

OS-14 Initial Rate Proposal

Direct Testimony

November 2012

BPA Exhibit No.	Topic	Witnesses
OS-14-E-BPA-01	Oversupply Rate	Fredrickson, <i>et al.</i>



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OS-14-E-BPA-01	Oversupply Rate	Rebecca E. Fredrickson Raymond D. Bliven Mark A. Jackson Nancy Parker

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TESTIMONY of

REBECCA E. FREDRICKSON, RAYMOND D. BLIVEN,

MARK A. JACKSON, AND NANCY PARKER

Witnesses for Bonneville Power Administration

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1 TESTIMONY of

2 REBECCA E. FREDRICKSON, RAYMOND D. BLIVEN,

3 MARK A. JACKSON, AND NANCY PARKER

4 Witnesses for Bonneville Power Administration

5
6 **SUBJECT: OVERSUPPLY RATE (OS-14)**

7 **Section 1: Introduction and Purpose of Testimony**

8 *Q. Please state your names and qualifications.*

9 A. My name is Rebecca E. Fredrickson, and my qualifications are contained in OS-14-Q-
10 BPA-02.

11 A. My name is Raymond D. Bliven, and my qualifications are contained in OS-14-Q-
12 BPA-01.

13 A. My name is Mark A. Jackson, and my qualifications are contained in OS-14-Q-BPA-03.

14 A. My name is Nancy Parker, and my qualifications are contained in OS-14-Q-BPA-04.
15

16 **Section 2: Purpose and Scope of the OS-14 Rate Proceeding**

17 *Q. What is the purpose of the OS-14 rate proceeding?*

18 A. The purpose of the OS-14 rate proceeding is to propose new rates to recover costs
19 attributable to BPA's Oversupply Management Protocol (OMP). The OMP is described
20 in section 3 of this testimony. The OS-14 rates consist of two separate rates: a power rate
21 and a control area services rate. The proposed rates are shown in the rate schedules and
22 general rate schedule provisions provided in Attachment 1.

23 *Q. What is the scope of this rate proceeding?*

24 A. The scope is limited to setting the OS-14 rates, including determining costs to be
25 recovered by the rates, the functionalization and allocation of the costs, and the details
26 and language of the OS-14 rate schedules. Functionalization is the assignment of costs

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1 according to the major operating functions of a utility, such as transmission and power;
2 allocation is the assignment to customer groups within each function. The scope of the
3 proceeding does not include the substance and details of the OMP and its
4 implementation; those are being addressed in other forums.

5 Q. *Does the scope of this rate proceeding include whether BPA could implement the OMP in*
6 *a more cost-effective manner?*

7 A. No. The means by which costs are incurred pursuant to the OMP are within the purview
8 of the OMP, not the OS-14 rates.

9
10 **Section 3: Background**

11 Q. *What is oversupply?*

12 A. Oversupply is when too much electricity is available relative to the electric load at any
13 particular time. With minor exceptions, electricity is not storable; it must be consumed as
14 soon as it is generated. A limited amount of storage is available at times in the form of
15 potential energy in hydro reservoirs (water is conserved in the reservoir when energy is
16 not needed and released from the reservoir and run through generators when energy is
17 needed). Oversupply conditions occur when the availability of storage has been
18 exhausted. In a hydro-dominated power system such as BPA's, oversupply conditions
19 are generally addressed by spilling water over the dams. However, as explained below,
20 there are limits to how much water may be spilled over the dams, and when those limits
21 are reached, the generation of electricity is usually the only available option.

22 Q. *Why is BPA limited in how much water it can spill over the dams?*

23 A. The dams comprising the Federal Columbia River Power System (FCRPS) are part of a
24 complex hydroelectric system operated jointly by the Corps of Engineers, the Bureau of
25 Reclamation, and BPA to serve multiple purposes, including flood control, navigation,
26 irrigation, and power generation. In its roles as balancing authority (the entity

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1 responsible for balancing generation and load in its area), power marketer, and hydro
2 operator, BPA must coordinate closely with the Corps of Engineers and Bureau of
3 Reclamation to ensure that these purposes are met during all operating conditions. At the
4 same time, the system is subject to various constraints because of the need to maintain the
5 reliability of the interconnected transmission system and to protect fish and wildlife.

6 The Clean Water Act (CWA), the Endangered Species Act (ESA), and associated
7 court orders limit the amount of spill over the dams to protect the river's aquatic life,
8 including salmon, steelhead, sturgeon, bull trout, and other species listed under the ESA,
9 as well as non-listed species. Too much spill injects dangerous amounts of nitrogen into
10 the water that can harm fish by causing gas bubble trauma. As a result, the states of
11 Washington and Oregon have used their authority under the CWA to set water quality
12 standards, including total dissolved gas levels. In order to meet its legal responsibilities
13 under the CWA and the ESA, BPA must take all reasonable actions to avoid excess spill
14 and keep total dissolved gas levels within the water quality standards set by the states.
15 As explained below, BPA has determined that the displacement of other generating
16 resources interconnected to its transmission system is a reasonable action to avoid spill in
17 excess of state water quality standards.

18 Q. *How does BPA manage high water events when BPA is limited in the amount of water it*
19 *has the ability to store or spill?*

20 A. One of the management tools available to avoid harmful spill has been to run the excess
21 water through the turbines to generate more power, which is then sold to utilities (at zero
22 price if necessary), which use it to displace their own generation and serve their loads.
23 The additional generation maintains system reliability by ensuring that generation and
24 load are in balance. Before the integration of large amounts of wind generation, BPA
25 would offer the operators of thermal generation low- to zero-cost power for displacement.
26 Operators of thermal generation generally would accept BPA's offers because thermal

1 generation has a positive variable cost and thus has an incentive to shut down. Some
2 thermal generation must continue to operate during times of oversupply for various
3 reasons, including reliability requirements, environmental compliance, stable and safe
4 generation levels, minimum fuel take obligations, maximum ramp rates, or need to
5 support plant operations associated with co-generation facilities.

6 Q. *What is the effect of wind generation on BPA's ability to manage high-water events?*

7 A. The recent integration of over 4,000 megawatts of wind generation into the BPA
8 transmission system has threatened BPA's ability to displace generation necessary to
9 avoid spill and maintain system reliability. Unlike operators of thermal generation,
10 operators of wind generation do not accept BPA's offers of low- to zero-cost power to
11 displace their generation. Wind generation receives Production Tax Credits (PTCs) and
12 Renewable Energy Credits (RECs) for the actual amount generated. PTCs are tax credits
13 granted by the Federal government for every kilowatthour of electricity produced by the
14 generator. RECs are issued by states, including California, Oregon, and Washington, that
15 require electric utilities to generate or acquire renewable energy, such as wind generation,
16 as a certain percentage of their resource portfolio. RECs are issued for every
17 megawatthour of electricity produced that is under contract for sale to a utility together
18 with the underlying electricity produced (bundled), or that is sold under contract or on the
19 market separately from the electricity produced (unbundled). Thus, the displacement of
20 wind generation carries an additional cost, as wind generation seeks compensation for the
21 loss of PTCs and RECs caused by the displacement.

22 Q. *Prior to the OMP, how did BPA attempt to manage high-water events?*

23 A. In May 2011, the BPA Administrator adopted an Interim Environmental Redispatch
24 Policy, under which, during oversupply conditions, BPA displaced all available
25 generation within its balancing authority area with free Federal hydropower. On June 13,
26 2011, a group of wind customers filed a complaint with the Federal Energy Regulatory

1 Commission (Commission), requesting, among other things, that the Commission use its
2 authority under Section 211A of the Federal Power Act to order BPA to stop using its
3 Environmental Redispatch Policy because it failed to provide transmission service on
4 terms and conditions that are comparable to those under which BPA provides
5 transmission to itself and that are not unduly discriminatory or preferential. On
6 December 7, 2011, the Commission issued an order finding that BPA's Environmental
7 Redispatch policy failed to provide comparable transmission service and ordered BPA to
8 file revisions to its OATT to comply with the order.

