via portions of the proposed Gateway West and the Boardman-to-Hemmingway
25 transmission projects. Higher-temperature heat transfer fluids such as molten salt are expected to

1 be available by the earliest feasible date for energization of the necessary transmission
2 (ca. 2015). The reference plant is assumed to be equipped with a 2.5 solar multiplier collector
3 field and thermal storage sufficient to support six to eight hours of full-power operation. This
4 storage would allow output to be shifted to non-daylight hours, improve winter capacity factor,
5 levelize output on intermittently cloudy days, and impart some firm capacity value. No natural
6 gas backup is provided since natural gas service is not available in the vicinity of the reference
7 site.

8 9 **Capacity Factors and Temporal Output:**

10 Annual capacity factor and seasonal, daily and hourly output was 35.5 percent for the Ely site.
11 Output is highly seasonal, even with a collector field solar multiplier of 2.5.

12 13 **Unit Commitment Parameters:**

14 Concentrating solar thermal plants are assumed to operate as must-run units.
15

16 **Total Plant Cost:**

17 The total plant cost of a representative parabolic-trough concentrating solar plant is estimated to
18 be \$4,700/kW. Publicly available cost information was located for three proposed or recently
19 constructed parabolic-trough concentrating solar plants, ranging in size from 64 to 250 MW.
20

21 **Operating and Maintenance Cost:**

22 Fixed O&M cost is \$60/kW/yr, and variable O&M is \$1.00/MWh.
23

24 **Integration Cost:**

25 The thermal storage capacity of the representative solar thermal plant is assumed to eliminate the
26 need for the incremental regulation and load following.

Economic Life:

The economic life of a parabolic-trough concentrating solar thermal plant is assumed to be 30 years.

Transmission:

New long-distance transmission would be required to deliver power to Northwest load centers from a solar thermal power plant near Ely, Nevada.

Table 8.7.5: Transmission Costs and Losses (Ely location)

Load Center	Fixed Transmission Costs	Variable Transmission Costs (\$/MWh)	Transmission Losses
Southern Idaho	\$102	\$1.00	4.0%
Oregon & Washington	\$189	\$1.00	6.5%

8.7.2.6 Wind Power Plants

Wind power is modeled by defining a reference wind plant and then applying transmission costs and losses appropriate to the location of the wind resource and the load center served. Plant capacity factors are adjusted to reflect the quality of the various wind resource areas. Five wind resource areas were assessed, including the Columbia basin (eastern Washington and Oregon), southern Idaho, central Montana, southern Alberta, and eastern Wyoming. The combinations of wind resource areas, transmission, and points of delivery considered are shown in Table I-3 in the Transmission section.

Reference Plant:

The 100-MW reference plant consists of arrays of conventional three-blade wind turbine generators, in-plant electrical and control systems, interconnection facilities and on-site roads, meteorological towers, and support facilities.

Capacity Factors and Temporal Output:

The annual average capacity factors used for the five resource areas are shown in Table 8.7.6.

Table 8.7.6: Wind Average Annual Capacity Factors

Wind Resource Area >	Columbia Basin	Southern Idaho	Central Montana	Southern Alberta	Eastern Wyoming
Average annual capacity factor (net plant output)	32%	30%	38%	38%	38%

Unit Commitment Parameters:

Wind power plants are assumed to operate as must-run units.

Total Plant Cost:

The total plant cost of the reference wind plant is \$2,100/kW installed capacity.

Operating and Maintenance Cost:

Fixed O&M cost is \$40/kW/yr and escalates with total plant cost. The variable O&M cost of \$2.00/MWh is intended to represent land rent. Land rent is estimated to be approximately between 2 and 4 percent of the gross revenue from wind turbine generation.

Economic Life:

The economic life of a wind plant is assumed to be 20 years.

8.7.2.7 Coal-Fired Steam-Electric Plants

The pulverized coal-fired power plant is the established technology for producing electricity from coal. The basic components of a steam-electric pulverized coal-fired power plant include a coal storage, handling, and preparation facility; a furnace and steam generator; and a steam

1 turbine-generator. Coal is ground (*i.e.*, pulverized) to dust-like consistency, blown into the
2 furnace and burned in suspension. The energy from the burning coal generates steam that is used
3 to drive the steam turbine-generator. Ancillary equipment and systems include flue gas
4 treatment equipment and stack, an ash handling system, a condenser cooling system, and a
5 switchyard and transmission interconnection. Newer units are typically equipped with low-NO_x
6 burners, sulfur dioxide removal equipment, and electrostatic precipitators or baghouses for
7 particulate removal. Selective catalytic reduction of NO_x and CO emission is becoming
8 increasingly common, and post-combustion mercury control is expected to be required in the
9 future. Often, several units of similar design will be co-located to take advantage of economies
10 of design, infrastructure, construction, and operation. Most western coal-fired plants are sited
11 near the mine mouth, though some plants are supplied with coal by rail at intermediate locations
12 between mine mouth and load centers.

13
14 Most existing North American coal steam-electric plants operate at sub-critical steam conditions.
15 Supercritical steam cycles operate at higher temperature and pressure conditions at which the
16 liquid and gas phases of water are indistinguishable. This results in higher thermal efficiency
17 with corresponding reductions in fuel cost, carbon dioxide production, air emissions, and water
18 consumption. Supercritical units are widely used in Europe and Japan. Several supercritical
19 units were installed in North America in the 1960s and '70s, but the technology was not widely
20 adopted because of low coal costs and the poor reliability of some early units. The majority of
21 new North American coal capacity is now supercritical technology.

22
23 **Reference Plant:**

24 A single 450-MW net supercritical pulverized coal-fired power plant at a Greenfield site. This
25 plant is equipped with low-NO_x burners, overfire air, and selective catalytic reduction for control
26 of nitrogen oxides. The plant would be provided with flue gas desulfurization, fabric filter

1 particulate control, and activated charcoal injection for reduction of mercury emissions. The
2 capital costs include a switchyard and transmission interconnection.

3
4 The base case plant uses evaporative (wet) condenser cooling. Dry cooling uses less water, and
5 might be more suitable for arid areas of the West. But dry cooling reduces the thermal efficiency
6 of a steam-electric plant by about 10 percent, and proportionally increases per-kilowatt air
7 emissions and carbon dioxide production. The effect is about three times greater for steam-
8 electric plants than for gas turbine combined-cycle power plants, where recent proposals have
9 trended toward dry condenser cooling. For this reason, BPA Staff assumes the majority of new
10 coal-fired power plants would be located in areas where water availability is not critical and
11 would use evaporative cooling.

12
13 **Fuel:**

14 The reference plant is assumed to be fueled by western subbituminous coal.

15
16 **Total Plant Cost:**

17 The “overnight” total plant cost of the reference pulverized coal-fired plant is estimated to be
18 \$3,500/kW installed capacity.

19
20 **Operating and Maintenance Costs:**

21 The fixed O&M cost for the reference plant is estimated to be \$60/kW/yr (exclusive of property
22 tax and insurance). The variable O&M cost for the reference plant is estimated to \$2.75/MWh.

23
24 **Economic Life:**

25 The economic life of a coal-fired steam-electric plant is assumed to be 30 years.

8.7.2.8 Natural Gas Simple-Cycle Intercooled Gas Turbine Plant

Reference Plant:

The reference intercooled simple-cycle gas turbine plant consists of a single gas turbine generator set of 99 MW nominal capacity, an external intercooler, an evaporative mechanical draft cooling system for the intercooler, lube oil, fuel forwarding and other ancillary equipment, a control building, and switchyard. Cost and performance characteristics are based on the General Electric LMS100PB (dry low-NO_x combustors). Auxiliary loads for external intercooler technology will be greater than a conventional simple-cycle unit, and the net “new and clean” capacity of the plant under ISO conditions is 96 MW. The new and clean heat rate is degraded a further 2.2 percent for maintenance-adjusted lifecycle aging effects to yield a lifecycle average baseload capacity of 94 MW (ISO conditions). The gas turbine generator is enclosed for weather protection and acoustic control, and is provided with inlet air filters and exhaust silencers.

Fuel:

Natural gas is supplied on a firm transportation contract with capacity release capability. No backup fuel is provided.

Heat Rate:

The full-load, higher heating value (HHV) heat rate under “new and clean” conditions is estimated to be 8,810 Btu/kWh. This is based on the nominal lower heating value heat rate reported for a General Electric LMS100PB in Gas Turbine World (2009), converted to HHV and derated 3.1 percent for inlet, exhaust, auxiliary load, and transformer losses. The lifecycle average HHV full-load heat rate is estimated to be 8,870 Btu/kWh. This is based on the new and clean heat rate degraded 0.8 percent for maintenance-adjusted lifecycle aging effects.

1 **Total Plant Cost:**

2 The overnight total plant cost of the reference plant is estimated to be \$1,130/kW. This estimate
3 is based on a sample of one reported as-built plant cost, three “as-committed” cost estimates,
4 seven preconstruction cost estimates (including one range estimate), and five generic cost
5 estimates including two range estimates.

6
7 **Economic Life:**

8 The economic life of an intercooled hybrid simple-cycle gas turbine power plant is assumed to
9 be 30 years.

10
11 **Operating and Maintenance Cost:**

12 Fixed O&M cost is estimated to be \$8/kW/yr, and variable O&M is estimated to be \$5.00/MWh.

13
14 **8.7.2.9 Natural Gas Combined-Cycle Plant – Duct Firing**

15 Gas turbine combined-cycle power plants consist of one or more gas turbine generators provided
16 with exhaust heat recovery steam generators. Steam raised in the heat recovery units powers a
17 steam-turbine generator. Capture of the energy of the gas turbine exhaust increases the overall
18 thermal efficiency of a combined-cycle plant compared to a simple-cycle gas turbine generator.
19 The reference combined-cycle unit, for example, has a base load efficiency of 48 percent
20 compared to a full-load efficiency of 38 percent for the reference hybrid intercooled gas turbine.
21 Combined-cycle plants can serve cogeneration steam load (at some loss of electricity production)
22 by extracting steam at the needed pressure from the heat-recovery steam generator or steam
23 turbine. Additional generating capacity (power augmentation) can be obtained at low cost by
24 oversizing the steam turbine generator and providing the heat recovery steam generator with
25 natural gas burners (duct firing). The resulting capacity increment operates at somewhat lower

1 electrical efficiency than the base plant and is usually reserved for peaking operation. The
2 incremental efficiency, however, is comparable to that of simple-cycle gas turbines. Because
3 they often operate at or near market clearing prices, combined-cycle plants can be an economical
4 source of system balancing reserves. With high reliability, high efficiency, low capital cost,
5 short lead time, operating flexibility, and low air emissions, gas-fired combined-cycle plants
6 have been the bulk power generation resource of choice since the early 1990s.

7
8 **Reference Plant:**

9 The reference plant is a single-train (1x1) natural gas-fired combined-cycle plant consisting of a
10 “G-class” gas turbine generator, a fired heat recovery steam generator and a steam turbine
11 generator. The “new and clean” net base load capacity under ISO conditions is 395 MW with
12 25 MW of peaking power augmentation. The net baseload capacity is based on the nominal
13 capacity of a 1x1 Mitsubishi 501G combined-cycle unit (Gas Turbine World, 2009), derated
14 0.9 percent for SCR and main transformer losses. The new and clean heat rate is degraded a
15 further 2.7 percent for maintenance-adjusted lifecycle aging effects to yield a lifecycle average
16 baseload capacity of 385 MW. Air emission controls include dry low-NO_x combustors and
17 selective catalytic reduction for NO_x control, and an oxidation catalyst for CO and VOC control.
18 Condenser cooling is wet mechanical draft.

19
20 **Fuel:**

21 Natural gas supplied on a firm transportation contract with capacity release capability. No
22 backup fuel is provided.

23
24 **Heat Rate:**

25 The HHV heat rate at full baseload under “new and clean” conditions is estimated to be
26 6,790 Btu/kWh. This is the reported heat rate for the Port Westward plant (Mitsubishi MHI

501G). The lifecycle average HHV heat rate at full baseload is estimated to be 6,930 Btu/kWh. This is based on the new and clean heat rate degraded 2.1 percent for maintenance-adjusted lifecycle aging effects. The incremental heat rate of supplemental (duct-fired) capacity is estimated to be 9,500 Btu/kWh (Fifth Plan assumption).

Economic Life:

The economic life of a combined-cycle plant is assumed to be 30 years.

Total Plant Cost:

The overnight total plant cost of the reference plant is estimated to be \$1,120/kW. This estimate is based on an estimated cost of baseload capacity of \$1,160/kW and an estimated cost of supplementary (fired HSRG) capacity of \$465/kW. These estimates were derived from six reported as-built plant costs, 16 preconstruction cost estimates (one with low and high bound estimates), and four generic cost estimates (one including low and high bound costs) from 2004 or later.

Operating and Maintenance Cost:

Fixed O&M cost is \$14/kW/yr. Variable O&M is \$1.70/MWh.

8.8 Renewable Portfolio Standards

A Renewable Portfolio Standard (RPS) is a regulation that requires the increased production of energy from renewable energy sources, such as wind, solar, biomass, and geothermal. The RPS mechanism generally places an obligation on electricity supply companies to produce a specified

fraction of their electricity from renewable energy sources. Renewable energy sources may include:

- Biofuels
- Biomass
- Fuel cells
- Geothermal
- Hydro
- Landfill gas
- Ocean thermal
- Photovoltaic
- Solar thermal electric
- Tidal
- Waste tire
- Wave
- Wind

Following is a summary of RPS requirements by state for the Pacific Northwest.

8.8.1 Overview of State Renewable Portfolio Standards

Oregon

In June 2007, Oregon adopted RPS standards in Senate Bill 838 (ORS 469A). The bill directs Oregon utilities to meet a percentage of their retail electricity needs with qualified renewable resources. For Portland General Electric and PacifiCorp the standard starts at 5 percent in 2011, increases to 15 percent in 2015, 20 percent in 2020, and 25 percent in 2025.

1 The legislation also provides that Renewable Energy Credits (RECs) may be used to fulfill RPS
2 targets. In addition, utilities may bank unused RECs from one year to apply towards future RPS
3 requirements.

4
5 An Oregon utility may comply with the RPS using any combination of the following options:

6 Build an eligible facility (or continue to operate an existing one) and retain REC output from
7 these facilities.

- 8
- 9 • Buy power and REC output (a bundled REC) from another eligible facility.
- 10 • Buy unbundled REC output.
- 11 • Make “alternative compliance payments” with options to use these funds for construction
- 12 of an eligible facility in the future.
- 13

14 **Washington**

15 In November 2006, Washington voters approved Initiative Measure No. 937, which established
16 renewable energy targets starting at 3 percent of a qualifying utility’s load by 2012, 9 percent in
17 2015, and 15 percent by 2020. Qualifying utilities are public and private utilities that serve more
18 than 25,000 customers located in the state of Washington. Electricity produced from an eligible
19 renewable resource must be generated in a facility that started operating after March 31, 1999.

