INDEX

TESTIMONY of

DANIEL H. FISHER and REBECCA E. FREDRICKSON

Witnesses for Bonneville Power Administration

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TESTIMONY of

DANIEL H. FISHER and REBECCA E. FREDRICKSON

Witnesses for Bonneville Power Administration

**SUBJECT: GENERATION INPUTS PARTIAL SETTLEMENT AGREEMENT**

## Section 1: Introduction and Purpose of Testimony

*Q. Please state your names and qualifications.*

A. My name is Daniel H. Fisher, and my qualifications are contained in BP-16-Q-BPA-12.

A. My name is Rebecca E. Fredrickson, and my qualifications are contained in BP-16-Q-BPA-13.

*Q. What is the purpose of your testimony?*

A. The purpose of our testimony is to provide an overview of the BP-16 Generation Inputs and Transmission Ancillary and Control Area Services Rates Partial Settlement Agreement ("Partial Settlement Agreement" or "Settlement"), which is attached as Appendix A to this testimony. This testimony also sponsors the ACS-16 Ancillary and Control Area Services rate schedules that are in the Partial Settlement Agreement. See Partial Settlement Agreement, Attachment 2.

## Section 2: Partial Settlement Agreement and Initial Rate Proposal

*Q. Please describe how BPA and interested parties developed the Partial Settlement Agreement for the BP-16 rate proceeding.*

A. BPA Staff heard from customers in May of 2014 that several parties were interested in exploring a settlement of the Ancillary and Control Area Services portion of the BP-16 rate case. This customer interest in exploring settlement was expressed after roughly six months of public workshops that included seven all-customer meetings and approximately a dozen sub-team efforts targeted specifically on reaching collaborative solutions to the Ancillary and Control Area Service issues for the BP-16 rate period. BPA Staff responded with a presentation of a draft settlement concept to the customers on July 22, 2014. Customers provided BPA Staff feedback during the July 22, 2014, presentation as well as during various small meetings that occurred in the subsequent weeks. BPA Staff used this feedback to refine the settlement concept and presented a second settlement concept on August 27, 2014. Customers and BPA Staff determined that the settlement concept presented on August 27, 2014, had significant settlement potential. BPA Staff and the customers held drafting sessions on September 5, 2014, and September 8, 2014, to refine the settlement agreement. The drafting sessions resulted in a revised agreement that was released publicly on September 15, 2014.

Pursuant to the revised proposal, customers provided BPA their service elections for the BP-16 rate period on September 18, 2014. These elections were used to update the numbers in the settlement. BPA tendered the final Partial Settlement Agreement to customers on September 19, 2014. Customers were required to indicate their intent to contest the Settlement by close of business on September 25, 2014. No customers did so. BPA; ESI Vansycle; Iberdrola Renewables, LLC; Lewis County PUD; M-S-R Public Power Agency; Portland General Electric Company; Powerex; and Renewables Northwest signed the agreement. Avista Corporation; Cowlitz County PUD; EDP Renewables North America, LLC; Eugene Water & Electric Board; Franklin County PUD No. 1; Grays Harbor Energy, LLC; Industrial Customers of Northwest Utilities; Northwest Requirements Utilities; Pacific Northwest Generating Cooperative; PacifiCorp; Public Power Council; Puget Sound Energy, Inc.; RockTenn CP, LLC; Seattle City Light; Snohomish County PUD; Southern California Edison Company; Tacoma Power; TransAlta Energy Marketing; Turlock Irrigation District; and Western Public Agencies Group agreed not to contest the Settlement. On September 26, 2014, BPA notified customers of this positive response which meant that the BP-16 Initial Proposal would be developed using the provisions of the Partial Settlement Agreement.

*Q. Please provide an overview of the portion of the Initial Proposal that is based on the Partial Settlement Agreement.*

A. The Partial Settlement Agreement addresses all generation inputs and Ancillary and Control Area Services Rates for the BP-16 rate period, except (1) Scheduling, System Control, and Dispatch Service, and (2) Reactive Supply and Voltage Control from Generation Sources Service. The Partial Settlement Agreement is expected to provide a single high-quality balancing service to all customers and aims to do so through a substantial acquisition budget and enhanced acquisition flexibility for BPA. Specifically, the Settlement provides BPA more flexibility to effectively manage the supply (both Federal Columbia River Power System (FCRPS) and third-party sourced) of balancing capacity during the spring months (as defined in the Partial Settlement Agreement), which is a period of the year in which there is significant operational uncertainty. The Settlement also establishes the amount of balancing reserve capacity, both *inc* and *dec*, that is planned to be provided by the FCRPS and the cost at which that balancing reserve capacity is provided to BPA Transmission Services by BPA Power Services. This revenue, combined with the other revenue Power Services receives from Transmission Services for providing the other generation inputs included in the Settlement (*see* Attachment 3 of the Partial Settlement Agreement), is used to set power rates. Power Rates Study, BP-16-E-BPA-01, § 4.3. The recovery of these costs is included in the Transmission Rates Study and Documentation, BP-16-E-BPA-07, Table 12.

*Q. Please describe proposed changes to the ACS-16 rate schedules that are based on the Partial Settlement Agreement.*

A. Setting aside the Risk Mitigation Tools section of the proposed Settlement (*see* section 16 of Attachment 1 to the Partial Settlement Agreement) that has the potential to adjust the

Settlement rates, the proposed Settlement rates for Regulation and Frequency Response Service, Variable Energy Resource Balancing Service (VERBS), and Dispatchable Energy Resource Balancing Service (DERBS) are unchanged from the current BP-14 rates for those services. The proposed Settlement rates for Operating Reserves, both Spinning and Supplemental, are five percent higher than the BP-14 rates.

The proposed Settlement is designed around a single high-quality balancing service for all customers and removes the bifurcation of a "Base Service" and "Full Service" found in the BP-14 VERBS rate schedule. Similarly, the VERBS Supplemental Service, which was designed primarily to supplement the BP-14 VERBS Base Service, and the Purchases Charge for Purchases of Balancing Reserve Capacity to Support Full Service were removed. The 30/30 Committed Scheduling option under the VERBS rate schedule was also removed.

In addition to a name change made for clarity, the proposed Settlement also modified the formula for the Direct Assignment Charges, formerly the Formula Purchases Charges, under both the VERBS and DERBS rate schedules. Specifically, additional costs incurred by BPA under the Direct Assignment Charge provisions are passed on to the customer if those costs are greater than the cost used to set the applicable VERBS or DERBS rate. Under this situation, only the difference in cost is directly allocated to the customer. Under the BP-14 Formula Purchases Charges, the entire cost was directly allocated to the customer.

Finally, the proposed Settlement limits the applicability of the Persistent Deviation Penalty and replaces it with a new scheduling incentive called the Intentional Deviation Penalty Charge for Variable Energy Resources.

*Q. Are there other impacts to the rates from the Partial Settlement?*

A. The Partial Settlement Agreement also set cost allocations from Power Services to Transmission Services for synchronous condensing, generation dropping, redispatch, segmentation of COE and Reclamation network and delivery facilities, and station service. These costs are recovered in various transmission rates. *See* Partial Settlement Agreement, Attachment 3.

**Section 3: Equitable Allocation**

*Q. Do the proposed ACS-16 rates represent an equitable allocation of costs between Federal and non-Federal power?*

A. Yes. The parties to the Settlement recognized that many changes are occurring in the wider electricity markets over the BP-16 timeframe that may ultimately impact BPA's need to make additional acquisitions of reserve capacity and reduce or eliminate that need. In addition, many parties are concerned about the cost of acquisitions of balancing reserve capacity and the liquidity of markets for procuring that capacity. The Settlement establishes an agreed-upon means of allocating the risk that costs of reserve capacity may be greater than forecast or that reserve capacity may be unavailable in certain time periods. Parties to the Settlement also recognized that the landscape for providing balancing reserves may be fundamentally changing in the near future as the region explores a Security Constrained Economic Dispatch (SCED) market that is designed to resolve imbalance, lower generation costs, and capture diversity. Therefore, parties to the Settlement have agreed to a transition period that allows BPA and other stakeholders further time to explore the SCED market.

As a result, equitable allocation is demonstrated by the breadth of the parties that either signed the Partial Settlement Agreement or agreed not to contest it. These parties include requirements customers of Power Services; large wheeling customers, such as several investor-owned utilities and power marketers; and independent power producers. BPA would not have been able to obtain the agreement or consent of such a large and diverse group of customers (that is, Federal and non-Federal power users of the Federal transmission system) unless the proposed allocation of costs was equitable for the FY 2016–2017 rate period.

*Q.* *Does this conclude your testimony?*

A. Yes.

# Appendix A

# Partial Settlement Agreement

# Bonneville Power Administration 2016 Rate Case

# Generation Inputs and Transmission Ancillary and Control Area Service Rates

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## PARTIAL SETTLEMENT AGREEMENT

**Bonneville Power Administration 2016 Rate Case**
**Generation Inputs and Transmission Ancillary and Control Area Services Rates**

THIS PARTIAL SETTLEMENT AGREEMENT, including Attachments 1, 2, and 3 ("AGREEMENT"), dated and effective as of the date established pursuant to section 3 of this Agreement, is among the Bonneville Power Administration ("Bonneville") and the BP-16 rate case parties (in the singular, "Party," in the plural, "Parties").

WHEREAS

A. Starting in October 2013, Bonneville and the Parties have been engaged in public meetings to reach agreement on the rates for certain transmission ancillary and control area services for the FY 2016-2017 Rate Period ("Rate Period");

B. Bonneville and the Parties wish to settle their disputes concerning generation inputs and transmission ancillary and control area services rates for the Rate Period;

C. Bonneville and the Parties recognize that both the rate structure and the operations related to the integration of variable energy resources and dispatchable energy resources in Bonneville's balancing authority area are in a transitional period; that there is considerable disagreement about how to design Bonneville's transmission ancillary and control area services rates, terms and conditions; and that there is disagreement about the allocation of balancing reserve capacity and energy costs; and

D. The purpose of this Agreement is to settle those differences for the Rate Period, without precedent for subsequent rate periods, so that Bonneville and the Parties can work collaboratively on developing operational tools, terms and conditions, and proposals for rates and the allocation of costs for the services necessary to balance the system in future rate periods.

NOW, THEREFORE, Bonneville, the undersigned Party signatories ("Party Signatories"), and Parties who otherwise indicate assent to this Agreement by not objecting to this Agreement or the Settlement Proposal (as defined in section 1) on the record of the BP-16 rate proceeding pursuant to section 3 ("Non-Objecting Parties", and collectively with the Party Signatories, the "Assenting Parties") agree to the following:

1. In the BP-16 rate proceeding, Bonneville staff will propose that the Administrator adopt a proposal to establish the costs of generation inputs and rates for transmission ancillary and control area services for the Rate Period ("Settlement Proposal"). The Settlement

Proposal will include only the terms specified in Attachment 1, the rate schedules and general rate schedule provisions specified in Attachment 2, the terms in Attachment 3, and the terms of this Agreement.

2. During the Rate Period, Bonneville and the Assenting Parties will abide by the terms specified in Attachment 1 and this Agreement.