9 Q. *How did BPA respond?*

10 A. Although BPA requested rehearing of the Commission's order, on March 6, 2012, BPA
11 filed the OMP with the Commission as Attachment P to BPA's Open Access
12 Transmission Tariff. Under the OMP, generators can elect to be compensated for certain
13 costs related to displacement, including (1) production tax credits; (2) renewable energy
14 credits unbundled (that is, sold separately) from the sale of energy; and (3) for contracts
15 executed prior to March 6, 2012, certain losses under bundled contracts (that is, sales of
16 renewable energy credits and energy together) because of the generator's failure to
17 deliver wind power. The Commission has yet to issue an order approving the OMP or on
18 rehearing.

19 Q. *How does the OMP operate?*

20 A. Under the OMP, BPA uses a least-cost displacement cost curve to displace generation
21 located in BPA's balancing authority area in order to moderate total dissolved gas levels
22 in the Columbia River. The cost curve lists the costs of displacement for all participating
23 facilities from lowest to highest. During oversupply events, BPA displaces generation in
24 order of cost, from the lowest-cost facility to the highest-cost facility, until the necessary
25 relief is achieved (BPA can pass enough water through the generators to avoid spill that
26 exceeds total dissolved gas limits). If the highest-cost facility that BPA displaces in an

1 hour to achieve the required displacement quantity has the same cost as one or more other
2 generation facilities, BPA displaces all such facilities on a pro-rata basis.

3 For each hour of displacement, BPA pays the generator each displaced facility's
4 costs of displacement multiplied by the difference between (i) the MW of scheduled
5 generation for the hour, and (ii) the MW of generation that BPA has directed the
6 generator to reduce to under the OMP.

7 The OMP utilizes an independent evaluator that collects facility cost information
8 from generators and constructs the cost curve. The independent evaluator also performs
9 audits of the costs submitted by the generators.

10 11 **Section 4: Oversupply Costs and Term of OS-14 Rates**

12 *Q. Please describe the costs to be recovered by the proposed OS-14 rates.*

13 *A.* We are proposing that the OS-14 rates recover the following costs: (1) displacement costs
14 (the costs paid to generators pursuant to the OMP), and (2) administrative costs (the costs
15 paid to the independent third party evaluator). Attachment 2, Table 1, shows the OMP
16 displacement and administrative costs incurred for FY 2012. Attachment 2, Tables 2
17 and 4 show the FY 2012 OMP displacement and administrative charges for generators
18 and power customers.

19 *Q. What costs are paid to generators?*

20 *A.* To ensure that displacement is achieved at a reasonable cost to the region, BPA utilizes
21 the least-cost displacement cost curve described above. The payments BPA makes to
22 generators comprise the displacement cost portion of the OS-14 rates. Pursuant to the
23 OMP, a generator may choose not to be compensated for displacement of a facility, in
24 which case that facility will have a displacement cost of zero and that facility will not be
25 subject to the OS-14 rate. No facility will be displaced any lower than the minimum
26 generation levels established under the OMP.

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1 Q. *What costs are paid to the independent third-party evaluator?*

2 A. To ensure confidentiality of facility-specific costs, all generators that choose to be
3 compensated submit installed generating capacity information and costs of displacement
4 for their facilities to an independent evaluator through a Web site created and maintained
5 by the evaluator. The evaluator aggregates the costs and constructs the cost curve and
6 submits it to BPA, together with the total costs of displacement for each facility, so BPA
7 can appropriately compensate displaced generators. The evaluator is also responsible for
8 validating costs submitted by generators. The evaluator charged BPA \$248,844 in 2012
9 to perform these duties. These 2012 costs, and any future costs to engage an evaluator if
10 the OMP is renewed, comprise the administrative cost portion of the OS-14 rates.

11 Q. *What is the proposed effective period for the OS-14 rates?*

12 A. The OMP is currently effective from March 31, 2012, through March 30, 2013, pending
13 review by the Commission. However, in case the OMP is renewed after March 30, 2013,
14 we propose that the OS-14 rates stay in effect until September 30, 2015, thus avoiding the
15 need to conduct another rate proceeding to collect 2013, 2014, and 2015 costs. Because
16 the issues in a later rate case would be the same, holding just one rate proceeding is
17 administratively efficient.

18
19 **Section 5: Functionalization of Costs**

20 Q. *How do you propose to functionalize costs between the power and transmission*
21 *functions?*

22 A. We propose to functionalize one-half of the costs to the power function and one-half of
23 the costs to the transmission function. The contributors to the costs of oversupply are the
24 need for the hydrosystem to avoid spill (a power function – the cost of producing power)
25 and the integration of wind power (a transmission function – the cost of moving power on
26 the transmission system and maintaining reliability). The costs assigned to power rates

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1 would be recovered through a new general rate schedule provision added to the
2 (i) Priority Firm Power (PF) rate, paid by BPA's preference customers (public body and
3 cooperative utilities and Federal agencies); (ii) the Industrial Firm Power (IP) rate, paid
4 by direct service industry customers, which are end-users that take service directly from
5 BPA; and (iii) the New Resource Firm Power (NR) rate paid by consumer-owned utilities
6 for service to new large single loads and by investor-owned utilities for requirements
7 service. The costs assigned to transmission rates would be recovered through a new
8 control area services rate. Control area services are services BPA provides to generators
9 to meet reliability obligations.

10 Q. *Why have you chosen to functionalize the costs on a 50-50 basis?*

11 A. Generally in ratesetting, costs are functionalized based on cost causation. For example,
12 relative usage of a resource often correlates with costs—the more energy one consumes
13 the more costs one imposes on the system. In instances such as this, when you can
14 measure a definite quantity of energy consumed, clear measures exist to assign costs
15 appropriately. In the case of oversupply, however, no clearly measurable quantities are
16 available to determine an appropriate functionalization between the power and
17 transmission functions. Instead, the costs are caused by two separate factors—the
18 obligation to avoid spilling excess water over the dams that would harm endangered fish
19 and other aquatic life, and the integration of approximately 4,000 MW of wind generation
20 that requires compensation for displacement. Both of these factors result in the need for
21 the OMP and cause the costs; however, we believe it is impossible to precisely quantify
22 how much each factor contributes. We do know that the costs related to oversupply
23 would not exist without either factor. As a result, we believe that a fair and equitable
24 allocation is to split these costs equally between the power and transmission functions.
25
26

1 Q. *Would BPA incur oversupply costs if it had no obligation to avoid spill?*

2 A. No. As explained previously, BPA must take all reasonable actions to avoid spill.
3 Without this obligation, during periods of oversupply BPA could spill the excess water
4 and allow other generation to operate.

5 Q. *Would BPA incur oversupply costs if there was no wind generation interconnected to the
6 Federal Columbia River Transmission System (FCRTS)?*

7 A. No. As explained previously, before the integration of wind generation BPA was able to
8 resolve oversupply problems by displacing thermal generation with low- to zero-cost
9 Federal hydropower with no financial loss to the generators. Because wind generators
10 receive economic benefits based on actual generation, reduced generation creates a
11 financial loss for the generators that requires compensation. As a result, resolving
12 oversupply now carries a cost to BPA that was not present prior to the integration of wind
13 generation.

14
15 **Section 6: Allocation of Functionalized Costs**

16 Q. *Are the costs functionalized to the power function allocated to all power customers?*

17 A. No. The power costs are allocated to only those customers that are paying the PF, IP, or
18 NR rates. Firm Power Products and Services (FPS) power customers pay FPS rates that
19 are established by mutual agreement between BPA and the purchaser, and the levy of an
20 additional charge would be prohibited by the terms of the relevant contract.