20 Either the facility must be located in the Pacific Northwest, or the electricity from the facility
21 must be delivered into the state on a real-time basis. Incremental electricity produced from
22 efficiency improvements at hydropower facilities owned by qualifying utilities is also an eligible
23 renewable resource, if the improvements were completed after March 31, 1999.

1 Initiative 937 allows utilities to use RECs to meet their acquisition targets. RECs can be bought
2 and sold in the marketplace, and they may be used during the year they are acquired, the
3 previous year, or the subsequent year.

4 5 **Idaho**

6 There are currently no RPS requirements in Idaho.

7 8 **Montana**

9 In April 2005, Montana enacted its RPS as part of the Montana Renewable Power Production
10 and Rural Economic Development Act, which requires public utilities and competitive electricity
11 suppliers to obtain a percentage of their retail electricity sales from eligible renewable resources
12 according to the following schedule:

- 13 • 5 percent for compliance years 2008–2009 (1/1/2008–12/31/2009)
- 14 • 10 percent for compliance years 2010–2014 (1/1/2010–12/31/2014)
- 15 • 15 percent for compliance year 2015 (1/1/2015–12/31/2015) and for each year thereafter

16
17 Eligible facilities must begin operation after January 1, 2005, and must either be located in
18 Montana or located in another state and be delivering electricity into Montana.

19
20 Utilities and competitive suppliers can meet the standard by entering into long-term purchase
21 contracts for electricity bundled with RECs, by purchasing the RECs separately, or by a
22 combination of both.

23
24 A table showing the relationship between each exchanging utility's annual RPS requirement and
25 the amount of renewable resource MWh and RECs is shown in Table 2.10 of the Documentation.

8.8.2 Treatment of RPS Requirements in ASC Forecast Model

For certain utilities, additional renewable resources not specifically included in the individual IRPs were added so that each utility met RPS requirements through 2028. Avista fell slightly below RPS requirements in a few years, because the model did not include several small upgrades to existing hydro resources. When the upgrades are included, Avista meets RPS requirements in all years through 2028. Because Franklin did not prepare a formal IRP, wind resources were added to meet RPS requirements. Wind resources were also added to NorthWestern to meet its RPS requirements. For PGE and Snohomish, additional wind resources were added after 2021, the end of their IRP planning window. Clark's IRP stated that it would purchase RECs to meet RPS targets in certain years. Clark estimated that the price of a REC is \$20/MWh in 2012.

8.8.3 Load Forecasts

The load forecast portion of this Study shows the loads for FY 2009–2032. For FY 2009–2017, BPA Staff used the loads that were filed in each utility's 2009 Base Year Appendix 1, the only exception being the COUs. In the case of the COUs, Staff used its own load forecasts as was agreed upon in the TRM for the implementation of BPA's Tiered Rates. For the Long-Term Period, BPA Staff escalated the utility's ending year FY 2017 load forecast out to FY 2032, using the percentage load growth forecast published in the utility's IRP, if available. The following tables present each utility's long-term load forecast for FY 2009–2032.

8.8.3.1 Avista Corporation

This Study used Avista's retail load forecast from the 2009 Base Year Appendix 1 "Draft Report" for the years FY 2009–2017. For the FY 2018–2032 period, the Study used the following:

- 1 1. Avista reported in its 2009 IRP that retail load would grow by 1.8 percent from 2009 to
2 2029. See Avista’s 2009 Electric Integrated Resource Plan, August 31, 2009, at 2–11.
3 Avista did not report the level of load in 2029. Therefore, BPA forecast Avista’s
4 FY 2029 Total Retail Sales based on this growth rate to be 12,794,413 MWh in 2029.

5
$$FY2029 \text{ Total Retail Sales} = FY2009 \text{ Total Retail Sales} \times (1 + .018)^{20}$$

6
$$FY2029 \text{ Total Retail Sales} = 12,794,413$$

- 7
8 2. BPA then calculated the growth rate from the “Draft Report” FY 2017 Total Retail Sales
9 that would result in the forecast FY 2029 Total Retail Sales.

10
$$\text{Growth Rate FY2017–29} = ((FY2029 \text{ Total Retail Sales} / FY2017 \text{ Total}$$

11
$$\text{Retail Sales})^{(1/12)} - 1$$

- 12
13 3. Staff escalated the long-term load forecast from FY 2018 to 2032 by the 1.74 percent
14 load growth percentage.

15
16 Table 2.8.1 in the Documentation shows the load forecast from Avista’s 2009 Base Year
17 Appendix 1 “Draft Report” for the years FY 2009–2017 and the escalated forecast loads for the
18 years FY 2018–2032 as determined from Avista’s IRP load growth percentage.

19
20 **8.8.3.2 Clark County PUD**

21 The load forecast used in the LTAFM for Clark is shown in Table 2.8.2 of the Documentation.

22
23 **8.8.3.3 Franklin County PUD**

24 The load forecast used in the LTAFM for Franklin is shown in Table 2.8.3 of the
25 Documentation.

8.8.3.4 Idaho Power Company

This Study used Idaho Power’s retail load forecast from the 2009 Base Year Appendix 1 “Draft Report” for the years FY 2009–2017. For the FY 2018–2032 period, the Study used the following:

1. Idaho Power reported in its 2009 IRP that retail load would grow by 0.70 percent from 2009 to 2029. See Idaho Power’s 2009 Electric Integrated Resource Plan, Appendix C, December 2009, at 35. Idaho Power did not report the level of load in 2029. Therefore, BPA forecast Idaho Power’s FY 2029 Total Retail Sales based on this growth rate to be 16,000,360 MWh in 2029.

$$FY2029 \text{ Total Retail Sales} = FY2009 \text{ Total Retail Sales} \times (1 + .011)^{20}$$

$$FY2029 \text{ Total Retail Sales} = 16,000,360$$

2. BPA then calculated the growth rate from the “Draft Report” FY 2017 Total Retail Sales that would result in the forecast FY 2029 Total Retail Sales.

$$\text{Growth Rate } FY2017-29 = ((FY2029 \text{ Total Retail Sales} / FY2017 \text{ Total Retail Sales})^{(1/12)}) - 1$$

3. Staff escalated the long-term load forecast from FY 2018 to 2032 by the 1.12 percent load growth percentage.

Table 2.8.4 in the Documentation shows the load forecast from Idaho Power’s 2009 Base Year Appendix 1 “Draft Report” for the years FY 2009–2017 and the escalated forecast loads for the years FY 2018–2032 as determined from Idaho Power’s IRP load growth percentage.

8.8.3.5 NorthWestern Corporation

This Study used NorthWestern’s retail load forecast from the 2009 Base Year Appendix 1 “Draft Report” for the years FY 2009–2017. For the FY 2018–2032 period, the Study used the following:

1. NorthWestern reported in its 2009 IRP that retail load would grow by 0.80 percent from 2009 to 2029. See NorthWestern’s 2009 Electric Default Supply Procurement Plan, June 2010 at 112. NorthWestern did not report the level of load in 2029. Therefore, BPA forecast NorthWestern’s FY 2029 Total Retail Sales based on this growth rate to be 6,811,234 MWh in 2029.

$$FY2029 \text{ Total Retail Sales} = FY2009 \text{ Total Retail Sales} \times (1 + .008)^{20}$$

$$FY2029 \text{ Total Retail Sales} = 6,811,234$$

2. BPA then calculated the growth rate from the “Draft Report” FY 2017 Total Retail Sales that would result in the forecast FY 2029 Total Retail Sales.

$$\text{Growth Rate } FY2017\text{--}29 = ((FY2029 \text{ Total Retail Sales} / FY2017 \text{ Total Retail Sales})^{(1/12)}) - 1$$

3. Staff escalated the long-term load forecast from FY 2018 to 2032 by the 0.70 percent load growth percentage.

Table 2.8.5 in the Documentation shows the load forecast from NorthWestern’s 2009 Base Year Appendix 1 “Draft Report” for the years FY 2009–2017 and the escalated forecast loads for the years FY 2018–2032 as determined from NorthWestern’s IRP load growth percentage.

8.8.3.6 PacifiCorp

This Study used PacifiCorp’s retail load forecast from the 2009 Base Year Appendix 1 “Draft Report” for the years FY 2009–2017. For the FY 2018–2032 period, the Study used the following:

1. PacifiCorp reported in its 2009 IRP that retail load would grow by 1.13 percent from 2009 to 2028. See PacifiCorp’s 2009 Electric Integrated Resource Plan, May 28, 2009, at 71. PacifiCorp did not report the level of load in 2028. Therefore, BPA forecast PacifiCorp’s FY 2028 Total Retail Sales based on this growth rate to be 24,671,984 MWh in 2028.

$$FY2029 \text{ Total Retail Sales} = FY2009 \text{ Total Retail Sales} \times (1 + .0113)^{20}$$

$$FY2028 \text{ Total Retail Sales} = 24,671,984$$

2. BPA then calculated the growth rate from the “Draft Report” FY 2017 Total Retail Sales that would result in the forecast FY 2028 Total Retail Sales.

$$\text{Growth Rate FY2017–28} = ((FY2029 \text{ Total Retail Sales} / FY2017 \text{ Total Retail Sales})^{(1/12)}) - 1$$

3. Staff escalated the long-term load forecast from FY 2018 to 2032 by the 1.13 percent load growth percentage.

Table 2.8.6 in the Documentation shows the load forecast from PacifiCorp’s 2009 Base Year Appendix 1 “Draft Report” for the years FY 2009–2017 and the escalated forecast loads for the years FY 2018–2032 as determined from PacifiCorp’s IRP load growth percentage.

8.8.3.7 Portland General Electric

This Study used Portland General’s retail load forecast from the 2009 Base Year Appendix 1 “Draft Report” for the years FY 2009–2017. For the FY 2018–2032 period, the Study used the following:

1. Portland General reported in its 2009 IRP that retail load would grow by 1.8 percent from 2009 to 2029. See Portland General’s 2009 Electric Integrated Resource Plan, 2009, at 37. Portland General did not report the level of load in 2030. Therefore, BPA forecast Portland General’s FY 2030 Total Retail Sales based on this growth rate to be 23,797,064 MWh in 2030.

$$FY2029 \text{ Total Retail Sales} = FY2009 \text{ Total Retail Sales} \times (1 + .0191)^{20}$$

$$FY2029 \text{ Total Retail Sales} = 23,797,064$$

2. BPA then calculated the growth rate from the “Draft Report” FY 2017 Total Retail Sales that would result in the forecast FY 2030 Total Retail Sales.

$$\text{Growth Rate FY2017–30} = (FY2030 \text{ Total Retail Sales} / FY2017 \text{ Total Retail Sales})^{(1/12)} - 1$$

3. Staff escalated the long-term load forecast from FY 2018 to 2032 by the 1.75 percent load growth percentage.

Table 2.8.7 in the Documentation shows the load forecast from Portland General’s 2009 Base Year Appendix 1 “Draft Report” for the years FY 2009–2017 and the escalated forecast loads for the years FY 2018–2032 as determined from Portland General’s IRP load growth percentage.

8.8.3.8 Puget Sound Energy

This Study used Puget’s retail load forecast from the 2009 Base Year Appendix 1 “Draft Report” for the years FY 2009–2017. For the FY 2018–2032 period, the Study used the following:

1. Puget reported in its 2009 IRP that retail load would grow by 1.9 percent from 2009 to 2027. See Puget’s 2009 Electric Integrated Resource Plan, July 2009, at 4–14. Puget did not report the level of load in 2027. Therefore, BPA forecast Puget’s FY 2027 Total Retail Sales based on this growth rate to be 26,315,040 MWh in 2027.

$$FY2029 \text{ Total Retail Sales} = FY2009 \text{ Total Retail Sales} * (1 + .019) ^{20}$$

$$FY2029 \text{ Total Retail Sales} = 26,315,040$$

2. BPA then calculated the growth rate from the “Draft Report” FY 2017 Total Retail Sales that would result in the forecast FY 2029 Total Retail Sales.

$$Growth \text{ Rate } FY2017-29 = ((FY2029 \text{ Total Retail Sales} / FY2017 \text{ Total Retail Sales}) ^{(1/12)) - 1$$

3. Staff escalated the long-term load forecast from FY 2018 to 2032 by the 1.72 percent load growth percentage.

Table 2.8.8 in the Documentation shows the load forecast from Puget’s 2009 Base Year Appendix 1 “Draft Report” for the years FY 2009–2017 and the escalated forecast loads for the years FY 2018–2032 as determined from Puget’s IRP load growth percentage.

8.8.3.9 Snohomish County PUD

The load forecast used in the LTAFM for Snohomish PUD is shown in Table 2.8.9 of the Documentation.

8.9 Resource Additions

This section includes the forecast new resource additions through 2028. This Study assumes the following:

- The new resources for 2010 through FY 2012–2013 are the same as the resources filed in each utility’s ASC filing for FY 2012–2013.
- BPA used the utility’s most recent IRP for the basis for new resource additions through the 2028 forecast period.
- Resources identified in the IRP as becoming operational during the Exchange Period, but not identified in the utility’s ASC filing, were assumed to be delayed and brought on in FY 2014.
- If the utility’s IRP did not extend through 2028, BPA Staff did not attempt to add new resource additions for the out years not covered in the IRP except for RPS Compliance. Instead, BPA Staff assumed load growth was met with market purchases.
- BPA did test for RPS compliance. If a utility did not comply with the RPS requirements, BPA met the requirements with regional wind additions.

8.9.1 Avista Corporation

Table 8.9.1: Avista Corporation New Resources

MW Capacity																
Resource	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
SCCT - LMS100																
CCCT						250					250			250		750
Biomass																
Geothermal																
Landfill Gas																
Long-Haul Wind																
Solar																
Wind	150					150			50							350
Purchased Power																
REC																

Table 8.9.1 above agrees with Avista's 2009 Preferred Resource Strategy with the exception of 150 MW of wind coming online in 2014. Because this wind resource was not included in Avista's 2009 ASC filing, the on-line date was delayed in the LTAFM until 2014. See Avista's 2009 Electric Integrated Resource Plan, August 31, 2009.

8.9.2 Clark County PUD

Table 8.9.2: Clark County PUD New Resources

MW Capacity																
Resource	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
SCCT - LMS100	70															70
CCCT																
Biomass																
Geothermal																
Landfill Gas											22					22
Long-Haul Wind																
Solar																
Wind									20					10		30
Purchased Power																
REC		30					40									70

Table 8.9.2 above agrees with Clark's 2010 preferred Portfolio 1 from its IRP. See Clark Public Utilities Final Integrated Resource Plan, August 2010, at C-1. The REC purchases in 2015 and 2020 above are also based on Clark's 2010 Portfolio 2 analysis of RPS Requirements versus Renewable Purchases. See Clark's Final Integrated Resource Plan at 70.

8.9.3 Franklin County PUD

Table 8.9.3: Franklin County PUD New Resources

MW Capacity																
Resource	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
SCCT - LMS100																
CCCT																
Biomass																
Geothermal																
Landfill Gas																
Long Haul Wind																
Solar																
Wind		30			35											65
Purchased Power																
REC																

Due to Franklin's size, it is not required to file a comprehensive IRP. However, customer growth will likely subject Franklin to RPS requirements in the near future. In order to comply with RPS requirements, wind resources were added in 2015 and 2018 so that Franklin would comply with RPS requirements.