3. Bonneville will notify the Hearing Officer of the Agreement and move the Hearing Officer to: (1) require any Party that did not sign or assent to the Agreement to state its objection to the Settlement Proposal, the basis for its objection, and to identify each issue included in the Settlement Proposal that such Party chooses to preserve in the BP-16 rate proceeding within 5 days of the date interventions are granted in the rate proceeding; and (2) specify that any Party that does not state its objection to the Settlement Proposal on such date will waive its rights to preserve any objections to the Settlement Proposal and shall be treated as an Assenting Party for all purposes under this Agreement and on the record in the BP-16 rate proceeding. Unless this Agreement terminates under the terms set forth in sections 4 and 5 below, this Agreement will become effective on November 12, 2014, and will terminate on September 30, 2017. If a Party has not preserved any issues originally through an objection to the Settlement Proposal, the Party waives its right to preserve such issue.

4. If, in response to the Hearing Officer's order made pursuant to section 3, any Party states an objection to the Settlement Proposal, Bonneville or any Assenting Party will have three business days from the date of the objection to withdraw its assent to the settlement. If Bonneville or any Assenting Party withdraws its assent to the settlement, Bonneville shall promptly meet with any other interested rate case parties to discuss how to proceed.

5. If the Administrator does not adopt the Settlement Proposal in the BP-16 Final Record of Decision, this Agreement and the Settlem ent Proposal will terminate upon the date the Administrator declines to adopt the Settlement Proposal.

6. Waiver

    a. <u>Preservation of BP-16 ACS Rates and Settlement Proposal</u>

        i. The Parties agree that this is a black box settlement. If the Administrator adopts the Settlement Proposal, Bonneville and the Assenting Parties agree not to contest this Agreement or its implementation pursuant to its terms, including the Settlement Proposal and rates and rate schedule provisions in Attachment 2, from the effective date through September 30, 2017.

ii. The Assenting Parties agree to waive their rights to cross-examination and discovery with respect to the Settlement Proposal, except in response to issues raised by any party in the BP-16 rate proceeding that is not an Assenting Party to this Agreement.

b. Reciprocity

In the event that this Agreement is determined to be inconsistent or incompatible with a reciprocity transmission tariff, the Assenting Parties agree that this Agreement shall nonetheless remain in effect for the remainder of the Rate Period.

c. No Precedent or Issue Preclusion beyond the Rate Period

i. Bonneville and the Assenting Parties understand, and will not argue otherwise, that this Agreement does not constitute consent or agreement in any future rate proceedings to the transmission ancillary and control area services rates and rate schedule provisions in Attachment 2 or to any rate, charge, or rate schedule provision, and that they retain all of their rights to take and argue whatever position they believe appropriate as to such matters; and

ii. The Assenting Parties and Bonneville acknowledge that this Agreement is a package, and that acceptance of the package does not create or imply any agreement with individual components of the package. Therefore, the Assenting Parties and Bonneville agree that they will not assert in any forum that anything in the Settlement Proposal, or that any action taken or not taken with regard to this Agreement by any Assenting Party, the Hearing Officer, the Administrator, the Federal Energy Regulatory Commission ("Commission"), or a court, creates or implies: (1) any procedural or substantive precedent (including, but not limited to, a substantive precedent with respect to rate design and a 3 MW dead band under the Dispatchable Energy Resource Balancing Service rate); (2)

agreement to any particular or individual treatment of costs, expenses, or revenues; (3) agreement to any particular interpretation of Bonneville's statutes; (4) any precedent under any contract or otherwise between Bonneville and any Party; or (5) any basis for supporting any Bonneville rate, terms or conditions for any period after the Rate Period.

7. Reservation of rights

   a. Except as provided in section 6(a) above, no Assenting Party waives any of its rights, under Bonneville's enabling statutes, the Federal Power Act, or other applicable law, to pursue dispute resolution procedures consistent with Bonneville's open access transmission tariff or to pursue any claim that a particular charge, methodology, practice, or rate schedule has been improperly implemented.

   b. Bonneville and the Assenting Parties reserve the right to file new complaints, petitions, or litigation related to any rates, terms and conditions, or other matters that are not a part of the Settlement Proposal.

   c. Notwithstanding section 6(a), but subject to section 8 of this Agreement, the Assenting Parties may seek review of the reliability tool described in Section 10 of Attachment 1.

   d. Bonneville and the Assenting Parties reserve the right to litigate any transmission or power rate at issue in the BP-16 rate proceeding that is not included in the Settlement Proposal. In addition, Bonneville reserves the right to propose changes to the transmission and power rates, rate schedules, and associated general rate schedule provisions for services that are not included in the Settlement Proposal.

   e. Bonneville and the Assenting Parties reserve the right to litigate and advance any arguments: (1) in proceedings that are pending before the Commission, the United States Court of Appeals for the Ninth Circuit, or any other judicial forum as of the effective date of this Agreement; and (2) in administrative or judicial review, now or hereafter pending, of such proceedings (collectively, "Pending Proceeding(s)").

f. Bonneville and the Assenting Parties reserve the right to respond during the Rate Period to any new filings, protests, or claims, by Bonneville or others; however, Bonneville and the Assenting Parties will not support a challenge to any rates, terms and conditions, or other matters described in this Agreement.

g. The Parties specifically acknowledge that the self-supply and unbundling components of BPA's Self Supply of Balancing Services Business Practice, Version 1, and any successor thereto is not part of this Settlement Agreement for purposes of Sections 7(b) and 7(d). Nothing in this Section 7(g) is intended to give a Party the right to challenge the Mid-Rate Period Adjustment provisions under sections 7 and 8 in Attachment 1.

8. If because of a legal challenge, Bonneville would be required to materially modify or discontinue the rates, terms, and conditions provided in this Agreement, including but not limited to the use of its balancing reserve capacity-related curtailment protocols during the Rate Period, Bonneville will seek, and the Assenting Parties agree to support, or not contest, a stay of enforcement of that ruling until after the Rate Period and Bonneville may, but shall not be required to, initiate a section 7(i) rate proceeding to revise or supplement any of the rates in Attachment 2.

9. Attachment 1 (Rate Period Terms), Attachment 2 (Transmission Ancillary and Control Area Services Rate Schedules and General Rate Schedule Provisions) and Attachment 3 (Inter-Business Line Allocations) are incorporated by reference into this Agreement.

10. Section 6(c) (No Precedent or Issue Preclusion beyond the Rate Period) of this Agreement will survive termination or expiration of this Agreement.

11. Nothing in this Partial Settlement Agreement is intended in any way to alter the Administrator's authority and responsibility to periodically review and revise the Administrator's rates or the Assenting Parties' rights to challenge such revisions.

This Agreement may be executed in counterparts.

_______________________________________

[Print Party Name]

By: ______________________________

Name: ________________________________
*(Print/Type)*

Title: ________________________________

Date: ________________________________

**ATTACHMENTS**

**Attachment 1, Rate Period Terms**

**Attachment 2, Transmission Ancillary and Control Area Services Rate Schedules and General Rate Schedule Provisions**

**Attachment 3, Inter-Business Line Allocations**

## ATTACHMENT 1, RATE PERIOD TERMS

1. **Term.** The terms and conditions in this Attachment 1 will apply to and will be binding on Bonneville and the Assenting Parties during the Fiscal Year (FY) 2016-2017 Rate Period ("Rate Period"), but must expire and not survive in any form after September 30, 2017.

2. **Imbalance Service.** Bonneville shall attempt to provide an imbalance service based on the incremental (*inc*) and decremental (*dec*) reserve quantities described in this Attachment 1. Bonneville shall use reasonable efforts in accordance with this Agreement to provide an *inc* imbalance service that is equal to or better than the service provided in FY 2014. This is estimated to be less than 10 curtailment events in October, November, December, January, February, March, August and September ("Non-Spring Months") and less than 30 curtailment events in April, May, June and July ("Spring Months").

3. ***Dec* Reserve.** Bonneville will use reasonable efforts to provide 900 MW of *dec* balancing reserve capacity from the Federal Columbia River Power System ("FCRPS") during all hours of the Rate Period. Bonneville and the Assenting Parties acknowledge that operational constraints and significant energy imbalance accumulations during operationally constrained periods of the year may limit Bonneville's ability to provide 900 MW of *dec* balancing reserve capacity from the FCRPS at times during the Rate Period. Bonneville shall not make any *dec* balancing reserve capacity acquisitions unless Bonneville determines *dec* balancing reserve capacity acquisitions are necessary to maintain system reliability.

4. ***Inc* Reserve (Non-Spring Months).** Bonneville will use reasonable efforts to provide a total of 910 MW of *inc* balancing reserve capacity (subject to adjustment by the Mid-Rate Period Adjustment described in section 8 of this Attachment 1 and Direct Assignment Charges as described in section III, E.4 and F.4 of the ACS-16 rate schedules in Attachment 2) for all hours in Non-Spring Months of each fiscal year in the Rate Period. Nothwithstanding any other section in this Agreement and except as a direct result of Direct Assignment Charges as described in section III, E.4 and F.4 of the ACS-16 rate schedules in Attachment 2, Bonneville is not obligated to provide more than 910 MW of *inc* balancing reserve capacity, FCRPS-sourced or otherwise, in any hour during the Non-Spring Months of each fiscal year in the Rate Period.

    a. ***FCRPS Source.***

        1. Bonneville will plan to provide up to 900 MW of the Non-Spring Month *inc* balancing reserve capacity from the FCRPS. To the extent Bonneville is unable to provide 900 MW of *inc* balancing reserve capacity from the FCRPS, Bonneville will attempt to, but is not obligated to, replace that capacity with third-party *inc* reserve capacity purchases. In making such acquistions, Bonneville will consider previous monthly or quarterly purchases for that timeframe, the available remaining Annual Budget, the projected reserve needs and the expected impacts during the affected timeframe, and the remaining periods in the Non-Spring Months.

2. In the event Bonneville is unable to make available 900 MW of *inc* balancing reserve capacity from the FCRPS under section 4(a)(1) above, Bonneville Power Services will issue a refund to Bonneville Transmission Services in the amount of $0.29/kW/day for the planned capacity that was not available from the FCRPS. The total amount refunded by Bonneville Power Services under this section will be added to the Annual Budget described in Section 6(a) of this Attachment 1.

3. Bonneville may provide, at its sole discretion, any additional amounts of *inc* balancing reserve capacity from the FCRPS because of the conditions described in Direct Assignment Charges, section III, E.4 and F.4 of the ACS-16 rate schedule in Attachment 2. Such additional amounts of inc balancing reserve capacity will be provided at a cost of $0.29/kW/day.

b. ***Third-Party Source.*** Bonneville shall attempt to acquire 10 MW of *inc* balancing reserve capacity on a quarterly basis.