21 Q. *How are the costs functionalized to power allocated among the PF, IP, and NR
22 customers?*

23 A. We propose to allocate costs to these customers using a "Modified TOCA." The
24 Modified TOCA is based on the customer's load relative to the total system load. For
25 many years BPA has used relative loads as a cost allocator for power costs.

1 To determine each customer's relative load, we propose using an existing relative
2 load allocator established under the Tiered Rate Methodology (TRM) (BP-12-A-03)—the
3 Tier 1 Cost Allocator, or TOCA. A TOCA is established for each PF customer based on
4 the (i) lesser of the customer's Rate Period High Water Mark (RHW), which is the
5 customer's adjusted contractual right to Tier 1 power, or forecast net requirement divided
6 by (ii) the total of all customers' RHWs or forecast net requirements.

7 While the TOCA method is typically used to allocate costs only for PF customers,
8 we propose to use this same concept to allocate costs to PF, IP, and NR customers for
9 purposes of the oversupply rate by using a Modified TOCA for each customer. That is,
10 the TOCAs that are used as billing determinants for the PF Tier 1 rate are modified to
11 include IP and NR loads in order to allocate oversupply costs to all three types of power
12 sales. The TOCA is an accepted and well-understood measure of PF customers' rights to
13 take Federal power at PF Tier 1 rates and applies to the vast majority of power purchased
14 at PF rates through FY 2015. Use of the Modified TOCA for all customers will represent
15 each customer's load relative to the total system load and provides an equitable basis for
16 allocating costs incurred under the OMP among Power customers.

17 Q. *How would the Modified TOCA be calculated and applied to PF, IP, and NR customers?*

18 A. To establish a Modified TOCA for each customer, we propose to use each PF, IP, or NR
19 customer's load and divide that number by the sum of all PF, IP, and NR customer loads.
20 For PF customers, load is the lesser of the customer's RHW or forecast net
21 requirement. For IP and NR customers, load is the customer's contract energy amount.
22 Use of the contract energy amount for IP and NR ratepayers ensures that the Modified
23 TOCAs appropriately account for their contribution to cost recovery. A PF customer also
24 taking service under a Tier 2 rate will be allocated oversupply costs based only on its PF
25 Tier 1 service. PF customers have the option to take service from BPA at Tier 2 rates or
26 purchase non-Federal power to serve their loads above their RHWs. Generally under

1 the TRM, a customer taking service under Tier 2 rates should not be exposed to types of
2 costs significantly different than what that customer would pay if it purchases non-
3 Federal power. Currently, the sum of all RHWMs equals about 7,180 aMW, and the
4 forecast of all IP and NR contract energy loads equals about 312 aMW. Thus, PF
5 ratepayers would pay approximately 96 percent of oversupply costs, and IP ratepayers
6 would pay approximately 4 percent of oversupply costs. BPA has no NR ratepayers at
7 this time. FY 2012-2015 Modified TOCAs are included in the proposed oversupply rate
8 for power customers. Attachment 1, General Rate Schedule Provisions—Appendix B.

9 Q. *Are the costs functionalized to transmission allocated to all transmission customers?*

10 A. We are proposing to allocate oversupply costs to a control area service rate paid by
11 certain generators, not to wheeling rates. Only those generators that elect to receive
12 compensation under the OMP are creating costs. As a result, we propose to subject only
13 those generators that submit facility costs to an allocation of costs through the rate.
14 Control area services rates are available to charge costs to generators located within
15 BPA's balancing authority area; thus, we propose to use a control area services rate to
16 charge oversupply costs to these generators.

17 Q. *Please clarify whether a facility has to receive compensation to be subject to the control*
18 *area services rate?*

19 A. A facility does not have to receive compensation to be subject to the rate. The
20 determining factor for application of the rate is whether the facility was submitted to
21 receive compensation. Because of the least-cost displacement in the OMP, it is possible
22 that high-cost facilities never get selected for displacement. Still, these facilities will be
23 subject to the control area services rate.

1 Q. *How are costs allocated to eligible generators under the OS-14 Control Area Services*
2 *rate?*

3 A. We propose to use the nameplate capacity for each eligible generator divided by the sum
4 of all nameplate ratings of eligible generators.

5 Q. *Why are you proposing to use the nameplate capacity?*

6 A. We believe the nameplate capacity appropriately assigns costs to each generator because
7 it accounts for the relative size of the generator and thus the generator's relative
8 contribution to costs. The nameplate capacity is the maximum amount that a generator
9 can generate and represents a generator's potential impact on oversupply. Nameplate
10 capacity is the same allocator that BPA uses for other rates that apply to wind generation,
11 such as the Variable Energy Resource Balancing Service rate, under which BPA charges
12 wind resources for the costs caused by the variability of their generation. The FY 2012
13 generator oversupply charges and billing determinants under the proposed oversupply
14 rate are shown on Attachment 2, Tables 2 and 3.

15 Q. *Will there be later adjustments to these allocators for power customers and generators*
16 *during the rate proceeding?*

17 A. Possibly. As to the power customers, TOCAs may be adjusted during the BP-14 rate
18 proceeding. Adjustments could occur for several reasons, including significant forecast
19 load changes.

20 As to generators, new generators may come online or existing generators may
21 leave the BPA balancing authority area, changing the relative sizes of the other
22 generators. The proposed rate schedule includes mechanisms to adjust the billing
23 determinants to account for these adjustments.

1 Q. *Could changes to load forecasts or actual loads change the power allocations after the*
2 *conclusion of the rate proceeding?*

3 A. They could, but we are proposing that such changes not affect the Modified TOCAs. In
4 other cases in which BPA uses TOCAs as an allocator for purposes other than Tier 1
5 rates, the applicable TOCA is the TOCA established in the rate proceeding regardless of
6 later changes. For administrative efficiency and to give power customers more certainty
7 about the cost allocation, we propose to define the Modified TOCAs as those established
8 in the Final Proposal of the ratesetting process. Therefore, the OS-14 Modified TOCAs
9 in Attachment 1, pages 11-16, for FY 2014 and 2015 may be revised for the OS rate Final
10 Proposal to reflect the final BP-14 TOCAs and contract demands.

11
12 **Section 7: The OS-14 Rates**

13 Q. *Please describe the proposed OS-14 rate design.*

14 A. The power and control area services rates are virtually identical in all aspects except the
15 billing determinant. Both rates are formula rates that are designed to recover exactly the
16 costs that BPA incurs by incorporating after-the-fact determinations of the costs. Each
17 rate uses 50 percent of the oversupply costs as the numerator of the formula rates and the
18 sum of the billing determinants (load for power customers and nameplate capacity for
19 generators) as the denominator. Each rate includes one rate for displacement costs and
20 one rate for administrative costs. The charge to each eligible customer is computed by
21 multiplying the rate by the customer's billing determinant.

22 Q. *Are there any other notable features of the rate schedules?*

23 A. Two. First, the allocation to generators could change monthly if new generating facilities
24 come on line that choose to be compensated for displacement. We propose to incorporate
25 such changes during a month by averaging the installed capacity at the beginning and end

1 of each billing month. Second, we are proposing to cap the total costs billed per month at
2 \$8 million, \$4 million under each rate schedule.

3 Q. *Why are you proposing a billing cap?*

4 A. For 2013, BPA will not be able to bill for oversupply cost recovery until well after most,
5 if not all, costs have been accumulated. Thus, the amount that might be billed, when
6 combined with 2012 costs, could be high enough to create some cash flow concerns for
7 customers. Also, during 2014 and 2015, it is possible that the displacement costs
8 incurred in any one month may be substantial, again raising cash flow concerns. The
9 billing cap mitigates the potential for customers' cash flow concerns by spreading cost
10 recovery over several months if oversupply costs are substantial.

