Residential Exchange Program
Settlement Agreement Proceeding (REP-12)

Final Proposal

2012 REP Settlement
Evaluation and Analysis Study

July 2011

REP-12-FS-BPA-01

REP SETTLEMENT EVALUATION AND ANALYSIS STUDY

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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
Commission or FERC	Federal Energy Regulatory Commission
Corps or USACE	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
USACE or Corps	U.S. Army Corps of Engineers
USBR or Reclamation	U.S. Bureau of Reclamation
VOR	Value of Reserves

PART I THE SETTLEMENT IN ITS CONTEXT

1. INTRODUCTION

> I am well aware that it would be disingenuous to resolve indiscriminately the opposition of any set of men (merely because their situations might subject them to suspicion) into interested or ambitious views. … So numerous indeed and so powerful are the causes which serve to give a false bias to the judgment, that we, upon many occasions, see wise and good men on the wrong as well as on the right side of questions of the first magnitude to society. This circumstance, if duly attended to, would furnish a lesson of moderation to those who are ever so much persuaded of their being in the right in any controversy. And a further reason for caution, in this respect, might be drawn from the reflection that we are not always sure that those who advocate the truth are influenced by purer principles than their antagonists. Ambition, avarice, personal animosity, party opposition, and many other motives not more laudable than these, are apt to operate as well upon those who support as those who oppose the right side of a question. Were there not even these inducements to moderation, nothing could be more ill-judged than that intolerant spirit which has, at all times, characterized political parties. ALEXANDER HAMILTON, FEDERALIST NO. 1.

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

To respond to the Ninth Circuit's decisions, BPA revisited its WP-02 and WP-07 rate case assumptions through a comprehensive "Lookback" construct. As explained fully in the 2007

Supplemental Wholesale Power Rate Proceeding Administrator's Final Record of Decision (WP-07 Supplemental ROD, WP-07-A-05), the Lookback construct compared the amounts paid under the 2000 REP Settlement Agreements for fiscal years (FY) 2002–2008 with the amounts BPA would likely have paid qualifying IOUs under the traditional operation of the REP. *See also*, FY 2002-2008 Lookback Study, WP-07-FS-BPA-08. The difference between these two amounts, subject to certain specified rules, is generally referred to as the "Lookback Amount." The total Lookback Amount is composed of six IOU-specific Lookback Amounts. BPA determined that the Lookback Amount would be recovered from the IOUs over time through reductions in future REP benefits and returned to the eligible consumer-owned utilities (COUs), with interest, as credits on their power bills.

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

In this section 7(i) proceeding, BPA is evaluating and analyzing a proposed settlement of the litigation to determine whether the Administrator should sign the agreement and commit the agency to abide by its provisions for the term of the agreement. This Study sets forth BPA's evaluation and analysis of the agreement leading to the Administrator's conclusion to 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 the utility's 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 incurring 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 a monetary payment equal to the difference between the amount that would have been paid to the utility for the purchase of power at the utility's ASC and the amount that would have been paid to BPA for the purchase of power at the PFx rate, called "REP benefits." The Northwest Power Act requires that all of the REP benefits received by the utility be passed through directly to the utility's 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 dollars per megawatthour ($/MWh), which is equivalent to mills per kilowatthour (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 consultation with its customers and other stakeholders. The Federal Energy Regulatory Commission (Commission) granted final approval to the 2008 ASCM on September 4, 2009. The Review Processes for individual utilities' ASC filings occur in a separate administrative forum that is not part of BPA's rate proceedings.

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

Once the PFx rate has been established, two of the three necessary elements of the REP have been determined for each rate period. The third element, exchange loads, is based upon qualifying residential and small farm loads as measured by each utility participating in the REP. Subsequent to each calendar month, after each exchanging utility invoices BPA with its exchange load for the month, BPA computes the cost of purchase at the utility's ASC and the revenue from the sale at the PF Exchange rate by multiplying relevant rates by the kilowatthours of invoiced 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 the 1981 Residential Purchase and Sale Agreements (RPSAs) and ASC methodology. 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

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

2.3 *PGE* and *Golden NW*

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

BPA's WP-02 rates recovered the costs of the 2000 REP Settlement Agreements. After the Commission granted final confirmation and approval to the WP-02 rates, a number of parties challenged the WP-02 rates in the Ninth Circuit. In *Golden NW*, the Court concluded it was not proper for BPA to allocate to the PFp rate costs of the 2000 REP Settlement Agreements in excess of the section 7(b)(2) trigger amount. BPA's basis for such allocation was that such costs were 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. In doing so, BPA compared 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. *See*, FY 2002-2008 Lookback Study, WP-07-FS-BPA-08. 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 2000 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*. *See* WP-07 Supplemental ROD, WP-07-A-05.

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 a result of BPA's prior actions, BPA conducted a Lookback Analysis to determine the amount of REP costs that would have been incurred by BPA had it implemented the traditional REP during the Lookback period instead of implementing the 2000 REP Settlement Agreements with the region's IOUs. Based on those determinations, BPA established the amount by which preference customers were overcharged and provided appropriate repayments to preference customers through immediate refunds from collected funds on hand and through ongoing billing credits as funds were reclaimed from the IOUs. In other words, BPA established a means to recover 2000 REP Settlement Agreement overpayments through offsets to future REP benefits that would otherwise be payable to the IOUs. *See* FY 2002-2008 Lookback Study, WP-07-FS-08.

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

2.5 Current Litigation

BPA issued the Final WP-07 Supplemental ROD on September 22, 2008. In the Final ROD, as noted above, BPA redetermined 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 the Commission on September 29, 2008, for confirmation and approval, accompanied by the WP-07 Supplemental ROD and administrative record.

Beginning November 14, 2008, 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, 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 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-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.

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

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

On August 6, 2010, the Commission granted final confirmation and approval to BPA's WP-10 power and transmission rates. Certain IOUs, COUs, and a group of industrial consumers served by COUs filed petitions for review of the ratemaking decisions underlying the WP-10 rates. *See PacifiCorp et al. v. Bonneville Power Admin.*, Nos. 10-73348 *et al*. The petitions for review will likely be consolidated with the petitions for review in *PGE*, Nos. 09-73288 *et al*. The Court granted a motion staying the case.

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

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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 assumed "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 PFx rate 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 Rates Study, BP-12-FS-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 statutory rate directives. The final step, rate design, does not change the costs allocated to a rate pool, but defines the rate elements used to recover the costs allocated to the rate pool. This ratemaking sequence is programmed into a Microsoft Excel spreadsheet model called the Rate Analysis Model (RAM) for purposes of calculating BPA's requirements power rates.

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

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

Rate directive adjustments are made to recognize sections 7(a)(1), 7(c)(2), 7(b)(2), and 7(b)(3) of the Northwest Power Act. The first adjustment ensures cost recovery for certain surplus sales whose rates are set by contract by reassigning costs allocated to such sales that are not recoverable. The second adjustment implements section 7(c)(2) by adjusting the costs allocated to the Industrial Firm Power (IP) rate pool to ensure the IP rate is set at the level specified in section 7(c)(2). At 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 Section 7(b)(2) 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 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 provides partial protection because preference customers' firm power rates applied to their requirements loads are to be established as no higher than rates calculated using specific assumptions that may remove certain effects of the Northwest Power Act, but nevertheless include certain other effects. 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 customers, receive rate protection, while other PF purchasers, the REP participants, pay a portion of the cost of the rate protection. Thus, to allow the cost reallocations due to the rate protection, the PF rate is bifurcated into the PFp rate, which receives the rate protection, and the PFx rate, which does not receive rate protection and which recovers its allocated share of the rate protection costs. Forecast sales under the IP rate, the New Resources Firm Power (NR) rate, and the Firm Power Products and Services (FPS) rate also recover a share of the cost of the rate protection.

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

3.3 Reallocation of Rate Protection Costs

In the event the section 7(b)(2) rate test triggers, the difference between the average of the Program Case rates and the average of the 7(b)(2) Case rates is multiplied by the preference customer loads for the rate period. The resulting dollar amount, the rate protection amount, is allocated as a credit to the PFp rate pool to reduce the PFp rate to the level allowed by the rate test.

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

As a result of the decrease in the PFp rate and the direction by section 7(c)(2) to set the IP rate equal to the PFp rate, the IP rate (exclusive of its allocation of rate protection costs) is lowered to the PFp rate. The costs that must be reallocated due to linking the IP rate to the PFp rate are a direct result of the rate test. Therefore, none the costs of this linking can be allocated to the PFp rate, as was the case with the linking of the IP rate to the PF rate prior to the rate test. Instead, the cost of linking the two rates is allocated to the PFx rate pool and the NR rate pool. The rate protection cost previously allocated to and excluded from the IP rate pool is then reinstated to the IP rate.

In the WP-07 Supplemental proceeding, BPA implemented a new method of allocating rate protection costs within the PFx rate pool. Prior to the WP-07 Supplemental proceeding, BPA allocated rate protection costs to the PFx rate pool based on energy loads. This had the effect of increasing the PFx rate, which could result in disqualifying REP participants whose ASCs would now be less than the modified PFx rate. In the WP-07 Supplemental proceeding, BPA changed the allocator from energy loads to pre-rate test REP benefits ("Unconstrained Benefits"). This change in allocation retained all participants that qualified for the REP prior to the rate test. Therefore, BPA was able to spread the REP benefits more broadly across the region without increasing the costs of the REP borne by preference customers. The costs of the REP remain the same under this revised allocation methodology as under the prior allocation methodology, but the amounts paid to each REP participant are different, and each REP participant has a different PFx rate.

With these final reallocations, rate designs can be applied to each rate pool.

3.4 The Effect of the Rate Test

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

The level of REP benefits is determined by comparing each participant's ASC with its individual PFx rate and multiplying the difference by each participant's qualified exchange load. Because BPA's rates are set using forecasts of qualified exchange load, the variance between forecast and actual exchange loads can result in a different amount of REP benefits being paid during a rate period from the amount forecast in the rate proceeding.

Because the REP is the only BPA cost that changes as a result of the rate test, any change in the outcome of the rate test and the subsequent cost reallocations affects only REP benefits and which rate pools pay for the REP. Thus, the purpose of the rate test is confined solely to defining the amount of REP benefits expected to be paid and the sharing of the costs of the REP by the different rate pools.

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4. THE PROPOSED 2012 REP SETTLEMENT

4.1 History of Current Settlement Efforts

The 2012 REP Settlement reflects the efforts of a broad group of BPA customers and other interested parties which, 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 most 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 rates.

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

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

Both COUs and IOUs vigorously opposed the decisions BPA reached in the WP-07 Supplemental ROD. The COUs and entities supporting the COUs' positions claimed that BPA had grossly underestimated the IOUs' refund obligation and that the actual overcharge to COUs for the FY 2002–2008 period was at least $2 billion. The IOUs, public utility commissions, and ratepayer advocacy groups, in contrast, argued that no refunds were owed at all because the Court did not direct BPA to provide refunds and because the terms of the 2000 REP Settlement Agreements specifically prohibited BPA from recouping REP benefits paid under those agreements. The IOUs and COUs also opposed BPA's interpretation and implementation of the section 7(b)(2) rate test. It appeared inevitable that the parties would challenge in court the decisions BPA reached in the WP-07 Supplemental ROD. The Administrator, recognizing that endless litigation over BPA's decisions would only perpetuate uncertainty in the region over BPA's rates and the REP, appealed to the parties in the WP-07 Supplemental ROD not to give up on settlement efforts:

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

WP-07 Supplemental ROD, WP-07-A-05, at xx-xxi.

Following the publication of the WP-07 Supplemental ROD in 2008, BPA and principals from various IOU and COU groups continued to explore the possibility of settlement. Settlement discussions continued through the fall and winter of 2008 and moved into 2009. While these discussions were ongoing, petitions challenging BPA's implementation of the REP were filed with the Ninth Circuit Court of Appeals. These challenges were consolidated into four primary cases: *APAC, IPUC, Avista,* and *PGE II*. Briefing was set to begin in the *APAC* and *IPUC* cases in August of 2009. As the briefing in *APAC* and *IPUC* moved forward, BPA and representatives for the COUs and IOUs met to discuss the possibility of involving a mediator in the REP settlement discussions. In November of 2009, the parties tentatively agreed to engage a mediator following the completion of the briefing in the *APAC* and *IPUC* cases. Mediation sessions were 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 most 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 began immediately following the parties' execution of the AIP and continued through February 2011. Participants in that effort produced a final draft of the Settlement in early March. Once the Settlement was completed, it was 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 2012 REP Settlement resolves 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 are extinguished. The COUs' obligation to pay REP benefits in rates is limited to the COUs' share of the stream of REP benefits as set forth in the Settlement. The distribution of these REP payments to the IOUs will depend on each IOU's respective ASC and exchange load. The IOUs will continue to file ASCs with BPA pursuant to the 2008 ASCM.

In addition to the stream of REP benefits, the IOUs will 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 Settlement 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 2002–2006 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 will establish rates consistent with the terms of the Settlement for all BPA customers, whether or not they signed the Settlement. The settling parties recognize, 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 Settlement in the same manner as parties to the Settlement. Given this possible outcome, the Settlement includes provisions 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 Settlement establishes a schedule of annual REP benefits to be paid to the IOUs in the aggregate (Scheduled Amounts). Scheduled Amounts will increase over time from $182.1 million in FY 2012 to $286.1 million in FY 2028. *See* Table 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 permits 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 Settlement addresses equity issues among the COUs by establishing Refund Amounts to be provided to COUs during the next eight years of the settlement term. For FY 2012–2019, $76.538 million per year will 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 will be returned to BPA customers that purchase power at the PFp rate based on an allocation approach described in section 4.3.5.

4.3.4 Inclusion of REP Benefit Costs in Rates

Section 3.3 of the Settlement addresses how the REP benefit costs will be recovered in rates, including the allocation of REP benefit costs to COU parties to the Settlement. BPA will 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 Settlement), plus any COU REP benefits.

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

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

4.3.5 Allocation of Refund Amounts to COUs

Section 3.4 of the Settlement addresses how the Refund Amounts to COUs, described in section 4.3.3 above, will be calculated. Fifty percent of the amount ($38.269 million) will be returned to COUs based on PF-02 customer percentages set forth in the Settlement. *See* Table 2. These customer percentages are equivalent to the percentages BPA established in the WP-10 rate proceeding to allocate the FY 2010–2011 Lookback Credits to the COUs.

The remainder of the refund amount will be returned to COUs based on each customer's Tier 1 Customer TOCA Share, which is equal to each COU's TOCA divided by the sum of all COUs' TOCAs. TOCAs are the Tier 1 Cost Allocators established pursuant to BPA's Tiered Rate

Methodology (TRM). There are several vintages of TOCAs in the TRM. The Settlement will be implemented such that the TOCAs used to determine Refund Amounts will be those used to set rates for a given rate period, not actual TOCAs for Slice/Block customers or adjusted TOCAs for Load Following customers that might be different from TOCAs used to set rates due to load loss during the rate period. The Tier 1 Customer TOCA Shares used to determine Refund Amounts are slightly different from the TOCAs used to set rates because of two adjustments specified in the Settlement. One adjustment increases Grant PUD's TOCA and reduces the TOCAs of other customers to address an issue unique to Grant PUD. In addition, Refund Amounts only go to Existing Customers as that term is defined in BPA's Tiered Rates Methodology, which also results in slightly different TOCAs from those used to set rates.

Once the customer-specific Refund Amounts are established in the final rates proposal for a rate period, they do not change during the rate period even though the TOCAs used for billing may change due to the annual net requirements determinations for Slice/Block customers or for other reasons.

4.3.6 Court Determination Related to Allocation of Costs of REP Benefits

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

For example, assume for illustrative purposes that in the FY 2012–2013 rate period, 85 percent of REP costs are recoverable from the PFp rate and the remaining 15 percent from other rates (presumably the IP and NR rates). The COUs in total would be responsible for 85 percent of the $182.1 million per year of the Scheduled Amounts, or $154.4 million per year. If the allocated share of the COU parties to the settlement was 90 percent, then BPA would recover from these customers 90 percent of $154.4 million per year, or $139.3 million. Further assume that the 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 Settlement 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 Study (WP-10-FS-BPA-07).

If the Settlement is not challenged, BPA will pay the True-Up amounts 95 calendar days after the effective date of the Settlement (which is the date the BPA Administrator executes the Settlement). If the Settlement 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 Settlement. If Congress adopts the legislative authorization provided for in section 8 of the Settlement, 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.

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

4.3.8 Treatment of Environmental Attributes

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

In order for 14 percent of the RECs and Carbon Credits to be transferred to the IOUs, COU parties to the Settlement agreed to replace the current Exhibit H of their Contract High Water

Mark (CHWM) contracts with the revised Exhibit H in the Settlement. BPA will also offer Exhibit H of the Settlement to any COU that is not a party to the Settlement. If COUs that are not parties to the Settlement do not agree to replace their current CHWM Exhibit H with the Settlement Exhibit H, BPA will use its ratemaking authority as provided in section 9 of the current Exhibit H to determine and factor in the value or costs of RECs that were transferred to such COUs.

4.3.9 Allocation of REP Benefits to IOUs

Section 6 of the Settlement addresses the allocation of the Scheduled Amounts 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. Scheduled Amounts, for the most part, would be allocated in the same manner as REP benefits under the traditional REP. IOUs' ASCs will be determined in accordance with the 2008 ASCM. The IOUs' ASCs will also be compared to BPA-generated utility-specific PFx rates to determine the individual utility REP benefit amounts. Whether a particular IOU will be eligible to receive REP benefits will continue to depend on the relationship between the utility's ASC and BPA's rates. Section 6.1.2 of the Settlement 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 are 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. 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 will 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 are extinguished.

In consideration of these equity issues among the IOUs, the Settlement specifies an approach to reallocate the costs of rate protection among the IOUs and directs BPA to develop PFx rates that will result in the IOUs receiving REP benefits consistent with the Settlement. Although the adjustment is included in establishing the PFx rates, each IOU's REP benefits ultimately will be determined for each rate period based on its ASC, its PFx rate, and its contract exchange load. Each IOU's PFx rate will be based in part on the IOU-specific adjustment established in the Settlement. The following describes the IOU reallocation in the Settlement.

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

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

Both steps 1 and 2 capture 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 will perform to implement the Settlement.

In step 3, IOU-specific reductions will be made to the IOU-specific interim REP benefits for the IOUs. These annual adjustment amounts would be determined by a establishing initial adjustment balances and maximum annual reductions for Avista, Idaho Power, PacifiCorp and PGE. The initial balances (Initial IOU-specific Adjustment Amounts) and the maximum annual reductions (Maximum IOU Annual Adjustment Amounts) are specified in the Settlement in Table 3 and Table 4. The IOU-specific Adjustment Amounts will 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, are extinguished. The annual reduction for a given IOU is limited to the least of (i) the outstanding IOU-specific Adjustment Amount balance, (ii) the Maximum IOU Annual Adjustment Amount in Table 4, or (iii) the amount that would reduce an IOU's REP benefits for the year to zero. Section 6.2.4 of the Settlement specifies a separate adjustment for NorthWestern Energy.

In step 4, the IOU-specific reductions for each IOU determined in step 3 will be allocated to other IOUs. Idaho Power's reductions will be allocated to Avista, NorthWestern, PacifiCorp, PGE, and Puget. Avista and PacifiCorp's reductions will be allocated to NorthWestern, PGE, and Puget. PGE's reductions will be allocated to NorthWestern and Puget. NorthWestern's increases will be allocated to Avista, PacifiCorp, PGE, and Puget. In each reallocation, the receiving IOU will be allocated 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 will be allocated to NorthWestern, PGE, and Puget based on each of the receiving IOUs' share of the sum of the three IOU-Specific Unconstrained Benefit Amounts. At the completion of step 4, the total REP benefits for all IOUs will remain equal to the REP benefits in section 4.3.2 above.

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

5. IMPLEMENTING THE 2012 REP SETTLEMENT IN RATEMAKING

5.1 Ratesetting Pursuant to the Settlement

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

As described in sections 3.2 and 3.4 above, the purpose of the rate test is to calculate the level of rate protection due to preference customers pursuant to section 7(b)(2) of the Northwest Power Act. At the point in the rate modeling after the section 7(c) rate directive adjustments have been completed, the Settlement proposes a new set of rate calculations. This new set of rate calculations effectively implements the section 7(b)(2) rate test through alternative calculations that provide preference customers with an amount of rate protection based on the amount of IOU REP benefits specified in the Settlement, any COU REP benefits for qualified REP participants, and section 7(b)(3) adjustments to the IP and NR rates as specified in the REP Settlement.