5. ***Inc Reserve* (Spring Months).** Bonneville will use reasonable efforts to provide at least 600 MW of *inc* balancing reserve capacity for all hours in Spring Months of each fiscal year in the Rate Period. Bonneville is not obligated to provide more than 910 MW of *inc* balancing reserve capacity (subject to adjustment by the Mid-Rate Period Adjustment as described in section 8 of this Attachment 1 and Direct Assignment Charges as described in section III, E.4 and F.4 of the ACS-16 rate schedules in Attachment 2), FCRPS-sourced or otherwise, in any hour during the Spring Months of each fiscal year in the Rate Period.

a. ***FCRPS source.*** Bonneville will provide from the FCRPS at least 400 MW of *inc* balancing reserve capacity for all hours of the Spring Months of each fiscal year in the Rate Period. To the extent Bonneville is unable to provide 400 MW of *inc* balancing reserve capacity from the FCRPS, Bonneville will attempt to, but is not obligated to, replace that capacity with third-party *inc* balancing reserve capacity purchases. In making such acquistions, Bonneville will consider previous monthly or quarterly purchases for that timeframe, the available remaining Annual Budget, the projected reserve needs and the expected impacts during the affected timeframe, and the remaining periods in the Non-Spring Months.

b. ***Refund for replacement.*** In the event Bonneville is unable to make available 400 MW of *inc* balancing reserve capacity from the FCRPS under section 5(a) above, Bonneville Power Services will issue a refund to Bonneville Transmission Services in the amount of $0.29/kW/day for the planned capacity that was not available from the FCRPS. The total amount refunded by Bonneville Power Services under this section will be added to the Annual Budget described in Section 6(a) of this Attachment 1.

c. ***Balancing Reserve Capacity purchases on Forward Basis***. Bonneville shall attempt to acquire at least 200 MW of *inc* balancing reserve capacity (in addition to 400 MW from the FCRPS) for April, May, and June in each fiscal year at least 25 days in advance or such longer period as Bonneville determines is practicable ("Forward Basis"), except that Bonnevillle is not obligated to make any individual purchase of balancing reserve capacity if the price for that purchase would exceed $0.29/kW/day. Nothing in this subsection limits Bonneville's right to provide balancing reserve capacity on a Forward Basis from the FCRPS at a cost of $0.29/kW/day funded from the Annual Budget before making any purchases from third parties.

d. ***FCRPS source before third party source.*** Before attempting to acquire *inc* balancing reserve capacity from a third party, Bonnevillle will assess whether the balancing reserve capacity required to meet its forecast need is available from the FCRPS. If Bonneville determines that more than 400 MW of *inc* balancing reserve capacity is available from the FCRPS, Bonneville shall provide that *inc* balancing reserve capacity from the FCRPS. In that instance, the cost of Spring Month *inc* balancing reserve capacity that Bonneville provides from the FCRPS above 400 MW will be at a cost of $0.29/kW/day and will be funded by the Annual Budget.

e. ***Third Party Source.*** If Bonneville determines that the FCRPS is not capable of producing more than 400 MW of *inc* balancing reserve capacity as provided in section 5(a) above at the time of the purchase request, then Bonneville shall attempt to purchase, based on various factors as listed below in this section 5(e), up to 510 MW of *inc* balancing reserve capacity from third parties for imbalance service in the Spring Months and fund such purchases with the Annual Budget subject to section 6 below. In making such acquistions, Bonneville will consider previous monthly or quarterly purchases for that timeframe, the available remaining Annual Budget, the projected reserve needs and the expected impacts during the affected timeframe, and the remaining periods in the Spring Months.

6. **Annual Budget for the FY 2016-2017 rate period.**

a. Bonneville shall establish a base $17.5 million annual budget ("Annual Budget") to fund the purposes set forth in section 6(b) below during the Rate Period. Any unspent funds from the FY 2016 Annual Budget will increase the FY 2017 Annual Budget for the purposes in this section 6. Any unspent funds in FY 2017 will remain with Transmission Services.

b. The Annual Budget is subject to adjustment as provided for in this Attachment 1. The FY 2017 Annual Budget is subject to reduction by the Mid-Rate Period Adjustment as described in section 8 and as described in section 16 below. Bonneville will use the Annual Budget to fund (1) the purchase of 10 MW of *inc* balancing reserve capacity (subject to adjustment by the Mid-Rate Period Adjustment) during the Non-Spring Months (see Section 4(b) above); (2) the cost of any *inc* balancing reserve capacity that Bonneville provides from the FCRPS above 400 MW during the Spring Months (see section 5(d) above); (3) purchases of *inc* balancing reserve capacity from third parties during the Spring Months; (4) any differences between the energy cost Bonneville incurs for deployment of third-party capacity and the hourly energy index price in the Pacific Northwest; and (5) replacement *inc* balancing reserve capacity Bonneville purchased from third parties under Sections 4(a)(1) and 5(a) of this Attachment 1.

c. When the Annual Budget is exhausted, Bonneville shall treat any energy costs of third-party balancing reserve capacity deployment that exceed the hourly energy index price in the Pacific Northwest as a Transmission Services cost.

d. Bonneville will post quarterly reports on its OASIS website describing: (1) the types and amounts of expenditures made in the previous quarter and the status of the Annual Budget; and (2) any instances during the previous quarter in which Bonneville committed to provide *inc* balancing reserve capacity from the FCRPS, as contemplated by Sections 4(a)(1) and 5(a) of this Attachment 1, and was subsequently unable to do so.

e. The Annual Budget is subject to increase in an amount equivalent to the revenue received from the $0.20/kW-nameplate/mo fee (section III.E.2.a.(4)(d) of the ACS-16 rate schedules in Attachment 2) paid by customers that elect to opt out of the Intentional Deviation Penalty Charge.

f. If Bonneville anticipates or observes a total of 120 hours in which a curtailment event occurs due to lack of *inc* balancing reserve capacity in the Spring Months of FY 2016 before the expiration of such Spring Months or if Bonneville determines that it needs to spend additional funds above the Annual Budget for FY 2016 to support the *inc* imbalance service in FY 2016 Spring Months, Bonneville may use up to $5 million of the FY 2017 Annual Budget to support the *inc* imbalance service provided during the FY 2016 Spring Months. In such event, Bonneville shall inform all parties of the issue(s) causing the decreased quality of imbalance service and will convene a stakeholder process to discuss approaches to provide the quality of imbalance service intended in this settlement for the FY 2017 Spring Months without violating any other terms and conditions of this settlement. Nothwithstanding section 6(b) above, Bonneville will restore the FY 2017 Annual Budget by the amount of the FY 2017 Annual Budget used to support the *inc* imbalance service provided during the FY 2016 Spring Months, not to exceed $5 million. Under this approach, Bonneville shall treat any increase to the Annual Budget as a transmission cost.

g. To the extent Bonneville does not use all of the $5 million described in section 6(f) above to restore the FY 2017 Annual Budget, Bonneville may use the remainder of those funds to supplement the FY 2017 Annual Budget if Bonneville anticipates or observes a total of 120 hours in which a curtailment event occurs due to lack of *inc* balancing reserve capacity in the Spring Months of FY 2017 before the expiration of such Spring Months or if Bonneville determines that it needs to spend additional funds above the Annual Budget for FY 2017 to support the *inc* imbalance service in FY 2017 Spring Months. In such event, Bonneville shall inform all parties of the issue(s) causing the decreased quality of imbalance service and will convene a stakeholder process to discuss approaches to provide the quality of imbalance service intended in this settlement for the remaining FY 2017 Spring Months without violating any other terms and conditions of this settlement. Bonneville shall treat any increase to the Annual Budget described in this section 6(g) as a transmission cost.

h. If the Annual Budget is exhausted in either fiscal year of the Rate Period, Bonneville will not be obligated to purchase any additional *inc* balancing reserve capacity in the fiscal year, except as described in Direct Assignment Charges, section III, E.4 and F.4 of the ACS-16 rate schedules in Attachment 2.

i. Nothing in this Agreement is intended to limit Bonneville's right to purchase additional balancing reserve capacity for system reliability purposes.

7. **Mid-Rate Period Election.**

a. Bonneville will offer VERBS customers a mid-Rate Period election opportunity to change their scheduling elections to a superior scheduling commitment, elect self-supply, use Dynamic Transfer Capability ("DTC") to transfer out of Bonneville's balancing authority area (subject to implementation of necessary arrangements, which shall not be unreasonably delayed), or elect to participate in Customer Supplied Generation Imbalance ("CSGI"). VERBS customers that elect self-supply, use of DTC to transfer out of Bonneville's balancing authority area, or CSGI must provide Bonneville with written notice to change service by close of business on April 4, 2016, and the effective date of the election change will be October 1, 2016. Customers that elect to change their scheduling election to a superior scheduling commitment must provide Bonneville with written notice to change service by close of business on June 1, 2016, and the effective date of the election change will be October 1, 2016.

b. The election changes in 7(a) above will be capped at 800 MW of nameplate movement offered on a first-come first-served basis. The expansion of self-supply, including the CSGI program, and DTC will be limited to a total of 300 MW and will count toward the 800 MW cap on nameplate movement. Bonneville will use two adjustments to calculate the nameplate movement equivalent when a customer switches from CSGI to either (1) self-supply in accordance with Bonneville's self-supply Business Practice, as revised, or (2) use DTC to transfer out of Bonneville's balancing authority area. The amount of nameplate that switches from CSGI will be multiplied by 21% for purposes of calculating the impact on the 300 MW cap on nameplate movement. The amount of nameplate that switches from CSGI will be multiplied by 53% for purposes of calculating the impact on the 800 MW cap on nameplate movement and amount of nameplate that changed elections as used in section 8 below. Customers will pay the posted rates associated with their revised election choice.

8. **Mid-Rate Period Adjustment.** The Mid-Rate Period Adjustment ("Mid-Rate Period Adjustment" or "MidRPAdjustment") will apply to the second year of the Rate Period. The Mid-Rate Period Adjustment will adjust the amount of *inc* balancing reserve capacity Bonneville will provide in the Non-Spring Months in FY 2017 and the FY 2017 Annual Budget. Bonneville shall calculate the Mid-Rate Period Adjustment using the ratio of nameplate that changed elections ("Nameplate Movement") to the total amount of allowable nameplate movement (800 MW) under section 7 above. The Mid-Rate Period Adjustment will equal:

$$MidRPAdjustment = \frac{Nameplate\ Movement}{800\ MW}$$

a. The Mid-Rate Period Adjustment may reduce the 910 MW of *inc* balancing reserve capacity requirement described in section 4, *Inc* Reserve (Non-Spring Months), above. The second year amount will equal:

$$910\ MW - [10\ MW\ \times MidRPAdjustment]$$

b. The Mid-Rate Period Adjustment may reduce the FY 2017 Annual Budget. The FY 2017 Annual Budget will equal:

$$\$17.5\ million - [\$900{,}000\ \times MidRPAdjustment]$$

9. **Scheduling Elections.** Bonneville shall offer VERBS customers a mid-Rate Period election opportunity to change their scheduling elections from a sub-hourly scheduling commitment (30/15 or 40/15) to a 30/60 committed scheduling election, which will not be subject to the Direct Assignment Charges as described in Section III, E.4 and F.4 of the ACS-16 rate schedules in Attachment 2. These election changes will be capped at 800 MW of nameplate movement offered on a first-come first-serve basis. VERBS customers must provide Bonneville with written notice to change service by close of business on April 4, 2016, and the effective date of the election change will be October 1, 2016. Customers will pay the posted rates associated with their revised election choice.