11 Q. *How would the proposed billing cap work?*

12 A. Once the OS-14 rates take effect, BPA will begin billing for the accumulated oversupply
13 costs incurred prior to the effective date. If this accumulated amount exceeds \$8 million,
14 then the first \$8 million will be billed one month, the next \$8 million will be billed the
15 next month, and so on until all of the accumulated oversupply costs have been billed. If
16 the accumulated costs are less than \$8 million, then the entire amount will be billed in
17 one month. The same procedure would be used for 2014 and 2015 costs if any one
18 month's costs exceed \$8 million.

19 Q. *How did you determine to set the billing cap at \$8 million?*

20 A. We are seeking a balance between faster cost recovery and mitigating bill shock to
21 customers. For PF customers, the billing cap is about a two percent increase above the
22 amount they are currently paying. Different circumstances hold for transmission
23 customers; generally, the generators will be billed for oversupply costs concurrent with
24 the credits they receive for being displaced. Although the cash flow issues are different
25 for generators, we believe that it is appropriate to offer the same level of billing relief to
26 both sets of customers. The billing cap appropriately balances our two objectives.

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1 Q. *Why is the administrative charge based on each facility's relative contribution to costs*
2 *during June?*

3 A. First, the size of the administrative costs is small relative to the displacement costs. In
4 2012, the administrative costs were only 8 percent of the year's displacement costs, and
5 the displacement costs were lower than expected. Thus, billing such a small amount in
6 one month should not be burdensome and promotes administrative efficiency. Second,
7 we expect that June will generally be the mid-point of the spill season, and therefore, the
8 mid-point of the season in which the OMP is applied. Although installed capacities may
9 change throughout the spill season, using the mid-point would capture a fair
10 representation of the generating facilities paying the administrative charge. For power
11 customers, it makes no difference, because each power customer's Modified TOCA will
12 be a fixed number.

13
14 **Section 8: Commission Approval and Billing**

15 Q. *When do you expect to bill customers for oversupply costs?*

16 A. The OS-14 rate will become effective only after confirmation and approval (either
17 interim or final) by the Commission. We expect to begin billing under the OS-14 rate for
18 all costs already incurred within three months after receiving approval from the
19 Commission. The Commission typically grants interim approval within 60 days of
20 BPA's filing of the rate. Thus, the first bill would reflect all OMP costs incurred through
21 September 30, 2013, subject to the billing cap. For future costs incurred under the OMP,
22 costs would be included in the bill after the month the costs are incurred, subject to the
23 billing cap. However, it is possible that we will not have systems in place to calculate the
24 displacement costs quickly enough to allow for concurrent billing of both the credits for
25 displacement and the costs under the OS-14 rates. Therefore, all costs unavailable for
26 one month's billing cycle will be billed the following month.

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1 Q. *Does this conclude your testimony?*

2 A. Yes.

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Attachment 1

Rate Schedules

ACS-14 RATE SCHEDULE: III.G. OVERSUPPLY CHARGES

The Oversupply Charges apply to each generator that elects to submit a generating facility's costs of displacement pursuant to the Open Access Transmission Tariff (OATT), Attachment P, section 3.b., with respect to at least one of its generating facilities (Generator).

The Oversupply Charges shall collect 50 percent of (1) the amounts paid under Open Access Transmission Tariff (OATT) Attachment P for the period March 31, 2012, through September 30, 2015; and (2) the administrative cost of the independent evaluator selected by BPA pursuant to OATT Attachment P.

The Oversupply Charges shall remain in effect until all costs incurred pursuant to OATT Attachment P through September 30, 2015, are billed and fully paid.

1. Oversupply Charges

a. Displacement Charge

The Displacement Charge recovers the amounts paid under OATT Attachment P. For each month, the Displacement Charge for each of the Generator's facilities shall be:

$$50\% \times \text{Displacement Cost} \times \frac{\text{Facility Nameplate Capacity}}{\text{Total Nameplate Capacity}}$$

Where:

Displacement Cost = the total amount BPA paid during the billing month under OATT Attachment P to displace output from generating facilities, in dollars.

Facility Nameplate Capacity = for each generating facility for which the Generator has submitted the generating facility's displacement cost under OATT Attachment P, the average of (i) the generating facility's nameplate capacity, in kilowatts, on the last day of the prior month, and (ii) the facility's nameplate capacity, in kilowatts, on the last day of the month.

Total Nameplate Capacity = the sum of all Facility Nameplate Capacities of all Generators for the month.

b. Administrative Charge

The Administrative Charge recovers the annual contract cost of an independent evaluator. For each of the Generator's facilities, the annual Administrative Charge shall be:

$$50\% \times \text{Evaluator Cost} \times \frac{\text{Facility Nameplate Capacity--June}}{\text{Total Nameplate Capacity--June}}$$

Where:

Evaluator Cost = \$248,844 for the period March 31, 2012, through March 30, 2013, and the actual annual contract cost for each year after March 30, 2013.

Facility Nameplate Capacity--June and *Total Nameplate Capacity--June* = the Facility Nameplate Capacity and Total Nameplate Capacity values used for calculating each June's Displacement Charges in section 1.a., above.

2. Billing

a. Displacement Charge

A Displacement Charge for each customer shall be calculated for each month beginning April 2012. A cumulative Displacement Charge for all months prior to the effective date of this rate schedule shall be included on a bill issued within three months after the effective date of this rate schedule, subject to the billing cap (section c, below). The Displacement Charge for all months after the effective date of this rate schedule shall be included on bills for the month after Displacement Costs are incurred, subject to the billing cap. Any Displacement Costs not billed because of the billing cap, or because BPA was unable to determine the full amount of Displacement Costs for the month, shall be included on the following month's bill, subject to the billing cap, and on subsequent bills if necessary until all Displacement Costs have been billed.

b. Administrative Charge

An Administrative Charge shall be calculated for each year beginning April 1, 2012. A cumulative Administrative Charge for all years prior to the effective date of this rate schedule shall be included on a bill issued within three months after the effective date of this rate schedule. The Administrative Charge for each year after the effective date of this rate schedule shall be included on the bill for June.

c. Billing Cap

Total billing to all Generators for the Displacement Charges may not exceed \$4,000,000 in any month. If the total Displacement Charges exceed \$4,000,000 in any month, the excess over \$4,000,000 shall be billed in the following month, subject to this billing cap. If the billing cap is exceeded in such following month, excess charges shall be billed in each subsequent month, subject to this billing cap, until all charges are billed.

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Attachment 1

Power General Rate Schedule Provision

Power GRSP II.O. Oversupply Charges

The Oversupply Charges apply to Customers purchasing power at a Priority Firm Power (PF) Tier 1 rate, the Industrial Firm Power (IP) rate, or the New Resource Firm Power (NR) rate (Power Customers).

The Oversupply Charges shall collect 50 percent of (1) the amounts paid under Open Access Transmission Tariff (OATT) Attachment P for the period March 31, 2012, through September 30, 2015; and (2) the administrative cost of the independent evaluator selected by BPA pursuant to OATT Attachment P.

The Oversupply Charges shall remain in effect until all costs incurred pursuant to OATT Attachment P through September 30, 2015, are billed and fully paid.

1. Oversupply Charges

a. Displacement Charge

The Displacement Charge recovers the amounts paid under OATT Attachment P. For each month, the Displacement Charge for each Power Customer shall be:

$$50\% \times \text{Displacement Cost} \times \text{Modified TOCA}$$

Where:

Displacement Cost = the total amount BPA paid during the billing month under OATT Attachment P to displace output from generating facilities, in dollars.

Modified TOCA = Modified Tier 1 Cost Allocator, which equals:

- (i) For PF customers, the lesser of the customer's Rate Period High Water Mark (RHWM) or Net Requirement (aMW), as defined in the Tiered Rate Methodology (BP-12-A-03), as determined in the rate proceeding applicable to the billing month;

or

For IP and NR customers, the contract energy amount (aMW), or equivalent thereof, as determined in the rate proceeding applicable to the billing month;

divided by

(ii) the sum of the amounts calculated in section (i), above, for all Power Customers.