The Settlement ratesetting begins with total IOU REP benefits as specified in the Settlement, called Scheduled Amounts. Added to the Scheduled Amount for each year is an additional amount of REP benefits, also specified in the Settlement, known as the Refund Amount. The Refund Amounts are considered REP benefits because they are subject to the amount of rate protection afforded to the PFp rate. The Refund Amounts are not paid to the IOUs, however, but instead appear as a credit on preference customers' power bills.

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

The total rate protection provided to preference customers under Settlement ratemaking is composed of two parts. With the Unconstrained Benefits and the total IOU and COU REP benefits determined, the first amount of rate protection due to preference customers is calculated as the sum of Unconstrained Benefits minus the sum of REP benefits. The cost of this first part of rate protection is allocated entirely to the PFx rate pool. The cost of the second part of rate protection to be allocated to the IP and NR rate pools is calculated later. Settlement ratemaking allocates this first amount of rate protection to individual REP participants using the same process used in non-settlement ratemaking, a pro rata allocation based on each participant's Unconstrained Benefits. Settlement ratemaking next allocates the cost of providing Refund Amounts to IOUs using the same pro rata basis. Settlement ratemaking then calculates utility-specific 7(b)(3) surcharges to be added to the appropriate Base PFx rates to produce utility-specific PFx rates. After the utility-specific PFx rates are calculated, the utility-specific REP benefits are calculated and summed. At this point, the total annual utility-specific REP benefits for IOUs are equal to the Scheduled Amount for each year.

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

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

One further adjustment is made to recognize that the IOUs have differing levels of setoffs in repaying their Lookback Amounts. See section 4.3.9. This adjustment is accomplished through reallocations of the cost of rate protection allocated to the IOUs. The Settlement specifies a maximum annual adjustment amount for three IOUs and separate adjustments for Idaho Power and NorthWestern Energy. These adjustments change the initial amount of REP benefits that each IOU would receive and allocate this change to other IOUs. Once all of the adjustments are allocated, the cost of rate protection initially allocated to each IOU is recomputed to account for this adjustment. The adjusted allocations of the cost of rate protection are added to the allocation of the cost of Refund Amounts to compute each IOU's final PFx rate.

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

5.2 Comparing the Rate Test with the Settlement

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

Under the Settlement, rate protection is afforded to preference customers. The amount of rate protection is calculated in the manner prescribed by the Settlement. In the same manner as with no settlement, the rate protection reduces the costs allocated to the PFp rate applicable to preference customers. The cost of this rate protection is reallocated to all other power sales except surplus sales (the allocation to surplus sales is implicit in the REP Surcharge). Two PF rates are the result of this reallocation: the PFp rate, which receives the rate protection, and the PFx rate, which does not receive rate protection and bears its allocated share of the rate protection reallocation. The cost of rate protection continues to be collected through 7(b)(3) surcharges applied to non-PFp sales. An additional calculation is performed when determining utility-specific 7(b)(3) surcharges for IOUs, which assigns the cost of the Refund Amounts in the rate determination rather than through the current use of separate setoffs to the REP benefits paid to the IOUs.

5.3 Summarizing the PFp Rate

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

5.4 Summarizing the PFx Rate

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

5.5 Summarizing the IP and NR Rates

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

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PART II ANALYSIS AND EVALUATION OF THE 2012 REP SETTLEMENT

6. ANALYZING THE SETTLEMENT

6.1 Introduction

The 2012 REP Settlement 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. These parties informed the Administrator of their development of a proposed settlement. The Administrator requested that BPA Staff analyze and evaluate the 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 BPA 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.

6.2 Overview of Methodology Used to Analyze the 2012 REP Settlement

As noted in section 4 of this Study, the 2012 REP Settlement resolves existing and future challenges to BPA's implementation of the REP for a term of 27 years, FY 2002 through FY 2028. Beginning in FY 2012, BPA will not perform the traditional section 7(b)(2) rate test in setting its rates. Instead, the Settlement (assessed through the examination of numerous 7(b)(2) rate test scenarios) determines the amount of REP payments to the IOUs and, concomitantly, the amount of rate protection afforded to the COUs. REP payments to IOUs under the Settlement will begin in FY 2012 at approximately $182 million per year and gradually increase over 17 years to about $286 million by FY 2028. In addition, Refund Amounts of $76.5 million per year will start in FY 2012 and run for eight years. COUs may participate in the REP when eligible, resulting in additional REP payments. To be included in rates, all of these payments under the Settlement must be allowable under section 7(b)(2).

The protection and payments under the Settlement are well defined and can be computed without much interpretation. The REP payments to the IOUs are defined by a schedule, as are the Refund Amounts paid to the COUs. However, before the Administrator can make these payments and perform his obligations in the Settlement, the Settlement must have a clear and direct connection to the protections and requirements set forth in the Northwest Power Act. To that end, BPA has approached the analysis of the 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.

To analyze the protections and requirements set forth in the Settlement, BPA develops a set of potential future streams of results based on an examination of the major variables that would affect the amount of rate protection and REP payments. In addition, BPA develops a set of potential future streams of results based on an examination of the issues in litigation that would affect the amount of rate protection and REP payments. To accomplish this analysis, BPA uses two separate rate models.

6.3 Rate Models Used to Analyze the 2012 REP Settlement

BPA modified the existing RAM, RAM2012, to examine the effect of different resolutions of issues in litigation on the amount of rate protection provided by section 7(b)(2) and the amount of REP benefits that would paid after application of the 7(b)(2) alternatives. RAM2012 is the detailed rate model used to calculate the BP-12 rates. RAM2012 has the capability of developing rates based on either the Settlement or the 7(b)(2) rate test. In fact, RAM2012 is the model that would be used to set rates using the section 7(b)(2) rate test had the Administrator decided not to adopt the Settlement. However, RAM2012 in its current state cannot be used as the sole model for analyzing the Settlement because it calculates rates for only the FY 2012–2013 rate period.

To address the need for a long-term analysis of the Settlement, BPA developed a long-term rate forecast model (LTRM) to produce estimates of rate protection amounts and REP benefits in the absence of settlement. LTRM projects rates, including rate protection amounts and REP benefits, for the full 17-year term of the Settlement. It is a scaled-down version of RAM2012 and performs many of the same functions as RAM2012 in the portions of the ratesetting process necessary to analyze the Settlement. LTRM develops energy allocation factors in the same manner as RAM2012 and allocates costs and credits to rate pools in the same manner as RAM2012. LTRM links the IP rate to the PF rate in a simplified form. That is, it uses annual data only, so it cannot independently calculate a flat annual PF rate for use in the 7(c)(2) linking process. Most importantly, LTRM performs the 7(b)(2) rate test, and consequent 7(b)(3) reallocations, in essentially the same manner as RAM2012.

There are a few notable differences between the new long-term model and RAM2012. The long-term model is an annual model; it does not calculate rates based on a two-year rate period as in RAM2012. Thus, the rate test in the long-term model is based on each year plus the four subsequent years. This will create minor differences compared to RAM2012. Also, the long-term model calculates only average energy rates for different rate classes; RAM2012 can calculate monthly and diurnal rates and apply the effects of the demand rate to the energy rates. Finally, the long-term model does not calculate tiered rates, whereas RAM2012 implements the

Tiered Rate Methodology. The lack of tiered rates has only one effect on this analysis: the rate for COUs participating in the REP is based on Tier 1 costs and loads, whereas the long-term model forecasts the costs and loads associated with expected service at Tier 2 rates and removes them from the PFx rate for COUs. The assumptions used to develop inputs for the long-term model, including projected estimates of future ASCs, PF rates, and exchange loads, are discussed in sections 8 and 9 of this Study.

The analysis also incorporates the ability to compute REP benefits and rate protection amounts under a variety of different litigation scenarios. BPA recognizes that the level of future REP benefits could be influenced by the outcome of the pending litigation. To model these impacts on future REP benefits, BPA designed the long-term model to produce rate protection and REP benefits under differing section 7(b)(2) assumptions in the same manner as in RAM2012.

6.4 Overview of the Settlement Analysis

RAM2012 is used in the analysis to produce near-term results and is used as the basis for calibrating the long-term model. Using both RAM2012 and LTRM, scenarios are developed and results presented projecting near-term and long-term quantitative impacts on future REP benefits resulting from a number of different risk and litigation positions. The analysis considers factors that could affect the future amounts of rate protection and REP benefits, such as changes in costs, loads, and other revenues. The factors considered can affect the ASCs used as the price of BPA's purchases from REP participants and the PF rates used as the price of BPA's sales to REP participants. While any factor that could affect rates could produce a change in rate protection and REP benefits, the factors can be grouped into those that would cause ASCs to grow faster than BPA's rates and those that would cause BPA's rates to grow faster than ASCs.

If ASCs grow faster than BPA's rates, the increased spread between the two rates produces more rate protection and mitigates the increase in REP benefits that would otherwise occur as ASCs increase. If BPA's rates grow faster than ASCs, the decreased spread between the two rates produces less rate protection and mitigates the decrease in REP benefits that would otherwise occur as BPA's rates increase. BPA's analysis builds a high-ASC, low-BPA case and a low-ASC, high-BPA case to be representative of the variety of factors that can affect the two rates. The factors that affect ASCs are addressed primarily in section 7; the factors that affect BPA rates are addressed in section 8.

Among the litigation scenarios BPA considers in the analysis are a BPA best-case scenario (Reference Case), single issue analyses, an IOU best-case scenario where IOUs prevail on a combination of litigated issues (IOU Best Case), and a COU best-case scenario where COUs prevail on a combination of litigated issues (COU Best Case). The litigated issues BPA considers in this analysis are discussed in section 9, and the effects these issues have on future REP benefits are described in section 10.

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7. AVERAGE SYSTEM COST FORECASTS

7.1 Introduction

This section of the Study presents BPA'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 two 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 the Commission in September, 2009.

7.2 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. For the REP-12 exchange period, 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.

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

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

7.3 Determination of the 2009 Base Period ASC

The Base Period ASCs used in this Study are obtained directly from the Final ASC Reports BPA issued on July 26, 2011. Table 7.1 shows the 2009 Base Period ASC for each utility.

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:

- Schedule 1 – Plant Investment/Rate Base

- Schedule 1A – Cash Working Capital Calculation (Cash Working Capital)
- Schedule 2 – Capital Structure and Rate of Return (Rate of Return)
- Schedule 3 – Expenses
- Schedule 3A – Taxes
- Schedule 3B – Other Included Items (Other Items)
- Schedule 4 – Average System Cost Purchased Power and Sales for Resale (3-Year PP & OSS Worksheet)
- Load Forecast
- Distribution Loss Calculation (Distribution Loss Calc)
- Distribution of Salaries and Wages (Salaries)
- Ratios
- New Resources – Individual and Grouped
- Materiality – Individual and Grouped
- New Large Single Loads (NLSL Base New-Calc)
- Tiered Rates Above Rate Period High Water Mark (RHWM) ASC Calculation for COUs only (Tiered Rates)

7.3.1 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 are included. These values (and all subsequent values) are entered into the Appendix 1 as line items based on the Commission's Uniform System of Accounts. Because most financial systems used by COUs have the Commission account structure built in, the COUs can also prepare plant and expense reports based on the Commission 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 by subtracting the functionalized depreciation and amortization reserves from gross plant-in-service.

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

7.3.2 Schedule 1A – Cash Working Capital

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

Cash working capital is a ratemaking convention that is not included in the Commission's Uniform System of Accounts but is a part of all electric utility rate filings as a component of rate

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

base. To determine the allowable amount of cash working capital in rate base for a utility, the 2008 ASCM allows into rate base one-eighth of the functionalized costs of total production expenses, transmission expenses, and administrative and general expenses, less purchased power, fuel costs, and public purpose charges. Cash working capital is not functionalized *per se*. Instead, the cash working capital values shown on Schedule 1A are the functionalized value of each component. *See* 18 C.F.R. § 301, End. f.

7.3.3 Schedule 2 – Capital Structure and Rate of Return

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

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

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

7.3.4 Schedule 3 – Expenses

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

7.3.5 Schedule 3A – Taxes

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

7.3.6 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.

7.3.7 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).

7.3.8 Three-Year Purchased Power and Sales for Resale

This worksheet presents the detailed values by the Commission's statistical classification code[2] 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 sales for resale. *See* 18 C.F.R. § 301.4.(b) The price spread is used in the ASC Forecast Model and is discussed in Section 7.4.12.

7.3.9 Load Forecast

Each utility is required to provide an eight-year forecast (FY 2010–2017) of its total retail load and its qualifying residential and small farm retail load, both as measured at the retail meter. The total retail and residential and small farm load forecasts are adjusted for distribution losses and New Large Single Loads (NLSLs) when appropriate. The resulting load forecasts are the Contract System Load forecast and Exchange Load forecast, respectively. The Contract System Load forecast is used in the ASC Forecast Model to calculate the utility's ASC; the Exchange Load forecast is used in the rate case to calculate REP benefits.

For the COUs only, the Exchange Period Contract System Load forecasts (FY 2012–2017) are the load forecasts as determined by BPA under the Tiered Rate Methodology. The COUs provide their qualifying residential and small farm retail load (Exchange Load) as measured at the retail meter.

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[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.

7.3.10 Distribution Loss Calculation

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

7.3.11 Distribution of Salaries and Wages

This worksheet presents the salary and wage information that is used to determine the Labor ratio, shown on the Ratios schedule. The data is taken directly from page 354 of the FERC Form 1, which functionalizes utility total salary and wage costs into the components shown on the schedule. This worksheet includes salaries and wages from relevant operations and maintenance of the electric plant. For COUs, comparable information comes from the detailed salary and wage data of the utility's financial system.

7.3.12 Ratios

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

7.3.13 Exchange Period Major Resource Additions – Individual and Grouped

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

Utilities are required to provide forecasts of major resource additions, retirements, and sales, along with the associated costs, with their ASC Filings. In their major resource forecasts, utilities provide 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.*

7.3.14 Exchange Period Major Resources Materiality – Individual and Grouped

These worksheets determine the effects of major resource additions or reductions on a utility's Base 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 7.4.2 of this document.

7.3.15 New Large Single Loads

This worksheet calculates the Base Period cost of resources in an amount sufficient to serve any New Large Single Loads, which BPA must exclude from the utility's ASC pursuant to 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 that 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 10 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 with an NLSL and an amount of resource costs sufficient to serve such NLSL. *See* 16 U.S.C. § 839c(c)(7)(A). To determine the amount of resource costs to exclude from a utility's ASC, BPA follows the methodology described in Endnote d of the 2008 ASCM. *See* 18 C.F.R. § 301, End. d.

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

7.3.16 Tiered Rates

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

This worksheet contains the amount of Tier 1 load purchased from BPA, the amount of Existing Resources allowed in ASC, and the COU's Above-RHWM load, and comes from BPA's Power

Rates and Implementation Group (PFR). For background information and details, see Chapter 3 of the Power Rates Study, BP-12-FS-BPA-01.

7.3.17 Contract System Cost

Contract System Cost is the utility's cost for production and transmission resources, including power purchases and conservation measures. Contract System Cost is calculated by adding the functionalized Production and Transmission costs less revenue credits. Contract System Cost 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 7.2 shows the 2009 Base Period Contract System Cost for each utility.

7.3.18 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 7.3 shows the 2009 Base Period Contract System Load for each utility.

7.3.19 PacifiCorp and NorthWestern Jurisdictional Cost Allocation

Calculation of PacifiCorp's and NorthWestern's ASC involves consideration of unique jurisdictional allocation issues. The 2008 ASCM states that a single ASC will be used for each utility's entire regional load. Both PacifiCorp and NorthWestern provide retail service to customers both inside and outside the Pacific Northwest.

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 Pacific Northwest are included in PacifiCorp's ASC.

NorthWestern's FERC Form 1 contains some data that is specific to its Montana jurisdiction. In addition, Northwestern also files an annual report to the Montana Public Service Commission (MPSC) that identifies costs and loads related to its Montana retail electric customers. NorthWestern's FERC Form 1, MPSC annual report, and information from data requests are used to ensure that only costs and revenues related to NorthWestern's Montana retail electric service territory are included in its ASC.

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

Once the Base Period ASC is calculated, BPA 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), operations and maintenance (O&M), and general and administrative (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.

7.4.1 Escalation to Exchange Period (FY 2012–2013)

Table 7.4 shows the annual escalation rates used in the ASC Forecast Model through FY 2013.

7.4.2 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, major new resource additions come on line and are used to meet the utility's retail load, or resources are terminated. These additions or reductions will affect costs. Additions may include new production resource investments; new generating resource investments; new transmission investments; long-term generating contracts; pollution control and environmental compliance investments relating to generating resources, transmission resources, or contracts; hydro relicensing costs and fees; and plant rehabilitation investments. *See* 18 C.F.R. § 301.4(c)(4). Changes to an ASC, however, are limited to instances where the cost impact of the new resource passes a materiality threshold of an increase in the Base Period ASC of 2.5 percent or greater.

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

Under the Settlement, the IOUs agreed not to request a change in ASC for any new resource additions that come on line during the Exchange Period. Therefore, for the Exchange Period (FY2012–2013) ASC forecast, BPA assumed that any resource additions or reductions that parties indicated would be occurring during the Exchange Period would not be included in the utility's ASC.

7.4.3 Ratios

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

7.4.4 Schedule 1 – Plant Investment/Rate Base Forecast

7.4.4.1 Production and Transmission Plant

Gross production and transmission plant are held constant through the end of the Exchange Period, unless there are production plant or transmission plant resource additions. In such case, a new ASC is calculated including the plant addition, as described above. *See* section 7.4.2.

7.4.4.2 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 escalates the Base Period average per-megawatthour cost of distribution plant forward to the midpoint of the Exchange Period and uses the escalated average cost times the megawatthours 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.

7.4.4.3 Forecast General Plant-Related Costs

To escalate General Plant-related costs, BPA first calculates the ratio of base period general plant to the sum of base period production, transmission, and distribution plant. BPA 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.

7.4.4.4 Forecast Depreciation and Amortization Reserves

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

7.4.5 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 uses the projected component values.

7.4.6 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.

7.4.7 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 7.4.9, 7.4.11, and 7.4.12.
- 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 7.4.7.1.
- Operations and maintenance expense and fuel expense are escalated annually as described in the ASCM and increased for any additional O&M and fuel associated with new plant additions.

7.4.7.1 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)

7.4.8 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.

7.4.9 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 7.4.12.

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

> (Wheeling revenues (before additions) / net transmission plant (before additions)) × new transmission additions.

7.4.10 Load Forecast

7.4.10.1 Forecast Contract System Load and Exchange Load

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

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

For the Exchange Load forecasts through the end of the Exchange Period, BPA used the forecasts provided by the utilities. For the COUs, pursuant to the TRM, the total Exchange Load was reduced each year by each COU's Tier 1 percentage to determine the forecasts of exchange load for which the COUs could invoice BPA.

7.4.11 Forecast Methodology for Meeting Load Growth

All forecast load growth will first be met by new resource additions. If the power provided by the new resources is less than the total forecast load growth, the remaining load growth will be 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 determined by BPA, as discussed in section 7.4.12.

7.4.12 Treatment of Sales for Resale and Power Purchases

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

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

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

BPA used each utility's historical three-year weighted spread between short-term purchased power price and sales for resale price (the price spread) to determine that utility's forecast price spread.

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

Forecast purchase price = Escalated midpoint price × (1 + price spread)

Forecast sales price = Escalated midpoint price × (1 – price spread)

7.4.13 New Large Single Loads

An NLSL is any load associated with a new facility, an existing facility, or an expansion of an existing facility that was not contracted for or committed to prior to September 1, 1979, and that will result in an increase in power requirements of 10 average megawatts or more in any consecutive 12-month period. 16 U.S.C. § 839a(13)(A)-(B).

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

NLSL determinations are not made in the ASC review process. Instead, they are identified and made through a separate process conducted by BPA. Although NLSLs are determined in another forum, BPA must establish in the Draft and Final ASC Reports the removal of the costs of serving any potential NLSLs pursuant to the requirements in Endnote d(1)-(3) of the 2008 ASCM. Parties to the ASC Review Processes must also be allowed an opportunity to review and comment on BPA's calculation.

During review of utilities' ASC Filings for the FY 2012–2013 ASC Exchange Period, several large utility loads were identified at Idaho Power, PacifiCorp, and Portland General that met the statutory definition of an NLSL. The Final ASC Reports adjusted the utility's ASC to reflect BPA's final NLSL determinations.

For purposes of the LTAFM, each of the large loads identified as NLSLs for the FY 2012-2013 Final ASC Reports is treated as an NLSL through FY 2032. The megawatthours associated with each NLSL remain constant and are removed from each utility's total retail load. The cost of resources in an amount sufficient to serve these potential NLSLs is removed from each utility's allowable production and transmission costs using the NLSL worksheets of the LTAFM described in section 7.3.15. Costs of resources in an amount sufficient to serve NLSLs are escalated through FY 2032. When new resources are added for a utility in the LTAFM, they are also included in the NLSL worksheets to determine NLSL resource costs.