8.9.4 Idaho Power Company

Table 8.9.4: Idaho Power Company New Resources

MW Capacity																
Resource	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
SCCT - LMS100							100				200		200		400	900
CCCT																
Biomass																
Geothermal	20		20													40
Landfill Gas																
Long Haul Wind																
Solar																
Wind									100					400		500
Purchased Power																
REC																

Table 8.9.4 above agrees with Idaho Power's 2009 Action Plan in its IRP with the exception of the 20 MW of geothermal, which is shown in the table above as coming on line in 2014.

Because the geothermal resource was not included in Idaho Power Company's 2009 ASC filing, the on-line date was delayed until 2014 in the ASC Forecast Model. See Idaho Power Company's 2009 Integrated Resource Plan, December 2009, at 123-124.

8.9.5 NorthWestern Corporation

Table 8.9.5: NorthWestern Corporation New Resources

MW Capacity																
Resource	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
SCCT - LMS100																
CCCT		200														200
Biomass							25									25
Geothermal																
Landfill Gas																
Long Haul Wind																
Solar																
Wind	50		75	25												150
Purchased Power	-287															-287
REC																

Table 8.9.5 above agrees with NorthWestern's 2009 Action Plan in its IRP (Electric Default Supply Procurement Plan). See NorthWestern's 2009 Electric Default Supply Procurement Plan, June 2010, at 157.

8.9.6 PacifiCorp

Table 8.9.6: PacifiCorp New Resources

MW Capacity																
Resource	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
SCCT - LMS100			261													261
CCCT	570															
Biomass												25		25		50
Geothermal	35															
Landfill Gas																
Long Haul Wind	549	150	100	100	50	200	200	150								1499
Solar																
Wind	220															220
Purchased Power																
REC																

Table 8.9.6 above is based on PacifiCorp’s 2008 IRP preferred portfolio with a few exceptions. First, because the PacifiCorp’s IRP was published in 2008, the wind resources projected to come on line in 2009 were already reflected PacifiCorp’s 2009 FERC Form 1 filing and thus are contained in PacifiCorp’s existing resources. See PacifiCorp’s 2008 Integrated Resource Plan Volume I, May 28, 2009, at 245, and PacifiCorp’s 2009 FERC Form 1, pages 410–411. Second, the Blundell Geothermal resource, projected to come on line in 2013, was delayed until 2014 in the LTAFM because it was not included in PacifiCorp’s 2009 ASC filing. Third, the values for “Long Haul Wind” and “Wind” shown in 2014 represent the sum of individual wind plants projected to come on line between 2010 and 2014, but not included in PacifiCorp’s 2009 ASC filing. Fourth, the values shown for PacifiCorp’s new resource additions in the LTAFM represent the Oregon, Washington, and Idaho share or 40.98 percent of the actual values. This factor is the same on used by PacifiCorp to allocate total system generation to Oregon, Washington, and Idaho in its ASC filings. Finally, after 2021, PacifiCorp’s IRP assumed that

load growth would be met with front-office (purchased power) transactions. Because the ASC Forecast Model already contains logic to cover load/resource deficits with purchased power, the front-office transactions were not included.

8.9.7 Portland General Electric

Table 8.9.7: Portland General Electric New Resources

MW Capacity																
Resource	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
SCCT - LMS100	200															200
CCCT		441						440								881
Biomass				29		29										58
Geothermal						58										58
Landfill Gas																
Long Haul Wind																
Solar						27										27
Wind							200		100		200	200	200			900
Purchased Power																
REC																

Table 8.9.7 above agrees with Portland General's 2009 IRP with the exception of the four wind resources added after 2021. Because PGE's IRP did not extend beyond 2021, the wind resources were added to meet RPS requirements. See Portland General Electric's 2009 Integrated Resource Plan Addendum, April 9, 2010, at 119.

8.9.8 Puget Sound Energy

Table 8.9.8: Puget Sound Energy New Resources

MW Capacity																
Resource	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
SCCT - LMS100	160			160			160	160	160	160	160	160	160	160	160	1760
CCCT	275			275			275									825
Biomass							20					20				40
Geothermal																
Landfill Gas																
Long Haul Wind																
Solar																
Wind	100		200		200		200									700
Purchased Power																
REC																

Table 8.9.8 above agrees with Puget's 2009 IRP with two exceptions. Puget included 300 MW of wind resources projected to come on line 2011 and 2012 in its IRP, but did not include them in its 2009 ASC filing. However, Puget's ASC filing did include a new wind resource (LSR) with a nameplate capacity of 343 MW projected to come on line in 2012. The LFAFM used the LSR wind resource in place of the 2011 and 2012 wind resources contained in Puget's IRP.

Table 8.3.8 shows the new resources that were included in Puget's IRP and 2009 ASC filing. See Puget Sound Energy's 2009 Integrated Resource Plan, July 2009, at 8-(13-15).

8.9.9 Snohomish County PUD

Table 8.9.9: Snohomish County PUD New Resources

MW Capacity																
Resource	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
SCCT - LMS100																
CCCT																
Biomass			1.25													1.25
Geothermal			5.56		5.56		44.44									55.56
Landfill Gas			3.53													3.53
Long Haul Wind																
Solar																
Wind							50	20		20		20				110
Purchased Power																
REC																
Hydro					4		4									8

Table 8.9.9 above agrees with Snohomish’s preferred plan as contained in its 2010 IRP with the exception of wind resources, which in the above table are added beginning in 2020 in order to comply with RPS requirements. See Snohomish County PUD’s 2010 Integrated Resource Plan, August 17, 2010, at 4.

9. RISK FACTORS

9.1 Risk Factors Affecting BPA Rates and ASCs

BPA and REP participants face numerous risks that can impact the level of future REP benefits. Some of these risks impact both the PF rate and ASCs while other risks primarily impact either the PF rate or the ASC. These risks ultimately impact the costs and/or the revenues of BPA and the REP utilities. Because COU REP participants purchase much of their power from BPA and the cost of BPA purchases is included in ASCs, BPA's risks also directly translate into ASC risk for the COUs that participate in the REP. Some of these risks are in existence now and impact current financial conditions, some are currently foreseeable and may eventually happen but lack adequate specification, and still other risks are unforeseen but will likely occur over the course of a 17-year period.

In this section, the words "risk" and "uncertainty" are used interchangeably. Generally, each can have both up-side and down-side possibilities—that is, both beneficial and harmful. A "risk" in this discussion does not signify only the possibility of harm but rather the possibility of events occurring that have an impact on expected future outcomes. The outcomes that may be affected by the risks considered in this discussion are generally related to future rate levels.

9.1.1 Gas and Electric Market

Natural gas market conditions are important for two reasons. First, natural gas prices affect the overall cost of generation for utilities with gas-fired generation in their portfolios. Second, when natural gas-fired resources are the marginal unit dispatched in the electric marketplace, the price of natural gas determines the variable cost for that marginal generator, and hence, the market

1 clearing price of electricity. In the first instance, higher natural gas prices increase the cost of
2 producing electricity, which in turn increases the ASC of the utilities that rely on gas-fired
3 generation. Conversely, lower natural gas prices reduce the cost of producing electricity, which
4 in turn decreases the ASCs of the utilities that rely on gas-fired generation. The impact of
5 alternative natural gas prices is especially important when evaluating ASCs because natural gas
6 prices have historically been very volatile and can materially change the level of an ASC.

7
8 Second, changes in the electricity market prices are important because they can impact not only
9 the cost of producing power but the prices paid and received for buying and selling energy on the
10 wholesale power market. Two changes in the electricity market that are of particular importance
11 to the calculation of ASCs are state or possible Federal Renewable Portfolio Standards (RPS)
12 and the potential impact of CO₂ costs being reflected in the cost of electricity production from
13 resources that burn fossil fuels. Because BPA does not currently have gas-fired generation in its
14 resource portfolio, BPA-related risks stemming from market prices are generally confined to the
15 effects of wholesale electricity prices.

17 **9.1.2 Operating Cost Risk: Hydro (Including Fish), CGS, Wind**

18 **9.1.2.1 Hydro Generation Risk Impacts**

19 The amount of Federal hydro generation impacts the amount of surplus energy sold and power
20 purchased by BPA in everyday operations and the level of the revenue credits used when
21 calculating rates for PF customers. In the ratesetting process, hydro generation under critical
22 water conditions also impacts the amount of firm power available to meet BPA's sales
23 obligations. BPA not only faces the financial risk of reductions in the amount of hydro
24 generation, but also higher capital and expense costs associated with meeting fish-related
25 operational requirements. Hydro generation can be reduced due to additional hydro spill

1 requirements and monthly and hourly hydro generation can be reshaped into less valuable time
2 periods due to hydro operation changes specified in current and future fish-related requirements
3 for the Columbia and Willamette dams (which requirements may still be in their infancy). Such
4 operational requirements on the Columbia and Snake dams are currently being litigated and,
5 given past history, future operations will also likely be litigated and could result in additional
6 generation loss or reshaping.

7
8 Future fish mitigation requirements are also likely to result in higher capital costs and expenses,
9 especially if additional fish passage is required at the Columbia and Willamette dams. These
10 additional costs would put upward pressure on BPA's future rates. It is very likely that
11 additional outlays will be required for the dams and fish passage structures associated with
12 mussel control measures. An additional potential risk is the impact that global warming may
13 have on the amount of future hydro generation. There is also a possibility of higher than
14 expected capital investments and O&M expenses associated with maintaining the capability of
15 the Federal dams in the future. In conclusion, the foregoing hydro risks point to higher BPA rate
16 levels in the future. While these risks may somewhat affect IOUs' ASCs, they are primarily
17 focused on BPA's rates and COU ASCs.

18 19 **9.1.2.2 CGS Generation Risk Impacts**

20 The level of output of the Columbia Generation Station (CGS) impacts the amount of energy
21 sold and power purchased by BPA in everyday operations and can impact the amount of power
22 available to meet BPA's sales obligations. CGS generation risks can be largely categorized in
23 terms of the amount of output produced, or the level of capital expenditures and O&M costs to
24 maintain the plant's output. Given the current age of CGS, it is probable that over the next 17
25 years the output of CGS will diminish, resulting in more frequent unplanned outages and longer

1 maintenance outages. At the same time, capital expenditures are also likely to rise as the plant
2 ages and efforts are undertaken to maintain plant output and integrity. Also, the prices paid for
3 nuclear fuel on the spot and forward markets have been historically very volatile and represent a
4 sizable cost risk. Assessed independently or together, the foregoing CGS risks indicate generally
5 higher BPA rate levels in the future. These risks will not affect IOUs' ASCs; they are confined
6 to BPA's rates and COUs' ASCs.

8 **9.1.2.3 Wind Generation Risk Impacts**

9 The financial impacts of increasing amounts of wind generation in BPA's Balancing Area,
10 primarily in response to RPS requirements, are most likely to impact BPA in terms of reduced
11 surplus energy revenues, which in turn would increase BPA's rates. BPA's policy goal is that
12 the costs associated with higher wind penetration levels are to be borne by those benefiting from
13 BPA providing interconnection services. However, BPA may not be fully reimbursed to the
14 extent that surplus energy revenues are reduced due to the impact that increased quantities of low
15 variable cost (but high fixed cost) wind generation can have on electricity prices. Also, as wind
16 penetration levels continue to rise, it is likely that passing additional costs to the beneficiaries of
17 this service will lag until there is adequate data to support passing on the additional costs. These
18 wind generation risks indicate somewhat higher BPA rate levels in the future. These risks will
19 also affect ASCs through higher charges for wind integration services for utilities that own or
20 purchase wind generation.

22 **9.1.3 RPS, Carbon and Other Environmental Mandates**

23 Renewable resource additions to meet RPS requirements, primarily wind plants, are likely to
24 increase BPA's rates (primarily due to reduced net secondary revenues) and increase ASCs. The
25 impact on REP benefits under such conditions is not clear, but rather is dependent on the relative

1 magnitude of the change in BPA's rate levels compared to ASC levels. The change in BPA rates
2 will likely be impacted by the amount of wind generation that is built to serve the PNW or
3 California, and how much of the wind generation built for California is physically delivered to
4 California, rather than left in the PNW with the environmental attributes of the wind generation
5 being claimed by California utilities. The cost of wind resources in ASCs will be impacted by
6 whether Federal production/investment tax credits remain available. These tax credits reduce the
7 prices that wind generators need to receive in their contracts with utilities, which reduce the costs
8 of these resources in ASCs.

9
10 While there is currently much uncertainty in terms of whether, when, where, and how CO₂
11 markets will be implemented, BPA rate levels are more likely to benefit from the reflection of
12 CO₂ costs in electricity market prices relative to ASC levels. This is because the generation that
13 BPA sells is almost entirely hydro and nuclear generation (which emits almost no CO₂), whereas
14 the IOU and COU generation is mostly from coal and natural gas fired resources that emit
15 substantial amounts of CO₂. For this reason, BPA generation will likely be assigned very little
16 CO₂ costs while it would benefit from higher electricity prices for its net secondary revenues,
17 which lower BPA rates. While differing in terms of the magnitude of the impact depending on
18 the resource mix of each utility, the IOUs and COUs would pay the CO₂ costs, but may also
19 benefit from higher electricity prices. The net impact is that ASCs will likely increase for all the
20 IOUs and COUs, but the impact on each utility's ASC will vary depending on its resource mix,
21 especially for COUs with substantial purchases at lower BPA rates.

22 23 **9.1.4 Measuring the High and Low BPA Rate Effects**

24 Risk analysis scenarios are performed to assess the potential impact that high, medium, and low
25 BPA resource costs and high, medium, and low CO₂ costs might have on REP benefits under

1 high, medium, and low natural gas prices. Other than the probabilities associated with the high
2 and low natural gas prices, no probabilities are assigned to each of the risk analysis scenario.
3 These scenarios are developed to assess the range of possible rate levels and REP benefits under
4 plausible potential outcomes. The financial impact of the changes in the risk analysis scenarios
5 are accounted for in the Long Term Rates Model in terms of changes in surplus energy revenues,
6 balancing power purchase expenses, augmentation purchase expenses, and in the BPA revenue
7 requirement. The risk analysis scenarios assume that the risks occur during the FY 2012–2017
8 period, with the impact carried through 2032 using common escalation assumptions. Uncertainty
9 in the timing of when the risks might occur is not included in this analysis.

10
11 Annual average energy prices for BPA’s surplus energy sales are derived by dividing median
12 annual surplus energy revenues by average annual surplus energy sales reported in Table 23 of
13 the Power Risk and Market Price Study Documentation, BP-12-E-BPA-04A. These annual
14 average surplus energy prices reflect the overall impact of when and how much surplus energy
15 BPA sells each month. Annual average implied heat rates for BPA’s surplus energy sales are
16 then derived by dividing the annual average surplus energy prices by the forecast annual natural
17 gas prices at Stanfield, Oregon. Given these annual average implied heat rates, changes in
18 annual surplus energy revenues are computed under different natural gas price levels by
19 multiplying the alternative natural gas prices by the implied heat rates and the number of
20 megawatthours of annual surplus energy sales.

