INDEX

REBUTTAL TESTIMONY of

MARK A. JACKSON, KATHERINE L. BEALE, THOMAS D. COATNEY,

ALLEN E. INGRAM, and FRANCIS R. PUYLEART

Witnesses for Bonneville Power Administration

SUBJECT: ANCILLARY AND CONTROL AREA SERVICES RATE DESIGN

Page

List of Attachments

.

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Section 1: Introduction and Purpose of Testimony

Q. Please state your names and qualifications.

A. My name is Katherine L. Beale, and my qualifications are contained in BP-12-Q-BPA-01.

A. My name is Thomas D. Coatney, and my qualifications are contained in BP-12-Q-BPA-14.

A. My name is Allan E. Ingram, and my qualifications are contained in BP-12-Q-BPA-32.

A. My name is Mark J. Jackson, and my qualifications are contained in BP-12-Q-BPA-33.

A. My name is Francis R. Puyleart, and my qualifications are contained in BP-12-Q-BPA-62.

Q. What is the purpose of your testimony?

A. The purpose of our rebuttal testimony is to address the Ancillary and Control Area Services (ACS-12) rate design issues raised by the parties in their direct testimony and explain our proposed changes to the ACS-12 rate design since the Initial Proposal. Specifically, our rebuttal testimony responds to the direct testimony filed by several parties on topics discussed in our direct testimony and the Generation Inputs Study, BP-12-E-BPA-05 (Study) and Generation Inputs Study Documentation, BP-12-E-BPA-05A (Documentation).

Section 2: Dispatchable Energy Resource Balancing Service (DERBS) Rate

Q. Many parties raised concerns about the proposed rate design for DERBS. In response, are you proposing any revisions to the DERBS rate design proposal?

A. Yes. We are proposing some significant modifications to the proposed DERBS rate design, as we summarize in this answer. We discuss these revisions throughout our testimony below. We believe that the proposed revisions to the DERBS rate design will address most of the concerns expressed by the parties in their direct cases, while continuing to meet our goal of equitable cost recovery for the use of balancing reserve capacity by dispatchable energy resources.

First, we are proposing to change the DERBS billing factor to a per-megawatt charge, rather than a *pro rata* allocation of the hourly revenue requirement based on proportional use. We believe this proposed revision better aligns the charge for DERBS with the balancing reserve capacity actually used by dispatchable energy resources and addresses the majority of issues raised by the parties. In addition, we are proposing a base charge tied to the generator's nameplate generating capacity. The base charge will recover 20 percent of the forecast revenue requirement for DERBS and will provide 2 MW of balancing reserve capacity to each generator.

To establish a per-megawatt charge for use of DERBS beyond 2 MW, we propose using the 40th percentile of the distribution of expected DERBS station control error (minus the 2 MW) as the dominator and the remainder (80 percent) of the forecast annual revenue requirement as the numerator. This results in a fixed portion of the rate (the Hourly Base Rate) of $22.34 per megawatt of nameplate capacity per month. Usage charges (Hourly Variable Rates) would be $11.56 per megawatt of maximum one-minute generation below schedule for each hour for *inc* reserve and $3.01 per megawatt of maximum one-minute generation above schedule for each hour for *dec* reserve. Attachment 1, ACS-12 Rate Schedule, section F. Dispatchable Energy Resource

Balancing Service. On an annual basis, we expect the proposed rate to recover the costs of the allocated balancing reserve capacity to provide DERBS. This "base charge" rate design is our preferred approach for the DERBS rate.

Another potential rate design we considered is to provide a 2 MW dead band for all generators that are subject to DERBS, and then recover 100 percent of the revenue requirement through a per-megawatt charge for use greater than 2 MW. We believe this rate design would also meet our objective for cost recovery consistent with cost causation. Under this alternative rate design, the per-megawatt charge above 2 MW would be higher than the per-megawatt charge without the deadband, with the base charges \$3.76 per megawatt of *dec* capacity used each hour and \$14.44 per megawatt of *inc* capacity used each hour. This rate is based on the same data and balancing reserve capacity quantity forecast as our preferred rate design.

Second, we are proposing to change the applicability of the DERBS rate. We propose to apply the DERBS rate only to Dispatchable Energy Resources in the BPA Control Area (*i.e.*, balancing authority area) that are 3 MW nameplate rated capacity or greater. Attachment 1, ACS-12 Rate Schedule; see also section 2.2 below.

Third, based on our proposed revision to the DERBS rate design, we do not believe it is necessary to include a DERBS penalty charge at this time. We believe the new billing factor will be sufficient to incentivize better performance and minimize use of balancing reserve capacity by dispatchable energy resources.

Fourth, for purposes of the DERBS rate, we are proposing to define "dispatchable energy resource" to mean "any non-Federal thermally based generating resource that schedules its output or is included in BPA's Automatic Generation Control systems." *See* Attachment 1, ACS-12 Rate Schedule.

Fifth, during a qualifying contingency event in which a dispatchable energy resource calls upon contingency energy, we propose not to assess the DERBS charge for any balancing reserve capacity that is used during that scheduling period.

Finally, we recognize that during scheduling periods when BPA issues Dispatch Orders or curtailments affecting generation output, dispatchable energy resources may consume balancing reserve capacity in an effort to comply with such orders or curtailments. We are proposing to not apply the DERBS charge for any scheduling period in which BPA issues to the dispatchable energy resource a Dispatch Order or curtailment affecting generation output.

As noted above, we discuss these proposed revisions throughout our testimony below.

Q. Several parties (Snohomish PUD, Public Power Council (PPC), Joint Party 2[1] *(JP02), and Industrial Customers of Northwest Utilities (ICNU)) have raised concerns about having inadequate opportunities to discuss any potential improvement in balancing reserve capacity usage by dispatchable energy resources since the Initial Proposal and the proposed DERBS rate design. Miles and Finley, BP-12-E-SN-01, at 9-10; Baker et al., BP-12-E-PP-03, at 12-14; Scott et al., BP-12-E-JP02-02, at 9, 12; Wolverton, BP-12-E-IN-01, at 1. Will the parties have an additional opportunity to comment on your recent analysis of the use of balancing reserve capacity by dispatchable energy resources and proposed revisions to the DERBS rate proposal?*

A. That is our intent. As stated in Mainzer *et al.*, BP-12-E-BPA-42, to give the parties an opportunity to comment on the record regarding our reexamination of dispatchable energy resource balancing reserve capacity usage since the Initial Proposal (discussed below) and our proposed revisions to the DERBS rate proposal, BPA intends to file a

[1] JP02 comprises Northwest Requirements Utilities, Pacific Northwest Generating Cooperative, and Western Montana Generation and Transmission Cooperative.

motion to allow surrebuttal on the DERBS rate. In addition, we intend to hold a rate case workshop on March 18, 2011, in which BPA and parties can discuss the DERBS proposal, including our preferred rate design approach and alternative rate design mentioned above.

Section 2.1: DERBS Balancing Reserve Capacity Quantity Forecast

Q. Have you reexamined the use of balancing reserve capacity by dispatchable energy resources since the Initial Proposal?

A. Yes. In the Initial Proposal, we stated that we would reexamine the performance of the non-Federal dispatchable thermal generation from October 2010 through January 2011 to document any improvement in balancing reserve capacity usage during that time period. Jackson *et al.,* BP-12-E-BPA-29, at 43**.**

Q. Which generators are included in your analysis?

A. The generators that were included in our analysis are listed in Attachment 2 to this testimony, Dispatchable Energy Resources Subject to DERBS. We are aware that this list may change before the Final Decision in this rate proceeding. We will reflect any changes to this list in our Final Studies.

Q. Please explain your analysis of the October 2010 through January 2011 non-Federal thermal generation data set.

A. The data underlying the proposed DERBS rate reflects several changes from the Initial Proposal data. An extended period of test data was considered. We used data from the Plant Information database to create an aggregate one-minute station control error for the non-Federal thermal generation in BPA's balancing authority area. A percentile distribution on that station control error was then performed to determine the 99.5 percent balancing reserve capacity usage for these generators. This analysis was performed for October 2009 to January 2010 and October 2010 to January 2011. We chose to compare the balancing reserve capacity usage by dispatchable energy resources with the previous year's usage, which is the most accurate representation of the current dispatchable energy resource fleet in the BPA balancing authority area. We found that in the fall and winter of 2010, non-Federal thermal generation reduced its overall decremental (*dec*) balancing reserve usage by 19 percent from that of the previous year. *See* Attachment 3, Dispatchable Energy Resource Improvements. However, we found no improvement in the non-Federal thermal generation incremental (*inc*) balancing reserve usage during the fall and winter of 2010 compared to the previous year. *Id.*

Q. *How does your analysis affect the DERBS balancing reserve capacity quantity forecast?*

A. We propose to reduce the *dec* balancing reserve capacity for non-Federal thermal generation by 19 percent. All else being equal, this would lower the average *dec* balancing reserve capacity for the rate period from 88 MW to 71 MW. *Id.*

Q. *Joint Party 6*[2] *(JP06) argues that Federal thermal generation balancing reserve capacity requirements should not be excluded from the DERBS rate. Brown et al., BP-12-E-JP06-01, at 10-13. JP06 asserts that BPA's evidence fails to support the claim that Federal thermal generation balancing reserve capacity requirements are minimal, but non-Federal thermal generation balancing reserve capacity requirements are significant. Id. What is your response?*

A. The costs for all balancing reserve capacity beyond the capacity requirements assigned to DERBS and Variable Energy Resources Balancing Service (VERBS) are recovered by including those balancing reserve capacity requirements in the load balancing reserve requirements, as explained in the Study, section 2.8. Though the ratio of megawatts of balancing reserve capacity to megawatts of nameplate capacity is relatively close for both Federal and non-Federal thermal generation, Federal thermal generation is considered part of the overall Federal resource stack. As such, balancing reserve capacity for

[2] JP06 comprises Avista Corporation, Idaho Power Company, PacifiCorp, Portland General Electric Company, and Puget Sound Energy, Inc.

Federal generation is essentially self-supplied due to the fact that the Federal resource stack is dispatched automatically through BPA's Automatic Generation Control system (AGC). In addition to dynamically dispatching all reserves required for the balancing authority area, basepoint adjustments of the Federal system can be made at any time prior to or during the operating hour if needed to respond to changes in output or projected output of the Federal generation.

Q. The Western Public Agencies Group (WPAG) states that BPA's DERBS balancing reserve capacity requirement appears to be overstated. Saleba et al., BP-12-E-WG-01, at 30. WPAG states that BPA based its reserve calculation on historical data and, during that time, dispatchable generators were managing their resources to minimize Generation Imbalance but were not accounting for deviations from an integrated one-minute average. Id. Cowlitz PUD and Eugene Water and Electric Board (JP01), and Calpine and TransAlta Energy Marketing (Calpine) similarly argue that basing the DERBS rate on historical data may not represent actual use. Skeahan et al., BP-12-E-JP01-01, at 19-20; Smith et al., BP-12-E-CP-02, at 8-10. What is your response?