7.4.14 Rate Period High Water Mark ASC Calculation under the Tiered Rate Methodology

Exchanging COUs receive power from BPA under CHWM Contracts. By signing the CHWM 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-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 calculating both NewRes$ and NewResMWh, Existing Resources for CHWMs specified in Attachment C, Column D, of the Tiered Rate Methodology, BP-12-A-03, 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 market purchases at utility-specific market price. Short-term purchases are not allowed in the calculation of the cost to serve NLSLs.
- If output of new resources exceeds Above-RHWM Load, reduce short-term market purchases by the excess to the extent possible in the Contract System Cost calculation.
- Sell any remaining surplus at the utility-specific Sales for Resale price in the Contract System Cost calculation.

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

7.4.15.1 Contract System Cost Forecasts

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

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

The COU forecasts do not include the Federal income tax calculation from ROR (Rate of Return).

7.5 Determination of the Forecast ASCs for FY 2014–2032

To calculate ASCs for the Long-Term Period (FY 2014–2032), BPA 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.

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

Through CY 2017, the LTAFM uses Global Insight's forecast of cost increases for capital costs and fuel (except natural gas), operations and maintenance (O&M), and general and administrative (G&A) expenses. For CY 2018 through CY 2032, the annual escalation rate for each Global Insight escalator in the LTAFM is set equal to the CY 2017 escalation rate. Through CY 2017, the LTAFM uses BPA's forecast of natural gas prices For the CY 2018–2032 period, natural gas prices are escalated 3 percent annually. Through FY 2017, the LTAFM uses 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. For the FY 2018–2032 period, electric market prices are escalated 3 percent annually. Through FY 2032, the LTAFM uses BPA's estimates of the rates it will charge for its PF and other products.

Table 7.5 in the Documentation shows the escalation rates through FY 2032.

7.5.2 Plant Investment/Rate Base Forecast

New resource additions for the FY 2014–2028 period are based on each utility's most recent Integrated Resource Plan (IRP) or similar document, the Northwest Power and Conservation Council's Sixth Power Plan, and other sources. The analysis is described in greater detail in sections 7.7, 7.8, and 7.9. 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 in the IRPs the cost of maintaining or replacing existing resources. 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.

7.5.3 Load Forecast

7.5.3.1 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 7.8.3.

For the COUs, BPA 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 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 for which the COUs could invoice BPA, as required by the TRM.

7.6 ASC Inputs into the Long-Term Rate Model

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 cost, revenue, and load 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.

7.6.1 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.

7.6.2 Forecast Values

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

$$\text{Current FY Value} = [\text{Previous FY Value} \times (1 + \text{escalator})] + \text{Current FY New Resource Addition}$$

7.6.3 Short-Term Purchases and Sales

Short-term purchases quantity and expense and short-term sales quantity and revenue are calculated in the same way as they are in the ASC Forecast Model used to calculate Exchange Period ASCs. 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, priced at the utility's forecast sales for resale price as discussed in section 7.4.12.

7.6.4 Tier 1 Purchases

For FY 2012 and FY 2013, Tier 1 purchase expense is calculated using tiered rate estimates that assume no IOU settlement.

For FY 2014–2032, the tiered rates are escalated at the same rate as the average PF rate changes. These escalated tiered rates are then used to calculate the Tier 1 purchase expense in each fiscal year.

The annual Lookback credit equals Initial Proposal values. For all fiscal years, net Tier 1 purchase expense equals Tier 1 purchase expense less the Lookback credit.

7.6.5 NLSL and Above-RHWM Cost Components

For each fiscal year, the NLSL and Above-RHWM production rate base equals the CY 2009 Base Period ASC input value 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 calculated as discussed in section 7.4.14. Contract System Cost is calculated as discussed in section 7.4.15.1.

7.7 New Resource Additions for FY 2014–2032

New resource additions used in the Long-Term ASC Forecast Model are based on review and analysis of each utility's Integrated Resource Plan. The individual IRPs guided the timing, quantity, and resource type added for each utility. However, for the resources added in the

LTAFM, a set of 14 "generic" resources was developed and used when a utility IRP indicated that a new resource was added. Cost and operating characteristics for the 14 generic new resources were based largely on Appendix I of the Council's Sixth Power Plan, except as noted in the following paragraph.

First, Appendix I calculates resource costs in real, levelized 2006 dollars. Because the LTAFM calculates ASCs in nominal dollars for each year of the Long-Term Period, the data was converted using the Council's MicroFin model (used by the Council to develop the real, levelized values) so that the first-year costs for each resource could be calculated in nominal dollars. Appendix I of the Council's Sixth Power Plan also reports transmission costs and losses as a single value, also in real, levelized dollars per megawatthour. The LTAFM separates transmission costs and losses and requires transmission costs in nominal dollars per kilowatt per year. MicroFin was also used to convert transmission costs. For resource capacity factors, BPA relied on the Appendix I values except for combined and single-cycle combustion turbines. For these resources, BPA relied on the capacity factors from the California Energy Commission.[3] The cost and heat content of coal were based on the weighted average of those values for 19 coal plants owned by exchanging utilities. See Table 7.9 of the Documentation.

7.7.1 Global Parameters and Definitions Used in Determining Reference Plant Costs

7.7.1.1 Conventions

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

Year Dollars: Costs are expressed in nominal dollars.

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

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, operation, and 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 costs[4] 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 *(e.g.,* transmission, road, water, rail, waste water disposal); taxes; spares; furnishings; and working capital. Not included in Total Plant Cost are financing costs, escalation incurred during construction, and interest incurred during construction (IDC).

7.7.1.2 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 resource capital cost and the annual revenue requirements for the various resources. Depreciation is assumed to be straight-line over the life of the plant.

[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).

The financing parameter values used are shown in Table 7.5.

7.7.1.3 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 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.

7.7.1.4 Escalation Rates

For calculating the capital costs of the new resource additions included in the LTAFM, BPA uses Global Insight's CY 2014–2019 forecast of capital cost increases. For the CY 2020–2032 period, the capital cost escalation rates are set equal to the CY 2019 escalation rates. For calculating the operating costs of the new resource additions included in the LTAFM, BPA uses Global Insight's CY 2014–2017 forecast of cost increases for fuel (except natural gas), O&M, and G&A expenses. To escalate these items for the CY 2018–2032 period, the escalation rates are set equal to the CY 2017 escalation rates. Through CY 2017, the LTAFM also uses BPA's forecast of natural gas prices to calculate the natural gas fuel costs for new gas-fired resources. For CY 2018-2032, the natural gas fuel price is increased 3 percent annually. The escalators are shown in Table 7.6.

7.7.1.5 General Forecasts

<u>Transmission</u>

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 connecting 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. 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 OATT, Schedule 9 *see* http://transmission.bpa.gov/business/ts_tariff/default.cfm?page=oatt)).

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 are based upon the Council's Sixth Power Plan estimates of actual proposed new long-distance transmission alignments serving the resource areas of interest (Council Plan, Appendix I, Table I-3). Table I-24 of Appendix I shows the estimated transmission cost and losses in real, levelized dollars per megawatthour 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 in the LTAFM for long-haul wind. To develop the $126.56/kW/year used for transmission costs, the Council'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 Council Plan Documentation for results of the MicroFin model for this calculation. See Appendix I of the Council's 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 of the Council's Plan, 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.

7.7.1.6 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 7.8 provides the plant capacity factor for each of the reference resources, and Table 7.9 provides the adjusted plant capacity factor for each of the reference resources to reflect the transmission losses of energy delivered to the utilities' systems.

7.7.1.7 Fuel Costs, Purchase Power Expenses, and REC Costs

Coal

Coal costs ($/ton) and heat content values (Btu/lb) are based on the 2009 weighted average for the 19 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 7.9 of the documentation.

Natural Gas

Natural gas price ($/MMBtu) is the same gas price used to calculate BP-12 rates. This study assumes the inclusion of incremental transportation costs of $0.73/MMBtu ($2006).[5]

7.7.2 Assumptions for Reference Plants

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

7.7.2.1 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 is 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.

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

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.

Heat rate

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

Unit Commitment Parameters

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

Total Plant Cost

The "overnight" total plant cost of the reference plant is $2,350/kW installed capacity (2008 price year). This estimate is based on reported as-built costs for three landfill gas energy recovery plants and four generic estimates of plant development costs. Three of the latter were range estimates consisting of low and high bound costs. These cost observations, normalized as described in the Capital Cost Estimates subsection of Appendix I of the Council's Plan, are plotted by vintage in Figure I-4 of the Council's Plan. The increase in capital costs from 2004 to 2008 observed for most power generation technologies is not clearly evident here, particularly for the as-built costs. A reason may be that the built projects were of substantially different scopes (*e.g.,* with or without the gas collection system). For this reason, the representative project cost estimate was based on a projection of the 2005 and 2007 generic cost estimates,

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

which together with the 2006 actual project cost seem to reasonably track observed power plant cost escalation during this period. Because landfill gas energy recovery projects were not modeled in the Regional Portfolio Model, capital cost uncertainty was not estimated.

Construction costs are forecast to decline by 8 percent (real) in 2009, and then continue to decline to market equilibrium conditions, represented by the average of 2004 and 2008 costs, by 2011. Construction costs are assumed to remain constant in real terms thereafter.

<u>Development and Construction Schedule, Cash Flows</u>

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

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

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

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

<u>Operating and Maintenance Costs</u>

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

Economic Life

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

7.7.2.2 Biomass (Woody Residue Power Plants)

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

Reference Plant

The reference Greenfield plant is a 25 MW (nominal) fluidized-bed steam-electric plant with a full condensing steam turbine-generator. The plant is provided with mechanical draft condenser cooling. Selective non-catalytic nitrogen oxide (NOx) reduction, cyclones, and fabric filters are employed for air emission control. The plant consists largely of new equipment.

Fuel

The fuel supply consists largely of forest thinning and restoration residues within a 50- to 75-mile radius, augmented by mill, logging, forest thinning, and urban wood residues.

The fuel supply of the Greenfield plant consists largely of forest thinning residues, supplemented with limited quantities of mill residue, logging slash, and urban wood residues with an average 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.

Operating and Maintenance Costs

The estimated O&M costs for the reference Greenfield plant are $180/kW/yr fixed and $3.70/MWh variable.

Value of Steam Sales

Extracted 150-psi saturated steam is assumed to be valued at $5.00/1000 lb, based on the Port of Port Angeles (2009) plant characteristics and costs.

Economic Life

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

7.7.2.3 Geothermal

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

Reference Plant

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

Unit Commitment Parameters

Geothermal 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 90 percent.

Heat Rate: The average annual full load heat rate is 28,500 Btu/kWh, typical of an Organic Rankine Cycle (ORC) binary plant operating on 300°F geothermal fluid.

Total Plant Cost

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

Operating and Maintenance Cost

Estimated O&M costs for the reference plant are $175/kW/yr fixed plus $4.50/MWh variable.

Economic Life

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

7.7.2.4 Hydropower

Reference Plant

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

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

Operating and Maintenance Cost

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

Economic Life

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

7.7.2.5 Concentrating Solar Thermal Power Plant

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

Reference Plant

The reference plant is a 100-MW dry-cooled parabolic-trough concentrating solar thermal plant located in east-central Nevada near Ely. Power would be delivered to southern Idaho by the north segment of the proposed Southwest Intertie Project and then to the Boardman area by portions of the proposed Gateway West and Boardman-to-Hemingway transmission projects. Higher-temperature heat transfer fluids such as molten salt are expected to be available by the earliest feasible date for energization of the necessary transmission (ca. 2015). The reference plant is assumed to be equipped with a 2.5 solar multiplier collector field and thermal storage sufficient to support six to eight hours of full-power operation. This storage would allow output to be shifted to non-daylight hours, improve winter capacity factor, levelize output on intermittently cloudy days, and impart some firm capacity value. No natural gas backup is provided, because natural gas service is not available in the vicinity of the reference site.

Capacity Factors and Temporal Output

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

Unit Commitment Parameters

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

Total Plant Cost

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

Operating and Maintenance Cost

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

Integration Cost

The thermal storage capacity of the representative solar thermal plant is assumed to eliminate the need for 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. Estimated costs and losses appear in Table 7.9.

7.7.2.6 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 of the Council's Plan 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 7.10.

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 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.

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

Most existing North American coal steam-electric plants operate at sub-critical steam conditions. Supercritical steam cycles operate at higher temperature and pressure conditions, at which the liquid and gas phases of water are indistinguishable. This results in higher thermal efficiency, with corresponding reductions in fuel cost, carbon dioxide production, air emissions, and water consumption. Supercritical units are widely used in Europe and Japan. Several supercritical units were installed in North America in the 1960s and 1970s, but the technology was not widely adopted because of low coal costs and the poor reliability of some early units. The majority of new North American coal capacity is now supercritical technology.

Reference Plant

The reference plant is a single 450 MW net supercritical pulverized coal-fired power plant at a Greenfield site. This plant is equipped with low-NOx burners, overfire air, and selective catalytic reduction for control of nitrogen oxides. The plant would be provided with flue gas desulfurization, fabric filter particulate control, and activated charcoal injection for reduction of mercury emissions. The capital costs include a switchyard and transmission interconnection.

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

Fuel

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

Total Plant Cost

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

Operating and Maintenance Costs

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

Economic Life

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

7.7.2.8 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-NOx 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 rate 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.

Total Plant Cost

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

Economic Life

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

Operating and Maintenance Cost

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

7.7.2.9 Natural Gas Combined-Cycle Plant – Duct Firing

Gas turbine combined-cycle power plants consist of one or more gas turbine generators provided with exhaust heat recovery steam generators. Steam raised in the heat recovery units powers a steam-turbine generator. Capture of the energy of the gas turbine exhaust increases the overall thermal efficiency of a combined-cycle plant compared to a simple-cycle gas turbine generator.

The reference combined-cycle unit, for example, has a base load efficiency of 48 percent compared to a full-load efficiency of 38 percent for the reference hybrid intercooled gas turbine.

Combined-cycle plants can serve cogeneration steam load (at some loss of electricity production) by extracting steam at the needed pressure from the heat-recovery steam generator or steam turbine. Additional generating capacity (power augmentation) can be obtained at low cost by oversizing the steam turbine generator and providing the heat recovery steam generator with natural gas burners (duct firing). The resulting capacity increment operates at somewhat lower electrical efficiency than the base plant and is usually reserved for peaking operation. The incremental efficiency, however, is comparable to that of simple-cycle gas turbines.

Because they often operate at or near market clearing prices, combined-cycle plants can be an economical source of system balancing reserves. With high reliability, high efficiency, low capital cost, short lead time, operating flexibility, and low air emissions, gas-fired combined-cycle plants have been the bulk power generation resource of choice since the early 1990s.

Reference Plant

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

Fuel

Fuel for the plant is natural gas supplied on a firm transportation contract with capacity release capability. No backup fuel is provided.

Heat Rate

The HHV heat rate at full baseload under "new and clean" conditions is estimated to be 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 Power 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, 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.

7.8 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.

7.8.1 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 and increases to 15 percent in 2015, 20 percent in 2020, and 25 percent in 2025.

The legislation also provides that Renewable Energy Credits (RECs) may be used to fulfill RPS targets. Utilities may bank unused RECs from one year to apply to future RPS requirements.

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

- Build an eligible facility (or continue to operate an existing one) and retain REC output from these facilities.
- Buy power and REC output (a bundled REC) from another eligible facility.
- Buy unbundled REC output.
- Make "alternative compliance payments" with options to use these funds for construction of an eligible facility in the future.

Washington

In November 2006, Washington voters approved Initiative Measure No. 937, which established renewable energy targets starting at 3 percent of a qualifying utility's load by 2012, 9 percent in 2015, and 15 percent by 2020. Qualifying utilities are public and private utilities that serve more than 25,000 customers in the state of Washington. Electricity produced from an eligible renewable resource must be generated in a facility that started operating after March 31, 1999. Either the facility must be located in the Pacific Northwest, or the electricity from the facility must be delivered into the state on a real-time basis. Incremental electricity produced from efficiency improvements at hydropower facilities owned by qualifying utilities is also an eligible renewable resource, if the improvements were completed after March 31, 1999.

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

Idaho

There are currently no RPS requirements in Idaho.

Montana

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

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

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

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

The relationship between each exchanging utility's annual RPS requirement and the amount of renewable resource megawatthours and RECs is shown in Table 7.10 of the Documentation.

7.8.2 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. 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.

7.8.3 Load Forecasts

The load forecast portion of this Study shows the loads for FY 2009–2032. For FY 2009–2017, BPA used the loads that were filed in each IOU's 2009 Base Year Appendix 1. BPA used its own COU load forecasts as was agreed upon in the TRM. For the Long-Term Period for IOUs, BPA 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. Tables 7.8.1 through 7.8.8 present each utility's long-term load forecast for FY 2009–2032.

7.8.3.1 Avista Corporation

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

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

   FY 2029 Total Retail Sales = FY 2009 Total Retail Sales × (1 + .018) ^ 20

   FY 2029 Total Retail Sales = 12,794,413 MWh

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

   Growth Rate FY 2017–2029 = ((FY 2029 Total Retail Sales / FY 2017 Total Retail Sales) ^ (1/ 12)) – 1

3. BPA escalated the long-term load forecast from FY 2018 to 2032 by the 1.74 percent load growth percentage.

Table 7.8.1 in the Documentation shows the load forecast from Avista's 2009 Base Year Appendix 1 Final ASC Report for the years FY 2009–2017 and the escalated forecast loads for the years FY 2018–2032 as determined from Avista's IRP load growth percentage.

7.8.3.2 Clark County PUD

The load forecast used in the LTAFM for Clark is shown in Table 7.8.2 of the Documentation.

7.8.3.3 Idaho Power Company

This Study used Idaho Power's retail load forecast from the 2009 Base Year Appendix 1 Final ASC 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. BPA forecast Idaho Power's FY 2029 Total Retail Sales based on this growth rate to be 16,116,331 MWh.

   FY 2029 Total Retail Sales = FY 2009 Total Retail Sales × (1 + .725) ^ 20

   FY 2029 Total Retail Sales = 16,116,331 MWh

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

   Growth Rate FY 2017–2029 = ((FY 2029 Total Retail Sales / FY 2017 Total Retail Sales) ^ (1/ 12)) − 1

3. BPA escalated the long-term load forecast from FY 2018 to 2032 by the 0.16 percent load growth percentage.

Table 7.8.3 in the Documentation shows the load forecast from Idaho Power's 2009 Base Year Appendix 1 Final ASC 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.

7.8.3.4 NorthWestern Corporation

This Study used NorthWestern's retail load forecast from the 2009 Base Year Appendix 1 Final ASC 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. BPA forecast

NorthWestern's FY 2029 Total Retail Sales based on this growth rate to be 6,811,234 MWh.

FY 2029 Total Retail Sales = FY 2009 Total Retail Sales × (1 + .008) ^ 20

FY 2029 Total Retail Sales = 6,811,234 MWh

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

   Growth Rate FY 2017–2029 = ((FY 2029 Total Retail Sales / FY 2017 Total Retail Sales) ^ (1/ 12)) − 1

3. BPA escalated the long-term load forecast from FY 2018 to 2032 by the 0.72 percent load growth percentage.

Table 7.8.4 in the Documentation shows the load forecast from NorthWestern's 2009 Base Year Appendix 1 Final ASC 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.

7.8.3.5 PacifiCorp

This Study used PacifiCorp's retail load forecast from the 2009 Base Year Appendix 1 Final ASC 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 its regional retail load would grow by approximately 1.13 percent annually 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. BPA escalated PacifiCorp's total regional retail Sales by the annual growth rate of 1.13 percent for the FY 2018-2032 period.

Table 7.8.5 in the Documentation shows the load forecast from PacifiCorp's 2009 Base Year Appendix 1 Final ASC 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.

7.8.3.6 Portland General Electric

This Study used Portland General's retail load forecast from the 2009 Base Year Appendix 1 Final ASC 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 1.91 percent from 2009 to 2030. *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.

   FY 2030 Total Retail Sales = FY 2009 Total Retail Sales × (1 + .0191) ^ 21

   FY 2030 Total Retail Sales = 23,797,064 MWh

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

   Growth Rate FY 2017–2030 = ((FY 2030 Total Retail Sales / FY 2017 Total Retail Sales) ^ (1/ 13)) − 1

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

Table 7.8.6 in the Documentation shows the load forecast from Portland General's 2009 Base Year Appendix 1 Final ASC 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.

7.8.3.7 Puget Sound Energy

This Study used Puget's retail load forecast from the 2009 Base Year Appendix 1 Final ASC 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 1.95 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 30,984,120 MWh prior to adjustments for conservation or demand side resources.