Each year's Modified TOCAs for each Power Customer are set forth in Appendix B to these General Rate Schedule Provisions.

b. Administrative Charge

The Administrative Charge recovers the annual contract cost of an independent evaluator. For each Power Customer, the annual Administrative Charge shall be:

$$50\% \times \text{Evaluator Cost} \times \text{Modified TOCA}$$

Where:

Evaluator Cost = \$248,844 for the period March 31, 2012, through March 30, 2013, and the actual annual contract cost for each year after March 30, 2013.

Modified TOCA = the Modified TOCA values used in section 1.a., above.

2. Billing

a. Displacement Charge

A Displacement Charge for each Power Customer shall be calculated for each month beginning April 2012. A cumulative Displacement Charge for all months prior to the effective date of this rate schedule shall be included on a bill issued within three months after the effective date of this rate schedule, subject to the billing cap (section c, below). The Displacement Charge for all months after the effective date of this rate schedule shall be included on bills for the month after Displacement Costs are incurred, subject to the billing cap. Any Displacement Costs not billed because of the billing cap, or because BPA was unable to determine the full amount of Displacement Costs for the month, shall be included on the following month's bill, subject to the billing cap, and on subsequent bills if necessary until all Displacement Costs have been billed.

b. Administrative Charge

An Administrative Charge shall be calculated for each year beginning April 1, 2012. A cumulative Administrative Charge for all years prior to the effective date of this rate schedule shall be included on a bill issued within three months after the effective date of this rate schedule. The Administrative Charge for each year after the effective date of this rate schedule shall be included on the bill for June.

c. Billing Cap

Total billing to all customers for the Displacement Charges may not exceed \$4,000,000 in any month. If the total Displacement Charges exceed \$4,000,000 in any month, the excess over \$4,000,000 shall be billed in the following month, subject to this billing cap. If the billing cap is exceeded in such following month, excess charges shall be billed in each subsequent month, subject to this billing cap, until all charges are billed.

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Attachment 1 Power Rate Schedule Additions

Schedule PF-14 Priority Firm Power Rate:

7 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable to PF rates as shown in the following table.

<i>GRSP II.</i>	<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>Applicable to:</i>			
		<i>Firm Requirements</i>			<i>REP</i>
		<i>Load Following</i>	<i>Block only and Block Portion of Slice/Block</i>	<i>Slice Portion of Slice/Block</i>	
		* * * *			
O	Oversupply Rate	X	X	X	
		* * * *			

Schedule NR-14 New Resource Firm Power Rate:

5 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>GRSP II.</i>
* * * *	
Oversupply Rate	O
* * * *	

Schedule IP-14 Industrial Firm Power Rate:

3 Adjustments, Charges, and Special Rate Provisions

Adjustments, charges, and special rate provisions are applicable as shown in the following table.

<i>Adjustments, Charges, and Special Rate Provisions</i>	<i>GRSP II.</i>
* * * *	
Oversupply Rate	O
* * * *	

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Attachment 1
Power General Rate Schedule Provision Appendix

Appendix B

Oversupply

Modified TOCAs for Power Customers

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Table 1**FY 2012-2015 Modified TOCAs**

A	B	C	D	E	F
		Modified TOCA 2012	Modified TOCA 2013	Modified TOCA 2014	Modified TOCA 2015
	<u>Power Customer</u>				
10005	Alder Mutual	0.0000768	0.0000760	0.0000751	0.0000748
10015	Asotin County PUD #1	0.0000834	0.0000828	0.0000825	0.0000822
10024	Benton County PUD #1	0.0271574	0.0271302	0.0270550	0.0270940
10025	Benton REA	0.0093945	0.0092876	0.0091523	0.0091180
10027	Big Bend Elec Coop	0.0084712	0.0084882	0.0083926	0.0083612
10029	Blachly Lane Elec Coop	0.0024134	0.0024436	0.0024161	0.0024070
10044	Canby, City of	0.0028462	0.0028171	0.0027852	0.0027750
10046	Central Electric Coop	0.0109675	0.0110632	0.0111565	0.0111836
10047	Central Lincoln PUD	0.0212318	0.0211472	0.0208533	0.0208211
10055	Albion, City of	0.0000554	0.0000553	0.0000546	0.0000544
10057	Ashland, City of	0.0028240	0.0028072	0.0028630	0.0028788
10059	Bandon, City of	0.0010154	0.0010104	0.0010477	0.0010438
10061	Blaine, City of	0.0012106	0.0012130	0.0011996	0.0011951
10062	Bonniers Ferry, City of	0.0007463	0.0007378	0.0007296	0.0007269
10064	Burley, City of	0.0019733	0.0019508	0.0018985	0.0018988
10065	Cascade Locks, City of	0.0003110	0.0003077	0.0003049	0.0003037
10066	Centralia, City of	0.0033759	0.0033805	0.0033425	0.0033300
10067	Cheney, City of	0.0022193	0.0021940	0.0021693	0.0021612
10068	Chewelah, City of	0.0003850	0.0003945	0.0003805	0.0003806
10070	Declo, City of	0.0000503	0.0000498	0.0000492	0.0000490
10071	Drain, City of	0.0002969	0.0002983	0.0002712	0.0002713
10072	Ellensburg, City of	0.0033649	0.0033266	0.0032891	0.0032768
10074	Forest Grove, City of	0.0033894	0.0033693	0.0034718	0.0035686
10076	Heyburn, City of	0.0006759	0.0006682	0.0006606	0.0006581
10078	McCleary, City of	0.0005856	0.0005789	0.0004786	0.0004781
10079	McMinnville, City of	0.0119906	0.0122346	0.0113647	0.0115803
10080	Milton, Town of	0.0010435	0.0010316	0.0010171	0.0010162
10081	Milton-Freewater, City of	0.0013201	0.0013182	0.0013689	0.0013778
10082	Minidoka, City of	0.0000166	0.0000164	0.0000162	0.0000162
10083	Monmouth, City of	0.0011734	0.0011601	0.0011470	0.0011427
10086	Plummer, City of	0.0005535	0.0005472	0.0005411	0.0005391
10087	Port Angeles, City of	0.0115047	0.0114061	0.0116403	0.0116120
10089	Richland, City of	0.0138386	0.0140224	0.0138715	0.0138195
10091	Rupert, City of	0.0012518	0.0012380	0.0012378	0.0012331
10094	Soda Springs, City of	0.0004164	0.0004105	0.0004081	0.0004053

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Attachment 1

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Table 1**FY 2012-2015 Modified TOCAs**