10. **Operating Practices.**

a. Bonneville shall replace Dispatcher Standing Order No. 216 with a reliability tool that applies to all non-Federal non-controlling generation—both dispatchable and variable energy resources—in Bonneville's Balancing Authority Area, except the schedule curtailment protocol will not apply to behind-the-meter generation. Bonneville will design the new reliability tool to attempt to equitably allocate curtailments among all resources that are subject to the reliability tool. Bonneville shall use reasonable efforts to provide a mechanism for multiple resources to combine their Station Control Error to take advantage of diversity benefits during balancing reserve capacity-related events. Bonneville shall not apply its automated balancing reserve capacity-related generation limitation protocol to dispatchable energy resources.

b. Bonneville shall research potential impacts that Federal dispatchable resources have on Bonneville's Balancing Authority Area net Station Control Error during *inc* reliability events and provide results to customers in spring 2015. Any material impacts discovered will be mitigated through changes in internal Bonneville business practices or modifications to implementation of balancing reserve capacity-related schedule curtailments of dispatchable and variable energy resources.

c. Bonneville shall conduct a stakeholder process through the Joint Operating Committee or other public forum to discuss Bonneville's proposed reliability tool and provide an opportunity for customers to comment on the reliability tool.

11. **Intentional Deviation.** One Hundred Percent (100%) of the revenue that Bonneville receives through the Intentional Deviation Charge shall remain with Transmission Services. Revenue that Bonneville receives from Energy Imbalance ("EIrev"), Generation Imbalance ("GIrev"), and Persistent Deviation

("PDrev") will be split between Power Services and Transmission Services. Power Services' share ("PSshare") in such revenue will equal:

$$PSshare = [EIrev + GIrev + PDrev] - \sum Hr3PSD \times HrIndex$$

Where:

*Hr3PSD* = The MWh amount of third-party *inc* balancing reserve capacity deployed each hour.

*HrIndex* = The hourly energy index in the Pacific Northwest during the hour when the third-party *inc* balancing reserve capacity was deployed.

12. **Revenue Credit.** Power Services will receive a payment of at least $50,834,800 each year of the Rate Period from Transmission Services in exchange for planned balancing reserve capacity provided from the FCRPS as described in sections 3, 4 and 5 above. Power Services will set power rates with the revenue credit expectation that it will receive $54,834,800 from Transmission Services. This section 12 is subject to section 16(b) below.

13. **Rate Period Initiative.**

a. Bonneville and customers will establish a Solar Task Force to discuss transmission and integration issues related to solar energy development in Bonneville's Balancing Authority Area, including the discussion of customer proposals on Solar VERBS rate design.

b. Bonneville shall hold a workshop in October of 2014 to discuss with customers the potential for an acquisition strategy for the Spring Months that includes long-term purchases of *inc* balancing reserve capacity that are 6 to 9 months in advance of the Spring Months.

14. **Other charges.** Pursuant to the conditions under Direct Assignment Charges, section III, E.4 and F.4 of the ACS-16 rate schedules in Attachment 2, Bonneville will use the following table to assess the additional amount of *inc* balancing reserve capacity.

| From Service in Row to Service in Column | Direct Assignment Charges. Additional Amount of *Inc* Capacity on Nameplate | | | | | | |
|---|---|---|---|---|---|---|---|
| | **30/15** | **40/15** | **30/60** | **Uncommitted** | **Solar** | **DERBS** | **CSGI** |
| **30/15** | N/A | 2.5% | 5.2% | 8.1% | N/A | N/A | N/A |
| **40/15** | N/A | N/A | 2.7% | 5.6% | N/A | N/A | N/A |
| **30/60** | N/A | N/A | N/A | 2.9% | N/A | N/A | N/A |
| **CSGI** | 3.3% | 5.8% | 8.5% | 11.4% | N/A | N/A | N/A |
| **No Service** | 8.3% | 10.8% | 13.5% | 16.4% | 2.4% | 0.5% | 5.0 % |

15. **Inter-Business Line Allocations.** Bonneville and Assenting Parties agree to the Inter-Business Line Allocations described in Attachment 3.

16. **Risk Mitigation Tools.**

a. ***CRAC, DDC, and NFB Mechanisms.*** 8.2 percent of the Cost Recovery Adjustment Clause, Dividend Distribution Clause, and NFB Mechanisms (the NFB Adjustment and the Emergency NFB Surcharge) will apply to the balancing reserve capacity-based rates specified in Section II.H of the General Rate Schedule Provisions in Attachment 2.

b. ***Planned Net Revenues for Risk.*** The rates under this Agreement are based on the assumption that Bonneville's power revenue requirement will not contain Planned Net Revenues for Risk or any risk mitigation tool that: (1) supports Bonneville's power Treasury Payment Probability; (2) supports Bonneville's credit rating; or (3) enhances Bonneville's financial strength or financial standing by improving Bonneville's cash position ("Risk Mitigation Tool" or "RMT"). If Bonneville adopts any RMT in its overall power revenue requirement as determined in the BP-16 Final Proposal, then the following will apply:

(i) The Annual Budget will decrease by 4.27% multiplied by the RMT.

(ii) Notwithstanding section 12 above, Power Services will receive a payment of at least $\$50{,}834{,}800 + [8.2\% \times RMT]$ each year of the Rate Period from Transmission Services in exchange for planned balancing reserve capacity provided from the FCRPS as described in sections 3, 4 and 5 above. Power Services will set power rates with the revenue credit expectation that it will receive $\$54{,}834{,}800 + [8.2\% \times RMT]$ from Transmission Services.

(iii) The ancillary and control area service rates in Attachment 2, ACS-16, sections II and III, will increase to collect each rate's percentage share of the $[8.2\% \times RMT]$ amount based on the following table:

| **Rates** | **Percent Share of RMT** |
|---|---|
| Regulating and Frequency Response Service | 0.46% |
| Dispatchable Energy Resource Balancing Service (DERBS) *Inc* | 0.09% |
| DERBS *Dec* | 0.09% |
| Operating Reserve - Spinning | 1.65% |
| Operating Reserve – Spinning default | Function of Operating Reserves Spinning (115%) |
| Operating Reserve - Supplemental | 1.65% |
| Operating Reserve – Supplemental default | Function of Operating Reserves Supplemental (115%) |

17. **Official Forecast.** Bonneville will attempt to provide the results of the Super Forecast Methodology to

customers at 15 minutes or earlier after the top of the hour, but will commit to provide the results of the Super Forecast Methodology to customers no later than 20 minutes after the top of the hour.

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# ACS-~~14~~16
# ANCILLARY AND CONTROL AREA SERVICES RATES

## SECTION I. AVAILABILITY

This schedule supersedes the ACS-~~12~~ 14 rate schedule. It is available to all Transmission Customers taking service under the Open Access Transmission Tariff and other contractual arrangements. This schedule also is available for transmission service of a similar nature that may be ordered by the Federal Energy Regulatory Commission (FERC) pursuant to sections 211 and 212 of the Federal Power Act (16 U.S.C. §§ 824j and 824k). Service under this schedule is subject to BPA's General Rate Schedule Provisions (GRSPs), which follow the rate schedules in this document.

## A. ANCILLARY SERVICES

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission Provider is required to provide, and the Transmission Customer is required to purchase, the following Ancillary Services: (a) Scheduling, System Control, and Dispatch, and (b) Reactive Supply and Voltage Control from Generation Sources.

In addition, the Transmission Provider is required to offer to provide the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area: (a) Regulation and Frequency Response, and (b) Energy Imbalance. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Provider is also required to offer to provide (a) Operating Reserve – Spinning and (b) Operating Reserve – Supplemental to the Transmission Customer in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer taking these services in the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply in accordance with applicable NERC, WECC, and NWPP standards.

The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

**Ancillary Services available under this rate schedule are:**

1. Scheduling, System Control, and Dispatch Service
2. Reactive Supply and Voltage Control from Generation Sources Service
3. Regulation and Frequency Response Service
4. Energy Imbalance Service
5. Operating Reserve – Spinning Reserve Service
6. Operating Reserve – Supplemental Reserve Service

## B. CONTROL AREA SERVICES

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all of its Reliability Obligations through the purchase or self-provision of Ancillary Services must purchase Control Area Services to meet its Reliability Obligations. Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations but do not have transmission agreements with BPA. Reliability Obligations for resources or loads in the BPA Control Area shall be determined consistent with the applicable NERC, WECC, and NWPP standards.

**Control Area Services available under this rate schedule are:**

1. Regulation and Frequency Response Service
2. Generation Imbalance Service
3. Operating Reserve – Spinning Reserve Service
4. Operating Reserve – Supplemental Reserve Service
5. Variable Energy Resource Balancing Service
6. Dispatchable Energy Resource Balancing Service

## SECTION II. ANCILLARY SERVICE RATES

### C. REGULATION AND FREQUENCY RESPONSE SERVICE

The rate below for Regulation and Frequency Response (RFR) Service applies to Transmission Customers serving loads in the BPA Control Area. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

#### 1. RATE

The rate shall not exceed 0.12 mills per kilowatthour.

#### 2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

## D. ENERGY IMBALANCE SERVICE

The rates below apply to Transmission Customers taking Energy Imbalance Service from BPA. Energy Imbalance Service is taken when there is a difference between scheduled and actual energy delivered to a load in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis, and accounting for intra-hour schedules will be on the customer's shortest~~same basis as the intra-hour~~ scheduling period in the hour.

### 1. RATES

#### a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to (i) ± 1.5 percent of the scheduled amount of energy, or (ii) ± 2 MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net Energy Imbalance (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

(1) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is greater than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.

(2) When the monthly net energy (determined for HLH and LLH periods) taken by the Transmission Customer is less than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

#### b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation (i) greater than ± 1.5 percent of the scheduled amount of energy or (ii) ± 2 MW, whichever is larger in absolute value, up to and including (i) ± 7.5 percent of the scheduled amount of energy or (ii) ± 10 MW, whichever is larger in absolute value.

(1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 110 percent of BPA's incremental cost.

(2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

### c. Imbalances Within Deviation Band 3

Deviation Band 3 applies to the portion of the deviation (i) greater than ± 7.5 percent of the scheduled amount of energy, or (ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

(1) When energy taken by the Transmission Customer in a schedule period is greater than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.

(2) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

## 2. OTHER RATE PROVISIONS

### a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA will post the name of the index to be used on its OASIS Web site at least 30 days prior to its use. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual energy delivered is more than scheduled).

**b. Spill Conditions**

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual energy delivered is less than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

(1) For negative deviations (energy taken is less than the scheduled energy) within Band 1, no credit will be given.

(2) For negative deviations (energy taken is less than the scheduled energy) within Band 2, the charge is the energy index for that hour.

(3) For negative deviations (energy taken is less than the scheduled energy) within Band 3, the charge is the energy index for that hour.

**c. Persistent Deviation**

The following penalty charges shall apply to each Persistent Deviation (GRSP III.42):

(1) No credit is given when energy taken is less than the scheduled energy.

(2) When energy taken exceeds the scheduled energy, the charge is the greater of (i) 125 percent of BPA's highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (energy taken is less than the scheduled energy) that BPA determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA assesses a persistent deviation penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section II.D.1. of this ACS-~~14~~ 16 schedule.

**Reduction or Waiver of Persistent Deviation Penalty**

BPA, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if (i) the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but not limited to changing its schedule to mitigate the magnitude or duration of the deviation, or (ii) the Persistent Deviation was caused by extraordinary circumstances.

## E. OPERATING RESERVE – SPINNING RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve – Spinning Reserve Service from BPA, and to generators in the BPA Control Area for settlement of energy deliveries. Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. BPA will determine the Transmission Customer's Spinning Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

### 1. RATES

a. For customers that elect to purchase Operating Reserve –Spinning Reserve Service from BPA, the rate shall not exceed 11.40~~10.86~~ mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 13.11 ~~12.49~~mills per kilowatthour.