21
22 High and low trajectories of natural gas prices are derived from simulated annual FY 2012–2017
23 natural gas price data for 3,500 games developed for the BP-12 initial proposal. The
24 methodology used for simulating the natural gas prices is documented in the Power Risk and
25 Market Price Study, BP-12-E-BPA-04. The first step in the process of developing these natural
26 gas price trajectories involves calculating average annual natural gas prices from FY 2012–2017

1 for each of the 3,500 games, developing a cumulative probability of these values by sorting them
2 from lowest to highest, and determining what the values are at the 5% and 95% percentiles. The
3 second step in the process is to develop a cumulative probability distribution of natural gas prices
4 for each FY from FY 2012–2017 by sorting results for the 3,500 games from lowest to highest
5 and calculating the average price for each cumulative probability value over FY 2012–2017.
6 The final step in the process is to identify the set of sorted FY 2012–2017 prices at a given
7 cumulative probability level that average the natural gas prices determined at the 5% and 95%
8 values in the first step.

9
10 Table 9.4.1 of the Documentation reports the FY 2012–2017 high, median, and low natural gas
11 prices used in this analysis, the derived annual average surplus energy prices, the derived implied
12 heat rates, and the median surplus energy revenues under high, median, and low natural gas
13 prices. The Long Term Rate Model uses these results to calculate the BPA rate impacts
14 associated with changes in surplus energy revenues and the ASC impacts associated with
15 changes in the natural gas prices.

16
17 Low, medium, and high CO₂ costs are accounted for in the risk analysis scenarios assuming no
18 CO₂ prices and initial CO₂ prices of \$20.00/ton and \$40.00/ton in FY 2012 that escalate at a real
19 annual rate of 5.0% and at an inflation rate of 2.5% through FY 2017. In order to convert these
20 CO₂ prices into the impact on electricity prices (\$/MWh), it is assumed in this analysis that 40%
21 of the price of CO₂ per ton is reflected in the electricity prices. This value is based on assuming
22 gas-fired resources having a heat rate of 8,000 Btu/kWh are on the margin.

23
24 FY 2012–2017 surplus energy revenues under the \$20/ton and \$40/ton alternatives under high,
25 median, and low natural gas prices are calculated and input into the Long Term Rate Model to
26 determine the impact that these changes have on PF rates. The carbon prices for the high and

1 medium CO scenarios are input into the LTRM2012 as \$/MWh deltas to the BP-12 market price
2 curve and are accounted for in the model in two ways. First, these prices are used in the
3 computation of ASCs through adjusting the assumed market value for each exchanging utility's
4 open position on market purchases and sales. Second, for the reference case, these prices are
5 used to meet 50 percent of load growth through market purchases. The results from the risk
6 analysis scenarios (which produce deltas to the secondary energy credit) are converted into ratios
7 that are applied to the secondary energy and balancing purchase prices, such that the resulting
8 secondary energy revenues and balancing purchase expenses incorporate an equivalent dollar
9 delta. The augmentation price is adjusted in proportion to the CO high and medium scenarios'
10 effect on the market price forecast. Tables 4.4.2.1 and 4.4.2.2 of the Documentation report the
11 results of these risk analysis scenarios.

12
13 High and low resource cost scenarios are computed by evaluating the rate impact of high and low
14 nuclear fuel costs and potential future reductions in resource output from existing resources (for
15 the high resource cost scenario). The medium resource cost scenario reflects base case values
16 currently used in the BP-12 initial proposal. The impact of changes in nuclear fuel costs is
17 reflected in the Long Term Rate Model in terms of the amounts of dollars in the revenue
18 requirement. The impact of potential future reductions in resource output is reflected in the Long
19 Term Rate Model in terms of reductions in surplus energy revenues.

20
21 The high resource cost scenario evaluates the rate impact of high nuclear fuel costs and potential
22 future reductions in annual resource output from existing resources of 250 aMW. The low
23 resource cost scenario assumes no future reductions in annual resource output and evaluates the
24 impact that low nuclear fuel costs might have on reducing BPA's rates. The assumed future
25 reduction in annual resource output was subjectively determined and is meant to account for the
26 potential impact of a variety of both currently known and unknown factors that, over the course

1 of the 17-year contract period, could reduce generation and/or increase capital investment or
2 O&M costs from the values reflected in current generation output estimates and expenses
3 accounted for in the revenue requirement during FY 2012–2017.
4

5 The costs of converting uranium into the nuclear fuel used in reactors involves the costs of the
6 raw uranium (referred to as yellow cake or U308), the conversion services, and the enrichment
7 services. The quantity of product produced at each step decreases throughout the process. In
8 this analysis, the changes in costs of nuclear fuel for CGS are computed by multiplying the
9 annual reactor requirements (specified in terms of quantity) at each of these steps times the
10 associated costs. The annual reactor requirements are based on values reported by Energy
11 Northwest. The FY 2012–2015 forward market prices for raw uranium used in the base case
12 scenario, and from which the revisions in nuclear fuel costs are computed for the high and low
13 scenarios, are based on prices quoted on 12/10/2010 at the following website:

14 http://www.cmegroup.com/trading/metals/other/uranium_quotes_globex.html
15

16 Because forward price quotes were not available for FY 2016–2017, the FY 2015 prices quotes
17 are used for these years. The base case cost for enrichment services per Separative work unit is
18 based on a value reported by ENW. The base case cost for conversion services per kgU is based
19 on making a modest increase in this cost (\$.025 per kgU) from the historical data reported from
20 January 2002 through December 2007 by Ux Consulting Company, LLC. See website at
21 http://www.uxc.com/review/uxc_PriceTable.aspx.
22

23 While not explicitly derived from the historical data from Ux Consulting, values reported in its
24 data were considered when determining assumptions regarding the potential variability in
25 nuclear fuel cost risk, which are reflected in terms of high and low multiplier factors in this
26 analysis.

Values used in deriving the nuclear fuel cost scenarios and the resource cost scenarios are reported in Tables 4.4.3.1 through 4.4.3.4 of the Documentation.

9.2 Summary

Uncertainty is one thing that is certain when considering future rate levels. The risks discussed in this section will affect future BPA rates and utilities' ASCs. What is unknown is the timing of the risks and the magnitude of the risks. As discussed above, some risks affect both BPA's rates and utilities' ASCs, while others have differential effects on BPA's rates and utilities' ASCs.

The purpose of this section is to present a qualitative discussion of future risks and their effects on rate levels and to present a limited quantitative analysis of the effect of the risks on rate levels. The quantitative analysis is used in forming the effect of rate level differentials from a base case projection of future rate levels. These rate level differentials are aggregated into scenarios in the Settlement analysis, as discussed in the next section.

Impacts of this Risk Analysis on REP benefits are shown in Figure 4 of this Study. Section 4 of the Documentation includes tables that show the complete impact of this Risk Analysis on rates and REP benefits.

10. ANALYSIS OF THE SETTLEMENT: SCENARIO DEVELOPMENT

10.1 Analysis of the 2012 REP Settlement Agreement

This section of the Study presents Staff's technical analysis of the 2012 REP Settlement Agreement. The technical analysis examines the ratemaking provisions of the Agreement by constructing a variety of scenarios resulting in potential future streams of REP benefits based on differing implementations of the section 7(b)(2) rate test or other major drivers of REP benefits. Constructing these alternative results using the 7(b)(2) rate test allows evaluation of the Settlement through the comparison of the results specified in the Agreement with the results of the scenarios developed in this analysis. The analysis is divided into two major groups of scenarios; those that examine the issues in litigation that are developed and discussed in section 7 of this Study, and those that examine the two major "natural" drivers of REP benefits: ASC levels and BPA rate levels.

10.2 Rate Models Used in the Analysis

The analysis employs two rate models to measure the impact of changing inputs and assumptions on REP benefits: RAM2012 and the new Long-Term Rate Model (LTRM). RAM2012 is the model used when establishing rates for two-year rate periods and is currently being used in the BP-12 rate proceeding to calculate proposed rates. RAM2012 is limited to calculating rates for two years only. The new LTRM has been developed for this proceeding to extend rate analysis beyond the current ability of RAM2012 to the entire time period encompassed by the Settlement, ending in 2028.

The LTRM employs the same ratemaking logic as RAM2012 but in a scaled down form. It performs the same calculations as the COSA Step in RAM2012. See Section 2 of the Power

Rate Study, BP-12-E-BPA-01. LTRM uses the same input data used in RAM2012 whenever possible. LTRM is calibrated to RAM2012 for the FY 2012–2013 period, and the results are reasonably similar.

10.3 Reference Case: Base Case Forecasts and BPA’s Position on Issues

The Reference Case (or Scenario 0) employs BPA’s current 7(b)(2) implementation methodology and a base case, or best forecast, of inputs used in ratemaking. The Reference Case is built upon the Section 7(b)(2) Rate Test Study, REP-12-E-BPA-02. Performing Scenario 0 in RAM2012 produces the results shown in the Section 7(b)(2) Rate Test Study. Performing Scenario 0 in the LTRM produces 17 years of results consistent with the Section 7(b)(2) Rate Test Study.

Input data assumptions for LTRM include:

- **BPA Loads:** BPA load inputs build from loads presented in the Load and Resource Study, BP-12-E-BPA-03, as used in the Section 7(b)(2) Rate Test Study through 2017, and are consistent with BPA’s 20-year load forecasts.
- **BPA Resources:** BPA resource inputs build from resources presented in the Load and Resource Study, BP-12-E-BPA-03, as used in the Section 7(b)(2) Rate Test Study through 2017, and are consistent with BPA’s 20-year resource forecasts.
- **ASCs:** ASC inputs are described in section 8.
- **Exchange Load:** Exchange load inputs are described in section 8.
- **Costs:** BPA cost inputs build from costs developed in the Revenue Requirement Study, BP-12-E-BPA-02, as used in the Section 7(b)(2) Rate Test Study through 2017; starting with 2018, costs are escalated at 3.75 percent per year (2 percent real growth).

- 1 • **Revenue Credits:** BPA revenue credit inputs build from costs developed in the Power
2 Rate Study, BP-12-E-BPA-01, as used in the Section 7(b)(2) Rate Test Study through
3 2017; starting with 2018, costs are escalated at 3.75 percent per year (2 percent real
4 growth).
- 5 • **Market Electric Prices:** Market electric price inputs build from the forecasts developed
6 in the Power Risk and Market Price Study, BP-12-E-BPA-04, through 2017 and escalate
7 at 3 percent per year thereafter.
- 8 • **7(b)(2) Resource Stack Costs:** Resource costs are consistent with the costs developed in
9 the Section 7(b)(2) Rate Test Study, REP-12-E-BPA-02.
- 10 • **Miscellaneous Inputs:** BPA's transmission rates escalate after FY 2017 at the assumed
11 annual inflation rate of 1.75 percent; the IP rate net margin remains constant at the -
12 0.255 mills/kWh used in RAM2012; low density discount and irrigation rate discount
13 costs are RAM2012 values through FY 2017 and are escalated to 3.75 percent thereafter;
14 the PF flat load rate conversion factor is set at a constant 96.5 percent for all years; and
15 the 30-year Treasury borrowing interest rate is consistent with the forecast in the
16 Revenue Requirement Study Documentation, BP-12-E-BPA-02A, Table 1, at 85.
17 Roughly 40 percent of Above High Watermark Load is assumed to be met by Tier 2
18 purchases from BPA for 2017 and beyond.

20 **10.4 Analysis of Issues in Litigation**

21 Staff's analysis of the Settlement begins with examining the ratemaking effects that the issues in
22 litigation could have on REP benefits. As discussed in section 5 of the policy testimony,
23 Gendron *et al.*, REP-12-E-BPA-04, REP benefits are a good benchmark of comparison for
24 analyzing the Settlement because of the interrelationship between rate protection and REP
25 benefits. Scenarios are developed to analytically assess the impact of each of the issues in

litigation discussed in section 7 of this Study. The results of the scenarios are used in the evaluation of the Settlement; the evaluation is presented in section 11. A scenario is developed for each issue, followed by several scenarios that combine several issues to represent the aggregate position of the COU parties or the IOU parties. A discussion of each of the scenarios follows.

See Figures 1-3 for a graphical summary of post-Lookback IOU REP Benefits under alternative litigation scenarios.

10.4.1 Scenario 1: No Lookback (an IOU position)

Scenario 1 models the impacts of a successful challenge by the IOUs to BPA's decision to recover Lookback Amounts from the IOUs. See Section 7.2.1. The Lookback Amounts generally reflect the amount by which the IOUs were overpaid for FY 2002–2007 or, equally, the amount by which the COUs were overcharged due to the 2000 REP Settlement Agreements. This scenario models likely prospective REP benefits to the IOUs if the Invalidity Clause in the 2000 REP Settlement Agreements is found to be enforceable. See Section 7.2.1.1 for additional discussion regarding the IOUs' Invalidity Clause argument. Under this scenario, not only would the Lookback Amount of \$767 million be reduced to zero, but also BPA would likely return to the IOUs those amounts recovered during FY 2009–2011 – about \$237.6 million.

Table 10.1 presents the stream of annual Lookback Amounts recovered from the IOUs in FY 2009-2011 and assumed to be returned to them in FY 2012-2014. In order to raise the funds needed to return these amounts to the IOUs, BPA would need to include the costs in the PF Public rates or raise funds through surcharges on the COUs power bills.

10.4.2 Scenario 2: Large Lookback Without LRAs (a COU position)

Scenario 2 models the arguments by the COUs that BPA should limit its determinations of reconstructed REP benefits to the analysis, data, assumptions, and methodologies BPA established in the WP-02 case. See Section 7.2.2. This approach results in average annual REP benefits for FY 2002–2006 of approximately \$48 million. Section 7(b)(2) Rate Test Study, WP-02-FS-BPA-05A, at 166. This scenario is combined with the base case approach from BPA’s WP-07 Supplemental ROD where the LRA payments to PacifiCorp and Puget are “protected.” This means that PacifiCorp and Puget are allowed to keep the greater of their LRA payments or their reconstructed REP benefits.

Recovery of the revised Lookback Amounts under this scenario is presented in two payback schemata. The first schema assumes BPA continues its application of the “50-percent” rule adopted in the WP-07 Supplemental ROD. The second schema assumes that the 50-percent rule is abandoned and future REP benefits owed to an IOU are reduced until the Lookback Amounts are paid off over a seven year period, or as soon as possible thereafter if there are not sufficient REP benefits available to recover the full Lookback Amount in seven years.

Table 10.1 presents the two resulting streams of total annual Lookback Amounts recovered from the IOUs. Tables 6.1 and 6.2 in the Documentation show the full results of the Lookback Lookforward Model (Documentation, REP-12-E-BPA-01A).