A. We believe the historical data that we used in our analysis is reflective of the actual use of balancing reserve capacity by dispatchable energy resources. BPA Staff's direct testimony discusses why the time period was selected for use in the balancing reserve capacity quantity forecast for the BP-12 Initial Proposal. Puyleart *et al.*, BP-12-E-BPA-24, at 14. This justification is primarily focused on wind data and the interaction of wind generation with DSO 216, but the onset of $1,000 per MWh Failure to Comply (FTC) penalties on October 1, 2009, also may have an effect on the balancing reserve capacity quantity forecast for all generation types in the balancing authority area. In order for the correct seasonal interactions of load and generation to be captured in the incremental standard deviation approach used for the balancing reserve capacity quantity forecast, all time series data used for the calculations must be corresponding.

Furthermore, as discussed earlier, in our reexamination of the performance of the non-Federal thermal generation from October 2010 through January 2011, we found that in the fall and winter of 2010, the non-Federal thermal generation reduced its *dec* balancing reserve capacity usage by 19 percent over the previous year. Conversely, however, we found no improvement in non-Federal thermal generation *inc* balancing reserve capacity usage for the fall and winter of 2010 compared to the previous years. It is important to note that from a cost and revenue requirement perspective, *inc* balancing reserve capacity is a more significant driver of balancing reserve capacity costs than *dec* balancing reserve capacity. Thus, improvements in *dec* balancing reserve capacity will have a smaller impact on the DERBS rate. As illustrated by our analysis, the evidence does not support the parties' assertions.

Q. WPAG recommends that BPA recalculate the DERBS balancing reserve capacity requirement using the methodology that BPA employed to calculate the balancing reserve capacity requirement for the VERBS rate by assuming that the scheduling entities subject to the rate will utilize "best scheduling practices." Saleba et al., BP-12-E-WG-01, at 32. What is your response?

A. We are unaware of any universal thermal generation scheduling practice that can be made ahead of the hour of operation from publicly available information and accurately characterizes the generation scheduling practices seen in the BPA balancing authority area. Any such scheduling practice must apply to all hours of operation *(e.g.,* start-up, steady state, basepoint changes, shut-down) and to all types of thermal generation *(e.g.,* coal, combined cycle, natural gas, steam). In addition, application of a persistence forecast, similar to that of wind generation in the balancing reserve capacity forecast, would likely result in a substantial increase from the thermal balancing reserve capacity forecast in the BP-12 Initial Proposal. Absent a viable alternative to our DERBS balancing reserve capacity quantity analysis, we see no basis to support WPAG's recommendation.

Q. WPAG suggests that BPA calculate two separate balancing reserve capacity pools, one for non-Federal thermal merchant facilities and another for non-Federal thermal generators dedicated to serving Tier 1 requirements load under the contract high water mark agreement. Saleba et al., BP-12-E-WG-01, at 32-33. WPAG suggests that BPA should allocate the balancing reserve capacity requirement for generators serving Tier 1 load to load if such requirement is minimal. Id. Why would it be infeasible to calculate separate balancing reserve capacity requirements for both non-Federal thermal generators dedicated to serving Tier 1 requirements load and non-Federal thermal merchant facilities?

A. For non-AGC controlled generators that are included in BPA's AGC system, the generator's actual output and scheduled or estimated output become a part of the balancing authority area controller totals or balance of load, resources and interties. Therefore, AGC directs the Federal Columbia River Power System (FCRPS) to respond to any variation of that generator's output from schedule, regardless of customer class. BPA considers the FCRPS to be a self-supplier of the balancing for federal non-AGC hydro and federal thermal resources and we have allocated these costs to loads.

Q. PPC and ICNU assert that the database used to calculate balancing reserve capacity requirement contains outlier plants that unfairly inflate the amount needed for the thermal fleet. Baker et al., BP-12-E-PP-03, at 5, 8; Wolverton, BP-12-E-IN-01, at 6-7. Why is it appropriate to include all non-Federal thermal generators in your study to determine the DERBS balancing reserve capacity quantity forecast?

A. While we have observed that some thermal plants in our data set contributed to the balancing reserve capacity requirement more than other dispatchable energy resources in the data set, all plants in the data set used some amount of balancing reserve capacity. As the balancing authority responsible for those plants, BPA must ensure that it has sufficient balancing reserve capacity available to provide balancing services for those plants. By specifically removing outlier plants from the data set, BPA would hold fewer reserves and increase its risk of being noncompliant with the North American Electric Reliability Corporation (NERC) balancing standards, which is unacceptable to BPA. Therefore, it is appropriate to include all plants in our analysis to determine the balancing reserve capacity requirement for DERBS. Nevertheless, as we discuss further below, we have proposed several revisions to the DERBS rate to better align cost recovery with the use of balancing reserve capacity. We believe these proposed revisions will address a majority of the parties' concerns. See section 2 above.

Q. ICNU maintains that customers cannot assess any cross-subsidies between good facilities and outlier facilities because the data for non-Federal thermal generators is confidential. Wolverton, BP-12-E-IN-01, at 8. What is your response?

A. Based on our proposed revisions to the DERBS billing factor, we believe that the cross-subsidies issue is now moot. Specifically, our proposed revisions to the DERBS rate design removes the interdependency of the DERBS charge on the balancing reserve usage by other thermal generators. These proposed revisions should address ICNU's concerns.

Q. ICNU testifies that BPA has not shown adequately the balancing reserve capacity needs and costs for thermal generators. Wolverton, BP-12-E-IN-01, at 3-4. Do you agree?

A. No. We examined the balancing reserve capacity requirement for thermal generators using actual generation and scheduling data from the thermal fleet. The forecast for the FY 2012-2013 rate period is reflective of actual usage in the past. As explained above, recent analysis indicates no material improvement in the use of *inc* reserve for thermal generators. Attachment 3, Dispatchable Energy Resource Improvement. We have observed slight improvement in the use of *dec* reserves; however, this improvement has minimal revenue impact on the DERBS rate. *Id.*

Q. Snohomish and PPC argue that BPA has failed to demonstrate: (1) if BPA requires additional inc and dec capability beyond what it provides for load following to address variations in behind-the-meter, non-Federal thermal generation; and (2) if BPA is incurring costs for providing balancing reserve capacity for behind-the-meter, non-Federal thermal generators beyond what BPA already collects under Regulation and Frequency Response, the contingency reserve portion of Operating Reserves, and Energy Imbalance Service. Miles and Finley, BP-12-E-SN-01, at 7-8; Baker et al., BP-12-E-PP-03, at 6. Why is it appropriate to include certain non-Federal behind-the-meter resources in BPA's balancing reserve capacity quantity forecast for DERBS?

A. As noted above, we have identified the generators, including certain behind-the-meter resources, that will be subject to the proposed DERBS rate. *See* Attachment 2, Dispatchable Energy Resources Subject to DERBS. These non-AGC controlled generators are included in BPA's AGC system. By being included in AGC, the generator's actual output and scheduled or estimated output are part of the balancing authority area total generation actual and schedule. Thus, these generators contribute to the balancing reserve capacity requirement regardless of their status as "behind-the-meter" resources. For the BP-12 Initial Proposal, the balancing authority area net load used in the balancing reserve capacity quantity forecast is a derived value from the total generation for the balancing authority area minus the sum of all interchanges for the balancing authority area. Since all of the identified non-Federal thermal generators are part of the total generation for the balancing authority area, the variability of those generators is not accounted for in net load for the balancing authority area. Therefore, additional *inc* and *dec* reserves are needed, and the costs associated with supplying those reserves currently are not being recovered through rates.

Q. *Snohomish argues that BPA has failed to recognize the diversity that behind-the-meter, non-Federal thermal generators provide in determining its balancing reserve capacity quantity forecast for DERBS. Miles and Finley, BP-12-E-SN-01, at 7-8. How did you account for the diversity provided from behind-the-meter, non-Federal thermal generators in your balancing reserve capacity quantity forecast for DERBS?*

A. As discussed above, all non-AGC controlled generators that are part of the AGC total generation actual and schedule in BPA's balancing authority area are included in the balancing reserve capacity quantity forecast, and the forecast methodology captures any diversity benefits associated with those resources. Moreover, our study describes the incremental standard deviation approach and how it accounts for benefits seen from the variability and diversity of all types of non-AGC controlled generation and load. Study, section 2.7.3. We disagree with Snohomish's assertion that our balancing reserve capacity quantity forecast has failed to capture any diversity of behind-the-meter, non-Federal thermal generators. We also note that Snohomish does not appear to challenge any specific aspect of our analysis.

Q. *How do you respond to WPAG's assertion that BPA has failed to provide sufficient data to allow parties potentially affected by the DERBS rate to reconcile and verify the balancing reserve capacity requirement allocated to the rate? Saleba et al., BP-12-E-WG-01, at 31.*

A. We have posted data in the response to data request IN-BPA-2. *See also* http://www.bpa.gov/corporate/ratecase/2012/models/DERBS_AggIncDec.zip; Attachment 2, Dispatchable Energy Resources Subject to DERBS. These data included the following two items for the two-year rate test period at one-minute granularity: (1) the sum of generator imbalances for all non-Federal thermal plants that were in *inc* status for that minute, and (2) the sum of generator imbalances for the corresponding *dec* side. These two fields are sufficient to allow parties to calculate and verify the balancing reserve capacity requirement allocated to the rate and the aggregate station control error data that can be used by an individual generator to assess its own station control error against the aggregate thermal fleet station control error. In addition, we assume that each generator has access to its own schedule and power output data for the test period. We note, however, that we propose significant revisions to the proposed DERBS rate design that increase billing transparency and reduce the interdependency of the DERBS charge on the performance of other dispatchable energy resources. *See* section 2.2 below. These proposed revisions should address WPAG's concerns.

Q. Calpine argues that BPA's analysis and rate design seem to depend on the presumption that every instantaneous deviation between metered generation and scheduled generation results in the deployment of reserve capacity. Smith et al., BP-12-E-CP-02, at 9-10. Calpine states that presumption is not true because (1) system deviations are random, and BPA balances the system based on aggregate, not individual, deviations; (2) NERC standards do not require that minute-to-minute deviations be continuously and perfectly balanced; and (3) BPA has not yet finalized the revenue requirement allocated to DERBS. Id. What is your response?

A. First, we disagree with Calpine's assertion that we presumed that every instantaneous deviation between metered generation and scheduled generation results in the deployment of balancing reserve capacity. As stated above, all non-AGC controlled generators that are part of the AGC total generation actual and schedule in BPA's balancing authority area are included in the balancing reserve capacity quantity forecast, and the forecast methodology captures any diversity benefits associated with those resources. Our Study describes the incremental standard deviation approach and how it accounts for benefits seen from the variability and diversity of all types of non-AGC controlled generation and load. Study, section 2.7.3.

Furthermore, the total balancing authority area balancing reserve capacity is established from the balancing authority area aggregate station control error, which includes all non-AGC controlled generation types and load. The incremental standard deviation methodology uses the correlation of individual components to the whole to account for the diversity of the components. By establishing the overall reserves on the aggregate station control error and using the incremental standard deviation methodology to allocate them, the balancing reserve capacity quantity forecast accurately captures the diversity benefits of the different non-AGC controlled generation types, including non-Federal thermal generation.

We agree that the NERC balancing standards do not require that minute-to-minute deviations be continuously and perfectly balanced. Nonetheless, the NERC balancing standards do require that sufficient reserves are held to respond to changes in the load-generation balance of the balancing authority area. We have performed studies to calculate regulating reserve and load following reserve needs based on the change in load through the hour for over 20 years. Historically, we have held 99.7 percent of the system movement in regulating and load following reserve in order to ensure that enough reserve was held to meet the NERC standards. NERC balancing standard BAL-001 requires 90 percent or better performance for compliance with CPS2. BPA's performance has historically been between 94 and 96 percent due to how AGC responds to deviations in the load-generation balance. When less reserve is held, BPA would see an even lower level of performance with respect to the NERC standards. If taken to an extreme, BPA would be at risk of being noncompliant with the NERC balancing standards. Such a result would be unacceptable.