For energy delivered, the generator shall, as directed by BPA, either:

(1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(2) Return the energy at the times specified by BPA.

### 2. BILLING FACTORS

a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Transmission Customer's Spinning Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Spinning Reserve Requirement. ~~If the Federal Energy Regulatory Commission approves a new Spinning Reserve Requirement during the FY 2014–2015 rate period, such Spinning Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Spinning Reserve Requirement posted on its OASIS Web site accordingly.~~

b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

## F. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

The rates below apply to Transmission Customers taking Operating Reserve – Supplemental Reserve Service from BPA and to generators in the BPA Control Area for settlement of energy deliveries. Supplemental Reserve Service is available within a short period of time to serve load in the event of a system contingency. BPA will determine the Transmission Customer's Supplemental Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

### 1. RATES

a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service ~~Transmission Services~~ from BPA, the rate shall not exceed 10.45~~9.95~~ mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 12.02~~11.44~~ mills per kilowatthour.

For energy delivered, the Transmission Customer (for interruptible imports only) or the generator shall, as directed by BPA, either:

(1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(2) Return the energy at the times specified by BPA.

The Transmission Customer shall be responsible for the settlement of delivered energy associated with interruptible imports. The generator shall be responsible for the settlement of delivered energy associated with generation in the BPA Control Area.

### 2. BILLING FACTORS

a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Transmission Customer's Supplemental Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Supplemental Reserve Requirement. ~~If the Federal Energy Regulatory Commission approves a new Supplemental Reserve Requirement during the FY 2014–2015 rate period, such Supplemental Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Supplemental Reserve Requirement posted on its OASIS Web site accordingly.~~

b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

## SECTION III. CONTROL AREA SERVICE RATES

### A. REGULATION AND FREQUENCY RESPONSE SERVICE

The rate below applies to all loads in the BPA Control Area that are receiving Regulation and Frequency Response Service from the BPA Control Area, and such Regulation and Frequency Response Service is not provided for under a BPA transmission agreement. Regulation and Frequency Response Service provides the generation capability to follow the moment-to-moment variations of loads in the BPA Control Area and maintain the power system frequency at 60 Hz in conformance with NERC and WECC reliability standards.

#### 1. RATE

The rate shall not exceed 0.12 mills per kilowatthour.

#### 2. BILLING FACTOR

The Billing Factor is the customer's total load in the BPA Control Area, in kilowatthours.

## B. GENERATION IMBALANCE SERVICE

The rates below apply to generation resources in the BPA Control Area if Generation Imbalance Service is provided for in an interconnection agreement or other arrangement. Generation Imbalance Service is taken when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a scheduling period. Accounting for hourly schedules will be on an hourly basis, and accounting for intra-hour schedules will be on the customer's shortest~~on the same basis as the intra-hour~~ scheduling period in the hour.

### 1. RATES

#### a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to (i) ± 1.5 percent of the scheduled amount of energy, or (ii) ± 2 MW, whichever is larger in absolute value. BPA will maintain deviation accounts showing the net Generation Imbalance (the sum of positive and negative deviations from schedule for each period) for Heavy Load Hour (HLH) and Light Load Hour (LLH) periods. Return energy may be scheduled at any time during the month to bring the deviation account balances to zero at the end of each month. BPA will approve the hourly schedules of return energy. The customer shall make the arrangements and submit the schedule for the balancing transaction.

The following rates will be applied when a deviation balance remains at the end of the month:

(1) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is less than the energy scheduled, the charge is BPA's incremental cost based on the applicable average HLH and average LLH incremental cost for the month.

(2) When the monthly net energy (determined for HLH and LLH periods) delivered from a generation resource is greater than the energy scheduled, the credit is BPA's incremental cost based on the applicable average HLH and LLH incremental cost for the month.

#### b. Imbalances Within Deviation Band 2

Deviation Band 2 applies to the portion of the deviation (i) greater than ± 1.5 percent of the scheduled amount of energy or (ii) ± 2 MW, whichever is larger in absolute value, up to and including

(i) ± 7.5 percent of the scheduled amount of energy or (ii) ± 10 MW, whichever is larger in absolute value.

(1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 110 percent of BPA's incremental cost.

(2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 90 percent of BPA's incremental cost.

**c. Imbalances Within Deviation Band 3**

Deviation Band 3 applies to the portion of the deviation (i) greater than ± 7.5 percent of the scheduled amount of energy, or (ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

(1) When energy delivered in a schedule period from the generation resource is less than the energy scheduled, the charge is 125 percent of BPA's highest incremental cost that occurs during that day. The highest daily incremental cost shall be determined separately for HLH and LLH.

(2) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 75 percent of BPA's lowest incremental cost that occurs during that day. The lowest daily incremental cost shall be determined separately for HLH and LLH.

## 2. OTHER RATE PROVISIONS

### a. BPA Incremental Cost

BPA's incremental cost will be based on an hourly energy index in the Pacific Northwest. If no adequate hourly index exists, an alternative index will be used. BPA will post the name of the index to be used on its OASIS Web site at least 30 days prior to its use. BPA will not change the index more often than once per year unless BPA determines that the existing index is no longer a reliable price index.

For any hour(s) that the energy index is negative, no credit is given for positive deviations (actual generation less than scheduled).

**b. Spill Conditions**

For any day that the Federal System is in a Spill Condition, no credit is given for negative deviations (actual generation greater than scheduled) for any period of that day.

If the energy index is negative in any hour that the Federal System is in a Spill Condition:

(1) For negative deviations (actual generation greater than scheduled) within Band 1, no credit will be given.

(2) For negative deviations (actual generation greater than scheduled) within Band 2, the charge is the energy index for that hour.

(3) For negative deviations (actual generation greater than scheduled) within Band 3, the charge is the energy index for that hour.

**c. Persistent Deviation for Generation**

Persistent Deviation for generation applies to (i) Dispatchable Energy Resources operating in the BPA Balancing Authority Area and (ii) Variable Energy Resources operating in the BPA Balancing Authority Area that are not subject to the Intentional Deviation Penalty Charge specified in GRSP II.I.

The following penalty charges shall apply to each Persistent Deviation (GRSP III.42):

No credit is given for negative deviations (actual generation greater than scheduled) for any hour(s) that the imbalance is a Persistent Deviation (as determined by BPA).

For positive deviations (actual generation less than scheduled) that are determined by BPA to be Persistent Deviations, the charge is the greater of (i) 125 percent of BPA's highest incremental cost that occurs during that day, or (ii) 100 mills per kilowatthour.

If the energy index is negative in any hour(s) in which there is a negative deviation (actual generation greater than scheduled) that BPA determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA assesses a Persistent Deviation Penalty charge in any scheduled period for a positive deviation, BPA will not also assess a charge pursuant to section ~~III.B.~~1~~.~~ of this ACS-16~~14~~ Generation Imbalance Service rate schedule.
~~Customers participating in committed scheduling to receive (i) BPA's 30-minute signal for each 15-minute schedule period (30/15 committed scheduling), each 30-minute schedule period (30/30 committed scheduling), or each 60-minute schedule period (30/60 committed scheduling), or (ii) BPA's 40-minute signal for each 15-minute schedule period (40/15 committed scheduling), and that submit schedules that are consistent with or result in less imbalance for the committed scheduled period are exempt from the Persistent Deviation penalty charge.~~

For V~~v~~ariable E~~e~~nergy R~~r~~esources (wind and solar resources), BPA will remove specific scheduled periods for billing purposes from a ~~p~~Persistent ~~d~~Deviation event when the deviation is equal to or less than the deviation that would result from 30-minute persistence scheduling for those scheduled periods.

New generation resources undergoing testing before commercial operation are exempt from the Persistent Deviation penalty charge for up to 90 days.

**Reduction or Waiver of Persistent Deviation Penalty**

BPA, at its sole discretion, may waive all or part of the Persistent Deviation penalty charge if (a) the customer took mitigating action(s) to avoid or limit the Persistent Deviation, including but not limited to changing its schedule to mitigate the magnitude or duration of the deviation, or (b) the Persistent Deviation was caused by extraordinary circumstances.

**d. No Credit for Negative Deviations During Curtailments**

No credit is provided for negative deviations (actual generation greater than schedules) during scheduling periods when a schedule from a generator is curtailed.

**e. Exemption from Deviation Band 2**

The 10 percent penalty charge under section 1.b., Imbalances Within Deviation Band 2, will not apply to customers participating in a committed 15-minute scheduling program in accordance with~~the shortest scheduling period available for committed scheduling~~ the ACS-16 Variable Energy Resources Balancing Service rates, section III.E.2.a.(2) and (3).

**f. Exemptions from Deviation Band 3**

The following resources are not subject to Deviation Band 3:

(1) wind resources
(2) solar resources
(3) new generation resources undergoing testing before commercial operation for up to 90 days

Unless otherwise stated in this section 2, all deviations greater than ± 1.5 percent or ± 2 MW will be charged consistent with section 1.b., Imbalances Within Deviation Band 2.

## C. OPERATING RESERVE – SPINNING RESERVE SERVICE

Operating Reserve – Spinning Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA and such Spinning Reserve Service is not provided for under a BPA transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC, and NWPP standards. BPA will determine the ~~Transmission~~Control Area Service Customer's Spinning Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

### 1. RATES

a. For customers that elect to purchase Operating Reserve – Spinning Reserves from BPA, the rate shall not exceed 11.40~~10.86~~ mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Spinning Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 13.11~~12.49~~ mills per kilowatthour.

For energy delivered, the customer shall, as directed by BPA, either:

(1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(2) Return the energy at the times specified by BPA.

### 2. BILLING FACTORS

a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Spinning Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Spinning Reserve Requirement. ~~If the Federal Energy Regulatory Commission approves a new Spinning Reserve Requirement during the FY 2014–2015 rate period, such Spinning Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Spinning Reserves Requirement posted on its OASIS Web site accordingly.~~

b. The Billing Factor for energy delivered when Spinning Reserve Service is called upon is the energy delivered, in kilowatthours.

## D. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

Operating Reserve – Supplemental Reserve Service must be purchased by a party with generation in the BPA Control Area that is receiving this service from BPA, and such Supplemental Reserve Service is not provided for under a BPA transmission agreement. Service is being received if there are no other qualifying resources providing this required reserve service in conformance with NERC, WECC, and NWPP standards. BPA will determine the ~~Transmission~~Control Area Service Customer's Supplemental Reserve Requirement in accordance with applicable NERC, WECC, and NWPP standards.

### 1. RATES

a. For customers that elect to purchase Operating Reserve – Supplemental Reserve Service from BPA, the rate shall not exceed 10.45~~9.95~~ mills per kilowatthour.

b. For customers that are required to purchase Operating Reserve – Supplemental Reserve Service from BPA because they defaulted on their self-supply or third-party supply obligations, the rate shall be 12.02~~11.44~~ mills per kilowatthour.

For energy delivered, the customer shall, as directed by BPA, either:

(1) Purchase the energy at the hourly market index price, but not less than zero, applicable at the time of occurrence, or

(2) Return the energy at the times specified by BPA.