10.4.3 Scenario 3: Large Lookback with LRAs (a COU position)

Scenario 3 models a combination of the COUs’ argument that BPA should limit reconstructed REP benefits to the WP-02 rate record assumptions (*i.e.*, \$48 million) and the COUs’ argument that the LRAs are invalid and therefore not protectable in the Lookback Amount calculation. See

1 Section 7.2.2.2. As in Scenario 2, two payback schemata are shown, one schema with the “50-
2 percent” rule and one schema without the rule.

3
4 Table 10.1 presents the two streams of annual Lookback amounts recovered from the IOUs in
5 total. Tables 6.2 and 6.4 in the Documentation show the full results of the Lookback
6 Lookforward Model (Documentation, REP-12-E-BPA-01A).

7 8 **10.4.4 Scenario 4: Idaho Deemer Balance**

9
10 In this scenario, it is assumed that Idaho Power and IPUC prevail in their arguments as described
11 in section 7.6.1. As a result, it is assumed that Idaho Power’s deemer balance would be
12 extinguished. However, all of Idaho’s REP benefits would go toward its relatively large deemer
13 balance until it is extinguished.

14 15 **10.4.5 Scenario 5: Conservation = General Requirements without Conservation Costs (a** 16 **COU position)**

17 Scenario 5 models the COUs’ contention that the loads in the 7(b)(2) Case should not be adjusted
18 for acquired conservation. See Section 7.3.1.1. To model this scenario, the load adjustment in
19 the 7(b)(2) Case is set to zero and the conservation resources in the 7(b)(2) resource stack are
20 also set to zero. This modification results in the 7(b)(2) Case starting with the same COU loads
21 as used in the Program Case and adding the within-or-adjacent DSI loads to develop the 7(b)(2)
22 Customer loads. The costs of the acquired conservation are not added to the 7(b)(2) Case
23 revenue requirement.

Table 10.3 presents the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1

10.4.6 Scenario 6: Conservation = General Requirements with Conservation Costs (an IOU position)

Scenario 6 models the IOU exchange customers' contention that the loads in the 7(b)(2) Case should not be adjusted for acquired conservation, as in Scenario 5, but also that Program Case conservation costs should be included in the 7(b)(2) Case. See Section 7.3.1.1. To model this scenario, the load adjustment in the 7(b)(2) Case is set to zero, the conservation resources in the 7(b)(2) resource stack are also set to zero, Program Case conservation costs are included in the 7(b)(2) Case revenue requirement, and the 7(b)(2) Case repayment study results are replaced with the Program Case repayment study results.

Table 10.3 presents the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1

10.4.7 Scenario 7: Same Repayment Study in Both Cases (a COU position)

Scenario 7 models the contention that inclusion of different repayment costs from the Program Case revenue requirement is not allowed in the 7(b)(2) Case. See Section 7.3.2. To model this scenario, the 7(b)(2) Case repayment study results are replaced with the Program Case repayment study results.

Table 10.3 presents the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.4.8 Scenario 8: Mid-C Resources Included in 7(b)(2)(D) Resource Stack (a COU position)

Scenario 8 models the COUs' contention that Mid-Columbia resources should be included in the resource stack pursuant to section 7(b)(2)(D) of the Northwest Power Act. See Section 7.3.3. To model this scenario, the Mid-C resources are included in the resource stack, with the available power equal to the energy capability of each plant less the amount of energy used to serve COU load.

Table 10.3 presents the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.4.9 Scenario 9: No 7(b)(3) Allocation to Surplus (a COU position)

Scenario 9 models the COUs' contention that the costs of rate protection should not be allocated to surplus and secondary sales. See Section 7.4.1 To model this scenario, the reallocation of rate protection to the secondary energy credit is removed and rate protection costs are allocated to only the PFx, IP, and NR rate pools.

Table 10.3 presents the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.4.10 Scenario 10: Same Secondary Credit in 7(b)(2) Case (an IOU position)

Scenario 10 models the IOUs' contention that the surplus sales to Slice customers should include a 7(b)(3) Supplemental Rate Charge and that BPA has not properly accounted for this allocation in the 7(b)(3) reallocations. See Section 7.4.2. To model this scenario, the post-7(b)(3) allocation of rate protection to the secondary credit is assumed in both the Program Case and the

7(b)(2) Case. This modification results in more costs of providing REP benefits being conveyed through the PFp rate.

Table 10.3 presents the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.4.11 Scenario 11: Conservation Resource Costs Are Expensed (an IOU position)

Scenario 11 models the IOUs' contention that the conservation resources included in the resource stack should be expensed and the cost of such resources recovered in the year that the resource is called upon. See Section 7.3.1.2. To model this scenario, the cost of each conservation resource is set equal to BPA's cost of acquiring the conservation and is recovered as an O&M expense, resulting in the acquisition cost being recovered in the year the resource is selected from the resource stack. This scenario is meaningless if considered in conjunction with either Scenario 5 or Scenario 6 where conservation resources are excluded from the resource stack.

Table 10.3 presents the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.4.12 Scenario 12: Conservation Resource Costs Are Capitalized (a COU position)

Scenario 12 models the COUs' contention that the conservation resources included in the resource stack should be capitalize over the useful life of the resource. See Section 7.3.1.2. To model this scenario, the cost of each conservation resource is set equal to BPA's cost of acquiring the conservation and is recovered as a capitalized expense, resulting in the acquisition cost being amortized over the number of years of useful life of the resource. This scenario is

1 meaningless if considered in conjunction with either Scenario 5 or Scenario 6 where
2 conservation resources are excluded from the resource stack.

3
4 Table 10.3 presents the stream of REP benefits resulting from this modification, adjusted for No
5 Settlement Lookback Amounts as shown in Table 10.1.

6 7 **10.5 Analyzing Effect of Issues That Are Expected to be Litigated in Challenges to** 8 **WP-07 Supplemental Rates and WP-10 Rates**

9 Section 7 identifies several issues that are expected to be raised before the Ninth Circuit if
10 briefing on BPA's WP-07 Supplemental rates and WP-10 rates proceeds. These issues are
11 described in the following sections.

12 13 **10.5.1 Scenario 13: Excluded Conservation Added to Resource Stack (an IOU position)**

14 Scenario 13 models the IOUs' contention that all acquired conservation should be included in the
15 resource stack rather than the smaller portion used in the Reference Case. See Section 7.5.2. To
16 model this scenario, the amounts of excluded conservation are added to the amounts already
17 included in the resource stack, such that the conservation resource capability is the full amount
18 acquired under each year's resource program. The full capability of the conservation resources
19 is also used in the load adjustment to determine the general requirements of 7(b)(2) Customers in
20 the 7(b)(2) Case.

21
22 Table 10.3 presents the stream of REP benefits resulting from this modification, adjusted for No
23 Settlement Lookback Amounts as shown in Table 10.1.

24 25 **10.5.2 Scenario 14: Placeholder**

26 Scenario 14 is reserved for possible future analysis and is not identified in the Initial Proposal.

1
2 **10.5.3 Scenario 15: Inflation Rate Used for Discount Rate (a COU position)**

3 Scenario 15 models APAC's contention that the projected rate of inflation should be used to
4 discount projected rate streams for the Program Case and the 7(b)(2) Case rather than the
5 forecast BPA borrowing rate. See Section 7.5.1. To model this scenario, the 30-year Treasury
6 borrowing rate forecast is replaced with the forecast inflation rate for purposes of discounting the
7 rate streams.

8
9 Table 10.3 presents the stream of REP benefits resulting from this modification, adjusted for No
10 Settlement Lookback Amounts as shown in Table 10.1.

11
12 **10.5.4 Scenario 16: Investment Rate Used for Discount Rate (an IOU position)**

13 Scenario 16 models the alternative IOUs' contention that the projected investment decision
14 discount rate should be used to discount projected rate streams for the Program Case and the
15 7(b)(2) Case rather than the forecast BPA borrowing rate. See Section 7.5.1. To model this
16 scenario, the 30-year Treasury borrowing rate forecast is replaced with an investment decision
17 discount rate of 13 percent for purposes of discounting the rate streams.

18
19 Table 10.3 presents the stream of REP benefits resulting from this modification, adjusted for No
20 Settlement Lookback Amounts as shown in Table 10.1.

21
22 **10.5.5 Scenario 17: Placeholder**

23 Scenario 17 is reserved for possible future analysis and is not described in the Initial Proposal.
24

10.6 Combined COU/IOU Scenarios

To further analyze the Settlement, the analysis is augmented with several scenarios combining those described above to define upper and lower bounds of litigation risk across the 17-year stream of REP benefits. The combinations take two forms with one alternative combination. Scenarios 18 and 19 combine all of the positions asserted by the COUs and IOUs, respectively, into two best case scenarios. An alternative IOU best case scenario, Scenario 20 is included to represent a combination of IOU positions that produces superior results for the IOUs than the scenario that assumes the IOU's positions on all issues. Scenarios 21 and 22 combine all of the positions asserted by the COUs and IOUs, respectively, that have already been briefed to the court; these scenarios exclude the positions on issues not yet briefed.

10.6.1 Scenario 18: COU Best Case

Scenario 18 is modeled by combining the COUs' position on the treatment of conservation from Scenario 5, their position on the 7(b)(2) Case repayment study from Scenario 7, their position on the inclusion of Mid-C resources in the resource stack from Scenario 8, their position on allocating 7(b)(3) rate protection costs to surplus sales from Scenario 9, their position on the capitalization of conservation resources from Scenario 12, and their position on discounting rate streams from Scenario 16.

Table 10.3 presents the stream of REP benefits resulting from this modification, adjusted for Scenario 3 Lookback (without 50% rule) Amounts as shown in Table 10.1.

10.6.2 Scenario 19: IOU Best Case

Scenario 19 is modeled by combining the IOUs' position on the treatment of conservation from Scenario 6, their position on allocating 7(b)(3) rate protection costs to Slice surplus sales from

Scenario 10, their position on the expensing of conservation resources from Scenario 13, and their position on discounting rate streams from Scenario 15.

Table 10.3 presents the stream of REP benefits resulting from this modification, adjusted for Scenario 1 Lookback Amounts as shown in Table 10.1.

10.6.3 Scenario 20: IOU Alternative Case

Scenario 20 is modeled by combining the IOUs' position on allocating 7(b)(3) rate protection costs to Slice surplus sales from Scenario 10, their position on the expensing of conservation resources from Scenario 13, and their position on discounting rate streams from Scenario 15. It omits their position the treatment of conservation from Scenario 6 to allow their position on expensing conservation resources to affect the combined results of the IOUs' positions.

Table 10.3 presents the stream of REP benefits resulting from this modification, adjusted for Scenario 1 Lookback Amounts as shown in Table 10.1.

10.6.4 Scenario 21: COU Brief Case

Scenario 21 is modeled by combining the COUs' position on the treatment of conservation from Scenario 5, their position on the 7(b)(2) Case repayment study from Scenario 7, their position on the inclusion of Mid-C resources in the resource stack from Scenario 8, their position on allocating 7(b)(3) rate protection costs to surplus sales from Scenario 9, and their position on the capitalization of conservation resources from Scenario 12. It omits their position on discounting rate streams from Scenario 16 because it has not yet been briefed.

Table 10.2 presents the stream of REP benefits resulting from this modification, adjusted for Scenario 3 Lookback (without 50% rule) Amounts as shown in Table 10.1.

10.6.5 Scenario 22: IOU Brief Case

Scenario 22 is modeled by combining the IOUs' position on the treatment of conservation from Scenario 6 and their position on allocating 7(b)(3) rate protection costs to Slice surplus sales from Scenario 10. Scenario 22 excludes their position on the expensing of conservation resources from Scenario 13 and their position on discounting rate streams from Scenario 15 because these have not yet been briefed.

Table 10.2 presents the stream of REP benefits resulting from this modification, adjusted for Scenario 1 Lookback Amounts as shown in Table 10.1.

See Figure 5 for a graphical summary of post-Lookback IOU REP Benefits under alternative brief scenarios.

10.7 Analyzing Effect of Non-Litigation Risk Factors

In addition to analyzing the effect of litigated issues on projected REP benefits and rates using LTRM, high and low rate scenarios are developed with high and low ASC levels and high and low BPA rate levels. These rate level scenarios are divided into two types. First, scenarios with high IOU ASCs, coupled with low PF rates (and vice versa) are run. These scenarios adjust the new resource cost assumptions for IOUs' ASCs and the revenue requirement assumptions for the PF Rate. Second, we analyze market price and generation cost risk. These scenarios include variation in gas prices, embedded CO₂ price assumptions in the market price curve, nuclear fuel price assumptions, as well as risk of resource output levels.

See Figures 4 for a graphical summary of post-Lookback IOU REP Benefits under alternative risk scenarios.

10.7.1 High ASCs, Low BPA Rates

High ASCs are represented by assuming that 100 percent of IOU load growth is met by new resources as specified in the respective IOUs' Integrated Resource Plans. Low BPA rates are represented by assuming that BPA's costs and revenue credits increase at the rate of inflation for 2018 onward. All other assumptions are consistent with the Reference Case.

Table 10.2 presents the stream of REP benefits resulting from this modification, adjusted for the No Settlement Lookback Amounts as shown in Table 10.1.

10.7.2 Low ASCs, High BPA Rates

Low ASCs are represented by assuming that 100 percent of IOU load growth is met by market purchases, using the Reference Case market forecast. High BPA rates are represented by assuming that BPA's costs and revenue credits increase at the rate of inflation plus 4 percent real growth for 2018 onward. All other assumptions are consistent with the Reference Case.

Table 10.2 presents the stream of REP benefits resulting from this modification, adjusted for the No Settlement Lookback Amounts as shown in Table 10.1.

10.7.3 High Benefits Risk Scenario

As discussed in section 9, several scenarios are constructed by varying natural gas and electricity market prices. In addition, scenarios with varying BPA resource costs are developed, comprising

1 both high and low nuclear fuel scenarios, as well as potentially reduced available generation for
2 secondary sales. The High Benefits Risk Scenario builds upon the “High ASC, Low BPA Rates”
3 in section 10.7.1 and assumes *high* carbon costs, *high* gas prices, *low* nuclear fuel, and *no loss* in
4 BPA generation. This, in general, causes IOUs’ ASCs to rise at a rate faster than BPA’s rates,
5 which generally raises REP benefits.

6
7 Table 10.2 presents the stream of REP benefits resulting from this modification, adjusted for the
8 No Settlement Lookback Amounts as shown in Table 10.1.

9 10 **10.7.4 Low Benefits Risk Scenario**

11 The Low Benefits Risk scenario builds upon the “Low ASC, High BPA Rates” in section 10.7.2,
12 and assumes *no* carbon costs, *low* gas prices, *high* nuclear fuel, and a *loss* in BPA generation.
13 This in generally causes IOUs’ ASCs to rise at a rate slower than BPA’s rates, which generally
14 depresses REP benefits.

15
16 Table 10.2 presents the stream of REP benefits resulting from this modification, adjusted for the
17 No Settlement Lookback Amounts as shown in Table 10.1.