Furthermore, if we were to allocate DERBS on 10-minute average deviations instead of using minute-to-minute deviation data to determine the DERBS station control error, we would need to allocate all balancing reserve capacity on 10-minute average deviations. Otherwise, the differences in the two allocation approaches would result in an over-allocation of reserves to the VERBS and load. This also removes the regulation component of the balancing reserve capacity, thereby lowering reserves to a level that is not acceptable.

We also disagree with Calpine's argument that allocating DERBS using 10-minute average station control error better addresses simultaneous use and allocation of balancing reserve capacity. Smith *et al.*, BP-12-E-CP-02, at 10. The balancing reserve capacity quantity forecast study supports our approach of accounting for diversity of uses by allocating reserve requirements for DERBS across all components (regulation, following, and imbalance). The parties have not presented viable alternatives to our study methodology. Moreover, Calpine offers no evidence to support its statement that a 10-minute average would produce superior results to our study methodology.

Section 2.2: DERBS Rate Design

Q. In section 2 above, you describe your proposed revisions to the DERBS rate design. With regard to the applicability of the DERBS rate, why are you no longer proposing to apply the DERBS rate to Dispatchable Energy Resources that are less than 3 MW rated nameplate capacity?

A BPA does not have access to one-minute power output data for resources that are smaller than 3 MW; thus, BPA would not have the ability to measure the variable component to our rate design for such resources. We also believe that Dispatchable Energy Resources with a rated nameplate capacity of less than 3 MW are unlikely to contribute significantly to BPA's balancing reserve capacity requirements. Therefore, we do not propose to subject smaller resources to the DERBS rate at this time.

Q. WPAG states that the proposed DERBS rate schedule does not contain a definition of what constitutes a "dispatchable energy resource." Saleba et al., BP-12-E-WG-01, at 31.

Are you proposing to include a definition of "dispatchable energy resource" in the Transmission General Rate Schedule Provisions?

A. Yes. As mentioned in section 2 above, we propose to define Dispatchable Energy Resource as "any non-Federal thermally based generating resource that schedules its output or is included in BPA's Automatic Generation Control systems." We propose to add this definition to the Transmission General Rate Schedule Provisions. Attachment 1, ACS-12 Rate Schedule. This definition is consistent with our analysis of balancing reserve capacity use by such resources in BPA's balancing authority area.

Q. Both ICNU and WPAG argue that the DERBS rate is unnecessary. ICNU states that BPA should consider whether the harm inflicted by DERBS outweighs the benefits it provides. Wolverton, BP-12-E-IN-01, at 4. WPAG argues that the DERBS rate is unnecessary because (1) dispatchable resources do not present the same kind of problems that the Federal system confronts due to the operational nature of the wind fleet; and (2) proposing a DERBS rate in order to maintain symmetry with the VERBS rate imposed on wind generation is insufficient justification for the DERBS rate given the materially different operational profiles of these categories of resources. Saleba et al., BP-12-E-WG-01, at 30. Why is the DERBS rate necessary for the rate period?

A. The DERBS rate is necessary to recover the costs of balancing reserve capacity used to balance non-Federal dispatchable energy resources. In our balancing reserve capacity quantity forecast study (Study, section 2.8) we found that there was significant use of balancing reserve capacity by non-Federal thermal resources during the test period. That use prompted the DERBS rate proposal.

We also disagree with WPAG's assertion that our DERBS rate proposal is merely an attempt to maintain symmetry with the VERBS rate. The primary goal of rate design is to recover costs. Our approach examined all uses of balancing reserve capacity in our balancing authority area and allocated the balancing reserve capacity requirement consistent with the use of balancing reserve capacity. We continue to adhere to the ratemaking principle of cost causation in charging users of balancing reserve capacity for their use of that capacity. If we did not follow that approach, the result would be an inequitable cost shift to other users of the balancing reserve capacity on the system.

Q. JP06 states that BPA's Initial Proposal fails to fairly allocate costs of providing balancing reserve capacity to those that create the need for balancing. Brown et al., BP-12-E-JP06-01, at 9-10, 13. How do your proposed revisions to the DERBS rate design better align with cost causation?

A. We disagree with the JP06 contention that our DERBS proposal fails to allocate costs on a fair and equitable basis. As JP06 states correctly in its testimony, the balancing requirements for Federal thermal generation are allocated to load. Brown *et al*., BP-12-E-JP06-01, at 10. Essentially, the FCRPS is self-supplying the balancing for Federal thermal generation. Since this generation serves load in the BPA balancing authority area, it is consistent with cost causation to include the costs for balancing the Federal thermal generation in the costs for loads that benefit from the Federal thermal generation. We are not treating Federal and non-Federal thermal generation differently with respect to allocation of the reserve requirement. We are, however, recovering the costs of providing the allocated reserve requirement from those that benefit from the use of those reserves, which is load. We believe this is a comparable and equitable basis due to the FCRPS self-supply of this specific reserve requirement.

Q. WPAG, PPC, ICNU, Iberdrola, JP01, JP02, and Snohomish object to the pro rata "share the rate" concept in which the proposed DERBS rate is based on inc and dec hourly charges that are shared by the group of non-Federal thermal resources. Saleba et al., BP-12-E-WG-01 at 31; Baker et al., BP-12-E-PP-03, at 9; Wolverton, BP-12-E-IN-01, at 9-10; Froese et al., BP-12-E-IR-01, at 37; Skeahan et al., BP-12-E-JP01-01, at 19; Scott et al., BP-12-E-JP02-02, at 6; Miles and Finley, BP-12-E-SN-01, at 8-9. Several of these *parties also argue that the interdependency of the rate on confidential hourly data of other generators diffuses responsibility for balancing reserve capacity use and makes billing difficult, if not impossible, to verify or predict. Baker et al., BP-12-E-PP-03, at 10; Skeahan et al., BP-12-E-JP01-01, at 20; Wolverton, BP-12-E-IN-01, at 9-10; Scott et al., BP-12-E-JP02-02, at 7; Miles and Finley, BP-12-E-SN-01, at 8-9. How do you propose to address these concerns about the DERBS rate design?*

A. We understand the concerns expressed by parties, and we believe that our proposed revision to the rate design addresses these concerns. As described earlier, our proposed revisions establish a base charge for 20 percent of the revenue requirement that will provide 2 MW of balancing reserve capacity per generator and will move the remainder of the revenue requirement to a billing factor based on a per-megawatt charge for maximum one-minute station control error during the scheduling period. This construct removes simultaneous uses by other generators from the billing calculation. Under the proposed revisions, a generator can verify its billing by simply comparing its maximum one-minute station control error during a scheduling period with the billed amount.

Q. Iberdrola asserts that the DERBS rate is inconsistent with the principle of cost causation because a generator can incur DERBS charges that far exceed the costs caused by such generator. Froese et al., BP-12-E-IR-01, at 37. Specifically, Iberdrola argues that it is possible for a single facility of any size to incur the entire DERBS revenue requirement in a single hour. Id. How do your proposed revisions to the DERBS rate design address this concern?

A. Under our proposed modifications, the billing factor is based on the use of balancing reserve capacity by each generator, calculated independently from other generators. We are no longer proposing to allocate the hourly revenue requirement as a function of proportional use; thus, no single generator would ever be responsible for the entire revenue requirement for any single hour.

Q. *ICNU, JP02, and Iberdrola argue that the Initial Proposal DERBS rate design could put a disproportionate share of hourly balancing costs and penalties on small generators. Wolverton, BP-12-E-IN-01, at 10-11; Scott et al., BP-12-E-JP02-02, at 6; Froese et al., BP-12-E-IR-01, at 37. How do your proposed revisions to the DERBS rate design address this concern?*

A. As described above, we are proposing to charge for balancing reserve capacity without taking into account the simultaneous use (or lack of use) by other generators. These proposed revisions better align the DERBS rate with the actual use of balancing reserve capacity by small and large generators.

Q. *Calpine argues that duplicative charges will apply to the lowest tier of deviations (within 1.5 percent), where generators will be assessed DERBS for the maximum one-minute energy imbalance. Smith et al., BP-12-E-CP-02, at 12-13. Calpine states that because Tier 1 generation imbalances allow an in-kind payback that cannot be scheduled, they would pay an equal (in terms of megawatts) and opposite DERBS charge when the energy is paid back through an encouraged, intentional and opposite deviation. Id. What is your response?*

A. If a generator has ramps between hours and incurs Generator Imbalance Service charges within Band 1 as a result of operating to the NERC standard ramp periods, then the generator can pay back that imbalance energy by submitting a payback schedule in subsequent hours when it is ramping the generator in the opposite direction. There would be no DERBS charge for scheduled energy payback, because it is scheduled and DERBS charges relate to schedule error. If a generator adheres to the NERC standard ramps there would be no balancing reserve capacity use, and Deviation Band 1 imbalance energy incurred during the scheduling period can be scheduled back without any Generation Imbalance Service charges. In addition, we believe that if a generator intentionally deviates from its schedule to effect a payback of imbalance energy during an hour, the generator is inappropriately using the payback provisions under Band 1 Generator Imbalance Service, since payback is required to be scheduled. Unscheduled energy return is new schedule error and would cause a DERBS charge because it would be using balancing service. We do not encourage this type of intentional deviation from the schedule, as Calpine appears to suggest.

Q. How do you respond to ICNU's argument, Wolverton, BP-12-E-IN-01, at 3, that its members have cogeneration that is not dispatchable, yet BPA proposes to apply the rate to those resources even though cogeneration resources are unlikely to contribute significantly to BPA's within-hour capacity needs?

A. Cogeneration resources that are larger than 3 MW are included in BPA's AGC system, and also contribute to the overall balancing reserve capacity requirement. Attachment 2, Dispatchable Energy Resources Subject to DERBS. We agree that these resources have a lesser cumulative imbalance (and balancing reserve capacity) need than the cumulative imbalances from larger thermal resources. However, we note that ICNU has submitted no evidence that the balancing reserve capacity requirement contribution of these resources is insignificant; accordingly, we see no basis to exempt such resources from the proposed definition of dispatchable energy resource and the DERBS rate proposal given the use of balancing reserve capacity by such resources.

Q. WPAG and PPC suggest that BPA should include a 1 MW dead band in the DERBS rate to avoid imposition of the rate for de minimis variations and to ease BPA's administrative burden associated with the DERBS rate. Saleba et al., BP-12-E-WG-01, at 35; Baker et al., BP-12-E-PP-03, at 12, 15-16. Do you agree that BPA should include a dead band for de minimis variations in the DERBS rate?

A. We disagree with WPAG and PPC's suggestion that including a 1 MW dead band in the DERBS rate would reduce BPA's administrative burden. Since we would still have to determine if a generator exceeded a dead band amount, the administrative burden is identical. As described earlier, our proposed revision to the rate design would provide 2 MW of imbalance as part of a nameplate capacity-based charge, with use beyond 2 MW charged on a per-megawatt basis. While that is not a dead band, it would result in a small charge for small generators with small imbalances. We note that, as an alternative, we also have considered a dead band of 2 MW with a higher per-megawatt charge. See section 2 above.