A	B	C	D	E	F
		Modified TOCA 2012	Modified TOCA 2013	Modified TOCA 2014	Modified TOCA 2015
	<u>Power Customer</u>				
10095	Sumas, Town of	0.0005111	0.0005052	0.0004996	0.0004978
10097	Troy, City of	0.0002859	0.0002827	0.0002794	0.0002784
10101	Clallam County PUD #1	0.0106609	0.0105458	0.0104271	0.0103880
10103	Clark County PUD #1	0.0422670	0.0422372	0.0436809	0.0435172
10105	Clatskanie PUD	0.0124547	0.0123631	0.0128340	0.0127859
10106	Clearwater Power	0.0032268	0.0032318	0.0030666	0.0030675
10109	Columbia Basin Elec Coop	0.0016758	0.0016809	0.0016620	0.0016558
10111	Columbia Power Coop	0.0004466	0.0004453	0.0004436	0.0004419
10112	Columbia River PUD	0.0078768	0.0078528	0.0078306	0.0078875
10113	Columbia REA	0.0052886	0.0052284	0.0051695	0.0051501
10116	Consolidated Irrigation District #19	0.0000320	0.0000316	0.0000313	0.0000312
10118	Consumers Power	0.0060473	0.0060338	0.0062640	0.0062406
10121	Coos Curry Elec Coop	0.0056271	0.0055983	0.0056060	0.0055850
10123	Cowlitz County PUD #1	0.0720028	0.0714400	0.0753215	0.0750393
10136	Douglas Electric Cooperative	0.0025028	0.0024813	0.0024885	0.0025145
10142	East End Mutual Electric	0.0003770	0.0003727	0.0003685	0.0003672
10144	Eatonville, City of	0.0004725	0.0004672	0.0004619	0.0004602
10156	Elmhurst Mutual P & L	0.0044721	0.0044682	0.0044214	0.0044048
10157	Emerald PUD	0.0070285	0.0070984	0.0070041	0.0070878
10158	Energy Northwest	0.0003684	0.0003641	0.0003793	0.0003779
10170	Eugene Water & Electric Board	0.0349407	0.0348296	0.0342187	0.0343084
10172	U.S. Airforce Base, Fairchild	0.0008361	0.0008371	0.0008450	0.0008503
10173	Fall River Elec Coop	0.0046484	0.0045955	0.0045437	0.0045267
10174	Farmers Elec Coop	0.0000698	0.0000694	0.0000697	0.0000694
10177	Ferry County PUD #1	0.0016125	0.0016181	0.0015999	0.0015939
10179	Flathead Elec Coop	0.0221890	0.0223216	0.0228036	0.0227936
10183	Franklin County PUD #1	0.0160116	0.0161624	0.0160946	0.0160342
10186	Glacier Elec Coop	0.0029110	0.0029290	0.0029236	0.0029126
10190	Grant County PUD #2	0.0007284	0.0007201	0.0007120	0.0007093
10191	Grays Harbor PUD #1	0.0184106	0.0182010	0.0179961	0.0179287
10197	Harney Elec Coop	0.0030997	0.0031049	0.0028661	0.0028697
10202	Hood River Elec Coop	0.0017899	0.0017886	0.0017964	0.0017897
10203	Idaho County L & P	0.0008718	0.0008619	0.0008521	0.0008489
10204	Idaho Falls Power	0.0109479	0.0109263	0.0109110	0.0108701
10209	Inland P & L	0.0145064	0.0146011	0.0147766	0.0147212
10230	Kittitas County PUD #1	0.0012892	0.0012753	0.0013307	0.0013257

Table 1**FY 2012-2015 Modified TOCAs**

A	B	C	D	E	F
		Modified TOCA 2012	Modified TOCA 2013	Modified TOCA 2014	Modified TOCA 2015
	<u>Power Customer</u>				
10231	Klickitat County PUD #1	0.0049608	0.0049930	0.0049559	0.0049651
10234	Kootenai Electric Coop	0.0069300	0.0069720	0.0069945	0.0069683
10235	Lakeview L & P (WA)	0.0045615	0.0045230	0.0044946	0.0044815
10236	Lane County Elec Coop	0.0039838	0.0039652	0.0039914	0.0039764
10237	Lewis County PUD #1	0.0152717	0.0152664	0.0155982	0.0155398
10239	Lincoln Elec Coop (MT)	0.0018696	0.0018766	0.0018989	0.0019156
10242	Lost River Elec Coop	0.0013151	0.0013166	0.0012596	0.0012643
10244	Lower Valley Energy	0.0120717	0.0119342	0.0117998	0.0117556
10246	Mason County PUD #1	0.0012610	0.0012466	0.0012325	0.0012279
10247	Mason County PUD #3	0.0110200	0.0110101	0.0109621	0.0109210
10256	Midstate Elec Coop	0.0064152	0.0064206	0.0064112	0.0063871
10258	Mission Valley	0.0049461	0.0050068	0.0051069	0.0051855
10259	Missoula Elec Coop	0.0036667	0.0036894	0.0037010	0.0036871
10260	Modern Elec Coop	0.0036040	0.0036271	0.0036049	0.0035914
10273	Nespelem Valley Elec Coop	0.0008252	0.0008158	0.0008067	0.0008036
10278	Northern Lights	0.0050409	0.0049835	0.0049275	0.0049090
10279	Northern Wasco County PUD	0.0084827	0.0084437	0.0085133	0.0085141
10284	Ohop Mutual Light Company	0.0014253	0.0014090	0.0013933	0.0013881
10285	Okanogan County Elec Coop	0.0009160	0.0009056	0.0008954	0.0008920
10286	Okanogan County PUD #1	0.0068259	0.0067896	0.0067131	0.0066880
10288	Orcas P & L	0.0034704	0.0034309	0.0033922	0.0033795
10291	Oregon Trail Coop	0.0102565	0.0103073	0.0104200	0.0104993
10294	Pacific County PUD #2	0.0042836	0.0048107	0.0049822	0.0049636
10304	Parkland L & W	0.0019390	0.0019387	0.0019295	0.0019222
10306	Pend Oreille County PUD #1	0.0029141	0.0032876	0.0035016	0.0036026
10307	Peninsula Light Company	0.0098396	0.0099149	0.0098726	0.0098356
10326	U.S. Naval Base, Bremerton	0.0037692	0.0037266	0.0041216	0.0038990
10331	Raft River Elec Coop	0.0046513	0.0046325	0.0047059	0.0047184
10333	Ravalli County Elec Coop	0.0025028	0.0025199	0.0025392	0.0025297
10338	Riverside Elec Coop	0.0003142	0.0003110	0.0003184	0.0003203
10342	Salem Elec Coop	0.0055265	0.0054635	0.0054021	0.0053818
10343	Salmon River Elec Coop	0.0042697	0.0042119	0.0043049	0.0042888
10349	Seattle City Light	0.0735084	0.0726716	0.0718534	0.0715842
10352	Skamania County PUD #1	0.0021808	0.0021810	0.0021553	0.0021627
10354	Snohomish County PUD #1	0.1102962	0.1108014	0.1055019	0.1065042
10360	Southside Elec Lines	0.0008961	0.0009084	0.0009132	0.0009152

Table 1**FY 2012-2015 Modified TOCAs**

A	B	C	D	E	F
		Modified TOCA 2012	Modified TOCA 2013	Modified TOCA 2014	Modified TOCA 2015
	<u>Power Customer</u>				
10363	Springfield Utility Board	0.0135517	0.0135489	0.0137052	0.0137599
10369	Surprise Valley Elec Coop	0.0021708	0.0021755	0.0021021	0.0021099
10370	Tacoma Public Utilities	0.0549346	0.0548325	0.0547437	0.0549563
10371	Tanner Elec Coop	0.0015480	0.0015303	0.0015130	0.0015073
10376	Tillamook PUD #1	0.0076101	0.0075568	0.0075492	0.0075733
10378	Coulee Dam, City of	0.0002841	0.0002809	0.0002777	0.0002766
10379	Steilacoom, Town of	0.0006683	0.0006670	0.0006594	0.0006569
10388	Umatilla Elec Coop	0.0157295	0.0157051	0.0155283	0.0154702
10391	United Electric Coop	0.0042059	0.0041580	0.0041113	0.0040959
10406	U.S. DOE Albany Research Center	0.0000636	0.0000629	0.0000628	0.0000625
10408	U.S. Naval Station, Everett (Jim Creek)	0.0002040	0.0002017	0.0002016	0.0002008
10409	U.S. Naval Submarine Base, Bangor	0.0027803	0.0027534	0.0027567	0.0027515
10426	U.S. DOE Richland Operations Office	0.0034801	0.0036424	0.0037277	0.0038771
10434	Vera Irrigation District	0.0036565	0.0036792	0.0037245	0.0037106
10436	Vigilante Elec Coop	0.0025363	0.0025532	0.0025906	0.0026168
10440	Wahkiakum County PUD #1	0.0006973	0.0006943	0.0006864	0.0006839
10442	Wasco Elec Coop	0.0018795	0.0018581	0.0018372	0.0018303
10446	Wells Rural Elec Coop	0.0132707	0.0132844	0.0131349	0.0130857
10448	West Oregon Elec Coop	0.0011797	0.0011714	0.0011493	0.0011480
10451	Whatcom County PUD #1	0.0035590	0.0037220	0.0036801	0.0036663
10482	Umpqua Indian Utility Cooperative	0.0004584	0.0004892	0.0005621	0.0005621
10502	Yakama Power	0.0008809	0.0008822	0.0013496	0.0013556
10597	Hermiston, City of	0.0017396	0.0017283	0.0017547	0.0017584
10706	Port of Seattle - SETAC Int'l. Airport	0.0023124	0.0022935	0.0023696	0.0023607
11680	Weiser, City of	0.0008657	0.0008631	0.0008680	0.0008647
12026	Jefferson County PUD #1	0.0000000	0.0010507	0.0061953	0.0061721
10007	Alcoa	0.0442383	0.0437347	0.0409736	0.0408200
10312	Port Townsend Paper	0.0027649	0.0027334	0.0016389	0.0016328