18 19 **10.8 Summary: Comparing Settlement with Scenario Analyses**

20 Results of REP benefits for the Reference Case, and the litigation scenarios for the FY 2012–
21 2013 period, are included in Table 10.2. These results utilize scenario analysis in RAM2012.
22 The Long Term Rates Model analysis results for the period FY 2012–2028 for the Reference
23 Case, the litigation scenarios, and the rate risk scenarios are shown in Tables 10.3.

11. EVALUATION OF THE SETTLEMENT

11.1 Introduction

Having completed the analysis of the issues in litigation and other factors that could affect the levels of rate protection and REP benefits between FY 2102 and FY 2028, Staff now undertakes an evaluation of the proposed 2012 REP Settlement. The protection and payments under the proposed Settlement are well defined and can be computed without much interpretation. The protection and payments under alternative views of 7(b)(2) and Lookback have been developed in the analysis. As stated before, Staff believes that the Settlement must have a clear and direct connection to the protections and requirements set forth in the Northwest Power Act. Thus, Staff has evaluated the proposed 2012 REP Settlement by comparing the protections and requirements set forth in the Settlement with protections and requirements that would be reasonably expected in absence of the Settlement.

11.2 Overview of Methodology Used to Evaluate 2012 REP Settlement Agreement

To evaluate the Settlement, Staff developed a set of criteria used to “test” the settlement. These criteria are comprised of three primary and two secondary criteria, which are:

- the settlement would provide COUs with at least as much rate protection compared to the rate protection afforded under section 7(b)(2) of the Northwest Power Act;
- the settlement would provide REP benefits in a manner consistent with section 5(c) of the Northwest Power Act and distribute such REP benefits among the settling IOUs in a manner consistent with BPA’s current ASC Methodology and with rates that are consistent with section 7 of the Northwest Power Act;

- the settlement would resolve, in a fair and equitable manner, all of the outstanding issues with BPA’s development and implementation of the Lookback for the FY 2002–2011 period;
- the settlement would recognize that not all COUs were equally harmed by the costs of the 2000 REP Settlement Agreements and that IOUs were differentially affected by BPA’s setting off REP benefits for Lookback Amounts;
- the settlement would provide reasonable rates for non-settling parties and other classes of BPA’s customers.

Although more criteria could have been added to this list, Staff believes that a settlement that satisfies the aforementioned criteria would be, from an analytical perspective, reasonable and consistent with the protections and requirements of the Northwest Power Act. Most significantly, in Staff’s view, a settlement that meets the foregoing criteria would also avoid the key concerns expressed over previous settlements of the REP with BPA.

To “test” whether the proposed 2012 REP Settlement satisfies the above criteria, Staff compares the projected rate protection amounts and REP benefits developed by the various litigation scenarios with the amounts provided under the 2012 REP Settlement. Based on this comparison, Staff provides an assessment of whether the 2012 REP Settlement satisfies the criteria set forth above.

11.3 Evaluation of the 2012 REP Settlement Agreement

Under almost all outcomes of the analysis, the Settlement provides superior rate protection compared to the 7(b)(2) rate test scenarios. The analysis performs the rate test under a variety of potential future rate scenarios and litigation results and shows that except in the instance that

1 COUs prevail on every contested issue, the rate protection is greater and REP benefits smaller
2 under the Settlement. The conclusion is that under most possible future results of the rate test,
3 rates for COUs would be higher than the rates under the Settlement, all other factors being the
4 same in both futures.

5
6 The Settlement continues to provide REP benefits to the settling IOUs in conformance with
7 section 5(c) of the Northwest Power Act. The determination of REP benefits is unchanged under
8 the Settlement. BPA continues to “purchase” power pursuant to section 5(c) at the average
9 system cost of the IOU. BPA continues to “sell” power pursuant to section 5(c) at rates
10 established pursuant to sections 7(b)(1), 7(b)(3), and 7(g) of the Northwest Power Act. The
11 amount of REP benefits BPA pays to the settling IOU continues to be the difference between the
12 amount BPA pays for the purchase and the amount BPA receives for the sale.

13
14 The Settlement continues to distribute the REP benefits among the settling IOUs in a manner
15 consistent with ASCs established under BPA’s current ASC Methodology and rates established
16 under section 7. The Settlement requires no changes to the ASC Methodology and no changes
17 have been proposed. Rates continue to be established using a very similar method to rates
18 without the Settlement. The majority of the cost of rate protection continues to be allocated to
19 the PFx rate, thereby reducing REP benefits below the Unconstrained Benefits. If a utility’s
20 ASC is less than the PFx rate, it will not receive any REP benefits under the Settlement, just as it
21 would not receive any REP benefits in absence of the Settlement. The cost of rate protection is
22 allocated among the eligible REP participants in the same manner as would be done without the
23 Settlement.

24
25 The Settlement resolves, in a fair and equitable manner, all of the outstanding issues with BPA’s
26 development and implementation of the Lookback for the FY 2002–2011 period. Lookback

1 Amounts are discharged as an individual obligation of each settling IOU. All of the settling
2 parties would agree that the stream of Scheduled Benefits appropriately captures the disputed
3 obligations and benefits arising from the past rate overcharges.

4
5 The COU reallocation of Refund Amounts takes into account the differential impacts of the past
6 overcharges on the individual COUs. The COUs have negotiated among themselves to resolve
7 these concerns.

8
9 The IOU reallocation of REP benefits seeks to equalize the IOUs' exposure to differential
10 impacts of REP benefit setoffs between FY 2008 and FY 2011. The IOUs' reallocations have
11 been agreed to among them and can be implemented in a way that does not introduce any change
12 to the section 5(c) procedures or any change in the section 7 ratemaking directives. It does not
13 change the costs borne by any other customer group.

14
15 The Settlement provides superior rate protection than the 7(b)(2) rate test provides in almost all
16 instances. To achieve higher rate protection, the non-settling COUs would have to prevail on
17 five litigated issues. Although it is always risky to lay odds on the possible decisions of the
18 Court, simply affixing a 50/50 probability to the outcome of each issue would mean that the
19 likelihood of receiving greater rate protection is about 3 percent ($=0.5^5$). Given the unlikely
20 probability of complete success before the Court, the Settlement would provide superior rate
21 protection for non-settling COUs.

22
23 COUs participating in the REP bear the same exposure to deleterious outcomes of 7(b)(2)-related
24 issues before the Court. While they do not bear any exposure to an adverse outcome regarding
25 Lookback issues, the Settlement methodology does not assign any Lookback consequence to the
26 COUs' REP benefit level. Thus, the Settlement puts COU REP participants in the same position

1 as IOU REP participants with regard to the outcome of 7(b)(2)-related litigation. By settling this
2 litigation, the COU REP participants gain the same certainty that the IOUs gain. The COUs are
3 in no worse or better position than the IOUs.

4
5 The IP rate is not protected from REP costs. Although the IP rate does receive a benefit by being
6 linked to the PFp rate after it has reduced by rate protection, the 7(b)(3) Supplemental Rate
7 Charge is excluded from the 7(c)(2) linking. The analysis of the Settlement shows that as ASCs
8 increase faster than BPA's rates (the more likely future), the IP rate increases because the 7(b)(3)
9 Supplemental Rate Charge increases with ASCs faster than the underlying PFp rates.

10 11 **11.4 Conclusion**

12 For the foregoing reasons, BPA Staff recommends that the Administrator adopt the proposed
13 Settlement and set rates consistent with its terms.

Table 4.1
Schedule of REP Benefit Payments to IOUs

Rate Period	Fiscal Year	Scheduled Amounts
FY 2012–2013	2012	\$182,100,000
FY 2012–2013	2013	\$182,100,000
FY 2014–2015	2014	\$197,500,000
FY 2014–2015	2015	\$197,500,000
FY 2016–2017	2016	\$214,100,000
FY 2016–2017	2017	\$214,100,000
FY 2018–2019	2018	\$232,200,000
FY 2018–2019	2019	\$232,200,000
FY 2020–2021	2020	\$245,200,000
FY 2020–2021	2021	\$245,200,000
FY 2022–2023	2022	\$259,000,000
FY 2022–2023	2023	\$259,000,000
FY 2024–2025	2024	\$273,600,000
FY 2024–2025	2025	\$273,600,000
FY 2026–2028	2026	\$286,100,000
FY 2026–2028	2027	\$286,100,000
FY 2026–2028	2028	\$286,100,000

Table 4.2
Schedule of Lookback Refund Payments to COUs

Rate Period	Fiscal Year	Scheduled Amounts
FY 2012–2013	2012	\$76,537,617
FY 2012–2013	2013	\$76,537,617
FY 2014–2015	2014	\$76,537,617
FY 2014–2015	2015	\$76,537,617
FY 2016–2017	2016	\$76,537,617
FY 2016–2017	2017	\$76,537,617
FY 2018–2019	2018	\$76,537,617
FY 2018–2019	2019	\$76,537,617
all years thereafter		\$0

Table 4.3
Initial IOU Adjustment Amount

IOU	Initial IOU Adjustment Amount
Avista	\$22,986,000
Idaho Power	\$41,310,000
PacifiCorp	\$66,721,000
Portland General	\$4,699,000
Puget Sound	\$0

Table 4.4
Maximum IOU Annual Adjustment Amount

IOU	Maximum IOU Annual Adjustment Amount
Avista	\$2,004,778
Idaho Power	50 percent of Idaho Power's interim REP benefits
PacifiCorp	\$8,442,636
Portland General	\$1,237,583
Puget Sound	\$0

Table 4.5
Interim True-Up Payment Principal Amounts

IOU	Interim True-up Payment Principal Amounts
Avista	\$ 2,410,000
NorthWestern Energy	\$10,199,000
PacifiCorp	\$12,007,000
Portland General	\$56,994,000
Puget Sound	\$81,610,000

Table 7.1
FY 2002–2006 Lookback Amounts
LRAs Valid
2009\$ in millions

	Base Case	LRAs Valid
PacifiCorp	\$203.5M	\$187.8M
Puget	\$262.2M	\$0
Total for all IOUs	\$746.2M	\$468.2M

Table 7.2
FY 2002–2006 Lookback Amounts
WP-02 REP Benefit Determinations
2009\$ in millions

	Base Case	WP-02 REP LRAs Protected	WP-02 LRAs Invalid	WP-02 LRAs Valid
Avista	\$64.6	\$64.6	\$54.6	\$64.6
Idaho Power	\$85.0	\$85.0	\$85.0	\$85.0
Northwestern	\$5.7	\$19.1	\$19.1	\$19.1
PacifiCorp	\$203.5	\$203.5	\$676.0	\$203.5
Portland General	\$125.1	\$267.7	\$267.7	\$267.7
Puget	\$262.2	\$289.3	\$828.6	\$132.5
Total	\$746.2	\$929.3	\$1,941.1	\$722.4

Table 7.3
FY 2002–2006 Lookback Amounts
LRAs Invalid
2009\$ in millions

	Base Case	LRAs Invalid
PacifiCorp	\$203.5	\$660.3
Puget	\$262.2	\$562.6
Total for all IOUs	\$746.2	\$1,503.3

Table 10.1
Lookback Amounts Recovered or Returned to IOUs for Scenarios 1, 2, and 3
(\$ in millions)

	A	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U
1																		
2	<u>Lookback Amounts Recovered By Year</u>																	
3																		
4		<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>2025</u>	<u>2026</u>	<u>2027</u>	<u>2028</u>
5																		
6	Base Case Lookback Amounts for No Settlement	\$82.50	\$81.20	\$81.20	\$81.11	\$39.18	\$39.18	\$30.04	\$8.67	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
7																		
8	<u>Scenarios</u>																	
9	10.4.1 No Lookback - Return the Amounts Recovered from the IOUs in FY 12-14	(\$77.49)	(\$82.08)	(\$81.07)														
10																		
11	10.4.2 Large Lookback with Protected LRAs																	
12	w/ 50% rule	\$128.53	\$111.58	\$133.97	\$132.98	\$96.35	\$44.73	\$3.92	\$0.00	(\$0.00)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
13	w/o 50% rule	\$162.13	\$140.01	\$170.78	\$153.64	\$0.00	\$0.00	\$0.00	\$0.00	(\$0.00)	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
14																		
15	10.4.3 Large Lookback with Invalid LRAs																	
16	w/ 50% rule	\$160.75	\$141.17	\$167.20	\$165.22	\$171.64	\$151.78	\$156.07	\$140.34	\$151.90	\$134.81	\$42.64	\$37.51	\$37.49	\$33.24	\$32.39	\$28.36	\$27.13
17	w/o 50% rule	\$275.26	\$242.65	\$289.45	\$284.05	\$232.02	\$165.39	\$89.61	\$87.34	\$88.10	\$84.26	\$21.89	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00

Table 10.2: RAM2012 REP Benchmarks under Alternative Scenarios

	Unconstrained REP Benefits	Rate Protection	7(b)(3) PFx Alloc	7(b)(3) IP Alloc	7(b)(3) NR Alloc	REP Benefits	REP paid by PFp
Settlement Case	861,413	607,161	584,211	22,950	0.0675	277,202	242,589
Reference Case	787,546	646,144	422,731	27,828	0.0819	318,022	276,965
Scenario 5 - Conservation = Gen. Req. w/o Costs.	766,166	807,836	528,515	34,792	0.1023	190,016	148,150
Scenario 6 - Conservation = Gen. Req. w/ Costs	782,338	685,323	448,363	29,516	0.0868	287,080	245,823
Scenario 7 - Single Repayment Study	785,220	663,557	434,123	28,578	0.0841	304,275	263,127
Scenario 8 - Mid-C in Stack	779,951	703,358	460,162	30,292	0.0891	272,838	231,491
Scenario 9 - No 7(b)(3) to Surplus	868,818	560,945	526,299	34,647	0.1019	297,946	251,297
Scenario 10 - Identical Secondary Credits	805,337	513,060	335,662	22,097	0.0650	423,114	382,732
Scenario 11 - Conservation Res. Expensed	795,257	588,309	384,892	25,337	0.0745	363,797	323,029
Scenario 12 - Conservation Res. Capitalized	781,932	688,433	450,397	29,650	0.0872	284,626	243,352
Scenario 13 - No Exclusions	790,936	620,647	406,049	26,730	0.0786	338,166	297,238
Scenario 15 - Discount Rate = Inflation	769,034	786,070	514,275	33,855	0.0996	207,277	165,518
Scenario 16 - Discount Rate = Investment	804,089	522,388	341,765	22,498	0.0662	415,787	375,358
Scenario 18 - COU Best Case	865,337	863,184	809,870	53,314	0.1568	13,355	-
Scenario 19 - IOU Best Case	829,315	335,821	219,706	14,463	0.0425	562,650	523,192
Scenario 20 - IOU Alternative Case	833,974	301,617	197,329	12,990	0.0382	589,532	550,255
Scenario 21 - COU Brief Case	866,854	730,721	685,588	45,133	0.1328	138,084	88,718
Scenario 22 - IOU Brief Case	801,331	542,911	355,191	23,382	0.0688	399,604	359,068

Table 10.3.1: Estimated IOU REP Benefits for FY 2012 - 2020 under Litigated Scenarios (\$1000s, nominal)