   *FY 2027 Total Retail Sales = FY 2009 Total Retail Sales * (1 + .0195) ^ 18*

   FY 2027 Total Retail Sales = 30,984,120 MWh

2. In its 2009 IRP, Puget reported that 533 aMW (or 4,669,080 MWh) of load growth would be met with demand side resources. *See* Puget's 2009 Electric Integrated Resource Plan, July 2009, at 8–7. BPA subtracted the 4,669,080 MWh from the FY 2027 total retail sales before conservation to get Total Retail Sales after conversation of 26,315,040 MWh.

3. BPA then calculated the growth rate from the Final ASC Report FY 2017 Total Retail Sales that would result in the forecast FY 2027 Total Retail Sales.

   Growth Rate FY2017–2027 = ((FY 2027 Total Retail Sales / FY 2017 Total Retail Sales) ^ (1/ 10)) − 1

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

Table 7.8.7 in the Documentation shows the load forecast from Puget's 2009 Base Year Appendix 1 Final ASC 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.

7.8.3.8 Snohomish County PUD

The load forecast used in the LTAFM for Snohomish PUD is shown in Table 7.8.8 of the Documentation.

7.9 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 did not add new resource additions for the outyears not covered in the IRP except for RPS Compliance. Instead, BPA assumed load growth was met with market purchases.
- BPA tested for RPS compliance. If a utility did not comply with the RPS requirements, BPA met the requirements with regional wind additions.

7.9.1 Avista Corporation

New resources for Avista are shown in Table 7.11. Table 7.11 is consistent 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.

7.9.2 Clark County PUD

New resources for Clark PUD are shown in Table 7.12. Table 7.12 is consistent 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 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.

7.9.3 Idaho Power Company

New resources for Idaho Power are shown in Table 7.13. Table 7.13 is consistent 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 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.

7.9.4 NorthWestern Corporation

New resources for NorthWestern are shown in Table 7.14. Table 7.14 is consistent 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.

7.9.5 PacifiCorp

New resources for PacifiCorp are shown in Table 7.15. Table 7.15 is based on PacifiCorp's 2008 IRP preferred portfolio, with a few exceptions. First, because PacifiCorp's IRP was published in 2008, the wind resources projected to come on line in 2009 were already reflected in 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 one 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.

7.9.6 Portland General Electric

New resources for Portland General are shown in Table 7.15. Table 7.16 is consistent 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.

7.9.7 Puget Sound Energy

New resources for Puget are shown on Table 7.17. Table 7.17 is consistent with Puget's 2009 IRP, with two exceptions. Puget included in its IRP 300 MW of wind resources projected to come on line 2011 and 2012 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.

7.9.8 Snohomish County PUD

New resources for Snohomish PUD are shown in Table 7.18. Table 7.18 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.

8. RISK FACTORS

8.1 Risk Factors Affecting BPA Rates and ASCs

BPA and REP participants face numerous risks that can impact the level of future REP benefits, since they ultimately impact the costs and/or the revenues of BPA and the REP utilities. Some of these risks impact both the PF rate and ASCs, while other risks primarily impact one or the other. Because COU REP participants purchase much of their power from BPA and the cost of BPA purchases is included in ASCs, risks to BPA can directly translate into ASC risk for COU REP participants. Some of these risks are in existence now and impact current financial conditions, some are currently foreseeable but lack specificity, and some 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 (beneficial) and down-side (harmful) possibilities, and thus a reference to "risk" in this discussion signifies the possibility of events occurring that can impact expected future outcomes, generally future rate levels.

8.1.1 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, the price of natural gas determines the variable cost for that marginal generator and hence, the market-clearing price of electricity. Higher natural gas prices increase the cost of producing electricity and thus the ASCs of the utilities that rely on gas-fired generation. Lower natural gas prices reduce the cost of producing electricity and thus the ASCs of the utilities that rely on gas-fired generation. Natural gas prices have historically been very volatile and can materially change the level of an ASC.

Changes in electricity market prices can impact the cost of producing power and the prices paid and received for buying and selling energy on the wholesale power market. Two changes in the electricity market that are of particular importance to the calculation of ASCs are state or federal Renewable Portfolio Standards and the potential impact of carbon dioxide (CO_2) costs being reflected in the cost of producing electricity from fossil fuels. Because BPA does not currently have gas-fired generation in its resource portfolio, BPA-related risks stemming from market prices are generally confined to the effects of wholesale electricity prices.

8.1.2 Operating Cost Risk: Hydro (Including Fish), Columbia Generating Station (CGS), Wind

8.1.2.1 Hydro Generation Risk Impacts

The amount of Federal hydro generation impacts the amount of surplus energy BPA can sell, the amount of power BPA needs to purchase, and the level of the revenue credits used when calculating rates for PF customers. BPA faces not only the financial risk of reductions in the amount of hydro generation, but also higher capital and expense costs associated with meeting fish-related operational requirements. That is, hydro generation can be reduced due to additional hydro spill requirements, and monthly and hourly hydro generation can be reshaped into less valuable time periods, due to hydro operation changes specified in current and future fish-related requirements for the Columbia and Willamette dams. Litigation of such operational requirements also may result in additional generation loss or reshaping.

Future fish mitigation requirements may result in higher capital costs and expenses, especially if additional fish passage is required at the Columbia and Willamette dams. It is likely that additional outlays will be required for the dams and fish passage structures associated with mussel control measures. An additional risk is the impact that global climate change may have on the amount and monthly shape of future hydro generation. Capital investments and O&M expenses associated with maintaining the capability of the Federal dams in the future also are unknown and may exceed current forecasts. The risks enumerated above are primarily focused on BPA's rates and COU ASCs.

8.1.2.2 CGS Generation Risk Impacts

The level of output from the Columbia Generation Station impacts the amount of energy BPA can sell and the amount of power BPA needs to purchase to meet its sales obligations. CGS generation risks include the amount of output produced and the level of capital expenditures and O&M costs to maintain the plant's output as it ages. The prices paid for nuclear fuel on the spot and forward markets are volatile and represent a sizable cost risk. CGS risks could lead to higher BPA rate levels in the future and higher COU ASCs.

8.1.2.3 Wind Generation Risk Impacts

The financial impacts of increasing amounts of wind generation in BPA's Balancing Authority Area are most likely to impact BPA in terms of reduced surplus energy revenues, resulting in higher BPA rates. BPA seeks to recover the costs associated with higher wind penetration levels from those benefiting from BPA providing interconnection services. However, such may not be possible to the extent that surplus energy revenues are reduced by the impact that increased quantities of low variable cost (but high fixed cost) wind generation can have on electricity prices. As wind penetration levels continue to rise, passing additional costs to the beneficiaries of this service may lag until there is adequate data to support such cost recovery. These wind generation risks could lead to higher BPA rate levels and higher ASCs due to higher charges for wind integration services for utilities that own or purchase wind generation.

8.1.3 RPS, Carbon, and Other Environmental Mandates

Renewable resource additions to meet RPS requirements are likely to increase BPA's rates (primarily due to reduced net secondary revenues) and increase ASCs. The impact on REP benefits under such conditions is not clear, but rather is dependent on the relative magnitude of the change in BPA's rate levels compared to ASC levels. The change in BPA rates will depend on the amount of wind generation that is built in the PNW to serve the PNW or California and how much of the wind generation built for California is physically delivered to California, rather than left in the PNW with the environmental attributes of the wind generation being claimed by California utilities. The cost of wind resources in ASCs will be impacted by whether Federal production/investment tax credits remain available. These tax credits reduce the prices that wind generators need to receive in their contracts with utilities, which can reduce the costs of these resources in ASCs.

There is currently much uncertainty in terms of whether, when, where, and how CO_2 markets will be implemented. BPA rate levels are more likely to benefit from the reflection of CO_2 costs in electricity market prices relative to ASC levels, because the generation that BPA sells is almost entirely hydro and nuclear generation (which emits almost no CO_2). In contrast, both IOU and COU REP participants' generation is mostly from coal and natural gas-fired resources that emit substantial amounts of CO_2. For this reason, BPA generation will likely be assigned very little CO_2 costs and would benefit from higher electricity prices for its net secondary revenues (which lower BPA rates). Depending on the resource mix of each utility (which can vary considerably), the IOUs and COUs would pay the CO_2 costs, but they may also benefit from higher electricity prices. The net impact is that ASCs will likely increase for all the IOUs and COUs; although likely to a lesser extent for COUs with substantial purchases at lower BPA rates.

8.1.4 Measuring the High and Low BPA Rate Effects

Risk analysis scenarios are performed to assess the potential impact that high, medium, and low BPA resource costs and high, medium, and low CO_2 costs might have on REP benefits under high, medium, and low natural gas prices. Other than the probabilities associated with the high and low natural gas prices, no probabilities are assigned to each of the risk analysis scenarios developed to assess the range of possible rate levels and REP benefits under plausible potential outcomes. The financial impacts of the changes in the risk analysis scenarios are accounted for in the Long Term Rate Model in terms of changes in surplus energy revenues, balancing power purchase expenses, augmentation purchase expenses, and the BPA revenue requirement. The risk analysis scenarios assume that the risks occur during the FY 2012–2017 period, with the impact carried through 2032 using common escalation assumptions. Uncertainty in the timing of when the risks might occur is not included in this analysis.

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

High and low trajectories of natural gas prices are derived from simulated annual FY 2012–2017 natural gas price data for 3,500 games developed for the BP-12 final proposal. The methodology used for simulating the natural gas prices is documented in the Power Risk and Market Price Study, BP-12-FS-BPA-04. The first step in the process of developing these natural gas price trajectories involves calculating average annual natural gas prices from FY 2012–2017 for each of the 3,500 games, developing a cumulative probability of these values by sorting them from lowest to highest, and determining what the values are at the 5th and 95th percentiles. The second step in the process is to develop a cumulative probability distribution of natural gas prices for each fiscal year from FY 2012 to FY 2017 by sorting results for the 3,500 games from lowest to highest and calculating the average price for each cumulative probability value over FY 2012–2017. The final step in the process is to identify the set of sorted FY 2012–2017 prices at a given cumulative probability level that average the natural gas prices determined at the 5 percent and 95 percent values in the first step.

Table 8.1 of the Documentation reports the FY 2012–2017 high, median, and low natural gas prices used in this analysis, the derived annual average surplus energy prices, the derived implied heat rates, and the median surplus energy revenues under high, median, and low natural gas prices. The Long Term Rate Model uses these results to calculate the BPA rate impacts associated with changes in surplus energy revenues and the ASC impacts associated with changes in the natural gas prices.

Low, medium, and high CO_2 costs are accounted for in the risk analysis scenarios assuming no CO_2 prices and initial CO_2 prices of $20.00/ton and $40.00/ton in FY 2012 that escalate at a real annual rate of 5.0 percent and at an inflation rate of 2.5 percent through FY 2017. In order to convert these CO_2 prices into the impact on electricity prices ($/MWh), it is assumed in this analysis that 40 percent of the price of CO_2 per ton is reflected in the electricity prices. This value assumes the marginal resource is a gas-fired resource with a heat rate of 8,000 Btu/kWh.

FY 2012–2017 surplus energy revenues under the $20/ton and $40/ton alternatives under high, median, and low natural gas prices are calculated and input into the Long Term Rate Model to determine the impact that these changes have on PF rates. The carbon prices for the high and medium CO_2 scenarios are input into the Long Term Rate Model as $/MWh deltas to the BP-12 market price curve and are accounted for in the model in two ways. First, these prices are used in the computation of ASCs through adjusting the assumed market value for each exchanging utility's open position on market purchases and sales. Second, for the reference case, these prices are used to meet 50 percent of load growth through market purchases. The results from the risk analysis scenarios (which produce deltas to the secondary energy credit) are converted into ratios that are applied to the secondary energy and balancing purchase prices, such that the resulting secondary energy revenues and balancing purchase expenses incorporate an equivalent dollar delta. Individual ratios of the high and medium CO_2 price to the base market price are computed. These ratios are then applied to the augmentation price, increasing the augmentation price in the same proportion for each of the high and medium CO_2 price scenarios. Tables 8.2.1 and 8.2.2 of the Documentation report the results of these risk analysis scenarios.

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

The high resource cost scenario evaluates the rate impact of high nuclear fuel costs and potential future reductions in annual resource output from existing resources of 250 aMW. The low resource cost scenario assumes no future reductions in annual resource output and evaluates the impact that low nuclear fuel costs might have on reducing BPA's rates. The assumed future reduction in annual resource output was subjectively determined and is meant to account for the potential impact of a variety of both currently known and unknown factors. Such factors could, over the course of the 17-year contract period, reduce generation and/or increase capital investment or O&M costs from the values reflected in current generation output estimates and expenses accounted for in the revenue requirement during FY 2012–2017.

The costs of converting uranium into the nuclear fuel used in reactors include the costs of the raw uranium (referred to as yellow cake or U308), conversion services, and enrichment services. The quantity of product produced at each step decreases throughout the process. In this analysis, the changes in costs of nuclear fuel for CGS are computed by multiplying the annual reactor requirements (specified in terms of quantity) at each of these steps times the associated costs. The annual reactor requirements are based on values reported by Energy Northwest. The FY 2012–2015 forward market prices for raw uranium used in the base case scenario, and from which the revisions in nuclear fuel costs are computed for the high and low scenarios, are based on prices quoted on 06/30/2011 at the following Web site: http://www.cmegroup.com/trading/metals/other/uranium_quotes_globex.html

Because forward price quotes were not available for FY 2016–2017, the FY 2015 price quotes are used for these years. The base case cost for enrichment services per Separative Work Unit is based on a value reported by Energy Northwest. The base case cost for conversion services per kilogram of uranium (kgU) is based on making a modest increase in this cost ($.025 per kgU) from the historical data reported from January 2002 through December 2007 by Ux Consulting Company, LLC. See Web site at http://www.uxc.com/review/uxc_PriceTable.aspx.

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

Values used in deriving the nuclear fuel cost scenarios and the resource cost scenarios are reported in Tables 8.3.1 through 8.3.4 of the Documentation.

8.2 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. This section presents a qualitative discussion of future risks and their effects on rate levels and 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 1 of this Study. Section 8 of the Documentation includes tables that show the complete impact of this risk analysis on rates and REP benefits.

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9. DESCRIPTION OF ISSUES IN LITIGATION

9.1 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.

9.2 Lookback Issues

Following the issuance of the *PGE*, *Golden NW*, and *Pub. Util. No. 1. of Snohomish County, Wash. v. Bonneville Power Admin.*, 506 F.3d 1145 (9th Cir. 2007) (*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). *See* FY 2002-2008 Lookback Study, WP-07-FS-BPA-08. 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. WP-07 Supplemental ROD, WP-07-A-05, at 253-294.

In the WP-07 Supplemental ROD, BPA determined that the COUs had been overcharged by approximately $1.003 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. Lookback Recovery and Return, WP-10-BPA-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. FY 2012–2013 Lookback Recovery and Return Study, REP-12-E-BPA-03 at 6; Table 2.

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. 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 BPA'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 for the Initial Proposal, REP-12-E-BPA-01A.

9.2.1 No Lookback Proposition

9.2.1.1 Invalidity Clause

The IOUs argue that no Lookback Amounts are owed to COUs because the 2000 REP Settlement Agreements included an "Invalidity Clause." In describing 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), BPA 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. BPA also assumes that the remaining portions of the Lookback Amount would not be recoverable.

9.2.1.2 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, it is assumed 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. It is also assumed 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 the Commission, 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.

9.2.1.3 Load Reduction Agreements (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 that 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 to retain the greater of their LRA payments or their revised REP benefits as determined in the Lookback (but not both). *Id.* at 78–80. This treatment of the LRA payments in BPA's Lookback proposal, referred to as "protecting" the LRA payments, had the effect of increasing PacifiCorp's and Puget's respective Lookback Amounts.

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

If PacifiCorp and Puget were to prevail on this argument, it is assumed that BPA would have to remove the LRA payments from BPA's Lookback calculations. This adjustment would have the effect of reducing PacifiCorp's Lookback Amount by approximately $15.7 million and Puget's Lookback Amount by approximately $262 million. *See* IOU *APAC* Br. at 47. *See* Table 6.

9.2.1.4 Exclusion of Power Sales

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

The IOUs allege that BPA improperly included in the Lookback calculation the value of the power BPA sold to the IOUs under the 2000 REP Settlement Agreements. *See* IOU *APAC* Br. at 37-45. The IOUs contend that the power sales made under the 2000 REP Settlement

Agreements were separate power sales made under section 5(b) of the Northwest Power Act and, therefore, were not invalidated by the Court's decisions in *PGE* and *Golden NW*. *Id.* at 42–45. The IOUs also argue that the COUs' rates were not adversely impacted by these sales because BPA would have sold the power to other parties at the same rate regardless of the settlement. *Id.* at 41, 44–45.

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

9.2.1.5 Combined Effect of IOU Positions

The combined effect of the IOU and related party positions is to reduce the initial FY 2002–2006 Lookback Amounts established for each IOU to zero. To analyze the REP Settlement, in one scenario it is assumed that the \$237.6 million in Lookback Amount refunds that BPA has already collected from the IOUs, and paid to the COUs, would have to be returned to the IOUs. It is also assumed that the remaining portions of the Lookback Amount would not be recoverable. *See* section 10.4.1.

9.2.2 Large Lookback Proposition

9.2.2.1 Use WP-02 Determinations

In *Golden NW*, the Court remanded BPA's WP-02 power rates to BPA with instructions "to set rates in accordance with this opinion." Upon remand, BPA had to determine whether the existing record was sufficient to reset rates. In order to correct overcharges to the COUs' rates, BPA determined to, in simple terms, compare the benefits the IOUs received under the 2000 REP Settlement Agreements with the REP benefits the IOUs would have received in the absence of the settlement and under the traditional implementation of the REP, referred to as reconstructed REP benefits. The difference would be recovered from the IOUs and refunded to the injured COUs. REP benefits are determined by comparing an IOU's ASC with BPA's PFx rate, and then multiplying the difference by the utility's exchange load. The WP-02 record, however, included IOUs' ASCs and exchange loads that were not reviewed for accuracy and appropriateness, and included a PFx rate that relied on faulty market price and load data. Consequently, BPA reopened the WP-02 record to correct known errors and supply adequate ASC and exchange load information.

APAC argues that, in reopening the WP-02 record, BPA violated the rule against retroactive ratemaking, violated the rule prohibiting retroactive rulemaking, and exceeded the scope of the Court's mandate. APAC claims that BPA should have simply relied on the existing WP-02 record to determine the reconstructed REP benefits due the IOUs in the absence of the 2000 REP Settlements. APAC claims that BPA exceeded the scope of the Court's mandate and violated the rules prohibiting retroactive ratemaking and rulemaking when BPA reopened the final rate determinations made in the WP-02 ROD, updated the rates with different load and market price assumptions, and revised the section 7(b)(2) Implementation Methodology and Legal Interpretation retroactively. *See* APAC *APAC* Br. at 38-39.

If APAC were to prevail on this argument, it is assumed that BPA would have to determine the IOUs' reconstructed REP benefits using the PFx rate developed in the original WP-02 rate proceeding. Under this scenario, the IOUs' reconstructed REP benefits for FY 2002–2006 would average $48 million per year, an $86 million reduction from the reconstructed average of

$134 million. The IOUs' Lookback Amounts would then be $929.3 million, if calculated the same way as in the WP-07 Supplemental proceeding, an increase of $183.1 million. *See* Table 7.

Similarly, the total Lookback Amount would be $1,933 million under the WP-02 determinations of REP benefits when combined with the assumption of void LRAs, and $764 million if the WP-02 determinations are combined with the assumption that the LRAs are valid and separate. All of these amounts are larger than the original Lookback Amount of $746 million.

9.2.2.2 LRAs Voided

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

APAC and Tillamook argue that the LRAs simply amended the 2000 REP Settlement Agreements to monetize as cash payments certain physical power deliveries required only by the 2000 REP Settlement Agreements. They state that despite the fact that the physical power deliveries required under the 2000 REP Settlement Agreements were later found by the Court to be unlawful, BPA elected to treat the cash payments required by the LRAs as binding obligations in the WP-07 Supplemental proceeding. They note that BPA further determined that the LRA payments would be "protected" against the section 7(b)(2) rate test and, ultimately, exempted from repayment to preference customers. APAC and Tillamook assert that BPA's refusal to include the LRA payments in the amount to be refunded to its preference customers is unlawful both because the LRAs were part and parcel of the 2000 REP Settlement Agreements held to be illegal and void, and because the LRA payments were charged to the preference customers in violation of the section 7(b)(2) rate test. APAC *APAC* Br. at 25, 28; APAC *APAC* Reply Br. at 28; Tillamook *APAC* Br. at 28; Tillamook *APAC* Reply Br. at 10.