Q. *WPAG states that the Initial Proposal's DERBS rate does not account for deviations from schedules caused by curtailments or redispatch made at the direction or request of BPA. Saleba et al., BP-12-E-WG-01, at 31. Similarly, Calpine suggests that at a minimum DERBS charges should be suspended entirely during events in which BPA's FTC penalty charge is applicable. Smith et al., BP-12-E-CP-02, at 13. Calpine testifies that since the FTC penalty is an order of magnitude higher than the prevailing energy prices, it creates a significant incentive to reduce output below the adjusted schedule. Id. According to Calpine, this places generators in a "Catch 22" situation where the generator must choose the least harmful of three bad outcomes—pay the costly FTC penalties, and/or pay imbalance energy charges—and DERBS—by being below FTC targets. Id. Do you agree that BPA should not charge customers for DERBS during curtailments or redispatch that are requested by BPA?*

A. Yes. As stated above, we propose not to charge for DERBS during scheduling periods in which the generator must change its operations pursuant to a BPA Dispatch Order. This proposed exemption should be sufficient to address the parties' concerns regarding operations during curtailments or redispatch.

Q. *PPC states that how BPA accounts for ramps is critically important in determining whether the charge is fair. Baker et al., BP-12-E-PP-03, at 6. In addition, Calpine argues that given the constraints of hourly scheduling on the BPA system, thermal generators cannot avoid the use of balancing reserves, particularly during start-ups,* *shut-downs, and ramps. Smith et al., BP-12-E-CP-02, at 11, 12. Is it appropriate to exempt dispatchable energy resource ramping periods (start-up, shut-downs, and ramps) from the DERBS rate?*

A. No. Whether the use of balancing reserve capacity is preventable or not is largely irrelevant. What is relevant is whether balancing reserve capacity is used. If balancing reserve capacity is used, then the users of that capacity should compensate the provider of that balancing reserve capacity. We acknowledge that not all use of balancing reserve capacity is unavoidable during startup, ramps, and shutdown. However, there are large thermal generators that use very little balancing capacity relative to other generators with the same combined-cycle generating technology. The goal of the DERBS rate is to recover the costs associated with a dispatchable energy resource's use of balancing reserve capacity, regardless of whether the use is avoidable or unavoidable.

Q. Calpine states that, fundamentally, a thermal generator that uses a steam turbine-generator cannot start, stop, or ramp in the 20-minute window presumed by BPA scheduling practices. Smith et al., BP-12-E-CP-02, at 20. Calpine explains that the ramps will occur as dictated by inherent machine dynamics and not by the calculated values of BPA. Id. These unavoidable deviations will be both above and below schedule during these transitions and will have, on a one-minute basis, maximum deviations that exceed the penalty thresholds set in BPA's proposal. Id. What is your response?

A. We have examined the data from other steam turbine generators and have found that it is not necessarily the case that deviations will exceed the penalty thresholds as Calpine states. Nonetheless, we are proposing to remove the penalty charge under DERBS based on our other proposed revisions to the DERBS rate proposal.

Q. Calpine argues that regardless of the actions of a plant operator, hourly scheduling will never be able to accurately reflect the step-wise and controlled start of a thermal generating facility. Smith et al., BP-12-E-CP-02, at 21. Thus, BPA's ramping *assumption that a plant has an infinite range of ramping capability is groundless. Id. What is your response?*

A. Contrary to Calpine's assertion, we did not assume that thermal generators have infinite ramping capability. We did assume, however, that generators could keep their ramps confined to the applicable NERC standard ramp periods. Marketing decisions by the generator to make schedule changes between scheduling periods that exceed the capabilities of the generator to ramp within the ramp periods seem inconsistent with the intent of the ramp periods. We also note that BPA does expect to have full 30-minute intra-hour scheduling functionality during the FY 2012-2013 rate period, and use of intra-hour schedules should reduce the balancing reserve capacity requirements and charges associated with schedule changes.

Q. WPAG disagrees with BPA Staff that large imbalances between scheduled and actual output of dispatchable generation are completely preventable. Saleba et al., BP-12-E-WG-01, at 30-31. WPAG states that the Initial Proposal's DERBS rate does not account for the fact that unforeseeable operational constraints (e.g., "heat soak") may cause deviations from schedule during start-ups and or shut-downs. Id. How do your proposed revisions to the DERBS rate account for unforeseeable operational constraints?

A. It is important to clarify that our position is not that imbalances from thermal generation are completely preventable. We believe that imbalances that consume balancing reserve capacity are preventable to a certain extent. Preventability of such imbalances, however, is not the issue. The imbalances require generation inputs for balancing reserve capacity whether they are preventable or not, and the provider of that capacity should be compensated for those generation inputs.

Q. PPC and ICNU generally state that small generating plants that produce in less than whole megawatt increments but schedule in whole megawatts are unduly burdened by the proposed DERBS rate design. Wolverton, BP-12-E-IN-01, at 10-12; Baker et al., BP-12-

E-PP-03, at 5. Do your proposed revisions to the DERBS rate design account for this scheduling constraint?

A. As discussed above, we are proposing to modify the DERBS rate proposal in a manner that will address this concern. The 2 MW allowance in our modified proposal will provide that amount of balancing at little cost to small generators.

Q. How do you respond to Iberdrola's suggestion, Froese et al., BP-12-E-IR-01, at 44, that BPA cap each generator's exposure to the DERBS revenue requirement to 50 percent of the generator's nameplate capacity?

A. We disagree with Iberdrola's suggestion, because a cap would remove the incentive for large generators to minimize their use of balancing reserve capacity. Under our proposed revisions to the DERBS rate design, a generator will pay for its imbalance on a per-megawatt basis without paying an additional penalty for excessive use. We believe that this is sufficient to incent generators to schedule accurately. We do not want to encourage generators to use hundreds of megawatts of balancing reserve capacity without any charges, and that could well be the result if we were to adopt Iberdrola's suggestion.

Q. JPO1 suggests that BPA should base the amount of balancing reserve capacity that BPA needs to maintain for thermal plants on the average station control error per installed capacity for the thermal generators whose station control errors are relatively small as a percent of their installed capacity. Skeahan et al., BP-12-E-JP01-01, at 21-22. JPO1 states that the revenue requirement associated with that amount of inc and dec balancing reserve capacity should be collected as a fixed charge per kilowatt of installed capacity. Id. at 22. JPO1 also suggests a variable charge component of the DERBS rate, which could vary by monthly and diurnal period, to be applied to the measured station control errors of generators. JP01 notes that such variable charge should not apply to an amount of station control error (as a percent of installed capacity) that was the basis for developing the fixed charge, and that there could also be an additional dead band to *which the variable charge would not apply. JP01 suggests that BPA could have more than a single variable charge applicable to different amounts of station control error if it wanted to penalize larger errors. Do you agree that BPA should adopt a fixed base rate and variable rate for DERBS?*

A. Yes. Although we do not agree with all aspects of JP01's suggested rate design, we believe many of JP01's suggestions have merit. As described above in section 2, we are proposing a base charge with a billing factor of nameplate generating capacity as part of the DERBS rate design. Two megawatts of balancing capacity is provided to each generating facility under the base charge. Additional megawatts of balancing reserve capacity used by the facility beyond the 2 MW provided under the base charge is then charged on a per MW basis. We disagree with JP01's suggestion to establish more than a single variable charge to penalize larger station control errors. We believe a single rate for use of balancing reserves above 2 MW should provide a clear and adequate financial incentive for generators to limit their use of balancing reserves to the extent they can do so.

Q. How do you respond to JP06's argument that if BPA adopts a rate for thermal resources, the rate should apply to both Federal and non-Federal thermal resources? Brown et al., BP-12-E-JP06-01, at 9.

A. For the reasons described above regarding the balancing reserve capacity quantity forecast, we disagree with JP06 that BPA should adopt a rate for both Federal and non-Federal thermal resources. *See* section 2.1.

Q. Calpine argues that the proposed DERBS charge and penalty are not just and reasonable. Smith et al., BP-12-E-CP-02, at 10. Calpine states that the charge and penalty appear to be redundant and duplicative. Id. Calpine notes that BPA already imposes charges for deviations in the form of FTC and Persistent Deviation penalties, and Generation Imbalance Deviation Bands 2 and 3. Id. Specifically, Calpine asserts *that "the penalties incorporated in [Generation Imbalance Service] Bands 2 and 3 fully compensate BPA for energy and capacity services." Id. Why is the proposed DERBS charge not redundant and duplicative with BPA's FTC and Generation Imbalance Service penalties, including Deviation Bands 2 and 3 and the persistent deviation penalty charge?*

A. Our proposed DERBS rate is designed to recover the cost of balancing reserve capacity that is used by dispatchable energy resources. In essence, the proposed DERBS charge is a capacity-based charge, as opposed to an energy-based charge or penalty-based charge. Thus, we disagree that DERBS is duplicative of the FTC penalty, Generation Imbalance charges, and Persistent Deviation penalty charges. Specifically, the FTC penalty charge is assessed when load or generation does not fully respond to a Dispatch Order.

Generator Imbalance Service charges and Persistent Deviation penalty charges are energy-based and do not explicitly or implicitly recover any costs for the balancing reserve capacity required to provide the energy for imbalances. Dispatchable Energy Resources are not expected to incur the proposed Persistent Deviation penalty because such resources would require significant error in the same direction for long periods (three hours or more) in order to incur a Persistent Deviation. *See also* section 4 below. In addition, the Generator Imbalance Service penalty bands incent overall scheduling accuracy to reduce imbalance energy during a scheduling period. Since Generator Imbalance Service only accounts for energy delivered or taken relative to the schedule, both *inc* and *dec* balancing reserve capacity are used during an hour, while the generation imbalance energy account can be near zero for that hour. This means there would be no hourly energy accounted for under the Generation Imbalance Service rate, but there would be uncompensated use of balancing reserve capacity in both directions during the hour.

We acknowledge that it is possible that a thermal generator may consume balancing reserve capacity when it complies with a Dispatch Order in order to stay below the generation limit of the sum of remaining e-Tags during a curtailment. Since BPA is requiring certain operational actions under those conditions, we are proposing to exempt from the DERBS rate any scheduling period in which BPA issues a Dispatch Order to the particular dispatchable energy resource. *See* Attachment 1, ACS-12 Rate Schedule.

Finally, as discussed further immediately below, we note that we are no longer proposing a DERBS penalty charge in light of our other proposed revisions to the DERBS rate design.

Section 2.3: DERBS Penalty Charge

Q. *Several parties (Calpine, WPAG, JP01 and PPC) raised concerns about the proposed DERBS penalty charge. Are you proposing any changes to the penalty charge in response to the parties' concerns?*

A. Yes. Based on our proposed revisions to the billing factor for DERBS discussed above, we are no longer proposing to include a DERBS penalty charge for the rate period. However, we will continue to evaluate the necessity of such a penalty charge for subsequent rate periods.