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Reference Case	233,726	195,907	247,622	243,005	329,244	395,323	413,189	456,145	491,964
Scenario 1 - No Lookback	393,711	359,190	409,895	324,118	368,426	434,505	443,232	464,812	491,964
Scenario 2 - Large Lookback w/o LRSs (50% rule)	187,688	165,526	194,850	191,141	272,074	389,771	439,308	464,812	491,964
Scenario 2 - Large Lookback w/o LRSs (no 50% rule)	154,091	137,099	158,046	170,476	368,423	434,505	443,232	464,812	491,964
Scenario 3 - Large Lookback w/ LRAs (50% rule)	155,475	135,939	161,623	158,900	196,790	282,728	287,163	324,475	340,061
Scenario 3 - Large Lookback w/ LRAs (no 50% rule)	40,956	34,461	39,380	40,071	136,406	269,118	353,626	377,477	403,859
Scenario 4 - Idaho Deemer Relief	233,726	195,907	247,622	243,005	329,244	395,323	413,189	456,145	491,964
Scenario 5 - Conservation = Gen. Req. w/o Costs.	119,488	71,333	133,460	85,493	186,882	198,863	245,409	249,027	320,292
Scenario 6 - Conservation = Gen. Req. w/ Costs	219,034	175,062	232,461	198,398	294,721	320,980	365,298	381,617	436,369
Scenario 7 - Single Repayment Study	222,041	189,179	236,992	229,988	313,908	378,435	395,386	437,777	472,693
Scenario 8 - Mid-C in Stack	114,653	76,073	122,557	93,107	196,252	222,858	257,578	272,918	319,641
Scenario 9 - No 7(b)(3) to Surplus	211,568	176,744	221,908	224,592	303,389	379,005	390,892	442,032	475,812
Scenario 10 - Identical Secondary Credits	333,946	299,372	355,664	349,624	436,798	503,325	522,702	568,857	614,776
Scenario 11 - Conservation Res. Expensed	711,658	694,567	779,674	758,030	889,375	917,686	972,474	1,002,095	1,097,409
Scenario 12 - Conservation Res. Capitalized	195,247	154,524	213,124	198,710	292,228	346,854	371,373	411,703	452,563
Scenario 13 - No Exclusions	243,964	217,584	266,268	254,066	349,064	390,091	423,441	493,307	517,537
Scenario 15 - Discount Rate = Inflation	149,682	107,658	156,888	148,425	228,355	303,458	312,563	357,870	381,733
Scenario 16 - Discount Rate = Investment	312,585	276,727	334,904	327,434	420,785	478,922	504,543	545,294	591,867
Scenario 18 - COU Best Case	-	-	-	-	-	-	-	-	14,678
Scenario 19 - IOU Best Case	568,450	533,555	595,825	480,161	547,701	570,383	607,444	601,711	659,018
Scenario 20 - IOU Alternative Case	886,305	873,377	952,822	846,212	937,513	965,399	1,010,153	1,012,435	1,098,738
Scenario 21 - COU Brief Case	-	-	-	-	-	15,164	117,221	112,929	150,310
Scenario 22 - IOU Brief Case	485,306	448,864	507,796	389,781	456,893	476,245	507,780	499,901	551,108
High ASC; Low PF	247,824	190,563	292,121	284,721	371,219	432,661	457,125	511,468	568,405
Low ASC; High PF	248,936	231,713	225,257	215,029	304,026	373,606	384,657	418,788	437,289
High ASC; Low PF - Risk	294,882	238,826	400,052	372,985	467,481	525,591	563,894	611,542	679,572
Low ASC; High PF - Risk	222,896	198,559	186,359	188,557	272,250	344,054	355,106	381,001	397,231
Settlement	182,100	182,100	197,500	197,500	214,100	214,100	232,200	232,200	245,200

Table 10.3.2: Estimated IOU REP Benefits for FY 2021 - 2028 under Litigated Scenarios (\$1000s, nominal) cont.

	2021	2022	2023	2024	2025	2026	2027	2028
Reference Case	503,649	536,435	528,047	563,884	568,270	602,885	604,474	623,782
Scenario 1 - No Lookback	503,649	536,435	528,047	563,884	568,270	602,885	604,474	623,782
Scenario 2 - Large Lookback w/o LRSs (50% rule)	503,649	536,435	528,047	563,884	568,270	602,885	604,474	623,782
Scenario 2 - Large Lookback w/o LRSs (no 50% rule)	503,649	536,435	528,047	563,884	568,270	602,885	604,474	623,782
Scenario 3 - Large Lookback w/ LRAs (50% rule)	368,841	493,792	490,542	526,389	535,030	570,492	576,113	596,653
Scenario 3 - Large Lookback w/ LRAs (no 50% rule)	419,392	514,544	528,047	563,884	568,270	602,885	604,474	623,782
Scenario 4 - Idaho Deemer Relief	503,649	536,435	528,047	563,884	568,270	602,885	604,474	623,782
Scenario 5 - Conservation = Gen. Req. w/o Costs.	311,948	336,224	320,031	354,890	339,362	385,500	364,675	402,747
Scenario 6 - Conservation = Gen. Req. w/ Costs	450,067	480,258	468,304	509,287	499,098	550,405	535,207	576,510
Scenario 7 - Single Repayment Study	484,442	516,384	507,448	542,371	546,096	579,894	580,776	599,353
Scenario 8 - Mid-C in Stack	350,381	354,318	351,443	388,492	377,775	399,956	380,106	411,025
Scenario 9 - No 7(b)(3) to Surplus	468,912	507,039	504,237	527,598	543,399	573,656	586,329	598,601
Scenario 10 - Identical Secondary Credits	625,124	661,611	651,494	686,125	691,218	725,127	717,570	735,353
Scenario 11 - Conservation Res. Expensed	1,087,321	1,138,134	1,112,644	1,177,887	1,166,528	1,225,204	1,215,670	1,268,239
Scenario 12 - Conservation Res. Capitalized	465,312	498,217	487,027	523,604	521,773	561,569	556,332	585,074
Scenario 13 - No Exclusions	550,465	589,833	599,899	615,651	622,419	643,837	674,541	657,918
Scenario 15 - Discount Rate = Inflation	396,941	428,167	421,967	453,942	461,323	493,218	500,357	515,342
Scenario 16 - Discount Rate = Investment	600,308	634,627	624,314	663,940	665,590	702,985	700,190	723,845
Scenario 18 - COU Best Case	5,388	95,827	107,577	124,181	116,936	162,690	150,372	187,428
Scenario 19 - IOU Best Case	664,380	699,944	682,777	727,759	715,496	765,822	746,055	801,035
Scenario 20 - IOU Alternative Case	1,087,321	1,138,134	1,112,644	1,177,887	1,166,528	1,225,204	1,220,874	1,284,899
Scenario 21 - COU Brief Case	141,701	234,796	245,051	267,847	260,741	306,259	293,674	331,739
Scenario 22 - IOU Brief Case	562,501	598,428	583,325	625,212	614,884	666,370	645,786	702,886
High ASC; Low PF	564,123	616,469	605,395	668,853	671,712	729,894	763,539	820,494
Low ASC; High PF	420,139	443,924	425,009	445,483	440,515	458,646	452,306	462,296
High ASC; Low PF - Risk	676,235	733,512	722,222	791,310	792,294	870,416	921,142	1,005,414
Low ASC; High PF - Risk	376,158	396,921	382,789	403,115	396,884	413,012	401,268	408,454
Settlement	245,200	259,000	259,000	273,600	273,600	286,100	286,100	286,100

Table 10.4: Net Present Value of REP Benefits FY2007-2028 (assuming 8% discount rate)

	Reference	Scenario	Settlement
Scenario 1 - No Lookback	3,079,765	3,454,177	2,050,628
Scenario 2 - Large Lookback w/o LRSs (50% rule)	3,079,765	2,963,268	2,050,628
Scenario 2 - Large Lookback w/o LRSs (no 50% rule)	3,079,765	2,960,661	2,050,628
Scenario 3 - Large Lookback w/ LRAs (50% rule)	3,079,765	2,547,368	2,050,628
Scenario 3 - Large Lookback w/ LRAs (no 50% rule)	3,079,765	2,391,087	2,050,628
Scenario 4 - Idaho Deemer Relief	3,079,765	3,079,765	2,050,628
Scenario 5 - Conservation = Gen. Req. w/o Costs.	3,079,765	2,027,816	2,050,628
Scenario 6 - Conservation = Gen. Req. w/ Costs	3,079,765	2,801,773	2,050,628
Scenario 7 - Single Repayment Study	3,079,765	2,979,361	2,050,628
Scenario 8 - Mid-C in Stack	3,079,765	2,104,366	2,050,628
Scenario 9 - No 7(b)(3) to Surplus	3,079,765	2,937,683	2,050,628
Scenario 10 - Identical Secondary Credits	3,079,765	3,774,376	2,050,628
Scenario 11 - Conservation Res. Expensed	3,079,765	6,512,836	2,050,628
Scenario 12 - Conservation Res. Capitalized	3,079,765	2,825,551	2,050,628
Scenario 13 - No Exclusions	3,079,765	3,252,102	2,050,628
Scenario 15 - Discount Rate = Inflation	3,079,765	2,468,858	2,050,628
Scenario 16 - Discount Rate = Investment	3,079,765	3,638,972	2,050,628
Scenario 18 - COU Best Case	3,079,765	867,616	2,050,628
Scenario 19 - IOU Best Case	3,079,765	4,469,309	2,050,628
Scenario 20 - IOU Alternative Case	3,079,765	6,930,963	2,050,628
Scenario 21 - COU Brief Case	3,079,765	1,284,149	2,050,628
Scenario 22 - IOU Brief Case	3,079,765	3,881,625	2,050,628
High ASC; Low PF	3,079,765	3,438,312	2,050,628
Low ASC; High PF	3,079,765	2,788,201	2,050,628
High ASC; Low PF - Risk	3,079,765	4,055,219	2,050,628
Low ASC; High PF - Risk	3,079,765	2,561,987	2,050,628

Figure 1: REP Benefits Extreme Scenarios

Base Case "No Settlement" Lookback Setoff and Idaho Deemer Reduction (Except IOU Best/Alternative)
IOU Load growth met 50% IRP, 50% Market; COSA Escalated at Inflation + 2%

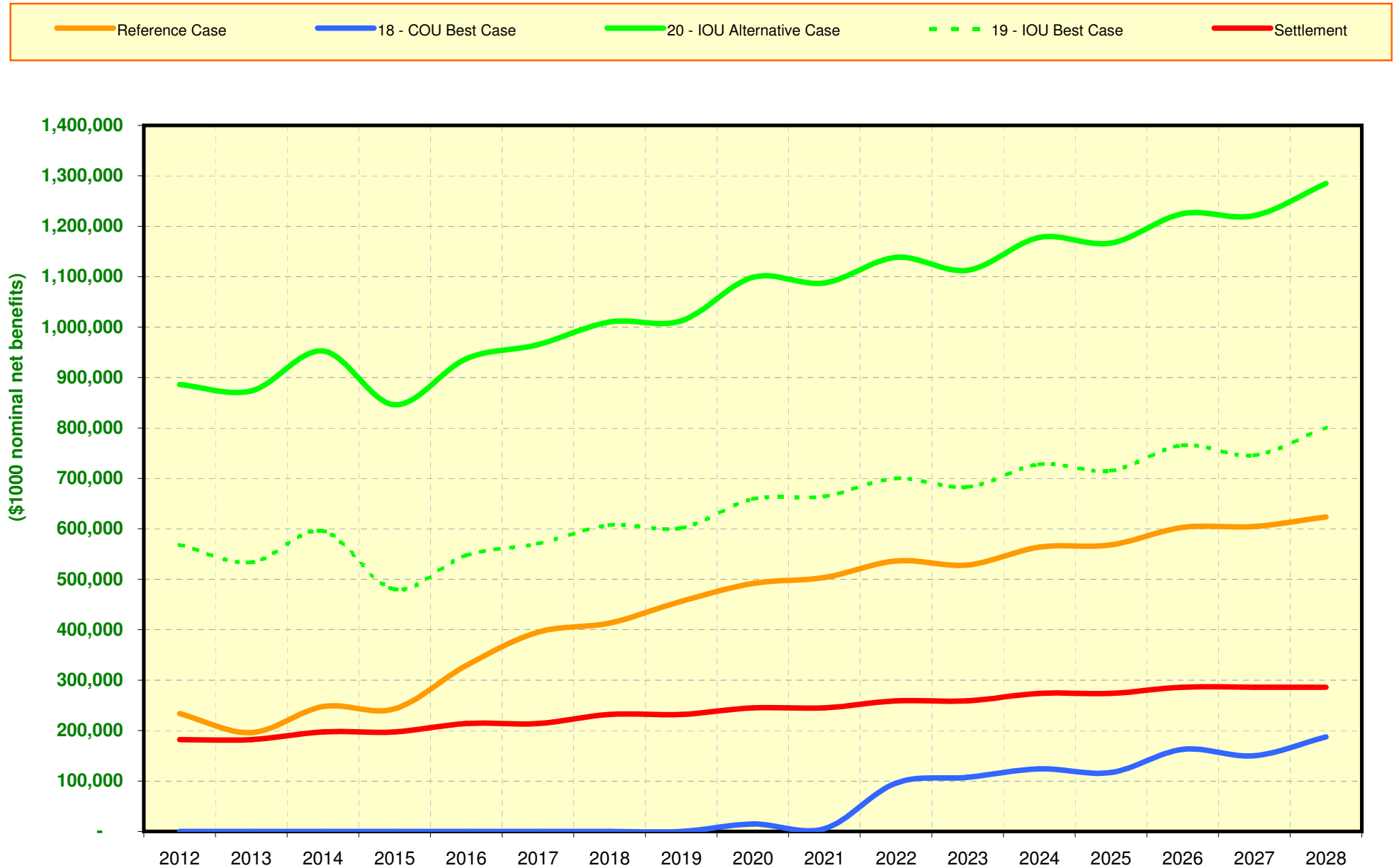


Figure 2: REP Benefits Lookback Scenarios

Based on Reference Case REP Benefits and Assuming Idaho Deemer Reduction
IOU Load growth met 50% IRP, 50% Market, COSA Escalated at Inflation + 2%.