If APAC and Tillamook were to prevail on this argument, it is assumed that BPA would have to include the value of the LRAs in the Lookback Amount calculation. As a result of this adjustment, PacifiCorp's Lookback Amount would increase from $203.5 million to $660.3 million, and Puget's Lookback Amount would increase from $262.2 million to $562.6 million. *See* Table 8.

9.2.2.3 Certainty of Repayment of Lookback

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

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

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

If APAC and Tillamook were to prevail on this argument, it is assumed that BPA would have to accelerate 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.

9.2.2.4 Combined Effect of COU Positions

The combined effect of the COU and related party positions is to increase the total Lookback Amount to $1,941 million. *See* Table 7. To analyze the Settlement, there are 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, which 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.

9.3 7(b)(2) Issues

9.3.1 Treatment of Conservation

9.3.1.1 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 7(b)(2) case will be the same as those used in the program case, except they will not include estimates of programmatic conservation savings." 1984 section 7(b)(2) Implementation Methodology, section V.1. Because conservation resources are included in the resource stack used to serve remaining loads if needed, these resources could not have already reduced loads in the 7(b)(2) Case. To remove the effects of conservation from the 7(b)(2) Case, the 7(b)(2) Customer loads were increased by an amount of load equal to the conservation savings BPA assumed in the Program Case. This adjustment ensured that conservation resources were given their full and intended effect when selected from the resource stack under section 7(b)(2)(D)(i).

Cowlitz and APAC argue that increasing preference customers' general requirements by BPA's estimate of conservation savings conflicts with the Northwest Power Act because it is contrary to the definition of "general requirements" in the Act. Cowlitz *APAC* Br. at 32–46; APAC *APAC* Br. at 52–54. They state that the definition, in section 7(b)(4), specifically defines the term "general requirements" as preference customers' "electric power purchased from [BPA] under § 5(b), exclusive of any new large single load." They argue that power *not purchased* because of conservation is *not* "power purchased." Cowlitz and APAC note that section 3(9) of the Act defines "electric power" as "electric peaking capacity, electric energy, or both." They argue that BPA's approach is inconsistent with the definition of "general requirements" in BPA's Legal Interpretation. They claim that Congress addressed the one and only change BPA should make to "general requirements" between the Program Case and 7(b)(2) Case, and the only permissible difference is set forth in the first assumption, which requires BPA to add to the general requirements only DSI loads. In summary, Cowlitz and APAC argue that had Congress wanted load-changing assumptions in the 7(b)(2) Case other than the required addition of certain DSI loads, it would have specified them. They argue that Congress did not, and BPA had no authority to modify the section 7(b)(2) assumptions adopted by Congress so as to increase preference customers' "general requirements."

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

If APAC and the PPC were to prevail on this argument, it is assumed that the conservation adjustment to 7(b)(2) Customers' loads in the 7(b)(2) Case would be removed and loads would be consistent with Program Case preference customer plus DSI loads. *See* section 10.4.5. If the IOUs were to prevail on this argument, it is assumed that the conservation adjustment to 7(b)(2) Customers' loads in the 7(b)(2) Case would be removed and loads would be consistent with the total of Program Case preference customer and DSI loads; plus the Program Case conservation costs would be included in the 7(b)(2) Case revenue requirement. *See* section 10.4.6.

9.3.2 7(b)(2) Repayment Study

BPA develops different revenue requirements, based on different repayment studies, for the Program Case and the 7(b)(2) Case. One is incorporated into the total Program Case revenue requirement, and the other is incorporated into the total revenue requirement developed specifically for the 7(b)(2) Case, based on the relevant assumptions that guide the two respective Cases. In each Case, BPA's outstanding debt and appropriation repayment obligations are considered; however, for the 7(b)(2) Case repayment study, conservation repayment obligations are removed because the resources are considered not to 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 that 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 that BPA cannot as a matter of law base that study on an arbitrarily truncated set of revenue requirements. Cowlitz argues that 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 it is assumed 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.

9.3.3 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 section 6 of the Northwest Power Act, or (ii) not committed to load under section 5(b) of the Northwest Power Act. 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 insufficient to meet COU loads, any additional needed resources are obtained at the average cost of all other new resources acquired by the Administrator.

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

BPA's preference customers note that under section 7(b)(2)(D), "resources owned or purchased by public bodies or cooperatives" are available in the 7(b)(2) Case if they are "not committed to load pursuant to section 5(b)." 16 U.S.C. § 839e(b)(2)(D). Cowlitz *APAC* Br. at 49–58. Cowlitz notes that the Act defines "resources" as "electric power, including the actual or planned electric power *capability* of generating facilities." 16 U.S.C. § 839e(b)(2)(D) (emphasis added). Cowlitz states that therefore a generator's capability is a "resource" for purposes of section 7(b)(2)(D). Cowlitz then argues that under section 5(b)(1)(A), a generator's *capability* can be committed to serve only the load of the generator's owner *(i.e.,* "the capability of such entity's firm … resources used … to serve its firm load in the region."). 16 U.S.C. § 839c(b)(1)(A). Cowlitz concludes that under these statutory provisions, the capability of non-Federal resources, including the capability of the Mid-Columbia resources, cannot be "committed to load pursuant to section 5(b)" unless their capability is committed to the load of the resource owner.

If the preference customers were to prevail on this argument, it is assumed that BPA would have to include Mid-Columbia resources in the resource stack to the extent that such resources are not committed to serving COU loads. *See* section 10.4.8.

9.4 7(b)(3) Issues

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

Section 7(b)(3) of the Northwest Power Act governs the reallocation of costs in the event the section 7(b)(2) rate test triggers. Section 7(b)(3) provides 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). In other words, if the rate test triggers, the trigger amount must be allocated away from preference customers' power sales priced under section 7(b) and reallocated to other power sales, including sales to utilities participating in the REP. These costs increase the PFx rate, which is the rate at which BPA sells power to utilities participating in the REP. When the PFx rate increases, the difference between that rate and the utility's ASC rate decreases, resulting in a reduction of REP benefits paid to the utility.

9.4.1 Allocation of Rate Protection to Surplus Power Sales

In the section 7(b)(2) rate test, if the average of the discounted Program Case rates exceeds the average of the discounted 7(b)(2) Case rates, the rate test is said to "trigger." The difference between the rates in the two cases is called the "trigger amount" and is multiplied by the preference customer loads for the rate period to yield the "7(b)(3) allocation amount." Section 7(b)(3) of the Northwest Power Act prescribes the manner in which the 7(b)(3) allocation 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 7(b)(3) allocation amount from BPA's forecast surplus power sales on a prospective basis, beginning with rates being established for FY 2009. Such recovery is accomplished by incorporating 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.

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. They claim that the result will be, in economic terms, placing back into preference customers' wholesale power rates the costs that were supposedly removed by operation of section 7(b)(2). Cowlitz WP-07 Br., WP-07-B-CO-01, 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 "other" power sales. They criticize an "allocation," wherein the rates would remain the same but the allocation would only cause the surplus revenue credit to decrease or a surplus revenue deficit to increase. They assert that allocating the trigger amount to the FPS rates, with the "net effect" of shrinking the secondary revenues credit and raising the PFp rate, is contrary to the section 7(b)(2) statutory guarantee.

If the preference customers were to prevail on this argument, it is assumed that BPA would remove the 7(b)(3) allocation to surplus sales in the ratesetting process. *See* section 10.4.9.

9.4.2 Treatment of Secondary Energy Credit

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

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

If the IOUs were to prevail on this argument, it is assumed that BPA would have to adjust the secondary revenue credit in the 7(b)(2) Case to use the same reduced secondary revenue credit as used in the Program Case. *See* section 10.4.10.

9.5 Additional Issues Subject to Litigation

9.5.1 7(b)(2) Accounting and Financing Treatment of Conservation Costs

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

PPC disagrees with BPA’s treatment of financing conservation resources available to serve preference customer load in the 7(b)(2) Case. PPC contends that the manner in which conservation is acquired in the 7(b)(2) Case is fundamentally different from that in the Program

Case. PPC states that BPA must determine how the Joint Operating Agency in the 7(b)(2) Case would finance a very large resource brought on to meet load, and argues that standard industry practice for financing such a resource is to capitalize all costs of such a resource and amortize those costs over the useful life of the resource.

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

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

If the PPC were to prevail on this argument, it is assumed that BPA would have to capitalize all costs of the conservation resources included in the resource stack and recover the costs over the useful life of the resources. If the OPUC were to prevail on this argument, and the IOUs were to prevail on their alternative argument, it is assumed that BPA would have to expense all costs of the conservation resources in the resource stack and recover costs in the first year the resource is selected from the stack.

9.5.2 Discounting of the Stream of 7(b)(2) Rate Projections

In the 1984 7(b)(2) Implementation Methodology, BPA decided that after calculating the stream of annual rates in the Program and 7(b)(2) Cases, it would be appropriate to discount the rates to the beginning of the rate test period before averaging the rate streams to perform the 7(b)(2) rate test. The purpose of the statutory directive to include four years beyond the rate period is to ensure that the rate period 7(b)(2) rate test trigger in one rate case is similar to the rate test triggers in later rate cases, all else being equal, by discounting rate period anomalies through the inclusion of more normalized forecast years. This process has the effect of reducing the weighting of an anomalous rate period difference between the Program Case and the 7(b)(2) Case. BPA uses the forecast long-term interest rate on Federal debt for this discounting. In establishing the discounting methodology and use of the long-term interest rate, BPA stated "[i]t is logical to use BPA's borrowing rate, since BPA could theoretically borrow the money in the test year to reimburse the 7(b)(2) customers for the five-year section 7(b)(2) rate test differential. The value to BPA of money over time is thus the economically correct value for the rate differential over time." Melton and Armstrong, b2-84-E-BPA-01, at 35-36. Also, smoothing the within-rate-case annual data is not necessarily a meaningful criterion; nor is minimizing the differences between the rate test period average difference and the annual differences between the Program Case and 7(b)(2) Case rates.

APAC argues that the methodology BPA uses to perform the present value calculation and the averaging in the 7(b)(2) rate test distorts the rate test results in future years. APAC WP-10 Br., WP-10-B-AP-01, at 13. APAC further argues that the trigger calculation should be based on an inflation adjustment internal to the data for BPA costs and ASC levels. APAC claims that this methodology better smoothes the annual trigger data while minimizing the difference between the annual values and the combined trigger.

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

If APAC were to prevail on this argument, it is assumed that BPA would use the current inflation rate forecast as discount factors in the rate discounting. If the IOUs were to prevail on this argument, it is assumed that BPA would use its current investment decision rate forecast for the rate discounting. *See* sections 10.5.3 and 10.5.4.

9.5.3 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, it is assumed 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.

9.6 RPSA Issues

9.6.1 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 applicable PF 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 PF 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 PF 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 PF rate due to application of section 7(b)(3) of the Act. 16 U.S.C. §§ 839c(c)(4), 839e(b)(3).

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

Between 1984 and 1993, Idaho Power accrued a deemer balance of approximately $91 million. Idaho Power subsequently terminated its participation in the REP. Upon termination, Idaho Power agreed that its outstanding deemer balance would accrue interest. Between 1993 and October 2000, Idaho Power's deemer balance grew to approximately $158 million. Idaho Power and BPA then entered the 2000 REP Settlement Agreement, wherein BPA and Idaho Power agreed to hold the deemer balance "in abeyance" during the term of that agreement.

Idaho Power and the Idaho Public Utilities Commission (IPUC) vigorously oppose BPA's decision to recover the outstanding deemer balances accrued under the 1981 RPSA. Idaho Power and the IPUC argue that BPA has not articulated a "cost or power planning purpose" for recovering the outstanding deemer balance against future ratepayers of Idaho Power. IPUC *IPUC* Br. at 43.

If Idaho Power and the IPUC were to prevail on this argument, it is assumed that BPA would have to cease collecting deemer balances from Idaho Power. Because Idaho Power was not eligible to receive REP benefits in the Lookback period (FY 2002–2006), the WP-07 rate period (FY 2007–2009), or the WP-10 rate period (FY 2010–2011), no retroactive adjustments to Idaho Power's REP benefits would be necessary if Idaho Power were to succeed in its challenge. Prospectively, however, BPA expects Idaho Power to become eligible to receive REP benefits beginning in FY 2012. If Idaho Power's historical deemer balance is extinguished or otherwise unrecoverable, it is assumed that Idaho Power would receive its full allocation of 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 (FY 2028).

9.6.1.2 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.*

If the IPUC and Idaho Power were to prevail on this argument, it is assumed that BPA would remove the Payment Balancing Account provision from the 2008 and subsequent RPSAs. Under this scenario, an exchanging utility would have no risk of losing future REP benefits if its ASC fell below BPA's PFx rate.

9.6.2 Exit/Reentry of REP Participants

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

The IPUC and OPUC allege that sections 1 and 11 of the 2008 RPSAs are unlawful in requiring utilities to agree to a single long-term contract as a condition for participating in the REP, which impermissibly and unreasonably restricts utilities' rights to enter and exit residential exchange transactions and make new offers for new residential exchange transactions. IPUC *IPUC* Br. at 34–37; OPUC *IPUC* Br. at 10–16. The IPUC and OPUC argue that because the Northwest Power Act allows utilities to offer to sell power to BPA to begin the exchange, utilities should be able to determine the period of time the exchange will exist. IPUC *IPUC* Br. at 34; OPUC *IPUC* Br. at 7.

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

10. ANALYSIS OF THE SETTLEMENT: SCENARIO DEVELOPMENT

10.1 Analysis of the 2012 REP Settlement

This section of the Study presents BPA's technical analysis of the 2012 REP Settlement. The technical analysis examines the ratemaking provisions of the Settlement 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 Settlement with the results of the scenarios developed in this analysis. The analysis is divided into two major groups of scenarios: (1) those that examine forecasting risk and uncertainty around BPA's base forecast in the Reference Case, and (2) those that examine litigation risks related to Lookback, conservation treatment and other statutory implementations currently under dispute.

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 used to calculate BP-12 rates. RAM2012 is limited to calculating rates for the two-year rate period. The LTRM was developed for this proceeding to extend rate analysis through the end of the Settlement, 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 Rates Study, BP-12-FS-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 updated results to section 7(b)(2) Rate Test Study, REP-12-E-BPA-02. *See* Documentation, Tables 10.2 and 10.3. Performing Scenario 0 in RAM2012 produces the results shown for FY 2012-13 in Table 10.6 of this Study, and are consistent with the methodology from the section 7(b)(2) Rate Test Study from the Initial Proposal, updated to the latest available data. Performing Scenario 0 in the LTRM produces 17 years of results consistent with RAM2012, as updated to the latest available data. Reference Case projected benefits for FY 2014-2028 rely on LTRM.

As discussed in section 6.3, LTRM is a long term model with several simplifying assumptions. Documentation is presented for FY 2012–2013 for data inputs used in RAM2012. (REP-12-FS-BPA-01A, Tables 10.2 through 10.3). However, given the term of forecasts necessary to complete 7(b)(2) rate tests for each of 17 years for 2012 through 2028, 6 year forecasts used in RAM were expanded for use in LTRM. Input data assumptions for LTRM include:

- **BPA Loads**: BPA load inputs build from loads presented in the Power Loads and Resource Study, BP-12-FS-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 Power Loads and Resource Study, BP-12-FS-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 Chapter 7.
- **Exchange Load**: Exchange load inputs are described in Chapter 7.

- **Costs**: BPA cost inputs build from costs developed in the Power Revenue Requirement Study, BP-12-FS-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). For debt financing forecast assumptions, values from the full 20-year Repayment Study in BP-12-FS-BPA-02 are used.
- **Revenue Credits**: BPA revenue credit inputs build from costs developed in the Power Rates Study, BP-12-FS-BPA-01, as used in the updated results to 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).
- **Market Electric Prices**: Market electric price inputs build from the Aurora forecasts developed in the Power Risk and Market Price Study, BP-12-FS-BPA-04, through 2017 and escalate at 3 percent per year thereafter.
- **7(b)(2) Resource Stack Costs**: Resource costs are consistent with the costs developed in the section 7(b)(2) Rate Test Study, REP-12-E-BPA-02, with updated data for the Final Proposal. *See* Documentation Table 10.3.2.2.
- **Miscellaneous Inputs:**
    - BPA's transmission rates escalate after FY 2017 at the assumed annual inflation rate of 1.75 percent.
    - The IP rate net margin remains constant at the -0.255 mills/kWh used in RAM2012.
    - Low density discount and irrigation rate discount costs are RAM2012 values through FY 2017 and are escalated to 3.75 percent thereafter.
    - The PF flat load rate conversion factor is set at a constant 96.5 percent for all years.

- The 30-year Treasury borrowing interest rate is consistent with the forecast in the Power Revenue Requirement Study Documentation, BP-12-FS-BPA-02A, Table 1.

10.4 Analyzing Effect of Forecasting Risk and Uncertainty

The analysis does not rely on a single static forecast of future costs. Recognizing inherent hurdles with forecasting, the analysis is stressed against a wide degree of future variation in the two "natural" drivers of REP benefits and associated rate protection: exchanging utility ASCs and BPA costs.

Base ASC forecasts used in the Reference Case are adjusted in these risk scenarios to reflect a wide range of outcomes throughout the 17-year period. As with the ASCs forecast for the Reference Case, these adjustments rely on resource cost expectations expressed in individual IOU integrated resource plans (IRPs), but are increased (or decreased) by high (or low) cost estimates for resource additions. High ASC cost scenarios assume that the full gamut of new resource needs identified in each exchanging utility's IRP are met through new resource additions, while low ASC cost scenarios assume that these resource needs are met solely through market purchases using BPA's current (and relatively low) market price forecast. These cost assumptions are an adequate proxy for the many cost variations that can be reasonably expected to occur through the next 17 years. Additional variation around high and low ASCs is modeled by further adjusting the natural gas and electricity market price assumptions as discussed in section 7.

BPA cost forecasts used in the Reference Case are adjusted in these risk scenarios to reflect a wide range of outcomes throughout the 17-year period. Variance around the Reference Case is implemented through adjustment to the escalation rates assumed for BPA costs through the future. While the Reference Case assumes inflation plus 2 percent, the high BPA cost scenario assumes inflation plus 4 percent, while the low BPA cost scenario assumes costs grow solely at the rate of inflation. Additional variation around high and low BPA costs is modeled by further adjusting uranium resource costs, the quantity of secondary energy available in future rate cases, as well as natural gas and electricity market prices.

Both high and low BPA revenue requirement scenarios are combined with the low and high ASC scenarios to produce a reasonable set of projections with upper and lower REP benefit bounds around the base ASC and BPA rates from the Reference Case. The pairing of “Low ASCs” with “High PF costs,” by the nature of the arithmetic workings of the REP benefit calculations, results in a cautious while reasonable lower bound for benefits expected over the 17-year period. Conversely, the pairing of “High ASCs” with “Low PF costs” results in a generous while reasonable upper bound for benefits expected over the 17-year period.

This pairing is deliberate: one would expect some positive degree of correlation between costs faced by BPA and costs faced by IOUs (regardless of the price scenario). The specific design of risk scenarios to test divergence between BPA and IOU costs (which therefore posits a negative correlation between costs faced by BPA and costs faced by IOUs) stresses the lower and upper bounds of REP benefits. This intentional design in the scenario development acknowledges inherent uncertainty in forecasting and compensates for such uncertainty by expanding the “jaws” of foreseeable benefits, upon which the analysis and evaluation is based.

Figure 1 summarizes post-Lookback IOU REP Benefits under alternative risk scenarios.

10.4.1 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.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for the No Settlement Lookback Amounts as shown in Table 10.1. For 2012–2013, results from RAM are displayed; for 2014 onward, results from LTRM are displayed.

10.4.2 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.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for the No Settlement Lookback Amounts as shown in Table 10.1. For 2012–2013, results from RAM are displayed; for 2014 onward, results from LTRM are displayed.

10.4.3 High Benefits Risk Scenario

As discussed in section 8, several scenarios are constructed by varying natural gas and electricity market prices. In addition, scenarios with varying BPA resource costs are developed, comprising both high and low nuclear fuel scenarios, as well as potentially reduced available generation for secondary sales. The High Benefits Risk Scenario builds upon the "High ASC, Low BPA Rates" scenario in section 10.7.1 and assumes *high* carbon costs, *high* gas prices, *low* nuclear fuel, and *no loss* in BPA generation. This, in general, causes IOUs' ASCs to rise at a rate faster than BPA's rates, which generally raises REP benefits.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for the No Settlement Lookback Amounts as shown in Table 10.1. For 2012–2013, results from RAM are displayed; for 2014 onward, results from LTRM are displayed.

10.4.4 Low Benefits Risk Scenario

The Low Benefits Risk scenario builds upon the "Low ASC, High BPA Rates" scenario in section 10.7.2, and assumes *no* carbon costs, *low* gas prices, *high* nuclear fuel, and a *loss* in BPA generation. This, in general, causes IOUs' ASCs to rise at a rate slower than BPA's rates, which, places downward pressure on REP benefits.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for the No Settlement Lookback Amounts as shown in Table 10.1. For 2012–2013, results from RAM are displayed; for 2014 onward, results from LTRM are displayed.