### 2. BILLING FACTORS

a. The Billing Factor for the rates specified in sections 1.a. and 1.b. is the Supplemental Reserve Requirement determined in accordance with applicable NERC, WECC and NWPP standards. BPA will post on its OASIS Web site the Supplemental Reserve Requirement. ~~If the Federal Energy Regulatory Commission approves a new Supplemental Reserve Requirement during the FY 2014–2015 rate period, such Supplemental Reserve Requirement will go into effect on the effective date set by FERC, and BPA will update the Supplemental Reserves Requirement posted on its OASIS Web site accordingly.~~

b. The Billing Factor for energy delivered when Supplemental Reserve Service is called upon is the energy delivered, in kilowatthours.

## E. VARIABLE ENERGY RESOURCE BALANCING SERVICE

### 1. APPLICABILITY

The rates contained in this rate schedule apply to all wind and solar generating facilities of 200 kW nameplate rated capacity or greater in the BPA Control Area except as provided in section 2.c. of this rate schedule.

**Variable Energy Resource Balancing Service** (“VERBS” or “Balancing Service”) ~~**Base Service (“Base Service”)**~~ is comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load), following reserves (which compensate for larger differences occurring over longer periods of time during the hour), and imbalance reserves (which compensate for differences between the generator’s schedule and the actual generation during an hour). Variable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

~~**Variable Energy Resource Balancing Service Full Service (“Full Service”)** is an optional quarterly service except as provided in section 2.c.3. BPA offers this service only upon request to Variable Energy Resource Balancing Service customers in accordance with BPA business practices. Under this Full Service option, the amount of balancing reserve capacity available to the customer under a committed scheduling Base Service option is augmented through BPA purchases of additional balancing reserve capacity.~~

~~**Variable Energy Resource Balancing Service Supplemental Service (“Supplemental Service”)** is an optional monthly service. BPA offers this service only upon request to Variable Energy Resource Balancing Service customers in accordance with BPA business practices. Purchase of this Supplemental Service augments balancing reserve capacity available to the Customer to mitigate the effects of DSO 216 curtailments on variable energy resource schedules.~~

## 2. BALANCING~~BASE~~ SERVICE FOR WIND RESOURCES

The total charge for Balancing~~Base~~ Service is the applicable ~~Base Service~~ rate in section 2.a., below, plus ~~Purchases Charges for~~ Direct Assignment Charges under section 4~~6~~ and Intentional Deviation Penalty Charges under section 5.

### a. BALANCING ~~BASE~~ SERVICE RATES

#### (1) Rate for 30/60 Committed Scheduling

This rate is applicable to customers taking Balancing~~Base~~ Service that commit to receive BPA's 30-minute signal for each 60-minute schedule period (30/60 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

| | | |
|---|---|---|
| (a) | Regulating Reserves | $0.08 per kilowatt per month |
| (b) | Following Reserves | $0.32 per kilowatt per month |
| (c) | Imbalance Reserves | $0.80 per kilowatt per month |

#### (2) Rate for 40/15 Committed Scheduling

This rate is applicable to customers taking Balancing~~Base~~ Service that commit to receive BPA's 40-minute signal for each 15-minute schedule period (40/15 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

| | | |
|---|---|---|
| (a) | Regulating Reserves | $0.08 per kilowatt per month |
| (b) | Following Reserves | $0.32 per kilowatt per month |
| (c) | Imbalance Reserves | $0.54 per kilowatt per month |

~~(3) Rate for 30/30 Committed Scheduling~~

~~This rate is applicable to customers taking Base Service that commit to receive BPA's 30-minute signal for each 30-minute schedule period (30/30 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.~~

| | | |
|---|---|---|
| ~~(a)~~ | ~~Regulating Reserves~~ | ~~$0.08 per kilowatt per month~~ |
| ~~(b)~~ | ~~Following Reserves~~ | ~~$0.32 per kilowatt per month~~ |
| ~~(c)~~ | ~~Imbalance Reserves~~ | ~~$0.47 per kilowatt per month~~ |

**(~~4~~3) Rate for 30/15 Committed Scheduling**

This rate is applicable to customers taking Balancing~~Base~~ Service that commit to receive BPA's 30-minute signal for each 15-minute schedule period (30/15 committed scheduling) and submit schedules that are consistent with the signal or that result in less imbalance for the scheduling period.

| | | |
|---|---|---|
| (a) | Regulating Reserves | $0.08 per kilowatt per month |
| (b) | Following Reserves | $0.32 per kilowatt per month |
| (c) | Imbalance Reserves | $0.33 per kilowatt per month |

**(~~5~~4) Rate for Uncommitted Scheduling**

This rate is applicable to customers taking ~~Base~~ Balancing Service that do not commit to 30/60, ~~30~~40/~~60~~ 15 or 30/~~30~~ 15 scheduling ("uncommitted scheduling").

| | | |
|---|---|---|
| (a) | Regulating Reserves | $0.08 per kilowatt per month |
| (b) | Following Reserves | $0.32 per kilowatt per month |
| (c) | Imbalance Reserves | $1.08 per kilowatt per month |

(d) Opt Out Fee
The fee for customers that opt out of the Intentional Deviation Penalty Charge (GRSP II.I) shall be $0.20 per kilowatt per month.

**b. BILLING FACTOR**

The Billing Factor for rates in section 2.a. is as follows:

(1) For each wind plant, or phase of a wind plant, that has completed installation of all units no later than the 15th of the month prior to the billing month, the billing factor in kW will be the greater of the maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.

(2) For each wind plant, or phase of a wind plant, for which some but not all units have been installed by the 15th day of the month prior to the billing month, the billing factor will be the maximum measured hourly output of the plant through the 15th day of the prior month in kW.

(3) For each wind plant, or phase of a wind plant, where none of the units have been installed on or before the 15th of the month prior to the billing month, but some units have been installed before the start of the billing month, the billing factor will be zero.

**c. EXCEPTIONS**

(1) The rates under section 2.a. above will not apply to a V~~v~~ariable E~~e~~nergy ~~r~~Resource, or portion of a V~~v~~ariable E~~e~~nergy R~~r~~esource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to the criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, the dynamic transfer of plant output out of BPA's Balancing Authority Area to another Balancing Authority Area.

(2) Individual rate components under section 2.a.(1)-(5) above will not apply to a V~~v~~ariable E~~e~~nergy R~~r~~esource, or portion of a V~~v~~ariable E~~e~~nergy ~~r~~Resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to criteria specified in BPA business practices, no later than the 15th day of the month prior to the billing month, self-supply of that component of ~~b~~Balancing ~~s~~Service, including by contractual arrangements for third-party supply.

~~(3) Application of Full Service charge to all Base Service Customers: If because of a legal challenge to DSO 216, BPA is prevented from implementing DSO 216 or is required to amend it materially, except as provided in sections 2.c. and 5 of this rate schedule, all Base Service customers shall pay the total Full Service charge in accordance with section 3 below.~~

~~**3. FULL SERVICE FOR WIND RESOURCES**~~

~~The total charge for Full Service is:~~

~~a. the applicable Base Service rate in section 2.a.(1), 2.a.(2), 2.a.(3), or 2.a.(4) plus any Purchases Charges for Direct Assignment; plus~~

~~b. Purchases Charges for Full Service under section 6.~~

**4~~3~~. ~~VARIABLE ENERGY RESOURCE~~ BALANCING SERVICE FOR SOLAR RESOURCES**

The total charge for this service is the applicable rate below, plus Direct Assignment ~~Purchases~~ Charges under section ~~6~~4 and Intentional Deviation Penalty Charges under section 5.

**a. RATES**

| | | |
|---|---|---|
| (1) | Regulating Reserves | $0.04 per kilowatt per month |
| (2) | Following Reserves | $0.17 per kilowatt per month |

**b. BILLING FACTOR**

For each solar plant that has completed installation no later than the 15th of the month prior to the billing month, the billing factor in kW will be the greater of the maximum one-hour generation or the nameplate of the plant. A unit has completed installation when it has generated and delivered power to the BPA system.

**c. EXCEPTIONS**

See section 2.c. above.

~~**5. SUPPLEMENTAL SERVICE**~~

~~**a. RATES**~~

~~The monthly Supplemental Service rate in $/MW shall equal:~~

~~Purchase Cost / Imbalance Reserve~~

~~*Where:*~~

~~Purchase Cost = The sum of all purchase costs incurred by BPA to supply Supplemental Service for the relevant number of months to customers that commit to take such service, in dollars ($).~~

~~Imbalance Reserve = The sum of all imbalance reserves purchased by BPA to supply Supplemental Service for the relevant month or months for customers that commit to take such service, in MW-months.~~

~~**b. BILLING FACTOR**~~

~~The billing factor shall be the monthly amount of reserve that the Supplemental Service customer has contractually committed to purchase.~~

~~**c. EXCEPTIONS**~~

~~None.~~

## ~~6~~4. DIRECT ASSIGNEMENT~~FORMULA PURCHASES~~ CHARGES

~~These charges will recover the cost of *inc* balancing reserve capacity purchases.~~

~~**(1) Purchases Charge for Purchases of Balancing Reserve Capacity to Support Full Service**~~

~~BPA will apply the Purchases Charge for Full Service to customers taking Full Service if BPA purchases balancing reserve capacity beyond the level of balancing reserve capacity that is made available under a committed scheduling Base Service election to meet the increased balancing reserve capacity requirements of Full Service customers.~~

~~**Purchases Charge for Full Service:**~~

~~For each Full Service customer, the monthly charge for Full Service Purchases shall be:~~

~~Full Svc $ = (Aug Cost / Svc BF) * Billing Factor~~

~~*Where:*~~

~~Full Service $ = The monthly charge for each Full Service customer for purchases of balancing reserve capacity to support the Full Service option, in $.~~

~~Aug Cost = The total costs associated with acquiring balancing reserve capacity to augment the balancing capacity needs of Full Service customers, in $/mo.~~

~~Svc BF = The sum of the billing factors, as identified in section 2.b., for the month for which the balancing reserve capacity was purchased for Variable Energy Resources that take Full Service, in kilowatts.~~

~~Billing Factor = The Variable Energy Resource billing factor, as identified in section 2.b. for the month for which the balancing reserve capacity was purchased, in kilowatts.~~

**a.~~(12)~~ ~~Purchases~~ Charge for Direct Assignment of Costs ~~to a Customer~~**

BPA shall directly assign to the customer the cost of incremental balancing reserve capacity purchases that are necessary to provide Variable Energy Resource Balancing Service to the customer if:

~~(a)~~a. the customer elected to self-supply in accordance with section 2.c. but is unable to ~~continue~~ self-supply~~ing~~ one or more components to Variable Energy Resource Balancing Service; or

~~(b)~~b. the customer has a projected generator interconnection date after FY 2017~~5~~, but chooses to interconnect during the FY 2016~~4~~–2017~~5~~ rate period; or

~~(c)~~c. the customer elected to take service under section 2.a.(1), 2.a.(2), or 2.a.(3)~~, or 2.a.(4)~~ above, but fails to conform to the committed scheduling criteria specified in BPA business practices; or

~~(d)~~d. the customer elected to take service under section 2.a.(1), 2.a.(2), or 2.a.(3)~~, or 2.a.(4)~~ above, but chooses to take a ~~Base~~ Balancing Service scheduling option with a longer scheduling period in accordance with the criteria specified in BPA business practices; or

e. the customer either elected to dynamically transfer its resource out of BPA's Balancing Authority Area or has successfully dynamically transferred its resource out of BPA's Balancing Authority Area, but chooses to keep its resource in BPA's Balancing Authority Area.