Section 3: Variable Energy Resource Balancing Service (VERBS) Rates

Section 3.1: Provisional VERBS (referred to as "Provisional Balancing Service")

Q. *Has your proposal for Provisional Balancing Service changed since the Initial Proposal?*

A. Yes. We have made an adjustment to the proposed rate when certain conditions occur. Although BPA does not anticipate recalling Dynamic Transfer Capability (DTC) during the rate period, we have revised our proposal for Provisional Balancing Service to address that issue. We propose that if, as a result of limited DTC on BPA's system, BPA were to recall an award of DTC for the remainder of the rate period from a VERBS customer that is self-supplying balancing reserves and, as a result of BPA's recall of such award, that customer must take Provisional Balancing Service, then the discounted rate for Provisional Balancing Service would be set at 70 percent of the VERBS rate. Under those circumstances, we are proposing to set the discounted Provisional Balancing Service rate at an amount equal to the percentage of balancing reserves used by BPA's balancing authority that would trigger a DSO 216 event for such customer. Because we anticipate that the trigger would be 70 percent of available reserves used by the balancing authority, we have established the discount for Provisional Balancing Service accordingly.

We also clarify that, for DSO 216 purposes, the allocation of reserves that a self-supply customer has when it purchases the Regulation and Following components from BPA will still be available to the customer if it must take Provisional Balancing Service during the rate period. This is not an increase in the reserve requirement for the BPA balancing authority area. Rather, it reflects the customer's use of the Regulation and Following reserves that it was paying for as a self-supply customer.

Q *Iberdrola contends that the charges for Provisional Balancing Service should be decreased to reflect the reserves provided to customers taking Provisional Balancing Service. Froese et al., BP-12-E-IR-01, at 44. Is a discount to the VERBS rate appropriate if BPA recalls an award of DTC for a customer that self-supplies VERBS?*

A. Yes. As discussed above, we are proposing a discounted Provisional Balancing Service rate if a customer must take Provisional Balancing Service because BPA recalls an award of DTC for the rate period. The proposed discounted rate reflects the anticipated DSO 216 trigger level of reserves used by the balancing authority for customers taking Provisional Balancing Service.

Q. *Are you proposing to provide a rate discount for Provisional Balancing Service to a customer that is responsible for termination of its self-supply status during the rate period?*

A. No. We are not proposing a rate discount for Provisional Balancing Service customers that terminate their own self-supply status, either voluntarily or through poor performance under the self-supply requirements. We discuss our rationale for this proposal below.

Q. *Iberdrola asserts that BPA will not incur measurable costs in providing Provisional Balancing Service and that it is thus inappropriate to charge the full VERBS rate for limited access to the service. Froese et al., BP-12-E-IR-01, at 20. Why is it appropriate to charge Provisional Balancing Service customers the full VERBS rate?*

A. Customers taking Provisional Balancing Service will be subject to a lower threshold for curtailment under DSO 216. Given that DSO 216 events are relatively low in frequency, those customers taking Provisional Balancing Service would receive the same quality of service as customers taking full VERBS most of the time and would receive a lesser quality of service for a small percentage of the time. We believe that charging the full VERBS rate, but setting the rate discount under certain conditions consistent with the threshold for DSO 216 under Provisional Balancing Service, is consistent with cost-causation while simultaneously protecting the quality of service for other VERBS customers.

In addition, we believe charging the full VERBS rate for such customers will provide an incentive for customers to commit to the services they intend to take, whether from BPA or through self-supply for the rate period. BPA is requiring each customer to elect to take either VERBS from BPA or self-supply by May 1, 2011. It is critical that BPA receives this information in advance of the final rate proposal in order to set rates and to plan the BPA system. Although we originally anticipated having a balancing service election business practice and an election form posted by March 1, 2011, we now anticipate posting this information by April 1, 2011.

Q. Iberdrola maintains that self-supply participants are reducing the balancing reserve requirement for the BPA balancing authority area and that, as such, Iberdrola is subject to inappropriate risk exposure to (1) the full cost of VERBS and (2) heightened DSO 216 curtailments because "Bonneville can unilaterally make a decision to recall DTC." Froese et al., BP-12-E-IR-01, at 21. What is your response?

A. We agree that self-supply participants would be at some risk of facing the full cost of VERBS under our Initial Proposal if BPA were to recall an award of DTC. As described above, in recognition of that risk, BPA is modifying its proposal to implement a lower rate for Provisional Balancing Service in certain circumstances. We note, however, that under BPA's applicable business practice, BPA will allocate DTC to customers for a two-year term that coincides with the rate period. Dynamic Transfer Capability: Request and Award Business Practice, section 3, *available at* http://transmission.bpa.gov/includes/getForCF8.cfm?ID=1909&CFID=6786872&CFTOKEN=41867973. Given the terms and conditions of the business practice, it is unlikely that BPA would recall an award of DTC for the rate period to the extent that it would force a customer into Provisional Balancing Service.

We distinguish the recall of an award of DTC from more limited interruptions in DTC. The business practice states that "BPA reserves the right to temporarily suspend or limit use of Dynamic Transfer Capability when necessary to protect reliability or when the terms of this Business Practice or other applicable business practices or their successors are not being met." *Id.*, section 5.6. We do agree that if BPA temporarily suspends or limits DTC to protect reliability, self-supply customers would be at a heightened risk of DSO 216 during that time period.

Q. *Iberdrola asserts that under Provisional Balancing Service, the frequency of DSO 216 limits and curtailments would "severely and unacceptably impact Iberdrola Renewables' business" in the absence of an additional balancing reserve capacity allocation. Froese et al., BP-12-E-IR-01, at 19. What is your response?*

A. Iberdrola is in the best position to assess how its business would be impacted in the event that it takes Provisional Balancing Service and becomes subject to more frequent DSO 216 events. As stated above, however, we are proposing a rate discount in the event BPA recalls an award of DTC from a customer that self-supplies VERBS. We also clarify that the allocation of reserves that a self-supply customer has for the Regulation and Following components that it was purchasing under self-supply will still be available to the customer under Provisional Balancing Service.

Further, although the tail of the reserve provision would be limited during DSO 216 events, during the majority of time when DSO 216 events do not occur, Iberdrola's balancing needs would be met and its use of VERBS balancing reserve capacity would be analogous to that of all other customers. BPA would limit Iberdrola to the self-supply amount of reserve allocation only under DSO 216 events, but Iberdrola could in fact be using the full range of balancing reserve capacity comparable to normal VERBS during all other times. Also, if DTC is limited but not completely recalled, a Provisional Balancing Service customer could utilize the remaining DTC to provide some balancing reserve capacity through resources that would be adjusted only on the half hour. Therefore, the self-supply customer would retain some capability to manage the DSO 216 risk.

Q. Iberdrola maintains that BPA should not assess Provisional Balancing Service until it has implemented 15-minute scheduling and collected data for a year. Froese et al., BP-12-E-IR-01, at 44. What is your response?

A. As explained in the testimony of Mainzer *et al.*, BP-12-E-BPA-42, BPA does not expect to have 15-minute scheduling capability during the rate period. However, we do expect to have expanded 30-minute intra-hour scheduling capability during the rate period. Mainzer *et al.*, BP-12-E-BPA-23, section 5.6. We believe it is necessary for BPA to provide a reasonable balancing service option for unanticipated customer needs during the rate period. As a result, we have proposed Provisional Balancing Service to meet those needs.

Section 3.2: VERBS Formula Rates I and II

Q. Please describe in general terms the positions taken by the parties that commented on your proposed Formula I and II rates.

A. Generally, public power parties support the Initial Proposal's formula rate design for VERBS to recover the costs of non-Federal balancing reserve capacity purchases during the rate period. Baker *et al.*, BPA-12-E-PP-01, at 20; Saleba *et al.*, BP-12-E-WG-01, at 28-29. PPC disagrees with BPA's proposed net cost approach for Formula Rate I and recommends that BPA use a total cost approach, similar to the total cost approach under the proposed Formula Rate II. Baker *et al.*, BPA-12-E-PP-01, at 20-21.

Northwest Wind Group (NWG) challenges the proposed formula rate design on the basis that BPA Staff's proposal provides inadequate notice and comment opportunities for customers and inappropriately allocates costs solely to wind customers rather than all users of balancing reserve capacity from the Federal system. Yourkowski and Goggin, BP-12-E-NG-01, at 17.

Q. Why is it necessary for BPA to establish VERBS Formula Rates during the rate period?

A. The proposed Formula Rates allow the Administrator to recover costs consistent with the principle of cost causation in the event of unforeseen changes to operations of the FCRPS. Without this ability BPA would be forced to use financial reserves to fund *inc* and *dec* balancing reserve capacity purchases that are needed to continue to provide VERBS. This would create an inequitable cost shift to the customers that do not take VERBS. *See also* Jackson *et al.*, BP-12-E-BPA-29, at 39.

Q. NWG states that BPA should establish a threshold below which it would procure a de minimis amount of balancing reserves from non-Federal resources without adjusting rates. Yourkowski and Goggin, BP-12-E-NG-01, at 27-28. NWG states that if BPA's costs of providing balancing reserves exceeds this threshold, the BPA Administrator should initiate another rate case and establish rates for generation inputs under a full 7(i) proceeding. Id. Is it appropriate for BPA to establish a de minimis amount of balancing reserves to procure from non-Federal resources without adjusting rates?

A. No. Essentially NWG argues that BPA should rely upon BPA's financial reserves to procure balancing reserve capacity before establishing a rate to recover those costs. We strongly disagree with such an approach because it would result in an inequitable cost shift to other rate customers. Jackson *et al.,* BP-12-E-BPA-29, at 39. In addition, without a cost recovery mechanism like the proposed VERBS formula rates, any BPA purchase of non-Federal balancing reserve capacity—whether *de minimis* or significant—could adversely affect BPA financial reserves during the rate period.

We note that NWG does not specify whether BPA should rely upon transmission or power financial reserves to procure a *de minimis* amount of non-Federal balancing reserve capacity. Nor does NWG suggest a specific balancing reserve capacity quantity that would constitute "*de minimis*." Nevertheless, we believe that it would be inappropriate for BPA to rely upon any financial reserves to fund purchases of non-

Federal balancing reserve capacity when such purchases are necessary only because of the need to provide VERBS during the rate period and no other service, and BPA would not need to make such purchases of non-Federal balancing reserve capacity but for the significant increase of variable energy resources in BPA's balancing authority area.

If BPA relied upon Power Services' financial reserves, the financial impact could increase the risk of a Cost Recovery Adjustment Clause (CRAC) rate adjustment. The majority of these affected customers do not take VERBS service and therefore should not bear any risk or cost associated with non-Federal balancing reserve capacity purchases for VERBS. *See also* Jackson *et al.*, BP-12-E-BPA-29, at 39. Similarly, if BPA relied upon Transmission Services' financial reserves to fund purchases of non-Federal balancing reserve capacity during the rate period, it would create a cost shift risk to other customers taking transmission service. *Id.*

We also disagree with NWG's suggestion that BPA should defer the establishment of a rate to recover the costs of non-Federal balancing reserve capacity purchases to an additional section 7(i) rate proceeding during the rate period. We discuss this issue further immediately below.

Q. In lieu of BPA Staff's proposed Formula 1 and 2 rate design, if BPA must make non-Federal purchases of balancing reserve capacity during the rate period to continue to provide VERBS, should BPA initiate a full section 7(i) rate proceeding during the rate period to establish a rate to recover BPA's costs?