Attachment 2 FY 2012 Oversupply Costs and Charges

Table 1
FY 2012 Oversupply Costs

Displacement Costs (\$)		A	B	C
1	Apr-12	607,121		
2	May-12	371,777		
3	Jun-12	183		
4	Jul-12	1,722,937		
5	Total	2,702,018		
6				
7			Power	Transmission
8	2012 Displacement Costs	\$2,702,018	\$1,351,009	\$1,351,009
9	2012 Evaluator Contract Cost	\$248,844	\$124,422	\$124,422
10	2012 Total	\$2,950,862	\$1,475,431	\$1,475,431

Attachment 2

Table 2

FY 2012 Generator Oversupply Charges

A		B	C
		Displacement	Administrative
		Charge 2012	Charge 2012
Generators		\$1,351,009	\$124,422
1	Arlington	\$39,346	\$3,584
2	Big Horn	\$76,778	\$6,993
3	Big Horn 2	\$19,119	\$1,741
4	Biglow Canyon	\$171,954	\$15,662
5	Eurus/Combine Hills	\$24,090	\$2,194
6	Goodnoe Hills	\$35,943	\$3,274
7	Hay Canyon	\$38,543	\$3,511
8	Hopkins Ridge	\$59,880	\$5,454
9	Horseshoe Bend	\$39,103	\$4,203
10	Klondike 2	\$85,499	\$7,788
11	Klondike 3	\$29,252	\$2,664
12	Klondike 3A	\$29,249	\$2,668
13	Leaning Juniper 1	\$38,429	\$3,500
14	Linden	\$19,119	\$1,741
15	Lower Snake River	\$131,040	\$11,936
16	North Hurlburt	\$101,330	\$9,230
17	PaTu	\$3,575	\$326
18	Pebble Springs	\$37,740	\$3,438
19	South Hurlburt	\$72,369	\$7,316
20	Star Point	\$37,740	\$3,438
21	Stateline	\$34,322	\$3,126
22	Tuolumne	\$52,233	\$4,758
23	Vansycle	\$9,590	\$874
24	Wheatfield	\$36,938	\$3,364
25	Willow Creek	\$27,569	\$2,508
26	Windy Flats Dooley	\$100,259	\$9,132

Attachment 2

Table 3											
FY 2012 Monthly Detail of Generator Cost Allocation											
A	B	C	D	E		F	G	H	I	J	K
	Average Monthly Installed Capacity (MW)				Costs:	\$303,561	\$185,889	\$92	\$861,469	\$1,351,009	\$124,422
	Apr-12	May-12	Jun-12	Jul-12		Apr-12	May-12	Jun-12	Jul-12	Displacement	Admin.
1 Arlington	102.90	102.90	102.90	102.90		9,242	5,576	3	24,526	\$39,346	\$3,630
2 Big Horn	200.79	200.79	200.79	200.79		18,035	10,880	5	47,858	\$76,778	\$7,083
3 Big Horn 2	50.00	50.00	50.00	50.00		4,491	2,709	1	11,917	\$19,119	\$1,764
4 Biglow Canyon	449.70	449.70	449.70	449.70		40,391	24,367	12	107,185	\$171,954	\$15,864
5 Eurus/Combine Hills	63.00	63.00	63.00	63.00		5,659	3,414	2	15,016	\$24,090	\$2,222
6 Goodnoe Hills	94.00	94.00	94.00	94.00		8,443	5,093	2	22,405	\$35,943	\$3,316
7 Hay Canyon	100.80	100.80	100.80	100.80		9,054	5,462	3	24,025	\$38,543	\$3,556
8 Hopkins Ridge	156.60	156.60	156.60	156.60		14,066	8,485	4	37,325	\$59,880	\$5,524
9 Horseshoe Bend	0.00	42.84	103.19	154.31		0	2,321	3	36,779	\$39,103	\$3,640
10 Klondike 2	223.60	223.60	223.60	223.60		20,083	12,116	6	53,294	\$85,499	\$7,888
11 Klondike 3	76.50	76.50	76.50	76.50		6,871	4,145	2	18,234	\$29,252	\$2,699
12 Klondike 3A	76.32	76.32	76.46	76.60		6,855	4,135	2	18,256	\$29,249	\$2,697
13 Leaning Juniper 1	100.50	100.50	100.50	100.50		9,027	5,446	3	23,954	\$38,429	\$3,545
14 Linden	50.00	50.00	50.00	50.00		4,491	2,709	1	11,917	\$19,119	\$1,764
15 Lower Snake River	342.70	342.70	342.70	342.70		30,781	18,569	9	81,681	\$131,040	\$12,089
16 North Hurlburt	265.00	265.00	265.00	265.00		23,802	14,359	7	63,162	\$101,330	\$9,348
17 PaTu	9.35	9.35	9.35	9.35		840	507	0	2,229	\$3,575	\$330
18 Pebble Springs	98.70	98.70	98.70	98.70		8,865	5,348	3	23,525	\$37,740	\$3,482
19 South Hurlburt	138.31	146.41	182.28	218.20		12,422	7,933	5	52,008	\$72,369	\$6,430
20 Star Point	98.70	98.70	98.70	98.70		8,865	5,348	3	23,525	\$37,740	\$3,482
21 Stateline	89.76	89.76	89.76	89.76		8,062	4,864	2	21,394	\$34,322	\$3,166
22 Tuolumne	136.60	136.60	136.60	136.60		12,269	7,402	4	32,558	\$52,233	\$4,819
23 Vansycle	25.08	25.08	25.08	25.08		2,253	1,359	1	5,978	\$9,590	\$885
24 Wheatfield	96.60	96.60	96.60	96.60		8,676	5,234	3	23,024	\$36,938	\$3,408
25 Willow Creek	72.00	72.00	72.00	72.16		6,467	3,901	2	17,199	\$27,569	\$2,540
26 Windy Flats Dooley	262.20	262.20	262.20	262.20		23,550	14,207	7	62,495	\$100,259	\$9,250
27 Total	3379.71	3430.66	3527.01	3614.35		\$303,561	\$185,889	\$92	\$861,469	\$1,351,009	\$124,422