When determining the balancing reserve capacity requirement for a resource subject to direct assignment charges, BPA will round the incremental increase down to the nearest whole megawatt.

Customers that are subject to direct assignment charges will be billed for all costs incurred above $0.29 per kilowatt-day for any incremental balancing reserve capacity acquisitions. Customers billed for direct assignment charges will also be billed at the applicable VERBS rate in section 2.

## 5. INTENTIONAL DEVIATION PENALTY CHARGE

Customers taking Variable Energy Resources Balancing Service under this rate schedule are subject to the Intentional Deviation Penalty Charge specified in GRSP II.I.

## F. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE

The rate below applies to all ~~non-Federal~~ Dispatchable Energy Resources of 3 MW nameplate rated capacity or greater in the BPA Control Area except as provided in section ~~III.F.~~3 below. Dispatchable Energy Resource Balancing Service ("DERBS") is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

The total charge for service is the charge determined by applying the~~for the applicable~~ rates in section 1 below, plus ~~Purchases Charges for~~ Direct Assignment Charges in section 4 below.

### 1. RATES

The rates for Dispatchable Energy Resource Balancing Service shall not exceed:

a. Incremental Reserves = 18.15 mills per kW maximum hourly deviation

b. Decremental Reserves = 3.94 mills per kW maximum hourly deviation

### 2. BILLING FACTORS

a. The hourly billing factor for use of Incremental Reserves is the maximum of the absolute value of the five-minute average negative S~~s~~tation ~~c~~Control E~~e~~rror (under-generation), including ramp periods, that exceeds 3 MW for that hour.

b. The hourly billing factor for use of Decremental Reserves is the maximum of the five-minute average positive ~~s~~Station C~~c~~ontrol ~~e~~Error (over-generation), including ramp periods, that exceeds 3 MW for that hour.

### 3. EXCEPTIONS

a. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, that, in BPA's determination, has put in place, tested, and successfully implemented no later than the 15th day of the month prior to the billing month the dynamic transfer of plant output out of BPA's Balancing Authority Area to another Balancing Authority Area.

b. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any schedule period in which the Dispatchable Energy Resource has called on contingency reserve.

c. This rate will not apply to a Dispatchable Energy Resource, or portion of a Dispatchable Energy Resource, for any hour in which the Dispatchable Energy Resource has been ordered by BPA or a host utility within BPA's Balancing Authority Area to generate at a level different from the schedule or generation estimate that the Dispatchable Energy Resource submitted to BPA for any schedule period during that hour.

d. Five-minute average station control periods where system frequency deviates by more than 68 mHz shall be excluded from determining the maximum positive (Decremental) or negative (Incremental) value of five-minute station control error for the hour.

**4. DIRECT ASSIGNMENT CHARGES**

~~**a. Purchases Charge for Full Service**~~

~~Not applicable.~~

~~**ab. Purchases Charge for Direct Assignment of Costs to a Customer**~~

BPA shall directly assign to the customer the cost of incremental balancing reserve capacity purchases that are necessary to provide Dispatchable Energy Resource Balancing Service to the customer if:

~~(1)~~a. the ~~C~~customer elected to self-supply but is unable to ~~continue~~ self-supply~~ing~~ the Dispatchable Energy Resource Balancing Service; or

~~(2)~~b. a ~~C~~customer has a projected generator interconnection date after FY 2017~~5~~ but chooses to interconnect during the FY 2016~~4~~-2017~~5~~ rate period; ~~or~~

~~(3)~~c. a c~~C~~ustomer operating in another Balancing Authority Area chooses to dynamically transfer into the BPA Balancing Authority Area during the FY 2016~~4~~-2017~~5~~ rate period; or

d. the customer elected to dynamically transfer its resource out of BPA's balancing authority area, but chooses to keep its resource in the BPA balancing authority area.

When determining the balancing reserve capacity requirement for a resource subject to direct assignment charges, BPA will round the incremental increase down to the nearest whole megawatt.

Customers that are subject to direct assignment charges will be billed for all costs incurred above $0.29 per kilowatt-day for any incremental balancing reserve capacity acquisitions.  Customers billed for direct assignment charges will also be billed at the DERBS rates in section 1.

## SECTION IV. ADJUSTMENTS, CHARGES, AND OTHER RATE PROVISIONS

### A. RATE ADJUSTMENT DUE TO FERC ORDER UNDER FPA § 212

Customers taking service under this rate schedule are subject to the Rate Adjustment Due to FERC Order under FPA § 212 specified in GRSP II.D.

### B. RATE ADJUSTMENT DUE TO BPA POWER SERVICES ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

Customers taking Regulation and Frequency Response Service, Operating Reserve – Spinning Reserve Service, Operating Reserve – Supplemental Reserve Service, Variable Energy Resource Balancing Service, or Dispatchable Energy Resource Balancing Service under this rate schedule are subject to the Cost Recovery Adjustment Clause, Dividend Distribution Clause, and NFB Mechanisms specified in GRSP II.H.

# GENERAL RATE SCHEDULE PROVISIONS

# SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

## H. CRAC, DDC, AND NFB MECHANISMS

The Cost Recovery Adjustment Clause (CRAC), Dividend Distribution Clause (DDC), and NFB Mechanisms (the NFB Adjustment and the Emergency NFB Surcharge) are detailed in the BPA Power Rate Schedules, GRSPs II.C, II.E, and II.N.

The CRAC and the Emergency NFB Surcharge are upward adjustments to certain Power and Transmission rates. The DDC is a downward adjustment to certain Power and Transmission rates. The NFB Adjustment is an upward adjustment to the cap on the amount of incremental BPA revenue that can be generated by a CRAC during a fiscal year. Except as otherwise provided, the CRAC, DDC, and Emergency NFB Surcharge apply to the following Ancillary and Control Area Service (ACS) rate schedules:

- Regulation and Frequency Response Service
- Operating Reserve – Spinning Reserve Service
- Operating Reserve – Supplemental Reserve Service
- Variable Energy Resource Balancing Service (VERBS)

  Exception: For the VERBS rate schedule, the CRAC, DDC, and Emergency NFB Surcharge do not apply to any charge calculated under section III.E.2.a.(4), opt out fee, section III.E.~~6~~4., Direct Assignment~~Formula Purchases~~ Charges and Intentional Deviation, GRSP II.I.

- Dispatchable Energy Resource Balancing Service (DERBS)

  Exception: For the DERBS rate schedule, the CRAC, DDC, and Emergency NFB Surcharge do not apply to any charge calculated under section III.F.4., Direct Assignment~~Formula Purchases~~ Charges~~ and Intentional Deviation, GRSP II.I~~.

### 1. CUSTOMER CHARGES FOR THE ACS CRAC

The ACS CRAC Amount is the share, in dollars, of the total CRAC Amount that is to be recovered from the ACS rates specified above; the balance of the CRAC Amount is to be recovered from specified Power rates. The ACS CRAC Amount is converted to an ACS CRAC Percentage by dividing the ACS CRAC Amount by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the CRAC.

Line items will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS CRAC Percentage times each of the applicable rates times the billing factors for each rate for each customer.

## 2. CUSTOMER CREDIT FOR THE ACS DDC

The ACS DDC Amount is the share, in dollars, of the total DDC Amount that is to be distributed from the ACS rates specified above; the balance of the DDC Amount is to be distributed from specified Power rates. The ACS DDC Amount is converted to an ACS DDC Percentage by dividing the ACS DDC Amount by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the DDC.

Line items showing a credit will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS DDC Percentage times each of the applicable rates times the billing factors for each rate for each customer.

## 3. CUSTOMER CHARGES FOR THE ACS EMERGENCY NFB SURCHARGE

The ACS Surcharge amount is the share, in dollars, of the total Surcharge Amount that is to be collected from the ACS rates specified above; the balance of the Surcharge Amount is to be collected from specified Power rates. The ACS Surcharge is converted to an ACS Surcharge Percentage by dividing the ACS Surcharge by the most recent forecast of revenues for the relevant fiscal year at the ACS rates subject to the Emergency NFB Surcharge.

Line items will be added to the bills for each service during the 12 months of the applicable year by multiplying the ACS Surcharge Percentage times each of the applicable rates times the billing factors for each rate.

## 4. CRAC, DDC, AND NFB MECHANISM RATE PROVISIONS

The CRAC, DDC, and NFB Mechanism rate provisions specified in the Power Rate Schedules, GRSPs II.C, II.E, and II.N, are incorporated by reference.

## I. INTENTIONAL DEVIATION PENALTY CHARGE

### 1. APPLICABILITY

Except as otherwise provided, the Intentional Deviation Penalty Charge applies to Variable Energy Resources taking service at the ACS-16 Variable Energy Resources Balancing Service rate.

Exceptions:

a. With 90 days' notice before the start of the applicable billing month, customers taking service at the VERBS rate for uncommitted scheduling can elect to opt out of the Intentional Deviation Penalty Charge for an additional Opt Out Fee (ACS-16 VERBS rate schedule, section III.E.2.a.(4)). The opt-out election will remain in place until the customer elects to change its opt-out election with 90 days' notice before the start of the applicable billing month. Once each fiscal year, a customer can: (1) opt out of the Intentional Deviation Penalty Charge, and (2) change its opt-out election. Customers that opt out of the Intentional Deviation Penalty Charge are subject to the Persistent Deviation for Generation penalty charge as specified in the ACS-16 Generation Imbalance Service rate schedule (section III.B.2.c).

b. New Variable Energy Resources undergoing testing before commercial operation are exempt from the Intentional Deviation Penalty Charge during testing for up to 90 days.

c. Customers participating in the Customer Supplied Generation Imbalance ("CSGI") Pilot Program are not subject to the Intentional Deviation Penalty Charge.

### 2. RATE

For each Intentional Deviation event, the Intentional Deviation Penalty Charge rate shall be $100 per megawatthour (MWh).

An Intentional Deviation event occurs when:

ABS(Intentional Deviation Measurement Value – Resource Schedule) > 1

(See section 3, below, for definition of terms.)

### 3. BILLING FACTOR

The Billing Factor in MWh shall be:

ABS(Intentional Deviation Measurement Value – Resource Schedule) – 1

*Multiplied by*

Minutes of schedule divided by 60 minutes

*Where:*

ABS = the absolute value of the term in parentheses.

Intentional Deviation Measurement Value = one of the following three values:

1) for wind generating customers taking VERBS at a committed scheduling rate (VERBS rate schedule, sections 2.a.(1)-(3)), the applicable committed schedule value provided by BPA;

2) for wind generating customers taking VERBS at the uncommitted scheduling rate (VERBS rate schedule, section 2.a.(4)), the 40-minute forecast schedule value produced by the Super Forecast Methodology; or

3) for solar generating customers taking VERBS (section 3), the matrix forecast schedule value or applicable committed schedule value provided by BPA.

Resource Schedule = for each wind or solar resource, the amount in megawatts of generation that is scheduled by the customer for the scheduling period.

Minutes of schedule = 15 if a 15-minute schedule, 30 if a 30-minute schedule, or 60 if a 60-minute schedule.