A. No. It is important to acknowledge the legitimate quality of service and cost impacts that could occur during the rate period in the absence of the proposed VERBS formula rates. NWG argues that BPA should initiate a section 7(i) rate proceeding during the rate period in lieu of adopting the proposed VERBS formula rates. Yourkowski and Goggin, BP-12-E-NG-01, at 18**.** Under NWG's approach, BPA has only two practical choices: (1) rely upon financial reserves to make any emergency purchases of non-Federal balancing reserve capacity to provide VERBS; or (2) degrade the quality of VERBS until BPA can implement a rate pursuant to a section 7(i) rate proceeding during the rate period. We find these outcomes to be unacceptable.

As we explained above, among other things, it is inconsistent with cost causation to rely upon BPA financial reserves to fund purchase of non-Federal balancing reserve capacity to provide VERBS. In addition, the triggers for Formula Rates I and II require critical response times to maintain the forecasted quality level of VERBS. *See also* Study, sections 10.5.2.1-10.5.3 (discussing the triggers for Formula Rates I and II). Without the flexibility to acquire non-Federal balancing reserve capacity during the rate period to continue to provide VERBS, VERBS customers could be subjected to significant reliability and operational restrictions if it were no longer physically feasible for BPA to provide the forecast balancing reserve capacity for VERBS from the FCRPS. These restrictions would need to remain in place until BPA established a rate pursuant to a potentially costly and time-consuming section 7(i) rate proceeding *and* completed any necessary purchases of non-Federal balancing reserve capacity and any technical and operational modifications to accommodate such balancing reserve capacity. Given the amount of time it takes to conduct a full section 7(i) rate proceeding and the potential for delays, it is likely that BPA would not have a rate in place until the last year of the rate period, or months before the start of the FY 2014-2015 rate period.

Finally, a 7(i) rate proceeding would require re-litigation of the merits of the very same issues already discussed in this proceeding. Indeed, the primary basis for NWG's argument that BPA should hold a section 7(i) rate proceeding in lieu of the proposed formula rates rests on whether NWG will have adequate notice and comment opportunities before BPA makes any non-Federal balancing reserve capacity purchases. As we discuss further below, we believe our proposed public process regarding non-

Federal balancing reserve capacity is adequate to provide reasonable notice and opportunities to comment.

Q. NWG states that BPA is proposing to move resource acquisition and ratemaking decisions from the statutory 7(i) process into a notice and comment process. Yourkowski and Goggin, BP-12-E-NG-01, at 17. NWG claims that other than a one-time opportunity to make verbal comments at a pubic meeting and an opportunity to file written comments within 15 calendar days, customers will have no ability to question the need or reasonableness of the cost of acquiring long-term resources. Id. NWG states that in the case of short-term purchases (60 days or less), customers are not even entitled to the right of notice or comment. Id. Why is your proposed public process sufficient to give parties notice and comment opportunities regarding purchases of non-Federal balancing reserve capacity?

A. The proposed public process provides the necessary flexibility for BPA to make purchases of non-Federal balancing reserve capacity as necessary to continue to provide VERBS on both a short-term and long-term basis. Moreover, when considering that BPA's rate period is only two years, we believe the proposed public process affords interested parties adequate notice and comment opportunities for any purchases of balancing reserve capacity during this short timeframe.

NWG asserts that customers will not have the ability to question the need or reasonableness of the cost of acquiring long-term resources. *Id.* The intent of the public process is to review BPA's proposed long-term purchases of non-Federal balancing reserve capacity with customers before committing to the purchase. The circumstances requiring such purchases will be publicly available for discussion at the public meeting, and oral and written comments will be taken on the issue. Jackson *et al.*, BP-12-E-BPA-29, at 38.

With regard to short-term purchases of 60 days or less, we believe it is necessary, based on the circumstances (*i.e.*, an inability to provide forecast balancing reserve capacity to continue to provide VERBS) to give notice to customers after-the-fact for these purchases. BPA's response to the trigger conditions for Formula Rates I and II must occur quickly to maintain system reliability and the forecast level of quality of VERBS. During the rate period, however, BPA will make reasonable efforts to effectively communicate with customers and be accountable for short-term purchases of balancing reserve capacity. At the same time, we acknowledge that BPA will need the flexibility to make business decisions to purchase additional balancing reserve capacity on a short-term basis. We believe this is the best balance between meeting the needs of VERBS customers and BPA's legitimate business interests.

Q. NWG argues that if BPA is capable of providing balancing reserves from the FCRPS, BPA should not be unnecessarily incurring additional costs on behalf of its transmission customers. Yourkowski and Goggin, BP-12-E-NG-01, at 15. Do you agree?

A. No. We disagree that BPA should make additional Federal balancing reserve capacity available mid-rate period from the FCRPS for VERBS beyond the amount forecast in this rate proceeding. During the rate period, cost shifts to other customers would result from additional and un-forecast use of FCRPS resources to provide VERBS as opposed to making purchases of non-Federal balancing reserve capacity. To avoid such cost shifts, BPA would be required to revisit rate case allocations of FCRPS resources and costs mid-rate period. This analysis would be based on the un-forecast availability of FCRPS balancing reserve capacity to supply VERBS customers for the remainder of the rate period. Reconciling these issues during the rate period would require a potentially time-consuming and costly section 7(i) rate proceeding, essentially revisiting all rate case input forecasts.

Even if BPA were unconcerned with potential mid-rate period cost shifts associated with un-forecast use of FCRPS capability, we believe it would be imprudent to forgo the proposed formula rates and choose to rely on the uncertain availability of additional FCRPS capability to provide VERBS. In this rate proceeding, we have proposed Formula Rates to recover costs that will be incurred only if purchases of additional balancing reserve capacity are necessary during the rate period to continue to provide VERBS. *See also* Study, sections 10.5.2.1 and 10.5.3. We continue to believe that our Initial Proposal delineates appropriate boundaries for the FCRPS ability to provide VERBS service during the rate period.

Q. NWG disagrees that purchases of non-Federal balancing reserve capacity during the rate period will be used solely to provide VERBS during the rate period. Yourkowski and Goggin, BPA-12-E-NG-01, at 15-16. NWG asserts that "any incremental acquisitions of balancing reserves would be used to meet BPA's total system balancing obligations." Id. at 15. NWG explains that BPA does not segregate its use of balancing reserves between and among different customers and that BPA deploys its balancing reserves in response to a net signal comprised of loads and generating resources, which include, but are not limited to, wind generating resources. Id. at 15-16. NWG argues that BPA's balancing reserves are not "color-coded' for the VERBS customers or the Load Following Reserves customers. Id. at 16. Why is it appropriate to allocate the costs of non-Federal balancing reserve purchases only to the VERBS rate?

A. BPA Staff has forecast a significant increase in the amount of wind generation integrating into the BPA balancing authority area during the rate period. Documentation, Table 2.1. If BPA did not offer VERBS or integrate variable energy resources, BPA would have sufficient FCRPS balancing reserve capacity available to provide the forecast balancing reserve capacity requirements for forecast loads and other resources in the BPA balancing authority area. In that case, it would be unnecessary to make non-Federal purchases of balancing reserve capacity. Accordingly, we believe assigning the costs of non-Federal balancing reserve capacity purchases to provide VERBS during the rate period is consistent with the principle of cost causation and is, therefore, appropriate. *See* Mainzer *et al.*, BP-12-E-BPA-23, at 10.

Q. NWG states that under BPA's formula rate proposal, BPA is, in effect, requesting the ability to purchase as many balancing reserves as it determines it needs, in its sole discretion, with a blank check drawn on the account of the VERBS customers. Yourkowski and Goggin, BP-12-E-NG-01, at 17. Under this "pass through" proposal, NWG claims, BPA will have little to no incentive to manage costs, especially with respect to short-term purchases. Id. NWG argues that there are no limits on the potential rate increases that could be passed through to customers taking service under the VERBS rate, but that other rate adjustments, such as the CRAC, are subject to limits. Id. What is your response?

A. We disagree with NWG that the proposed formula rates provide no incentive for BPA to minimize costs. The purpose of the proposed formula rates is not to arbitrarily increase costs to VERBS customers. To the contrary, the proposed formula rates are designed to ensure that BPA can continue to provide the expected quality level of balancing service to all VERBS customers during the rate period. The proposed rates also ensure that those who create the costs bear the costs.

Moreover, BPA does not operate in isolation, independent from public review or scrutiny. Indeed, one of primary goals in designing the proposed formula rates was to ensure transparency through the process. We proposed a public process specifically to ensure customer review of BPA's decisions regarding non-Federal balancing reserve capacity purchases. The proposed public process provides an additional check to ensure that BPA incurs only reasonable costs that are necessary under the circumstances. We recognize that customers will not have advance notice of balancing reserve capacity purchases of a term of two months or less. However, we believe this flexibility is necessary for BPA to maintain system reliability while continuing to provide VERBS to its customers.

We also note that the potential cost exposure under proposed Formula Rate I is not unlimited. Cost recovery under the proposed Formula Rate I is limited to the amount of balancing reserve capacity that is necessary to maintain BPA's balancing reserve capacity quantity forecast for the rate period. Formula rate I does not recover costs for un-forecast increases in VERBS service levels.

The proposed Formula Rate II may be triggered by a request for increased service levels above 99.5 percent or because DSO 216 curtailments are restricted by rule or court decision. Study, section 10.5.3. However, we do not believe the cost exposure under Formula Rate II is unreasonable. In the event that the proposed Formula Rate II is triggered, any BPA purchase of non-Federal balancing reserve capacity would be for the purpose of continuing to provide VERBS to BPA's customers at the requested or required quality level of service. Moreover, given that BPA would not need to purchase non-Federal balancing reserve capacity but for the growth and balancing requirements of wind generators (Documentation, Table 2.1), we strongly disagree with NWG's assertion that the proposed formula rates constitute a blank check for BPA.

In addition, DSO 216 serves as BPA's primary tool for managing reliability of the BPA balancing authority area and for enforcement of limits on BPA's balancing reserve capacity commitment. Mainzer *et al.*, BPA-12-E-BPA-23, at 6. In the event BPA's use of DSO 216 is prohibited, Formula Rate II allows BPA to recover the additional costs of maintaining service level and system reliability. This point is critical when considering that the alternatives include limiting or degrading balancing services for VERBS customers to maintain system reliability until, as NWG suggests, a rate for balancing reserve capacity purchases can be established or costs are shifted to other customers that do not take VERBS.

Q. PPC disagrees with BPA Staff's net cost approach under Formula Rate I. Baker et al., BP-12-E-PP-01, at 20-21. Please explain what you consider to be PPC's concerns?

A. PPC argues that the total cost of the purchase should be added to the VERBS rate. *Id.* at 20. PPC explains that rates for all customers are based on forecasts and all customers take the risk that forecasts will be wrong. *Id.* PPC states that the fact that the forecast was wrong or a piece of equipment breaks does not relieve the customer from the need to pay the full rate. *Id.* at 20-21. PPC argues that because these purchases are inherently incremental, there is no rationale for allocating the net cost of the purchase to the VERBS rate. *Id.* 21. PPC states that were BPA to allocate only the net cost to VERBS, the balance of the cost of the purchase would be allocated to the Tier 1 power customers as a group; although they did not cause the cost to be incurred and do not benefit from its incurrence. *Id.* PPC states that, this cost shift is contrary to BPA's stated policy of not creating such cost shifts. *Id.* Therefore, PPC argues, BPA should apply the gross cost approach to both the first and second formula rates. *Id.*

Q. How do you respond to PPC's concerns about the proposed Formula Rate I?

A. BPA has proposed to implement Formula Rate I only in the event of unexpected loss of FCRPS ability to supply balancing reserve capacity. Without the net cost calculation, customers paying a VERBS rate adjusted by the Formula Rate I would be paying additional duplicate costs for reserves supplied by third parties. These third party reserves would replace FCRPS services that, by definition, were unavailable. Power customers benefit from the provision of reserves from the FCRPS through a revenue credit based on forecast sales of reserves. Under the net cost approach, power customers and reserves customers share the cost of the inability of the FCRPS to supply these forecast reserves. Consequently, we believe that charging VERBS customers twice for the same supply of balancing reserve capacity would be inappropriate.