10.5 Analysis of Issues in Litigation

BPA's analysis of the Settlement further stresses forecast REP benefits (and implied 7(b)(2) rate protection) through acknowledging that certain aspects of the 7(b)(2) Implementation Methodology are currently under dispute. Ongoing litigation could potentially have material ratemaking effects on projections of REP benefits (and associated 7(b)(2) rate protection). Scenarios are therefore developed and modeled to analyze the impact of each of the issues in litigation discussed in Chapter 9 of this Study. 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 2-4 for a graphical summary of post-Lookback IOU REP benefits under alternative litigation scenarios.

10.5.1 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 9.2.1. The Lookback Amounts generally reflect the amount by which the IOUs were overpaid for FY 2002–2007 or 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 s*ection 9.2.1.1 regarding the IOUs' Invalidity Clause argument. Under this scenario, not only would the Lookback Amount of $767 million be reduced to zero, but 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. One plausible means to raise the funds needed to return these amounts to the IOUs would be for BPA to include the costs in the PF Public rates. Alternatively, BPA could raise funds through surcharges on the COUs' power bills. Staff is not proposing or modeling the source of these funds at this time. Reference Case stream of benefits is adjusted for the Scenario 1, and results are presented Tables 10.3.1-2.

10.5.2 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 *s*ection 9.2.2. 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, in which 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 alternatives. The first assumes BPA continues its application of the "50-percent" rule adopted in the WP-07 Supplemental ROD. The second 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 9.1 and 9.2 in the Documentation show the full results of the Lookback Lookforward Model (Documentation, REP-12-E-BPA-01A). Reference Case stream of benefits is adjusted for the Scenario 2, and results are presented Tables 10.3.1-2.

10.5.3 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 ($48 million) and the COUs' argument that the LRAs are invalid and therefore not protectable in the Lookback Amount calculation. *See* section 7.2.2.2. As in Scenario 2, two payback alternatives are shown, one with the "50-percent" rule and one without the rule.

Table 10.1 presents the two streams of annual Lookback amounts recovered from the IOUs in total. Tables 9.2 and 9.4 in the Documentation show the full results of the Lookback

Lookforward Model (Documentation, REP-12-E-BPA-01A). Reference Case stream of benefits is adjusted for the Scenario 3, and results are presented Tables 10.3.1-2.

10.5.4 Scenario 4: Idaho Deemer Balance

In this scenario, it is assumed that Idaho Power and IPUC prevail in their arguments, described in section 9.6.1, such that Idaho Power's deemer balance would be zero. However, all of Idaho's REP benefits would go toward its relatively large Lookback balance until it is extinguished. Reference Case stream of benefits is adjusted for the Scenario 4, and results are presented Tables 10.3.1-2.

10.5.5 Scenario 5: Conservation = General Requirements without Conservation Costs (a COU position)

Scenario 5 models the COUs' contention that the loads in the 7(b)(2) Case should not be adjusted for acquired conservation. *See* section 9.3.1.1. This scenario is a combination of two issues in litigation: 1) that conservation savings are general requirements under the Northwest Power Act, and 2) that conservation savings should be included in the 7(b)(2) Case at zero cost. To model this scenario, the load adjustment in the 7(b)(2) Case is set to zero, as are the conservation resources in the 7(b)(2) resource stack. This modification results in the 7(b)(2) Case starting with the same COU loads as used in the Program Case and adding the within-or-adjacent DSI loads to develop the 7(b)(2) Customer loads. The costs of the acquired conservation are not added to the 7(b)(2) Case revenue requirement.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.5.6 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 9.3.1.1. 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.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.5.7 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 9.3.2. To model this scenario, the 7(b)(2) Case repayment study results are replaced with the Program Case repayment study results.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.5.8 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 9.3.3. 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.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.5.9 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 9.4.1. 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.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.5.10 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 9.4.2. 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.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.5.11 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 9.3.1.2. 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.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.5.12 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 capitalized over the useful life of the resource. *See* section 9.3.1.2. 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 meaningless if considered in conjunction with either Scenario 5 or Scenario 6, where conservation resources are excluded from the resource stack.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.6 Analyzing the Effects of Issues That Are Expected to be Litigated in Challenges to WP-07 Supplemental Rates and WP-10 Rates

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

10.6.1 Scenario 13: Excluded Conservation Added to Resource Stack (an IOU position)

Scenario 13 models the IOUs' contention that all acquired conservation should be included in the resource stack rather than the smaller portion used in the Reference Case. *See* section 9.5.2. To model this scenario, the amounts of excluded conservation are added to the amounts already included in the resource stack, such that the conservation resource capability is the full amount acquired under each year's resource program. The full capability of the conservation resources is also used in the load adjustment to determine the general requirements of 7(b)(2) Customers in the 7(b)(2) Case.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.6.2 Scenario 14: Placeholder

Scenario 14 was reserved for possible other analysis and is not used.

10.6.3 Scenario 15: Inflation Rate Used for Discount Rate (a COU position)

Scenario 15 models APAC's contention that the projected rate of inflation should be used to discount projected rate streams for the Program Case and the 7(b)(2) Case rather than the forecast BPA borrowing rate. *See* section 9.5.1. To model this scenario, the 30-year Treasury borrowing rate forecast is replaced with the forecast inflation rate for purposes of discounting the rate streams.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.6.4 Scenario 16: Investment Rate Used for Discount Rate (an IOU position)

Scenario 16 models the IOUs' alternative contention that the projected investment decision discount rate should be used to discount projected rate streams for the Program Case and the 7(b)(2) Case rather than the forecast BPA borrowing rate. *See* section 9.5.1. To model this scenario, the 30-year Treasury borrowing rate forecast is replaced with an investment decision discount rate of 13 percent for purposes of discounting the rate streams.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for No Settlement Lookback Amounts as shown in Table 10.1.

10.6.5 Scenario 17: Placeholder

Scenario 17 was reserved for possible other analysis and is not used.

10.7 Combined COU/IOU Scenarios

To further analyze the Settlement, several additional scenarios combine those described above to define upper and lower bounds of litigation risk across the 17-year stream of REP benefits. 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 IOUs' 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.

10.7.1 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.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for Scenario 3 Lookback (without 50 percent rule) Amounts as shown in Table 10.1.

10.7.2 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.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for Scenario 1 Lookback Amounts as shown in Table 10.1.

10.7.3 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 on the treatment of conservation from Scenario 6 to allow their position on expensing conservation resources to affect the combined results of the IOUs' positions.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for Scenario 1 Lookback Amounts as shown in Table 10.1.

10.7.4 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.

Tables 10.2 and 10.3.1-2 present presents the stream of REP benefits resulting from this modification, adjusted for Scenario 3 Lookback (without 50 percent rule) Amounts as shown in Table 10.1.

10.7.5 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.

Tables 10.2 and 10.3.1-2 present the stream of REP benefits resulting from this modification, adjusted for Scenario 1 Lookback Amounts as shown in Table 10.1.

Figure 5 summarizes post-Lookback IOU REP Benefits under alternative brief scenarios.

10.8 Summary: Presenting Model Results

RAM2012 computation of REP benefits for the Reference Case and the litigation scenarios for the FY 2012–2013 period are included in Table 10.2. These results utilize scenario analysis in RAM2012. As presented in Tables 10.3.1-2, computed REP benefits for the Reference Case and all risk scenarios rely on RAM2012 for FY 2012–2013 and LTRM for FY 2014–2028. Computed REP benefits in Tables 10.3.1-2 for litigation and combined scenarios rely on LTRM analysis for the full FY 2012–2028 period, to provide consistency with associated Documentation.

11. EVALUATION OF THE SETTLEMENT

11.1 Introduction

The protection and payments under the 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 described earlier. It is important that the Settlement has a clear and direct connection to the protections and requirements set forth in the Northwest Power Act. Thus, BPA has evaluated the 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

To evaluate the Settlement, a set of criteria was developed and is used to "test" the Settlement. These criteria are comprised of three primary and two secondary criteria:

Primary criteria

- The Settlement would provide COUs with at least as much rate protection as 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.

Secondary criteria

- 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, BPA 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 BPA's view, a settlement that meets the foregoing criteria would also avoid the key concerns expressed over previous settlements of the REP.

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

11.3 Evaluation of the 2012 REP Settlement

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

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

The Settlement continues to distribute the REP benefits among the settling IOUs in a manner consistent with ASCs established under BPA's current ASC Methodology and rates established under section 7 of the Northwest Power Act. The Settlement requires no changes to the ASC Methodology, and no changes have been proposed. Rates continue to be established using a method very similar to that used to establish rates without the Settlement. The majority of the cost of rate protection continues to be allocated to the PFx rate, thereby reducing REP benefits below the Unconstrained Benefits. If a utility's ASC is less than the PFx rate, it will not receive any REP benefits under the Settlement, just as it would not receive any REP benefits in absence of the Settlement. The cost of rate protection is allocated among the eligible REP participants in the same manner as would be done without the Settlement.

The Settlement resolves, 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. Lookback Amounts are discharged as an individual obligation of each settling IOU. All of the settling parties, by signing the Settlement, would agree that the stream of Scheduled Benefits appropriately captures the disputed obligations and benefits arising from the past rate overcharges.

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

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

The Settlement provides rate protection superior to that provided by the 7(b)(2) rate test in almost all instances. To achieve higher rate protection, the non-settling COUs would have to prevail on five litigated issues. Although it is always risky to lay odds on the possible decisions of the Court, simply affixing a 50/50 probability to the outcome of each COU issue (and zero probability to countervailing IOU positions) would mean that the likelihood of receiving greater rate protection is $(\frac{1}{2})^5$, or about 3 percent. Given the unlikely probability of complete success before the Court, the Settlement would provide superior rate protection for non-settling COUs.

COUs participating in the REP bear the same exposure as the IOUs to deleterious outcomes of 7(b)(2)-related issues before the Court. While the COUs do not bear any exposure to an adverse outcome regarding Lookback issues, the Settlement methodology does not assign any Lookback consequence to the COUs' REP benefit level. Thus, the Settlement puts COU REP participants in the same position as IOU REP participants with regard to the outcome of 7(b)(2)-related litigation. By settling this litigation, the COU REP participants gain the same certainty that the IOUs gain. The COUs are in no worse or better position than the IOUs.

Furthermore, the Settlement provides direct benefits for the FY 2012–2013 rate period. IOU REP benefits under BPA's traditional 7(b)(2) Implementation Methodology (Reference Case from RAM Final Proposal results, Table 10.2) would, absent Settlement, result in an annual average for FY 2012–2013 of $271 million. This amount is exclusive of REP benefits which would otherwise accrue to Idaho, but for Idaho's outstanding deemer balance, and is before accounting for Lookback Amounts. The equivalent amount of REP Benefits under Settlement, including the Refund Amounts, is $258.6 million. Therefore, the Settlement provides a benefit to Public and DSI customers of roughly $12 million per year, for a total of $24 million of known savings for FY 2012–2013.

The IP rate under the traditional 7(b)(2) Implementation Methodology would result in an IP rate of $37.63 mills/kWh, compared to the IP-12 final rate of $36.32 mills/kWh under Settlement, as shown in Tables 10.5 and 10.6. Applied to Alcoa's flat annual load of 320 aMW, Settlement results in a direct savings to Alcoa of $7.4 million for FY 2012–2013.

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

Figure 6 compares the IP rate for FY 2012–2028 under Settlement relative to BPA's traditional Implementation methodology. Because ASCs are forecast to grow faster than the PF rate, the 7(b)(3) Surcharge under the traditional Implementation Methodology is expected to grow faster than under the REP Surcharge methodology under Settlement. The IP rate is therefore forecast to remain substantially lower under the Settlement than would otherwise be the case.

11.4 Conclusion

This Study forms the analytical basis supporting the findings in the REP-12 Final Record of Decision, REP-12-A-02. The analysis demonstrates that the conclusions reached by the Administrator in the Final ROD have a basis in fact and are supported by substantial evidence.

TABLES

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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: Refund Amounts to COUs

Rate Period	Fiscal Year	Refund 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
NorthWestern	$0
Idaho Power	$45,140,170
PacifiCorp	$66,721,315
PGE	$4,699,222
Puget	$0

Table 4.4: Maximum IOU Annual Adjustment Amount

IOU	Maximum IOU Annual Adjustment Amount
Avista	$2,004,778
NorthWestern	$0
Idaho Power	50 percent of Idaho Power's interim REP benefits
PacifiCorp	$8,442,636
PGE	$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	$10,199,000
PGE	$12,007,000
Puget	$56,994,000
Total	$81,610,000

Table 7.1: 2009 Base Period Average System Cost
(Dollars per megawatt hour)

Avista	56.04
Idaho Power	47.77
NorthWestern	58.10
PacifiCorp	58.70
Portland General	68.97
Puget Sound Energy	69.11
Clark	53.87
Snohomish	47.99

See REP-12-FS-BPA-01A, Section 7, and FY 2012–2013 Final ASC Reports for each of the exchanging utilities.

Table 7.2: 2009 Base Year Contract System Cost
(Dollars)

Avista	525,768,148
Idaho Power	679,834,891
Northwestern	353,188,004
PacifiCorp	1,239,331,429
Portland General	1,242,122,673
Puget Sound Energy	1,588,027,729
Clark	254,099,355
Snohomish	341,468,092

See REP-12-FS-BPA-01A, Section 7, and FY 2012–2013 Final ASC Reports for each of the exchanging utilities.

Table 7.3: 2009 Base Year Contract System Load
(MWh)

Avista	9,382,688
Idaho Power	14,230,732
Northwestern	6,078,493
PacifiCorp	21,112,995
Portland General	18,009,327
Puget Sound Energy	22,979,451
Clark	4,716,985
Snohomish	7,115,588

See REP-12-FS-BPA-01A, Section 7, and FY 2012–2013 Final ASC Reports for each of the exchanging utilities.

Table 7.4: Escalation Rates and Price Forecasts

Cost Item	Escalation	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	9.42%	-11.95%	10.56%	13.42%
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%
FY Market Price		19.19%	-3.98%	-8.75%	13.21%
FY Market Price ($/MWh)		38.19	36.67	33.46	37.88

Table 7.5: Financing and Other Common Parameter Assumptions
(Values are nominal unless stated)

	Municipal/ PUD	**Investor-Owned Utility**
Federal Income Tax Rate		35%
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%

Table 7.6: 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	9.4%	-11.9%	10.6%	13.4%	2.7%	4.6%	3.1%	4.4%	3.0%	3.0%
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%

Table 7.7: Plant Capacity Factor

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

Table 7.8: Capacity Factor (less losses)

Resource Type	Capacity Factor	Trans Loss Factor	Capacity Factor (less losses)
Coal Supercritical PC	93.0%	1.9%	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%	2.5%	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%
Purchased Power	100.0%	1.9%	98.1%
Hydro	50.0%	1.9%	49.1%

Table 7.9: 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%

Table 7.10: 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%

Table 7.11: 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 7.12: 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 7.13: 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 7.14: 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 7.15: 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															**570**
Biomass												25		25		**50**
Geothermal	35															**35**
Landfill Gas																
Long-Haul Wind	549	150	100	100	50	200	200	150								**1499**
Solar																
Wind	220															**220**
Purchased Power																
REC																

Table 7.16: 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 7.17: 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 7.18: 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																
Hydro					4		4									**8**

Table 9.1: FY 2002–2006 Lookback Amounts
WP-07 Supplemental Lookback Calculations
2009$ in millions

	LRAs Valid and Protected 1/	LRAs Valid but Separate and Unchallenged
PacifiCorp	$203.5M	$187.8M
Puget Sound Energy	$262.2M	$0
Total for all IOUs	$746.2M	$468.2M

1/ FY 2002-2008 Lookback Study, WP-07-FS-08, at 282-284. These three amounts are the FY 2002-2006 totals for lines 39, 57, and 69 of Table 15.9.

Table 9.2: FY 2002-2006 Lookback Amounts
Large Lookback Calculations based on WP-02 Determinations of REP Benefits
2009$ in millions

	Base Case 1/	Large Lookback with LRAs Valid and Protected	Large Lookback with LRAs Invalid	Large Lookback with LRAs Valid, but Separate and Unchallenged
Avista	$64.6	$64.6	$64.6	$64.6
Idaho Power	$85.0	$85.0	$85.0	$85.0
Northwestern	$5.7	$17.1	$17.1	$17.1
PacifiCorp	$203.5	$203.5	$669.6	$197.1
Portland General Electric	$125.1	$267.7	$267.7	$267.7
Puget Sound Energy	$262.2	$289.3	$828.6	$132.5
Total	$746.2	$927.3	$1,932.7	$764.0

Table 9.3: FY 2002–2006 Lookback Amounts
WP-07 Supplemental Lookback Calculations
2009$ in millions

	LRAs Valid and Protected	LRAs Invalid
PacifiCorp	$203.5	$660.3
Puget Sound Energy	$262.2	$562.6
Total for all IOUs	$746.2	$1,503.3

Table 9.4: REP Benefits, Lookback Amounts to be Recovered, and REP Benefits Paid – FY 2012–2013
($ in million)

	A	B	C	D	E	F
	REP Benefits Due		**Lookback Amount Recovered**		**REP Benefits Paid**	
	FY 2012	**FY 2013**	**FY 2012**	**FY 2013**	**FY 2012**	**FY 2013**
Avista	$20.18	$19.07	$10.09	$9.54	$10.09	$9.54
Idaho Power	$ 6.51	$10.42 1/	$ 0	$ 0	$0	$0
Northwestern	$ 2.67	$ 2.52	n/a	n/a	$2.67	$2.52
PacifiCorp	$58.44	$60.87	$29.22	$30.44	$29.22	$30.44
PGE	$83.46	$78.86	$15.93	$15.05	$67.52	$63.80
Puget	$106.89	$108.26	$23.10	$23.39	$83.79	$84.87
Total	$278.15	$280.00				
Total w/o IP	$271.64	$269.58	$78.34	$78.42	$193.30	$191.16

1/ Note that Idaho Power’s REP benefits will be applied to its deemer balance and not its Lookback Amount until the deemer balance is extinguished.