## 4. OTHER PROVISIONS

**Exemption from Intentional Deviation Penalty Charge**

A customer that schedules its resource to a value other than the Intentional Deviation Measurement Value is exempt from the Intentional Deviation Penalty Charge for a scheduling period if

ABS(Station Control Error) ≤ ABS(Intentional Deviation Measurement Value Error) + 1 MW

*Where:*

ABS(Intentional Deviation Measurement Value Error) = the absolute value of the Station Control Error that *would have resulted* from a schedule that was set equal to the resource's applicable Intentional Deviation Measurement Value.

# GRSP SECTION III. DEFINITIONS

(Note: Numbering of definitions may change for final rate proposal.)

## 1. ANCILLARY SERVICES

Ancillary Services are those services that are necessary to support the transmission of energy from resources to loads while maintaining reliable operation of BPA's Transmission System in accordance with Good Utility Practice. Ancillary Services include:

a. Scheduling, System Control, and Dispatch
b. Reactive Supply and Voltage Control from Generation Sources
c. Regulation and Frequency Response
d. Energy Imbalance
e. Operating Reserve – Spinning
f. Operating Reserve – Supplemental

Ancillary Services are available under the ACS rate schedule.

## 2. BALANCING AUTHORITY AREA

See definition in Control Area.

## 4. CONTROL AREA

A Control Area (also known as Balancing Authority Area) is an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

a. match at all times the power output of the generators within the electric power system(s) and the import of energy from entities outside the electric power system(s) with the load within the electric power system(s) and the export of energy to entities outside the electric power system(s);

b. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

c. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

d. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

## 5. CONTROL AREA SERVICES

Control Area Services are available to meet the Reliability Obligations of a party with resources or loads in the BPA Control Area. A party that is not satisfying all of its Reliability Obligations through the purchase or self-provision of Ancillary Services may purchase Control Area Services to meet its Reliability Obligations. Control Area Services are also available to parties with resources or loads in the BPA Control Area that have Reliability Obligations but do not have a transmission agreement with BPA. Reliability Obligations for resources or loads in the BPA Control Area are determined by applying the North American Electric Reliability Council (NERC), Western Electricity Coordinating Council (WECC), and Northwest Power Pool (NWPP) reliability criteria. Control Area Services include, without limitation:

a. Regulation and Frequency Response Service
b. Generation Imbalance Service
c. Operating Reserve – Spinning Reserve Service
d. Operating Reserve – Supplemental Reserve Service
e. Variable Energy Resource Balancing Service
f. Dispatchable Energy Resource Balancing Service

## 9. DISPATCHABLE ENERGY RESOURCE

For purposes of the ACS rate schedule~~Dispatchable Energy Resource Balancing Service~~, a Dispatchable Energy Resource is any non-Federal thermally based generating resource that schedules its output or is included in BPA's Automatic Generation Control system.

## 10. DISPATCHABLE ENERGY RESOURCE BALANCING SERVICE

Dispatchable Energy Resource Balancing Service (DERBS) is a Control Area Service that provides imbalance reserves (which compensate for differences between a thermal generator's schedule and the actual generation during an hour). DERBS is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

## 11. DYNAMIC SCHEDULE

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

## 12. DYNAMIC TRANSFER

See definition in Dynamic Transfer Operating and Scheduling Business Practice.

## 14. ENERGY IMBALANCE SERVICE

Energy Imbalance Service is provided when a difference occurs between the scheduled and actual delivery of energy to a load located within a Control Area. BPA must offer this service when the transmission service is used to serve load within BPA's Control Area. The Transmission Customer must either purchase this service from BPA or make alternative comparable arrangements specified in the Transmission Customer's Service Agreement to satisfy its Energy Imbalance Service obligation.

## 17. GENERATION IMBALANCE

Generation Imbalance is the difference between the scheduled amount and actual delivered amount of energy from a generation resource in the BPA Control Area.

## 18. GENERATION IMBALANCE SERVICE

Generation Imbalance Service is provided when there is a difference between scheduled and actual energy delivered from generation resources in the BPA Control Area during a schedule period.

## 39. OPERATING RESERVE – SPINNING RESERVE SERVICE

Operating Reserve – Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. BPA must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer or Control Area Service Customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. The Transmission Customer's or Control Area Service Customer's obligation is determined consistent with NERC, WECC, and NWPP criteria.

## 40. OPERATING RESERVE – SUPPLEMENTAL RESERVE SERVICE

Operating Reserve – Supplemental Reserve Service is needed to serve load in the event of a system contingency. It is not available immediately to serve load, but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation, or by interruptible load. BPA must offer this service in accordance with applicable NERC, WECC, and NWPP standards. The Transmission Customer or Control Area Service Customer must either purchase this service from BPA or make alternative but comparable arrangements to satisfy its Supplemental Reserve Service obligation. The Transmission Customer's or Control Area Service Customer's obligation is determined consistent with NERC, WECC, and NWPP criteria.

## 41. OPERATING RESERVE REQUIREMENT

Operating Reserve Requirement is a party's total operating reserve obligation (spinning and supplemental) to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserves associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

## 42. PERSISTENT DEVIATION

A Persistent Deviation event is one or more of the following:

a. **For Generation Imbalance Service only:**

All hours or scheduled periods in which either a negative deviation (actual generation greater than scheduled) or positive deviation (generation is less than scheduled) exceeds:

(1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;

(2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;

(3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or

(4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

b. **For Energy Imbalance Service only:**

All hours or scheduled periods in which either a negative deviation (energy taken is less than the scheduled energy) or positive deviation (energy taken is greater than energy scheduled) exceeds:

(1) both 15 percent of the schedule and 20 MW in each scheduled period for three consecutive hours or more in the same direction;

(2) both 7.5 percent of the schedule and 10 MW in each scheduled period for six consecutive hours or more in the same direction;

(3) both 1.5 percent of the schedule and 5 MW in each scheduled period for twelve consecutive hours or more in the same direction; or

(4) both 1.5 percent of the schedule and 2 MW in each scheduled period for twenty-four consecutive hours or more in the same direction.

c. A pattern of under- or over-delivery or over- or under-use of energy occurs generally or at specific times of day.

**50. REGULATION AND FREQUENCY RESPONSE SERVICE**

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generation control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with BPA. BPA must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from BPA or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation.

**62. SPILL CONDITION**

Spill Condition, for the purpose of determining credit or payment for Deviations under the Energy Imbalance and Generation Imbalance rates, exists when spill physically occurs on the BPA system due to lack of load or market. Spill due to lack of load or market typically occurs during periods of high flows or flood control implementation, but can also occur at other times. Discretionary spill, where BPA may choose whether to spill, does not constitute a Spill Condition. Spill for fish is included in discretionary spill and is not a Spill Condition.

**63. SPINNING RESERVE REQUIREMENT**

Spinning Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve – Spinning Reserve Service associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

**64. STATION CONTROL ERROR**

Station Control Error is the difference between the amount of generation scheduled from a generator and the actual output of that generator.

## 65. SUPER FORECAST METHODOLOGY

The Super Forecast Methodology is an algorithm that selects the best forecast for predicting generation from a particular project based on historical performance. The customer may submit its forecast for use by the methodology and its forecast will be used if it out-performs the BPA forecast vendors. BPA will deliver the model results to the customer each scheduling period electronically.

## 66. SUPPLEMENTAL RESERVE REQUIREMENT

Supplemental Reserve Requirement is a portion of a party's Operating Reserve Requirement to the BPA Control Area. A party is responsible for purchasing or otherwise providing Operating Reserve – Supplemental Reserve Service associated with its transactions that impose a reserve obligation on the BPA Control Area.

The specific amounts required are determined consistent with NERC Policies, the NWPP Operating Manual, "Contingency Reserve Sharing Procedure," and WECC Standards.

## 72. VARIABLE ENERGY RESOURCE

A Variable Energy Resource is an electric generating facility that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator. This includes, for example, wind, solar photovoltaic, and hydrokinetic generating facilities. This does not include, for example, hydroelectric, geothermal, biomass, or process steam generating facilities.

## 73. VARIABLE ENERGY RESOURCE BALANCING SERVICE

Variable Energy Resource Balancing Service (VERBS) is a Control Area Service comprised of three components: regulating reserves (which compensate for moment-to-moment differences between generation and load); following reserves (which compensate for larger differences occurring over longer periods of time during the hour); and imbalance reserves (which compensate for differences between the generator's schedule and the actual generation during an hour). Variable Energy Resource Balancing Service is required to help maintain the power system frequency at 60 Hz and to conform to NERC and WECC reliability standards.

## Attachment 3
## Inter-Business Line Allocations

| | A | B | C | D | E |
|---|---|---|---|---|---|
| | Generation Inputs | Rate or Cost | Unit | Annual Average for FY 2016-2017 Forecast Quantity | Annual Average for FY 2016-2017 Revenue Forecast |
| 1 | Regulating Reserve | 0.12 | mills/kWh/month | 5,921 | $ 6,224,155 |
| 2 | Variable Energy Resource Balancing Service Reserve - 30/60 Committed Scheduling | $ 1.20 | $/kW/month | 556 | $ 8,006,400 |
| 3 | Variable Energy Resource Balancing Service Reserve - 40/15 Committed Scheduling | $ 0.94 | $/kW/month | - | $ - |
| 4 | Variable Energy Resource Balancing Service Reserve - 30/15 Committed Scheduling | $ 0.73 | $/kW/month | 762 | $ 6,675,120 |
| 5 | Variable Energy Resource Balancing Service Reserve - Uncommitted Scheduling | $ 1.48 | $/kW/month | 2,100 | $ 37,296,000 |
| 6 | Variable Energy Resource Balancing Service Reserve - Self-Supply of Generation Imbalance | $ 0.40 | $/kW/month | 1,390 | $ 6,672,000 |
| 7 | Variable Energy Resource Balancing Service for Solar | $ 0.21 | $/kW/month | 34 | $ 85,680 |
| 8 | Dispatchable Energy Resource Balancing Service Reserve *inc* | 18.15 | mills/kW/month | 113,439 | $ 2,058,918 |
| 9 | Dispatchable Energy Resource Balancing Service Reserve *dec* | 3.94 | mills/kW/month | 99,133 | $ 390,584 |
| 10 | Dispatchable Energy Resource Balancing Service Reserve Total | | | | $ 2,449,502 |
| 11 | Settlement Annual Budget Adjustment | | | | $ (15,200,000) |
| 12 | Rounding Adjustment | | | | $ 25,943 |
| 13 | Adjustment for Settlement for Supplying Only 900 MW *dec* Balancing Reserve Capacity | | | | $ (1,400,000) |
| 14 | Expected Balancing Reserve Capacity Sales in Spring from FCRPS Above Planned | | | | $ 4,000,000 |
| 15 | Operating Reserve - Spinning | 11.40 | mills/kWh/month | 255.1 | $ 25,470,313 |
| 16 | Operating Reserve - Supplemental | 10.45 | mills/kWh/month | 255.1 | $ 23,347,787 |
| 17 | Operating Reserve Total | | | 510.1 | $ 48,818,100 |
| 18 | Synchronous Condensing | | | | $ 1,610,466 |
| 19 | Generation Dropping | | | | $ 415,417 |
| 20 | Redispatch | | | | $ 225,000 |
| 21 | Segmentation of COE/Reclamation Network and Delivery Facilities | | | | $ 7,367,000 |
| 22 | Station Service | | | | $ 2,479,123 |
| 23 | Generation Inputs Total | | | | $ 115,749,907 |

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