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Attachment 2

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Attachment 2

Table 4

FY 2012 Power Oversupply Charges

A	B	C	D
		Displacement Charge 2012 \$1,351,009	Administrative Charge 2012 \$124,422
	Power Customer		
10005	Alder Mutual	\$104	\$9
10015	Asotin County PUD #1	\$113	\$10
10024	Benton County PUD #1	\$36,690	\$3,376
10025	Benton REA	\$12,692	\$1,156
10027	Big Bend Elec Coop	\$11,445	\$1,056
10029	Blachly Lane Elec Coop	\$3,261	\$304
10044	Canby, City of	\$3,845	\$351
10046	Central Electric Coop	\$14,817	\$1,377
10047	Central Lincoln PUD	\$28,684	\$2,631
10055	Albion, City of	\$75	\$7
10057	Ashland, City of	\$3,815	\$349
10059	Bandon, City of	\$1,372	\$126
10061	Blaine, City of	\$1,636	\$151
10062	Bonniers Ferry, City of	\$1,008	\$92
10064	Burley, City of	\$2,666	\$243
10065	Cascade Locks, City of	\$420	\$38
10066	Centralia, City of	\$4,561	\$421
10067	Cheney, City of	\$2,998	\$273
10068	Chewelah, City of	\$520	\$49
10070	Declo, City of	\$68	\$6
10071	Drain, City of	\$401	\$37
10072	Ellensburg, City of	\$4,546	\$414
10074	Forest Grove, City of	\$4,579	\$419
10076	Heyburn, City of	\$913	\$83
10078	McCleary, City of	\$791	\$72
10079	McMinnville, City of	\$16,199	\$1,522
10080	Milton, Town of	\$1,410	\$128
10081	Milton-Freewater, City of	\$1,784	\$164
10082	Minidoka, City of	\$22	\$2
10083	Monmouth, City of	\$1,585	\$144
10086	Plummer, City of	\$748	\$68
10087	Port Angeles, City of	\$15,543	\$1,419
10089	Richland, City of	\$18,696	\$1,745
10091	Rupert, City of	\$1,691	\$154

Table 4
FY 2012 Power Oversupply Charges

A	B	C	D
		Displacement Charge 2012 \$1,351,009	Administrative Charge 2012 \$124,422
	Power Customer		
10094	Soda Springs, City of	\$562	\$51
10095	Sumas, Town of	\$690	\$63
10097	Troy, City of	\$386	\$35
10101	Clallam County PUD #1	\$14,403	\$1,312
10103	Clark County PUD #1	\$57,103	\$5,255
10105	Clatskanie PUD	\$16,826	\$1,538
10106	Clearwater Power	\$4,359	\$402
10109	Columbia Basin Elec Coop	\$2,264	\$209
10111	Columbia Power Coop	\$603	\$55
10112	Columbia River PUD	\$10,642	\$977
10113	Columbia REA	\$7,145	\$651
10116	Consolidated Irrigation District #19	\$43	\$4
10118	Consumers Power	\$8,170	\$751
10121	Coos Curry Elec Coop	\$7,602	\$697
10123	Cowlitz County PUD #1	\$97,276	\$8,889
10136	Douglas Electric Cooperative	\$3,381	\$309
10142	East End Mutual Electric	\$509	\$46
10144	Eatonville, City of	\$638	\$58
10156	Elmhurst Mutual P & L	\$6,042	\$556
10157	Emerald PUD	\$9,496	\$883
10158	Energy Northwest	\$498	\$45
10170	Eugene Water & Electric Board	\$47,205	\$4,334
10172	U.S. Airforce Base, Fairchild	\$1,130	\$104
10173	Fall River Elec Coop	\$6,280	\$572
10174	Farmers Elec Coop	\$94	\$9
10177	Ferry County PUD #1	\$2,179	\$201
10179	Flathead Elec Coop	\$29,978	\$2,777
10183	Franklin County PUD #1	\$21,632	\$2,011
10186	Glacier Elec Coop	\$3,933	\$364
10190	Grant County PUD #2	\$984	\$90
10191	Grays Harbor PUD #1	\$24,873	\$2,265
10197	Harney Elec Coop	\$4,188	\$386
10202	Hood River Elec Coop	\$2,418	\$223
10203	Idaho County L & P	\$1,178	\$107
10204	Idaho Falls Power	\$14,791	\$1,359

Table 4
FY 2012 Power Oversupply Charges

A	B	C	D
		Displacement Charge 2012 \$1,351,009	Administrative Charge 2012 \$124,422
	Power Customer		
10209	Inland P & L	\$19,598	\$1,817
10230	Kittitas County PUD #1	\$1,742	\$159
10231	Klickitat County PUD #1	\$6,702	\$621
10234	Kootenai Electric Coop	\$9,362	\$867
10235	Lakeview L & P (WA)	\$6,163	\$563
10236	Lane County Elec Coop	\$5,382	\$493
10237	Lewis County PUD #1	\$20,632	\$1,899
10239	Lincoln Elec Coop (MT)	\$2,526	\$233
10242	Lost River Elec Coop	\$1,777	\$164
10244	Lower Valley Energy	\$16,309	\$1,485
10246	Mason County PUD #1	\$1,704	\$155
10247	Mason County PUD #3	\$14,888	\$1,370
10256	Midstate Elec Coop	\$8,667	\$799
10258	Mission Valley	\$6,682	\$623
10259	Missoula Elec Coop	\$4,954	\$459
10260	Modern Elec Coop	\$4,869	\$451
10273	Nespelem Valley Elec Coop	\$1,115	\$101
10278	Northern Lights	\$6,810	\$620
10279	Northern Wasco County PUD	\$11,460	\$1,051
10284	Ohop Mutual Light Company	\$1,926	\$175
10285	Okanogan County Elec Coop	\$1,238	\$113
10286	Okanogan County PUD #1	\$9,222	\$845
10288	Orcas P & L	\$4,689	\$427
10291	Oregon Trail Coop	\$13,857	\$1,282
10294	Pacific County PUD #2	\$5,787	\$599
10304	Parkland L & W	\$2,620	\$241
10306	Pend Oreille County PUD #1	\$3,937	\$409
10307	Peninsula Light Company	\$13,293	\$1,234
10326	U.S. Naval Base, Bremerton	\$5,092	\$464
10331	Raft River Elec Coop	\$6,284	\$576
10333	Ravalli County Elec Coop	\$3,381	\$314
10338	Riverside Elec Coop	\$424	\$39
10342	Salem Elec Coop	\$7,466	\$680
10343	Salmon River Elec Coop	\$5,768	\$524
10349	Seattle City Light	\$99,311	\$9,042

Table 4
FY 2012 Power Oversupply Charges

A	B	C	D
		Displacement Charge 2012 \$1,351,009	Administrative Charge 2012 \$124,422
	Power Customer		
10352	Skamania County PUD #1	\$2,946	\$271
10354	Snohomish County PUD #1	\$149,011	\$13,786
10360	Southside Elec Lines	\$1,211	\$113
10363	Springfield Utility Board	\$18,309	\$1,686
10369	Surprise Valley Elec Coop	\$2,933	\$271
10370	Tacoma Public Utilities	\$74,217	\$6,822
10371	Tanner Elec Coop	\$2,091	\$190
10376	Tillamook PUD #1	\$10,281	\$940
10378	Coulee Dam, City of	\$384	\$35
10379	Steilacoom, Town of	\$903	\$83
10388	Umatilla Elec Coop	\$21,251	\$1,954
10391	United Electric Coop	\$5,682	\$517
10406	U.S. DOE Albany Research Center	\$86	\$8
10408	U.S. Naval Station, Everett (Jim Creek)	\$276	\$25
10409	U.S. Naval Submarine Base, Bangor	\$3,756	\$343
10426	U.S. DOE Richland Operations Office	\$4,702	\$453
10434	Vera Irrigation District	\$4,940	\$458
10436	Vigilante Elec Coop	\$3,427	\$318
10440	Wahkiakum County PUD #1	\$942	\$86
10442	Wasco Elec Coop	\$2,539	\$231
10446	Wells Rural Elec Coop	\$17,929	\$1,653
10448	West Oregon Elec Coop	\$1,594	\$146
10451	Whatcom County PUD #1	\$4,808	\$463
10482	Umpqua Indian Utility Cooperative	\$619	\$61
10502	Yakama Power	\$1,190	\$110
10597	Hermiston, City of	\$2,350	\$215
10706	Port of Seattle - SETAC Int'l. Airport	\$3,124	\$285
11680	Weiser, City of	\$1,170	\$107
12026	Jefferson County PUD #1	\$0	\$131
10007	Alcoa	\$59,766	\$5,442
10312	Port Townsend Paper	\$3,735	\$340

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