Table 10.1: Lookback Amounts Recovered in each Year

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
No Settlement Base Case											
Total Payments toward the Lookback Amount	$78.34	$78.42	$95.44	$97.13	$58.15	$29.37	$0.00	$0.00	$0.00	$0.00	$0.00
Total Payments toward Deemer balances	$6.51	$10.42	$4.59	$1.70	$3.89	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total of Lookback and Deemer balance payments	$84.85	$88.84	$100.03	$98.83	$62.03	$29.37	$0.00	$0.00	$0.00	$0.00	$0.00
Scenarios											
10.4.1 No Lookback - Return the Amounts Recovered from the IOUs in FY 12-14	($77.49)	($82.06)	($81.06)								
10.4.2 Large Lookback with Protected LRAs											
Lookback Payments w/ 50% rule	$100.73	$100.02	$128.49	$136.78	$114.50	$28.87	$14.72	$12.78	$1.55	$0.92	$0.69
Lookback Payments w/o 50% rule	$126.99	$126.24	$169.64	$165.53	$23.89	$3.48	$3.64	$3.29	$3.11	$1.84	$1.39
Total Payments toward Deemer balances	$29.36	$32.01	$13.95	$5.46	$8.75	$0.65	$0.00	$0.00	$0.00	$0.00	$0.00
Total of Lookback and Deemer balance payments w/ 50% rule	$130.08	$132.04	$142.44	$142.24	$123.25	$29.52	$14.72	$12.78	$1.55	$0.92	$0.69
Total of Lookback and Deemer balance payments w/o 50% rule	$156.35	$158.26	$183.59	$170.98	$32.63	$4.14	$3.64	$3.29	$3.11	$1.84	$1.39
10.4.3 Large Lookback with Invalid LRAs											
Lookback Payments w/ 50% rule	$124.39	$123.99	$155.97	$165.02	$189.56	$135.30	$143.73	$157.28	$151.48	$144.21	$133.17
Lookback Payments w/o 50% rule	$218.81	$219.66	$278.59	$293.44	$263.59	$220.91	$89.74	$100.98	$97.41	$78.78	$1.39
Total Payments toward Deemer balances	$29.36	$32.01	$13.95	$5.46	$8.75	$0.65	$0.00	$0.00	$0.00	$0.00	$0.00
Total of Lookback and Deemer balance payments w/ 50% rule	$153.75	$156.00	$169.92	$170.48	$198.30	$135.95	$143.73	$157.28	$151.48	$144.21	$133.17
Total of Lookback and Deemer balance payments w/o 50% rule	$248.16	$251.67	$292.54	$298.90	$272.34	$221.57	$89.74	$100.98	$97.41	$78.78	$1.39

Table 10.1: Lookback Amounts Recovered in each Year

	2023	2024	2025	2026	2027	2028
<u>**No Settlement Base Case**</u>						
Total Payments toward the Lookback Amount	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Payments toward Deemer balances	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total of Lookback and Deemer balance payments	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
<u>**Scenarios**</u>						
10.4.1 No Lookback - Return the Amounts Recovered from the IOUs in FY 12-14						
10.4.2 Large Lookback with Protected LRAs						
Lookback Payments w/ 50% rule	$0.12	$0.00	$0.00	$0.00	$0.00	$0.00
Lookback Payments w/o 50% rule	$0.24	$0.00	$0.00	$0.00	$0.00	$0.00
Total Payments toward Deemer balances	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total of Lookback and Deemer balance payments w/ 50% rule	$0.12	$0.00	$0.00	$0.00	$0.00	$0.00
Total of Lookback and Deemer balance payments w/o 50% rule	$0.24	$0.00	$0.00	$0.00	$0.00	$0.00
10.4.3 Large Lookback with Invalid LRAs						
Lookback Payments w/ 50% rule	$39.88	$44.15	$46.87	$47.30	$42.74	$43.64
Lookback Payments w/o 50% rule	$0.24	$0.00	$0.00	$0.00	$0.00	$0.00
Total Payments toward Deemer balances	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total of Lookback and Deemer balance payments w/ 50% rule	$39.88	$44.15	$46.87	$47.30	$42.74	$43.64
Total of Lookback and Deemer balance payments w/o 50% rule	$0.24	$0.00	$0.00	$0.00	$0.00	$0.00

Table 10.2: RAM2012 REP Benchmarks for FY 2012-2013 under Alternative Scenarios /1

	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	785,151	660,448	432,088	28,444	0.0837	306,235	265,126
Scenario 5 - Conservation = Gen. Req. w/o Costs.	765,278	809,702	529,735	34,872	0.1026	187,912	146,065
Scenario 6 - Conservation = Gen. Req. w/ Costs	781,586	686,567	449,176	29,569	0.0870	285,492	244,256
Scenario 7 - Single Repayment Study	782,886	677,861	443,480	29,194	0.0859	292,509	251,311
Scenario 8 - Mid-C in Stack	765,731	806,592	527,701	34,739	0.1022	190,419	148,585
Scenario 9 - No 7(b)(3) to Surplus	868,112	573,383	537,968	35,415	0.1042	285,693	238,869
Scenario 10 - Identical Secondary Credits	803,331	524,254	342,985	22,579	0.0664	413,771	373,357
Scenario 11 - Conservation Res. Expensed	796,023	580,224	379,603	24,989	0.0735	369,779	329,071
Scenario 12 - Conservation Res. Capitalized	779,774	700,249	458,127	30,159	0.0887	274,669	233,363
Scenario 13 - No Exclusions	789,681	627,488	410,524	27,025	0.0795	332,419	291,471
Scenario 15 - Discount Rate = Inflation	766,124	803,483	525,666	34,605	0.1018	192,868	151,051
Scenario 16 - Discount Rate = Investment	801,972	533,582	349,088	22,980	0.0676	406,319	365,861
Scenario 18 - COU Best Case	864,941	851,990	799,367	52,623	0.1548	23,338	(27,946)
Scenario 19 - IOU Best Case	829,152	333,333	218,078	14,356	0.0422	564,102	524,680
Scenario 20 - IOU Alternative Case	835,042	290,423	190,005	12,508	0.0368	597,857	558,658
Scenario 21 - COU Brief Case	866,694	720,149	675,669	44,480	0.1308	147,743	98,560
Scenario 22 - IOU Brief Case	800,613	544,154	356,005	23,436	0.0689	398,029	357,514

/1 These results assume both IOU and COU participation in the REP.

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

	2012	2013	2014	2015	2016	2017	2018	2019	2020
Reference Case	193,295	191,156	225,862	236,676	326,002	356,096	404,996	474,341	485,213
High ASC; Low PF	193,295	191,156	253,136	264,743	361,840	395,724	460,683	528,781	553,637
Low ASC; High PF	193,295	191,156	199,171	208,098	290,399	303,470	349,254	407,116	402,219
High ASC; Low PF - Risk	193,295	191,156	318,262	343,796	434,402	453,375	507,498	594,343	626,408
Low ASC; High PF - Risk	193,295	191,156	209,276	227,767	262,432	276,372	306,124	350,395	348,800
Scenario 1 - No Lookback	380,453	385,719	406,954	335,503	388,036	385,462	404,996	474,341	485,213
Scenario 2 - Large Lookback w/ Protected LRAs (50% rule)	172,880	171,621	183,451	193,265	264,791	355,941	390,271	461,560	483,659
Scenario 2 - Large Lookback w/ Protected LRAs (no 50% rule)	146,617	145,401	142,304	164,520	355,402	381,324	401,355	471,050	482,105
Scenario 3 - Large Lookback w/ LRAs Invalid (50% rule)	149,218	147,656	155,974	165,028	189,734	249,512	261,263	317,060	333,736
Scenario 3 - Large Lookback w/ LRAs Invalid (no 50% rule)	54,801	51,987	33,353	36,607	115,695	163,894	315,255	373,362	387,804
Scenario 4 - Idaho Deemer Relief	193,295	191,156	225,862	236,676	326,002	356,096	404,996	474,341	485,213
Scenario 5 - Conservation = Gen. Req. w/o Costs.	96,602	89,053	99,268	86,519	160,177	184,805	232,505	265,919	297,521
Scenario 6 - Conservation = Gen. Req. w/ Costs	199,297	198,300	211,926	212,359	298,150	331,438	394,854	443,356	489,797
Scenario 7 - Single Repayment Study	205,141	206,674	216,111	219,017	302,533	333,967	384,252	452,630	472,131
Scenario 8 - Mid-C in Stack	112,219	98,214	102,316	95,964	168,133	200,221	249,548	304,469	322,142
Scenario 9 - No 7(b)(3) to Surplus	197,549	196,949	205,490	222,376	308,696	327,366	373,038	448,876	454,559
Scenario 10 - Identical Secondary Credits	310,966	307,022	323,790	335,415	423,743	455,931	508,529	584,961	607,662
Scenario 11 - Conservation Res. Expensed	289,454	287,869	315,906	355,983	444,745	478,893	569,170	618,536	583,068
Scenario 12 - Conservation Res. Capitalized	178,418	173,535	186,579	193,938	285,573	312,263	363,044	428,444	449,571
Scenario 13 - No Exclusions	263,389	264,890	246,231	273,042	338,415	390,131	429,772	496,162	529,183
Scenario 15 - Discount Rate = Inflation	145,757	139,203	147,151	146,414	231,983	262,961	306,554	376,770	368,751
Scenario 16 - Discount Rate = Investment	298,469	295,036	310,749	316,854	408,389	436,619	490,998	559,879	585,851
Scenario 18 - COU Best Case	-	-	-	-	-	-	-	-	-
Scenario 19 - IOU Best Case	527,344	532,236	562,995	478,855	535,769	529,750	569,823	627,374	684,979
Scenario 20 - IOU Alternative Case	662,653	699,704	712,145	659,449	718,337	729,559	767,079	858,676	916,255
Scenario 21 - COU Brief Case	-	-	-	-	-	-	56,687	87,318	134,677
Scenario 22 - IOU Brief Case	445,998	450,198	479,837	399,204	458,380	450,380	485,010	537,266	586,458
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 Payments for FY 2021 - 2028 under Litigated Scenarios ($1000s, nominal) cont.

	2021	2022	2023	2024	2025	2026	2027	2028
Reference Case	468,204	515,352	490,364	573,660	642,054	682,466	695,563	751,988
High ASC; Low PF	542,434	610,389	572,168	657,309	727,096	799,195	815,761	872,919
Low ASC; High PF	387,618	430,692	405,467	478,562	537,397	587,274	585,187	639,937
High ASC; Low PF - Risk	613,091	673,855	645,038	753,549	833,429	904,795	929,917	992,230
Low ASC; High PF - Risk	325,860	344,667	338,061	391,687	479,787	501,539	505,889	503,721
Scenario 1 - No Lookback	468,204	515,352	490,364	573,660	642,054	682,466	695,563	751,988
Scenario 2 - Large Lookback w/ Protected LRAs (50% rule)	467,285	514,658	490,243	573,660	642,054	682,466	695,563	751,988
Scenario 2 - Large Lookback w/ Protected LRAs (no 50% rule)	466,366	513,965	490,121	573,660	642,054	682,466	695,563	751,988
Scenario 3 - Large Lookback w/ LRAs Invalid (50% rule)	323,999	382,179	450,482	529,510	595,180	635,168	652,825	708,351
Scenario 3 - Large Lookback w/ LRAs Invalid (no 50% rule)	389,429	513,965	490,121	573,660	642,054	682,466	695,563	751,988
Scenario 4 - Idaho Deemer Relief	468,204	515,352	490,364	573,660	642,054	682,466	695,563	751,988
Scenario 5 - Conservation = Gen. Req. w/o Costs.	264,453	297,533	271,718	350,119	416,394	471,219	444,137	495,343
Scenario 6 - Conservation = Gen. Req. w/ Costs	470,650	514,496	498,384	583,991	659,441	708,413	710,421	771,854
Scenario 7 - Single Repayment Study	447,146	476,895	433,974	498,556	546,059	582,718	595,223	647,924
Scenario 8 - Mid-C in Stack	301,483	337,937	318,530	391,111	464,715	479,059	486,094	536,385
Scenario 9 - No 7(b)(3) to Surplus	442,867	482,554	465,282	535,090	610,458	665,818	676,497	727,486
Scenario 10 - Identical Secondary Credits	591,261	639,606	613,673	696,753	769,628	809,304	816,364	868,593
Scenario 11 - Conservation Res. Expensed	600,782	667,511	632,645	711,435	784,556	852,558	880,111	939,197
Scenario 12 - Conservation Res. Capitalized	422,305	472,364	444,380	530,253	596,739	637,465	648,205	704,737
Scenario 13 - No Exclusions	531,501	565,603	576,869	643,186	749,797	780,172	817,754	859,740
Scenario 15 - Discount Rate = Inflation	352,083	398,995	373,330	453,961	519,584	555,307	571,295	627,265
Scenario 16 - Discount Rate = Investment	567,015	613,912	589,320	675,156	745,352	790,088	801,302	859,794
Scenario 18 - COU Best Case	-	29,800	-	25,589	75,350	131,322	112,976	158,815
Scenario 19 - IOU Best Case	663,906	712,927	692,140	780,940	856,229	910,722	906,246	972,917
Scenario 20 - IOU Alternative Case	941,130	984,189	1,010,800	1,078,060	1,214,226	1,265,347	1,332,375	1,385,817
Scenario 21 - COU Brief Case	120,009	189,898	149,211	197,535	246,370	304,007	289,441	339,174
Scenario 22 - IOU Brief Case	567,012	616,355	597,470	682,295	759,620	810,399	805,666	872,895
Settlement	245,200	259,000	259,000	273,600	273,600	286,100	286,100	286,100

Table 10.4: Net Present Value of IOU REP Payments FY 2007 - 2028 /1

	Reference	Scenario	Settlement
High ASC; Low PF	3,070,189	3,383,042	2,050,628
Low ASC; High PF	3,070,189	2,743,230	2,050,628
High ASC; Low PF - Risk	3,070,189	3,760,079	2,050,628
Low ASC; High PF - Risk	3,070,189	2,520,694	2,050,628
Scenario 1 - No Lookback	3,070,189	3,490,261	2,050,628
Scenario 2 - Large Lookback w/ Protected LRAs (50% rule)	3,070,189	2,961,276	2,050,628
Scenario 2 - Large Lookback w/ Protected LRAs (no 50% rule)	3,070,189	2,952,509	2,050,628
Scenario 3 - Large Lookback w/ LRAs Invalid (50% rule)	3,070,189	2,524,433	2,050,628
Scenario 3 - Large Lookback w/ LRAs Invalid (no 50% rule)	3,070,189	2,386,540	2,050,628
Scenario 4 - Idaho Deemer Relief	3,070,189	3,070,189	2,050,628
Scenario 5 - Conservation = Gen. Req. w/o Costs.	3,070,189	2,009,250	2,050,628
Scenario 6 - Conservation = Gen. Req. w/ Costs	3,070,189	3,042,585	2,050,628
Scenario 7 - Single Repayment Study	3,070,189	2,896,953	2,050,628
Scenario 8 - Mid-C in Stack	3,070,189	2,145,570	2,050,628
Scenario 9 - No 7(b)(3) to Surplus	3,070,189	2,952,082	2,050,628
Scenario 10 - Identical Secondary Credits	3,070,189	3,767,230	2,050,628
Scenario 11 - Conservation Res. Expensed	3,070,189	3,854,496	2,050,628
Scenario 12 - Conservation Res. Capitalized	3,070,189	2,836,170	2,050,628
Scenario 13 - No Exclusions	3,070,189	3,405,181	2,050,628
Scenario 15 - Discount Rate = Inflation	3,070,189	2,488,684	2,050,628
Scenario 16 - Discount Rate = Investment	3,070,189	3,655,538	2,050,628
Scenario 18 - COU Best Case	3,070,189	758,842	2,050,628
Scenario 19 - IOU Best Case	3,070,189	4,551,241	2,050,628
Scenario 20 - IOU Alternative Case	3,070,189	5,964,218	2,050,628
Scenario 21 - COU Brief Case	3,070,189	1,172,139	2,050,628
Scenario 22 - IOU Brief Case	3,070,189	4,005,802	2,050,628

/1 For FY2012-2028, NPV uses payment values presented in Tables 10.3.1 and 10.3.2. The following payments for FY2007-2011 are used: 2007=168,377,396; 2008=110,408,668; 2009=190,010,000; 2010=170,260,000; and 2011=176,180,000. NPVs assume a discount rate of 8%.

Table 10.5: Final Rates Under Settlement

			% above WP-10
Unbifurcated PF	$	38.88	7.1%
PF Public	$	30.27	5.2%
PF Exchange	$	54.30	11.5%
IP	$	36.31	4.9%
NR	$	69.50	1.2%

Residential Exchange Benefits	FY 2012	FY 2013	
Avista	$ 11,838	$ 11,838	
Idaho Power	$ 2,524	$ 2,524	
Northwestern	$ 2,907	$ 2,907	
PacifiCorp	$ 31,455	$ 31,455	
PGE	$ 58,257	$ 58,257	
Puget Sound Energy	$ 75,119	$ 75,119	
Net IOU Exchange	$ 182,101	$ 182,101	**$ 182,101**
Refund Amt	$ 76,538	$ 76,538	**$ 76,538**
Clark	$ 14,874	$ 15,029	
Franklin	$ -	$ -	
Snohomish	$ 4,587	$ 4,631	
Net COU Exchange	$ 19,461	$ 19,660	**$ 19,560**
		Total	**$ 278,199**

Annual Average $ (1000s).....................	WP-10	WP-12	Change
Composite Revenues.............................	$ 2,321,998	$ 2,262,417	-2.6%
Non-Slice Revenues...............................	$ (514,761)	$ (325,256)	36.8%
Slice Revenues.......................................	$ 2,422	$ -	
Load Shaping Revenues........................	$ 32,200	$ (14,083)	-143.7%
Demand Revenues	$ 53,303	$ 60,101	12.8%
Tier 1 Revenue Requirement	$ 1,895,163	$ 1,983,179	4.6%
Tier 2 Revenue Requirement		$ 16,363	
Lookback Return (credit)....................	$ (81,575)	$ (76,538)	
Value of Slice Secondary......................	$ (166,495)	$ (162,043)	2.7%
Net Power Cost to All PF.......................	$ 1,647,093	$ 1,760,961	6.9%
Total PF Load w/Slice (GWh)/yr.........	61,408	60,702	-1.2%
Average Net Cost $/MWh...................	26.82	29.01	8.2%
Tier 1 Average Net Cost ($/MWh).......		28.90	7.8%
Tier 2 ($/MWh)......................................	-	47.59	

Table 10.6: Final Rates Under No Settlement

		% above WP-10
Unbifurcated PF	$ 40.84	12.4%
PF Public	$ 30.37	5.6%
PF Exchange	$ 54.61	12.2%
IP	$ 37.63	8.8%
NR	$ 72.38	5.4%

Residential Exchange Benefits	**FY 2012**	**FY 2013**	
Avista	$ 20,181	$ 19,072	
Idaho Power	$ 6,509	$ 10,424	Deemer Amount
Northwestern	$ 2,667	$ 2,517	
PacifiCorp	$ 58,438	$ 60,873	
PGE	$ 83,457	$ 78,856	
Puget Sound Energy	$ 106,890	$ 108,256	**w/o Deemer $s**
Net IOU Exchange	$ 271,632	$ 269,573	**$ 270,603**
Refund Amt	$ -	$ -	**$ -**
Clark	$ 15,246	$ 14,447	
Franklin	$ -	$ -	
Snohomish	$ 2,550	$ 2,415	
Net COU Exchange	$ 17,796	$ 16,862	**$ 17,329**
		Total	**$ 287,932**

Annual Average $ (1000s)....................	WP-10	WP-12	Change
Composite Revenues.............................	$ 2,321,998	$ 2,268,352	-2.3%
Non-Slice Revenues...............................	$ (514,761)	$ (325,173)	36.8%
Slice Revenues..	$ 2,422	$ -	
Load Shaping Revenues........................	$ 32,200	$ (14,083)	-143.7%
Demand Revenues	$ 53,303	$ 60,101	12.8%
Tier 1 Revenue Requirement	$ 1,895,163	$ 1,989,196	5.0%
Tier 2 Revenue Requirement		$ 16,363	
Lookback Return (credit).....................	$ (81,575)	$ (78,377)	
Value of Slice Secondary......................	$ (166,495)	$ (162,043)	2.7%
Net Power Cost to All PF.......................	$ 1,647,093	$ 1,765,140	7.2%
Total PF Load w/Slice (GWh)/yr.........	61,408	60,702	-1.2%
Average Net Cost $/MWh...................	26.82	29.08	8.4%
Tier 1 Average Net Cost ($/MWh).......		28.97	8.0%
Tier 2 ($/MWh).......................................	-	47.59	

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FIGURES

Figure 1: IOU REP Payments Risk Scenarios

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

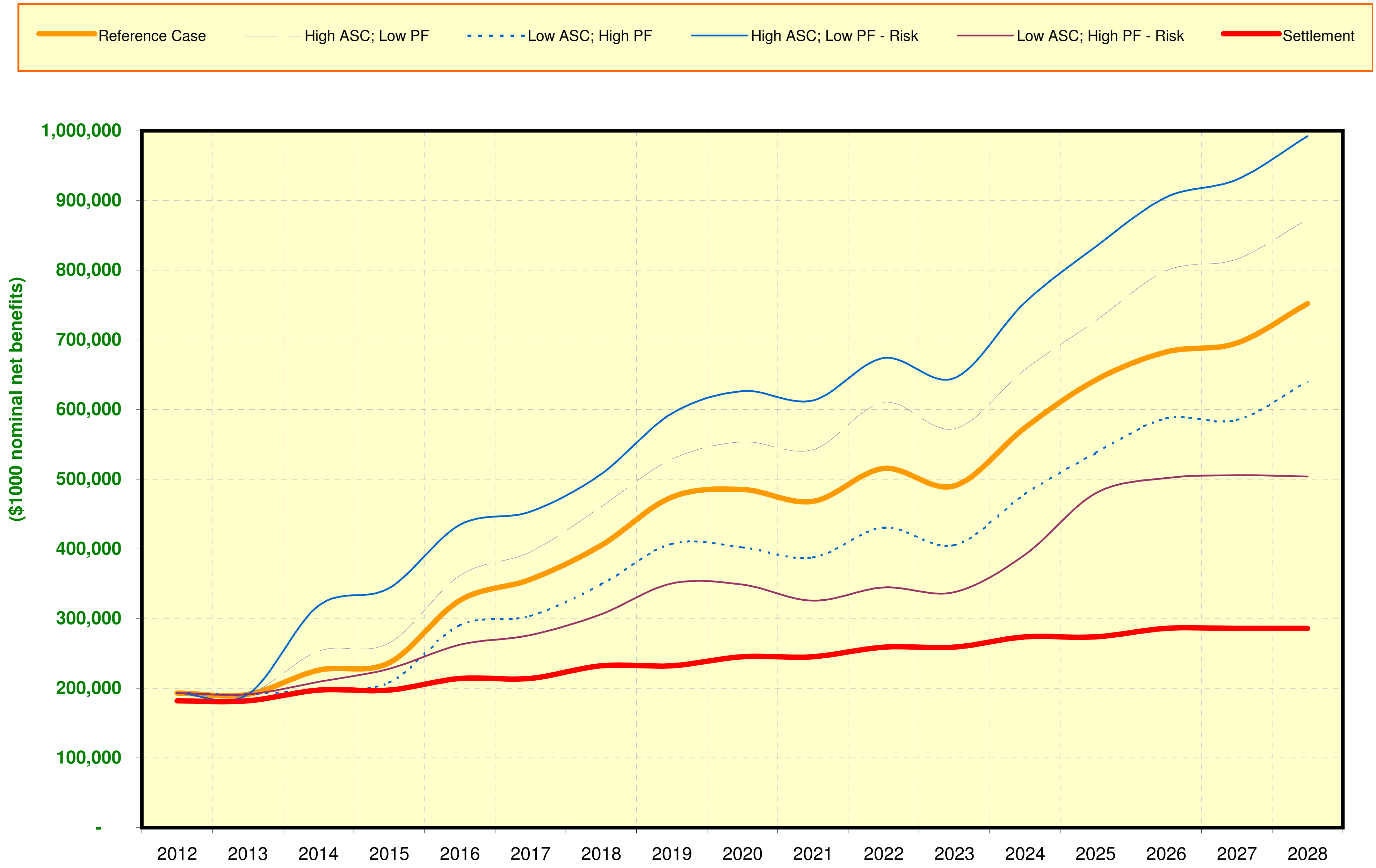

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Figure 2: IOU REP Payments Extreme Scenarios