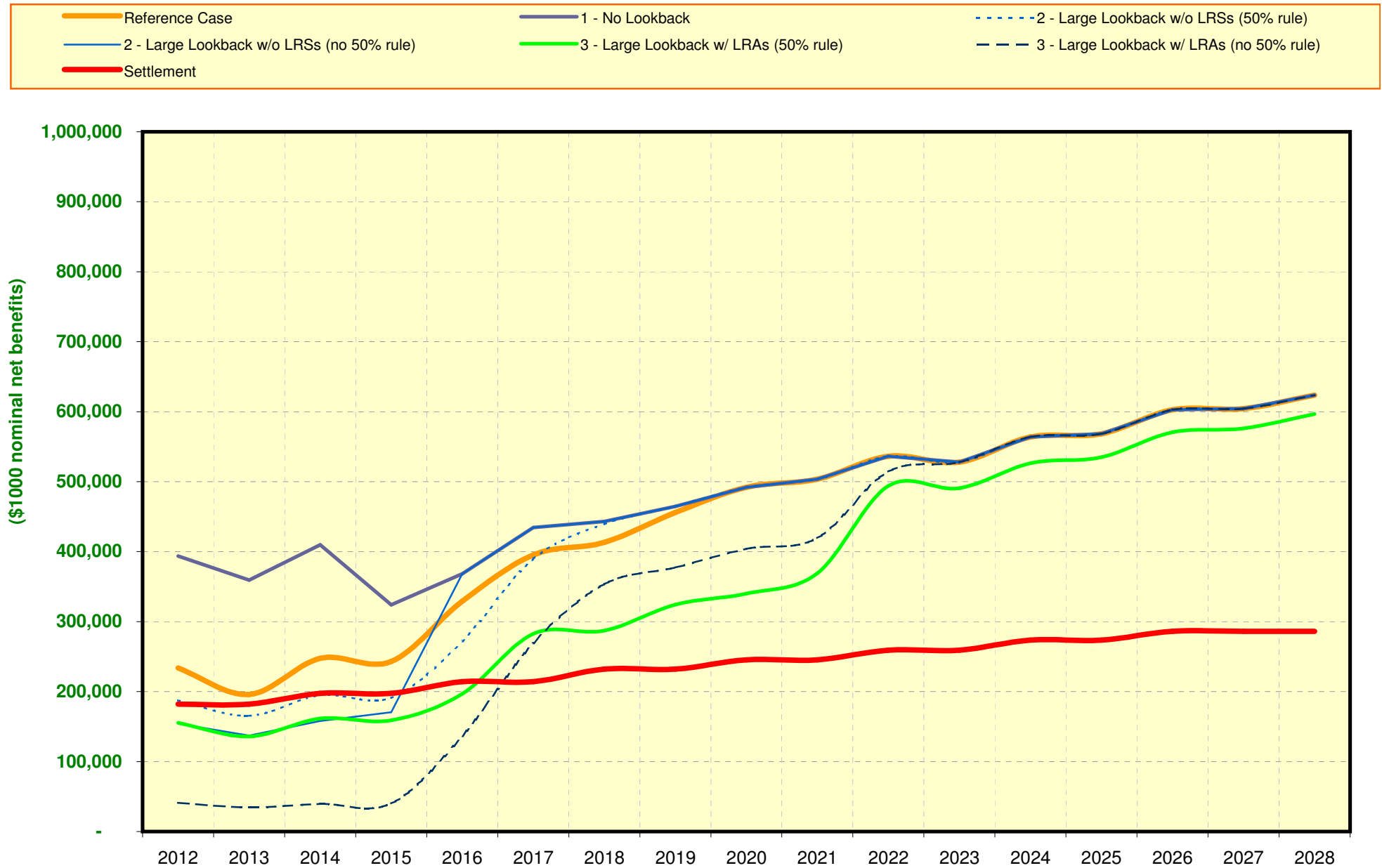


Figure 3: REP Benefits Other Scenarios

Base Case "No Settlement" Lookback Setoff and Idaho Deemer Reduction
IOU Load growth met 50% IRP, 50% Market, COSA Escalated at Inflation + 2%

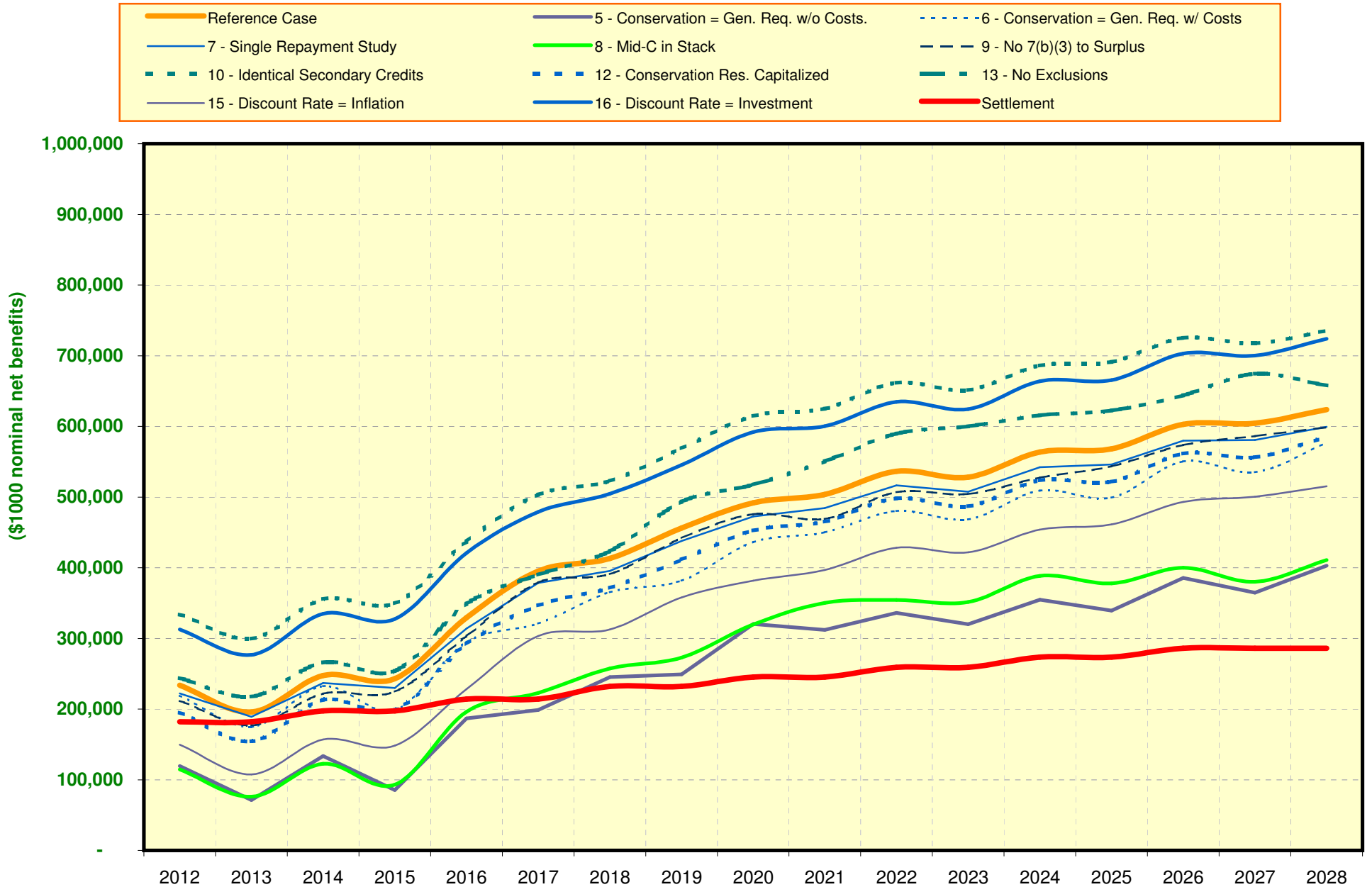


Figure 4: REP Benefits Risk Scenarios
 Base Case "No Settlement" Lookback Setoff and Idaho Deemer Reduction
 IOU Load growth met 50% IRP, 50% Market, COSA Escalated at Inflation + 2%.

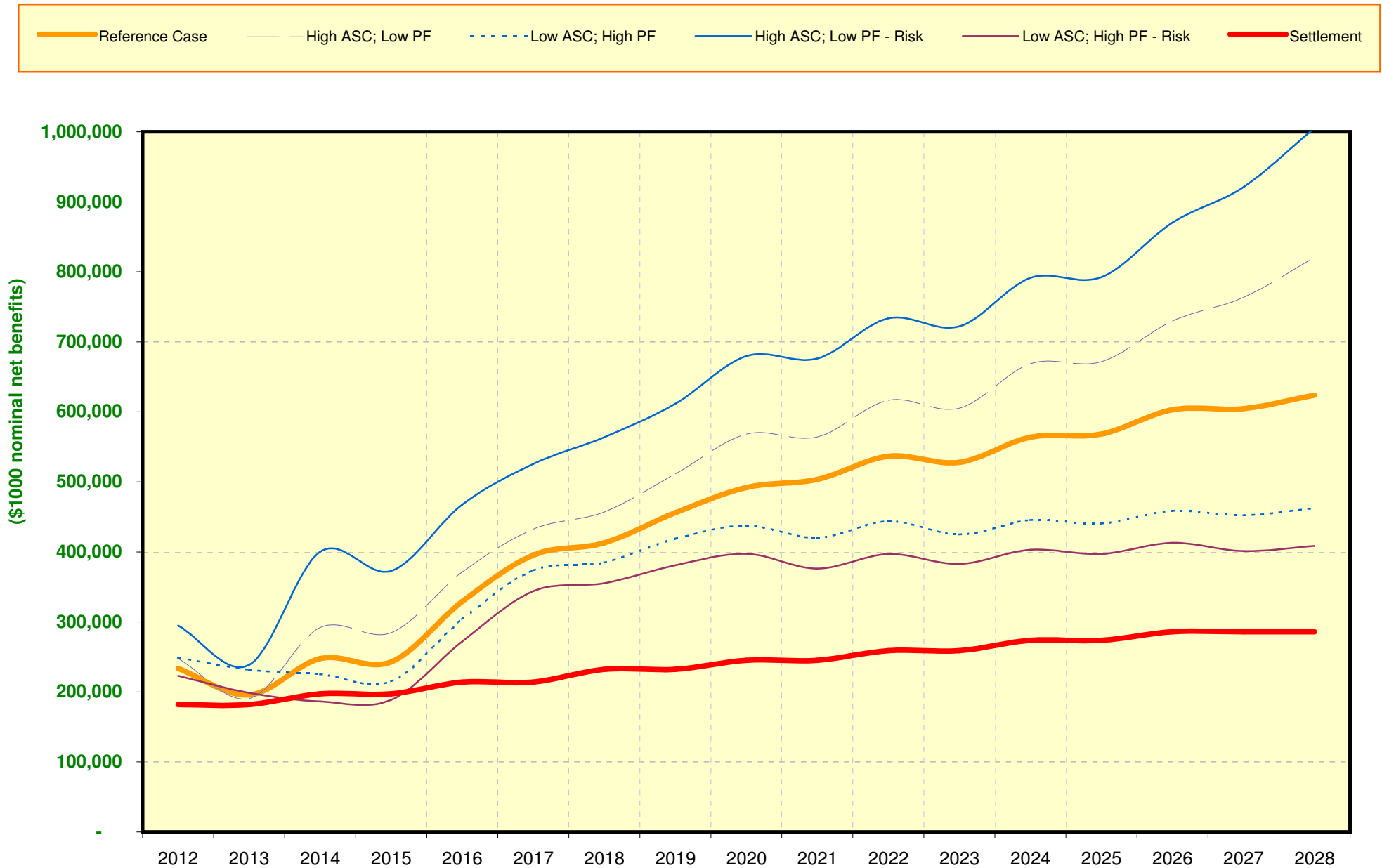
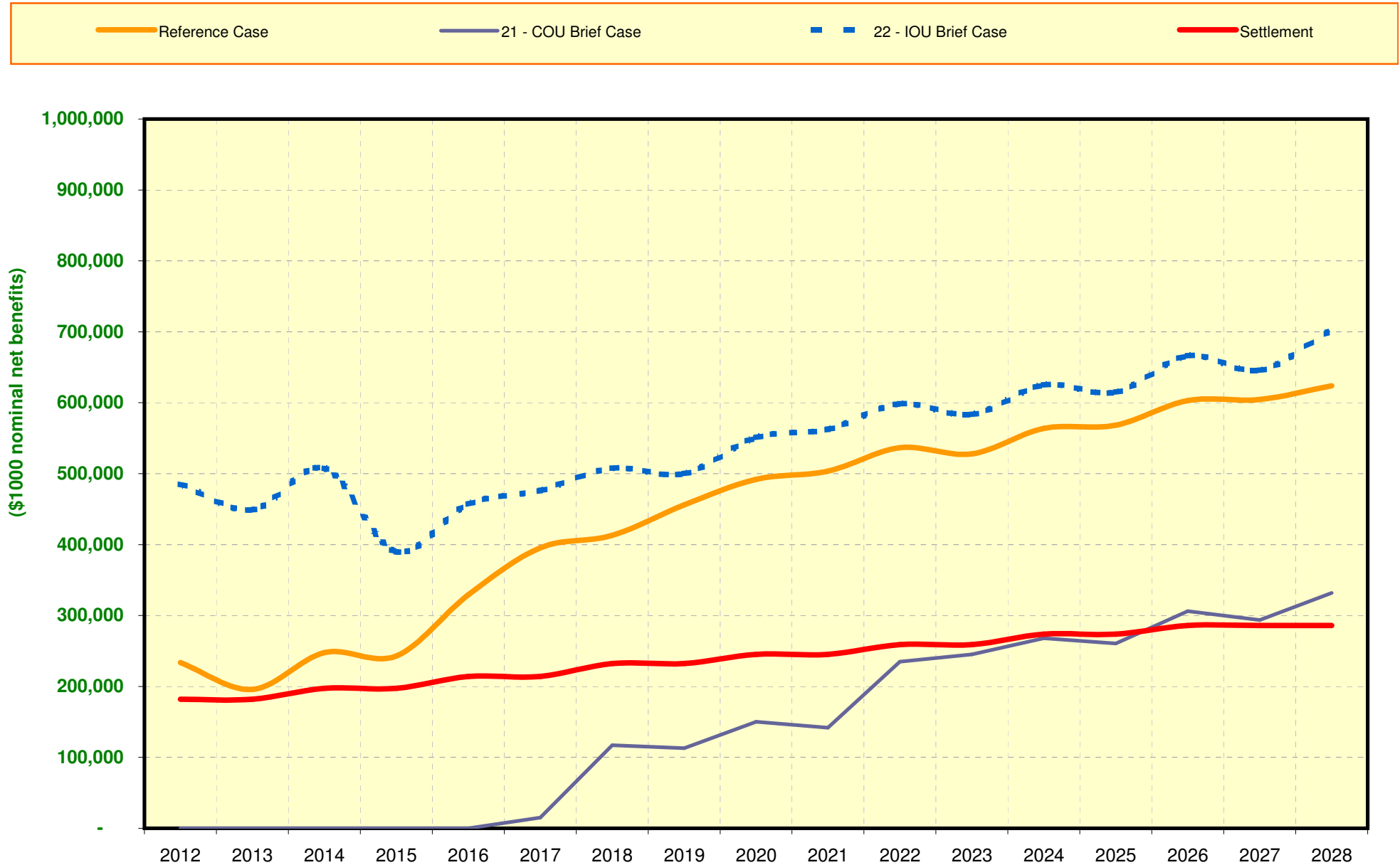


Figure 5: REP Benefits Brief Scenarios

Base Case "No Settlement" Lookback Setoff and Idaho Deemer Reduction (Except IOU Brief)
IOU Load growth met 50% IRP, 50% Market, COSA Escalated at Inflation + 2%.



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