Q. How does the CRAC apply to the VERBS formula rates?

A. For both Formula Rates I and II, only the underlying imbalance rate will be affected by CRAC. Lovell *et al.*, BP-12-E-BPA-37, at 4.

The proposed Formula Rate I is:

Adj Imb Rate = Imb rate + (Avg Net Cost / Avg Sales)

Any CRAC declared during the rate period will apply only to the Imbalance rate term (Imb rate) before the Formula Rate I Adjusted Imbalance Rate is calculated. *Id.*

The Proposed Formula Rate II is:

Adj Imb Rate = Imb rate + (Avg Cost / Avg Sales)

Any CRAC declared during the rate period will apply only to the Imbalance rate term (Imb rate) before the Formula Rate II Adjusted Imbalance Rate is calculated. *Id.*

Section 3.3: VERBS Supplemental Service Rate

Q. What is VERBS Supplemental Service?

A. As described in Kitchen *et al.*, BP-12-E-BPA-45, the proposed VERBS Supplemental Service is an optional service for VERBS customers. For customers that choose to purchase the proposed VERBS Supplemental Service, BPA would make available additional amounts of non-Federal balancing reserve capacity to decrease the number of curtailments a particular variable energy resource would face under DSO 216. Kitchen *et al.*, BP-12-E-BPA-45.

Q. How do you propose to recover the cost for VERBS Supplemental Service?

A. We propose to add a formula rate under the VERBS rate schedule to recover the total costs of non-Federal balancing reserve capacity purchases to provide VERBS Supplemental Service from VERBS customers that request VERBS Supplemental

Service. Under the proposed formula rate, the total cost of non-Federal balancing reserve capacity purchased to serve a VERBS Supplemental Service customer will be passed through to that customer. When more than one customer is served concurrently, all customers will be offered service at the same averaged rate.

The proposed VERBS Supplemental Service formula rate is a stand-alone rate and does not adjust the base VERBS rate. The monthly rate will vary depending on the total cost and purchase term of any non-Federal balancing reserve capacity to satisfy the customer's VERBS Supplemental Service request. The VERBS Supplemental Service rate will apply to only specific requests by individual customers over time periods defined in the business practice that is developed for this product outside of this rate proceeding.

As described in Kitchen *et al.*, BP-12-E-BPA-45, BPA Staff propose to include an administrative charge in the VERBS Supplemental Service rate to cover the costs incurred to implement this service. *See also* Attachment 1, ACS-12 Rate Schedule, VERBS Rate, section E.6(a) (Supplemental Service); Nelson, BP-12-E-SC-01, at 20 (supporting cost recovery for administrative costs associated with a VERBS Supplemental Service).

Q. Why is a formula rate necessary to recover the cost of VERBS Supplemental Service?

A. As mentioned above, BPA will provide the proposed VERBS Supplemental Service only in response to specific customer requests for such service. As a result, the VERBS Supplemental Service customer is solely responsible for determining its comfort level with regard to price and purchase period. The VERBS Supplemental Service rate is necessary to recover the total cost of providing VERBS Supplemental Service solely from the customer requesting VERBS Supplemental Service, and ensure that the users of VERBS Supplemental Service do not shift costs to customers that do not use such service.

Q. Who will be subject to the proposed VERBS Supplemental Service rate?

A. Only customers that commit to take VERBS Supplemental Service will be subject to the VERBS Supplemental Service rate. *Id.*

Q. What type of reserves will BPA make available under the proposed VERBS Supplemental Service?

A. BPA will make only additional *inc* balancing reserve capacity available to provide VERBS Supplemental Service to customers. *Id.* at 7.

Q. How will the VERBS Supplemental Service rate be calculated?

A. The VERBS Supplemental Service rate will be the average cost of supplemental *inc* balancing reserve capacity purchased by BPA for all customers that request VERBS Supplemental Service during the period of the purchase. The VERBS Supplemental Service rate is calculated by dividing the total purchase cost by the total MW purchased, then adding the administrative charge. Accordingly, each customer's monthly total billing amount is equal to the monthly VERBS Supplemental Service rate times its monthly megawatt imbalance reserve purchased. *See* Attachment 1, ACS-12 Rate Schedule, VERBS Rate, section E.6 (Supplemental Service). We note that the proposed VERBS Supplemental Service rate is calculated and applied independently from the proposed VERBS Formula Rates I and II, and depends only on the cost and quantity of the reserves that are purchased to provide VERBS Supplemental Service to the customer.

Q. Will BPA's CRAC, Dividend Distribution Clause (DDC) and NFB Mechanisms apply to the proposed VERBS Supplemental Service rate?

A. No. *Inc* balancing reserve capacity that is used to provide supplemental balancing reserve service will be purchased from third party non-Federal sources. Since the CRAC, DDC, and NFB Mechanisms apply only to rates recovering FCRPS costs, such rate adjustments will not apply to VERBS Supplemental Service. Mainzer *et al.*, BP-12-E-BPA-42, section 6.1.

Section 3.4: VERBS Rate for Solar Resources

Q. *Snohomish and NWG argue that BPA lacks any evidence to support the proposed VERBS rate for solar resources, and that BPA should wait until it has actual data about the performance and operating characteristics of grid-tied solar electricity facilities in its balancing authority before establishing a VERBS rate for solar resources. Miles and Deren, BP-12-E-SN-02, at 1, 3-4; Yourkowski and Goggin, BP-12-E-NG-01, at 21, 28. In response to the parties' concerns, did you perform any additional analyses to support a VERBS rate for solar resources?*

A. Yes. BPA Staff's forecast of solar resources expected during the FY 2012-2013 rate period is evolving. We now expect 34 MW of solar resources by the end of the rate period, and this expectation may be further revised prior to the BP-12 Final Proposal. Puyleart *et al.*, BP-12-E-BPA-43, section 3. Since the Initial Proposal, we have evaluated solar within-hour variability using hemispherical integrated pyranometer data obtained from the University of Oregon Solar Radiation Monitoring Laboratory (SRML). We do not have any scheduling data, but we believe the University of Oregon data set can be used to assess the Regulation and Following imbalance components required to balance solar resources.

Q. *Why is it reasonable to use that solar data as a proxy for grid-tied solar operational and performance data?*

A. Output from a grid-tied solar photovoltaic array is directly related to the radiation received by the array. The solar data set is the radiation available for the time series data collected at the sites. We believe these data are the best available data to assess solar variability. Attachment 4, List of Solar Data.

Q. Based on that solar data, how did you develop a balancing reserve capacity quantity forecast for solar resources for the rate period?

A. The solar reserve requirement calculation is built to mirror, in concept and to the extent data are available, the analysis done for the VERBS reserve requirement, which excludes solar resources thus far.

As with VERBS, there is a Following component and a Regulation component. The third component of the VERBS reserve requirement, the Imbalance component, was omitted because we have no data on the scheduling accuracy of the operators of solar generation facilities. We expect to reevaluate the imbalance component for future rate periods when sufficient scheduling data from operating facilities is available.

The Following and Regulation reserve requirement components were based on solar radiation observations from a public data repository. The estimated generation is from a software package from the SRML. This package was based upon the National Renewable Energy Laboratory (NREL) program called PVWatt.

The data are from two sites: Silver Lake, Oregon (SIRF prefix), and Challis, Idaho (CLRO prefix.). Silver Lake was selected for calculating the reserves needed for Following because that is where all the photovoltaic generation facilities are forecast to interconnect in 2012 for the FY 2012-2013 rate period. Silver Lake is in Christmas Valley, Oregon. There is a Christmas Valley monitoring station, but on the guidance of the SRML staffer, the Silver Lake station was selected, as it gets weekly cleaning visits from a U.S. Geological Survey (USGS) technician who visits the site for another project. The Christmas Valley site does not get this attention; so the data are assumed to be of lower quality. The Silver Lake data consist of five-minute granularity. This is the finest granularity available at this site.

To calculate the reserves needed for Regulation, we collected the Challis, ID, data because these data are the only clean data in the SRML inventory that have one-minute collection frequency. There are also one-minute data for the solar awning on the University of Oregon campus, but those data contain impacts from morning and afternoon shadows and large quantities of reflected light hitting the units and consists of actual generated kilowatthours from an installation that is fairly old. Given the poor quality of the data and the degradation associated with older photovoltaic (PV) facilities, the more remote site in Challis was preferred to get one-minute irradiance data.

The one-minute irradiance data were needed to estimate the Regulation component of the balancing reserve capacity requirement. This component is an estimate of the fluctuations in generation in the sub-ten minute range and is the same level of granularity that we had in the data used to calculate the VERBS and DERBS rates.

The irradiance data were used to generate the estimated alternating current (AC) power output for a one-kW PV installation at a fixed pitch of 35 degrees. The fixed pitch is the least expensive type of angled installation, and SRML staff stated that the rule of thumb for optimal efficiency of a fixed pitch installation is the latitude minus 10 degrees, or in this case approximately 35 degrees. The generation estimate was done using a Microsoft® Excel add-in called Solar Calculator published by the SRML that is based on the NREL PVWatt program, which is also written for this purpose. The advantage of the SRML product is that it is adapted to read the SRML data format directly, and the SRML was available to consult with us on the appropriate use of the program.

Q. How did you calculate the Following balancing reserve capacity requirement?

A. The average difference from a perfect hourly schedule for each ten-minute period was created from the five-minute estimated generation data. A perfect hourly schedule is the average of all the five-minute periods in the respective hour. These differences were calculated on data from October 1, 2007, through January 31, 2011. The reserve quantity indication for this component is the 99.75 percentile and 0.25 percentile of these differences for *dec* and *inc* following reserve requirements, respectively.

Q. How did you calculate the Regulation balancing reserve capacity requirement?

A. The difference of the one-minute generation from the ten-minute average generation was created from the one-minute data. These differences were calculated from the period from December 1, 2009, through December 31, 2010. The reserve quantity indication for this component is the 99.75 percentile and 0.25 percentile of these deviations for *dec* and *inc* regulation reserve requirements, respectively. As these requirements were scaled to the one kilowatt capacity of the estimated generator in the SRML Solar Calculator, the indicated balancing reserve capacity quantity forecast was derived by scaling from there up to the estimated generation facility size for the rate period.

Q. Based on the data that you analyzed, what is the balancing reserve capacity quantity forecast for solar resources?

A. The total forecast balancing reserve capacity quantities are 4.4 megawatts of *inc* and 4.3 megawatts of *dec*, including both Following and Regulation reserve requirements.

Q. Based on that balancing reserve capacity forecast, what would be the proposed VERBS rate for solar resources?

A. The VERBS rate for solar resources would be $1.40 per kilowatt per month based on the same Cost Allocation Methodology used for the VERBS rate and spread over 22.8 MW of installed capacity over the rate period. Attachment 5, VERBS Solar Cost Allocation.