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

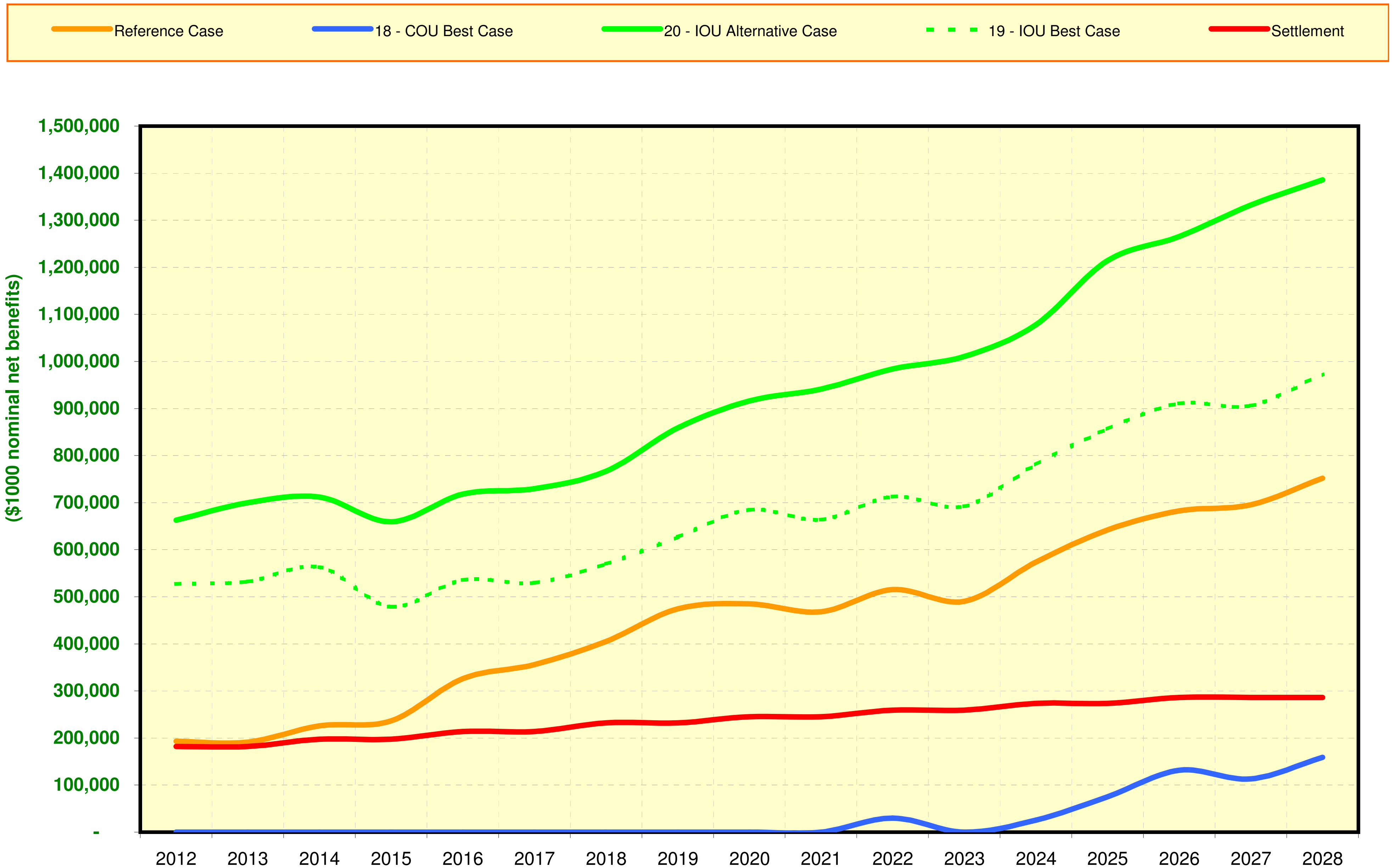

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Figure 3: IOU REP Payments Lookback Scenarios

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

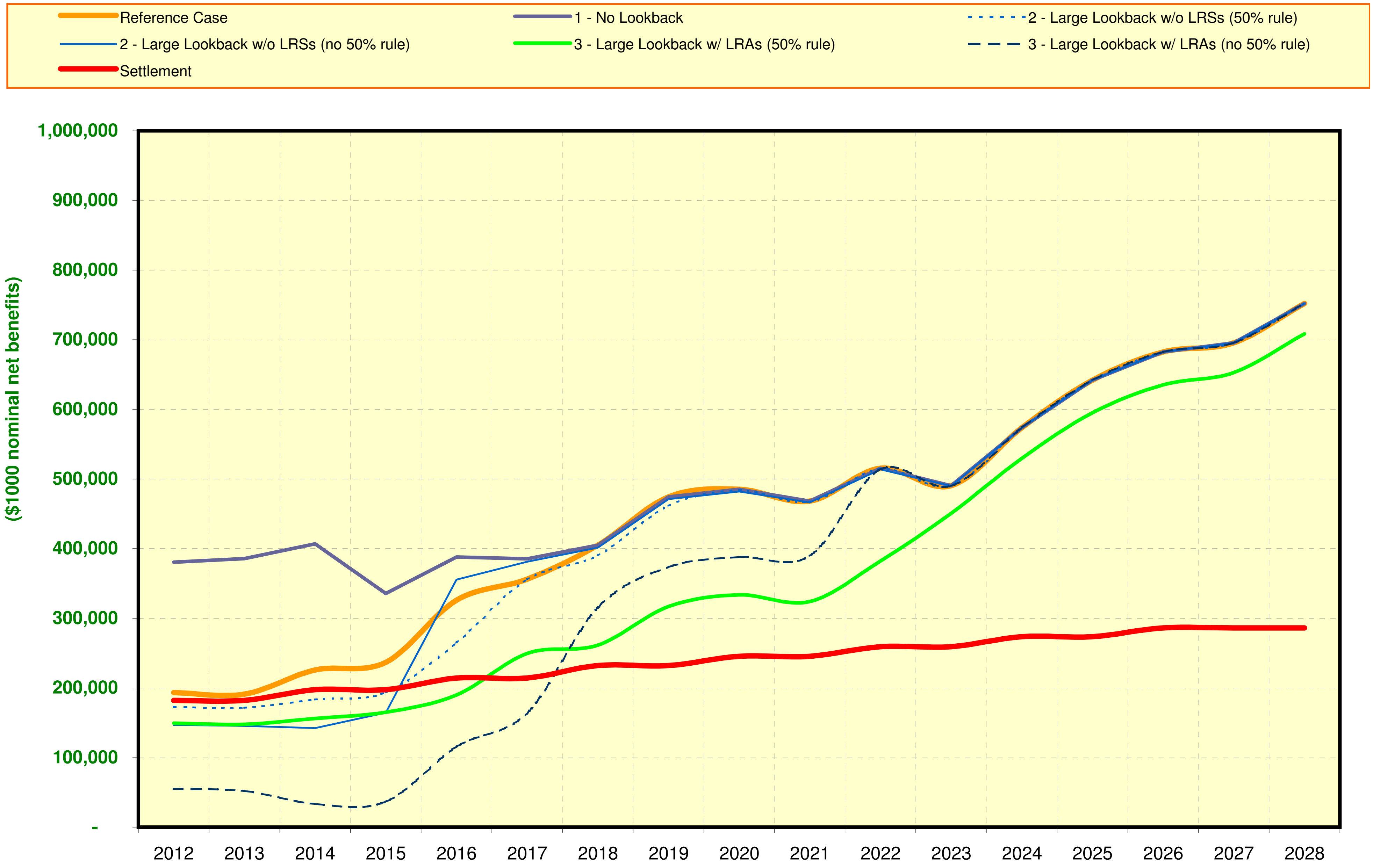

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Figure 4: IOU REP Payments Other Scenarios

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

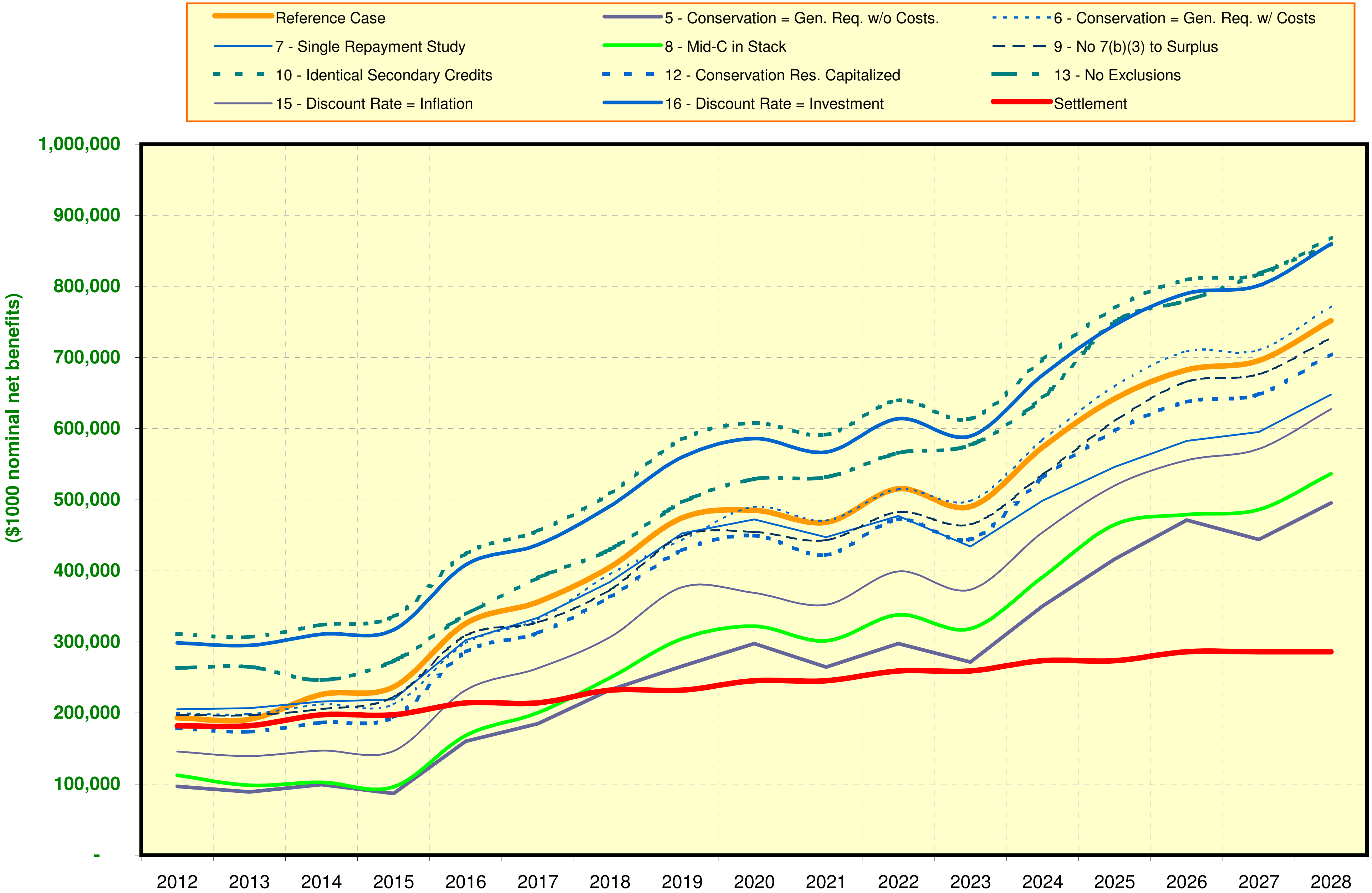

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Figure 5: IOU REP Payments Brief Scenarios

Reference Case "No Settlement" Lookback Setoff and Idaho Deemer Reduction (Except COU/IOU Brief)

IOU Load growth met 50% IRP, 50% Market, COSA Escalated at Inflation + 2%.

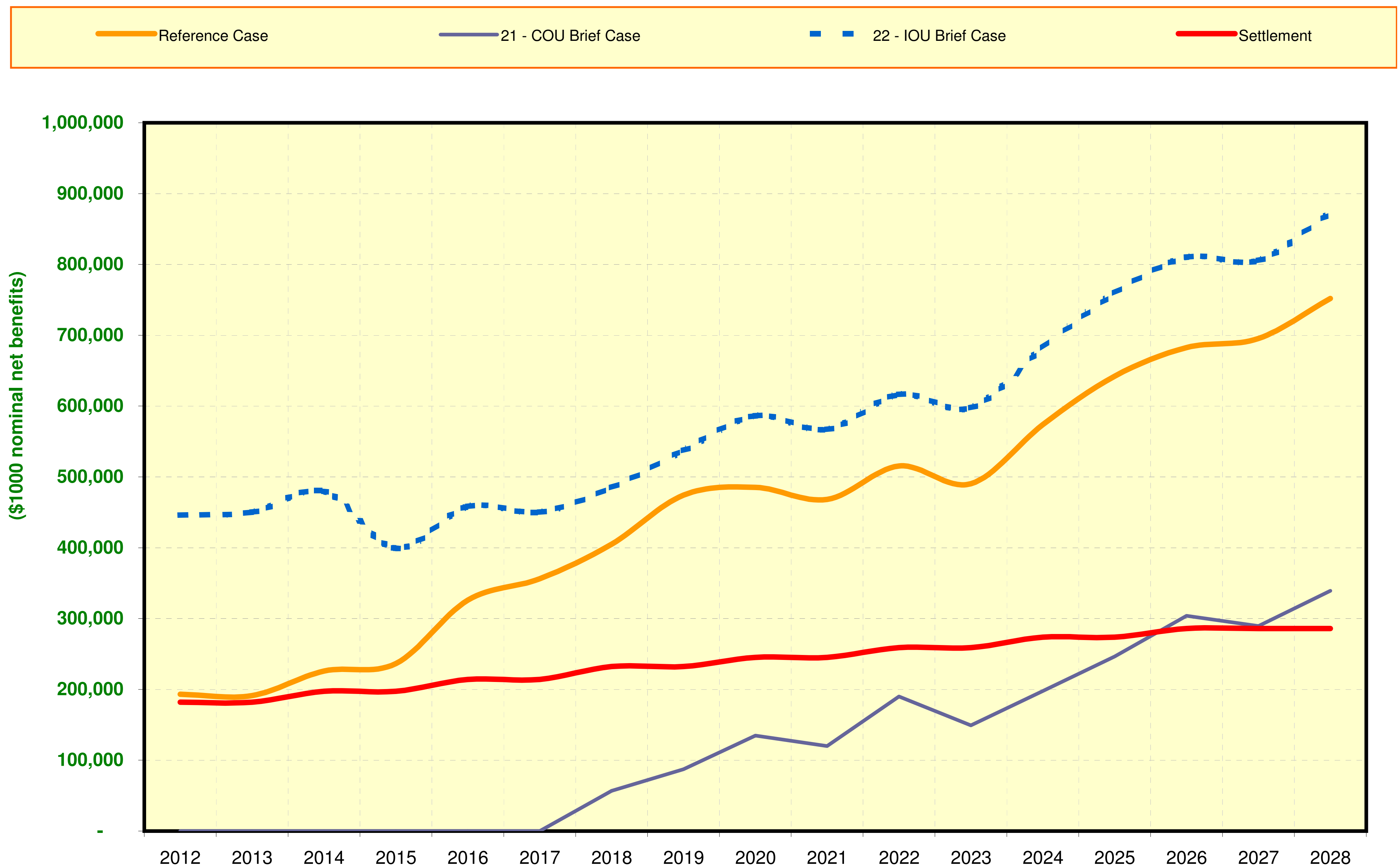

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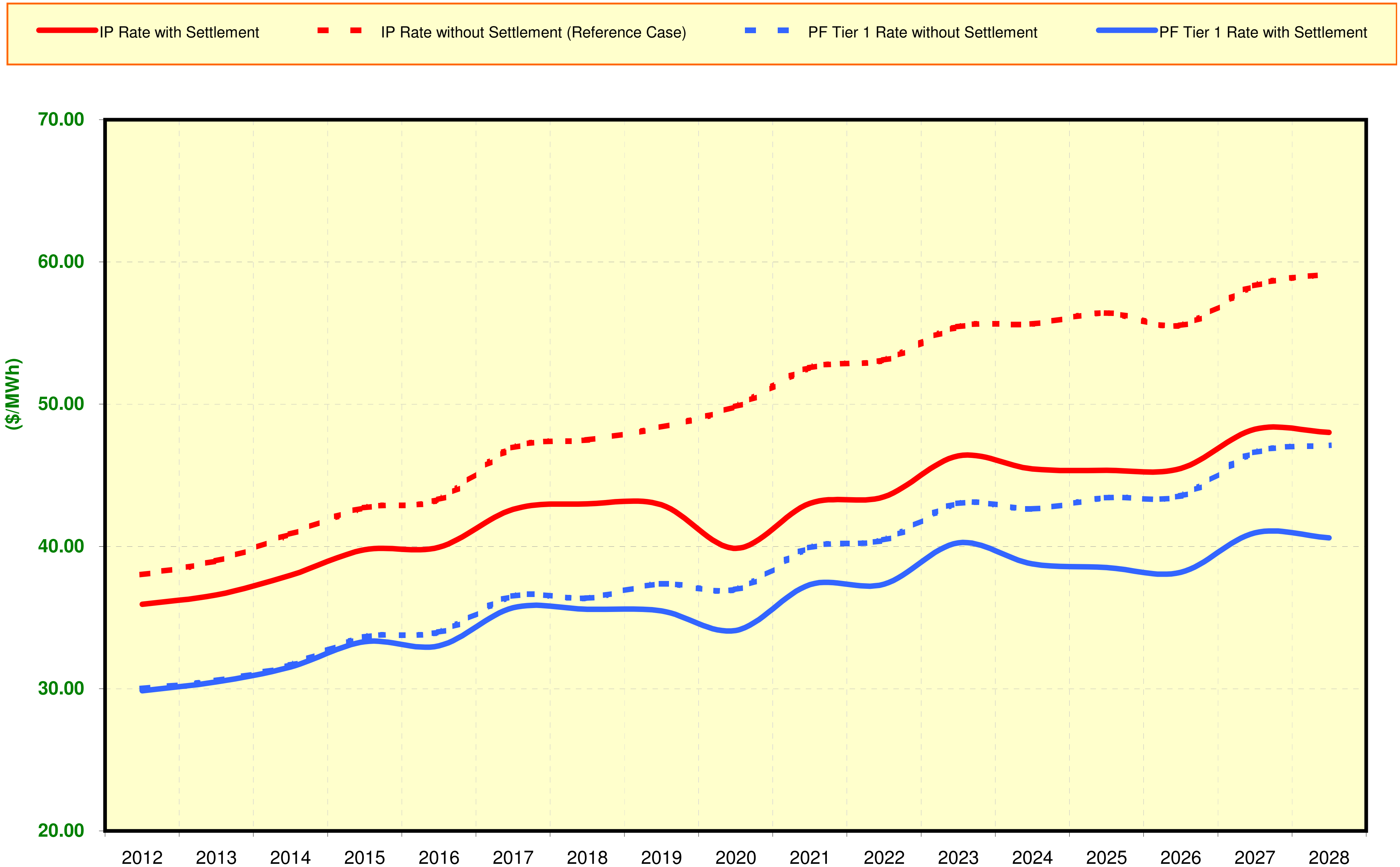
Figure 6: Comparison of Public and Industrial Priority Firm Rate Under Settlement vs. No Settlement

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



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