Q. Do you propose to base the VERBS rate for solar resources on that balancing reserve capacity forecast?

A. No. Although our analysis supports the establishment of a higher rate, we are aware that the balancing reserve capacity quantity forecast does not reflect the benefit that a diversity of additional resource types such as wind and non-Federal thermal and the effect of load variation may bring to reduce the reserve requirement. Thus, as an alternative and preferred approach, we propose to establish a VERBS rate for solar resources based on one-half of the VERBS regulation and following component rates, for a total VERBS solar rate of $0.21 per kilowatt per month. In our opinion, it is reasonable to focus the solar rate primarily on Regulation and Following costs for the first rate period and allow time for development of historic data, as we did for wind resources in the 2009 Wind Integration case. The alternative to our preferred approach is to adopt a higher rate based on the actual solar data and resulting balancing reserve capacity quantity forecast. We will continue to evaluate solar operational data during the rate period and propose adjustments as necessary in the next rate proceeding.

Q. What is the revenue forecast for your proposed VERBS rate for solar resources?

A. The revenue forecast for the proposed VERBS solar resource rate is $57,540 per year, based on a rate of $0.21 per kilowatt per month and an installed nameplate capacity averaging 22.8 MW per month over the rate period.

Q. If you are not proposing to base the solar rate on your analysis of solar data, why are you including this analysis with your testimony?

A. We included our analysis to inform policymakers and the BP-12 parties that solar resources are likely to contribute significantly to the balancing reserve capacity requirements of the BPA balancing authority. It is important to recognize that there are tangible costs associated with these resources, and our analysis supports the establishment of a rate to recover those costs.

Q. Are you proposing any changes to the VERBS billing factor for solar resources?

A. No, not for the rate period. We may propose to modify the rate design in future rate periods to establish a billing factor based on the station control error, similar to the proposed modification to the DERBS rate design. In addition, once we have scheduling data for these resources, we may further refine our methodology in subsequent rate periods to account for the hourly or scheduling period Imbalance in addition to the Regulation and Following components in the reserve requirements.

Q. Will the parties have an opportunity to review and comment on your revised proposal for solar resources?

A. Yes. BPA intends to file a motion to allow parties to file surrebuttal on our proposed VERBS rate for solar resources. We will also hold a rate case workshop on March 18, 2011, to discuss with the parties the proposed VERBS rate for solar resources, among other things. *See also* Mainzer *et al.*, BP-12-E-BPA-42, at 6-8.

Section 3.5: VERBS Billing Factor

Q. Are you proposing any other revisions to the VERBS rate schedule?

A. Yes. We are proposing a minor change to the billing factor for VERBS as follows:

> 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 will be <u>the greater of the maximum one-hour generation or</u> the nameplate of the plant in kW. A unit has completed installation when it has generated and delivered power to the BPA system.

See also Attachment 1, ACS-12 Rate Schedule, section E.2(b), Variable Energy Resource Balancing Service Billing Factor.

Q. Why are you proposing this change to the VERBS billing factor?

A. We have several instances where there is a mismatch between the reported nameplate capacity and the actual maximum output of the facility. This is typically only a few megawatts per plant, but there is a cumulative effect, and the balancing above the reported nameplate is an uncompensated use of balancing reserves.

Q. Will parties have an opportunity to comment on this proposed change?

A. Yes. BPA intends to file a motion to allow surrebuttal on this issue. We also intend to have a rate case workshop on March 18, 2011, which will include this issue in the agenda.

Section 4: Persistent Deviation for Imbalance Services

Section 4.1: Need for and Effectiveness of Persistent Deviation

Q. Have you read all parties' testimony on Persistent Deviation?

A. Yes, we have read and considered all parties' testimony on Persistent Deviation. Although NWG did not submit individual testimony on Persistent Deviation, we understand that NWG supports Iberdrola's testimony on Persistent Deviation. Yourkowski and Goggin, BP-12-E-NG-01, at 20-21. In this rebuttal testimony we address Iberdrola's testimony and thereby are also addressing NWG's supporting comments.

Q. In the Initial Proposal, BPA Staff explained why energy accumulation on the Federal system is a serious concern for BPA, and why a Persistent Deviation penalty is necessary. Study, section 10.8.6.2. Have parties challenged the legitimacy of the concerns you are trying to address with the Persistent Deviation penalty?

A. No. Parties have acknowledged that energy accumulation and other problems we are trying to address with the Persistent Deviation penalty are legitimate concerns. Iberdrola states that "Bonneville's testimony clearly articulates the constraints under which the FCRPS operates and presents good arguments for the need to minimize scheduling errors and the associated generation imbalance." Froese *et al.*, BP-12-E-IR-01, at 28. JP01 states that it "understand[s] BPA's concerns regarding biased scheduling errors and the large accumulation of imbalance energy associated with that bias." Skeahan *et al.*, BP-12-E-JP01-01, at 16-17.

The problems and risks we are addressing with the Persistent Deviation penalty are significant, and constraints on the hydro system are expected to increase. The amount of wind forecast to be integrated into the BPA balancing area during the FY 2012-2013 rate period is expected to nearly double from present levels. In addition, we have proposed to set the quantity of balancing reserve capacity to provide VERBS based on

30-minute persistence scheduling. Puyleart *et al.*, BP-12-E-BPA-24, at 18. We view the Persistent Deviation penalty as a risk mitigation measure to help ensure that customers schedule accurately and meet or come close to meeting the scheduling assumption on which the reserve quantity is based. The alternative to managing risk is to further limit the quantity of reserves provided from the FCRPS to ensure that operations can remain within the constraints.

Q. Iberdrola states that BPA has not proven that the Persistent Deviation penalty is causing more accurate scheduling; rather Iberdrola suggests that any reduction in Persistent Deviations is quite likely due to "improvement in scheduling skill." Froese et al., BP-12-E-IR-01, at 28. Iberdrola also describes improvements it has made in forecasting. Attachment 6, Data Request BPA-IR-18. What is your response?

A. We disagree with Iberdrola's broad statements regarding the efficacy of the Persistent Deviation penalty. Essentially, Iberdrola argues that the Persistent Deviation penalty may have had no effect on scheduling accuracy improvement, and that any reduction in Persistent Deviations may be due to improved scheduling skill during the study period. Froese *et al.*, BP-12-E-IR-01, at 28. To support this argument, Iberdrola cites to a variety of initiatives that it undertook to improve its forecast accuracy during the study period. Attachment 6, Data Request BPA-IR-18. We support Iberdrola's efforts to improve its scheduling accuracy. We recognize that improving schedule accuracy is the primary mechanism for reducing scheduling error and avoiding Persistent Deviation penalties. Therefore, suggesting that reduction in Persistent Deviations is due to improved scheduling accuracy supports the idea that the penalty has been effective in motivating parties to improve their forecasting practices and schedule more accurately. The presence of a penalty and negative economic consequences of poor scheduling accuracy is inherently more likely to motivate change than the absence of such a penalty.

Although NWG supports Iberdrola's argument, NWG concedes that they "have not conducted any independent analysis regarding advancements and improvements in scheduling accuracy over the last two years." Attachment 7, Data Request BPA-NG-36.

In addition to providing motivation for improvements that help parties to avoid penalties, the Persistent Deviation penalty serves as a deterrent for parties that may otherwise engage in poor scheduling practices. The impact of schedule error on BPA is the same regardless of its cause, and our study showed that persistent schedule errors declined when the penalty was enforced. Study, section 10.8.5.1. Iberdrola and NWG offer no proof that the Persistent Deviation penalty is not working, and other parties acknowledge that the Persistent Deviation penalty is working. JP01 states, "[w]e agree with Staff's conclusions that the current Persistent Deviation Penalty Charge seems to have resulted in less large and persistent scheduling errors." Skeahan *et al*., BP-12-E-JP01-01, at 16.

Q. Iberdrola states that the proposed Persistent Deviation penalty will not result in improved scheduling; rather, the proposed Persistent Deviation penalty will lead to "poor and arbitrary" scheduling. Froese et al., BP-12-E-IR-01, at 28-29. Similarly, Southern California Edison Company (SCE) states that the Persistent Deviation penalty does not incentivize accurate scheduling. Nelson, BP-12-E-SC-01, at 23-24. What is your response?

A. We disagree that the Persistent Deviation penalty incentivizes poor and arbitrary scheduling and note that nothing in the rate proceeding record supports such a conclusion. Although NWG argues that the Persistent Deviation penalty creates a financial incentive for generators to schedule to avoid the penalty, it concedes that "NWG has no first-hand knowledge of this actually occurring . . . ." Attachment 8, Data Request BPA-NG-34. Moreover, both NWG and Iberdrola state that they have not engaged in poor and arbitrary scheduling in the past, despite the fact that Persistent Deviation has been in effect since October 1, 2009. *Id.*; Attachment 9, Data Request BPA-IR-22. This fact is critical, because Iberdrola and NWG's members operate a significant portion of the wind fleet interconnected to BPA.

We acknowledge, however, that it is possible that a scheduling entity could choose to adopt poor or biased scheduling practices that have the potential to result in schedule error that deploys excessive amounts of balancing reserve capacity for one party or that produces large amounts of energy accumulation on the system. The possibility for such scheduling behavior to occur supports the need for a tool such as the Persistent Deviation penalty to manage the risks associated with large or persistent deviations. Indeed, one of the goals of the proposed Persistent Deviation penalty is to deter "an ongoing practice of submitting generation schedules that significantly vary from the best forecasting information available to the scheduler at the time the schedule is due." Attachment 9, Data Request BPA-IR-22 (defining "poor and arbitrary" scheduling practices). We note that since the Persistent Deviation penalty was implemented in October of 2009, there has been a significant decline in instances of schedule error that produce large amounts of energy accumulation on the system. Study, section 10.8.5.1. Additionally, "poor and arbitrary" scheduling is not required to avoid the penalty, since a schedule that is accurate to within the Persistent Deviation criteria and does not display a pattern of bias would not be subject to penalty.

Q. *SCE suggested that the structure of the Persistent Deviation penalty effectively exempts small facilities from the penalty. Nelson, BP-12-E-SC-01, at 24. What is your response?*

A. We agree with SCE's observation that the 20 MW band effectively exempts smaller wind plants from the shorter time window criteria. The penalty is targeted toward larger schedule errors that persist for three or four hours and toward smaller schedule errors if they persist for long periods of time. As the number of wind plants in the BPA balancing authority area grows, we may need to reconsider the 20 MW level of exemption, but we do not propose to do so in this rate proceeding.

Section 4.2: Proposed Shift from 4-Hour to 3-Hour Window

Q. You have proposed that the Persistent Deviation window move from 4 to 3 hours for deviations that are 15 percent of schedule and 20 MW once the intra-hour scheduling is implemented. Jackson et al., BP-12-E-BPA-29, at 19-20. Several parties oppose this shift to 3 hours. Specifically, Iberdrola states that BPA has not demonstrated a need for the switch to 3 hours, and that the only justification BPA has provided for the move to a 3-hour standard is the proposed exemption for scheduling that meets 30-minute persistence forecasting. Froese et al., BP-12-E-IR-01, at 24-25. What is your response?

A. Iberdrola's assertion that the proposed exemption for scheduling that meets or beats a 30-minute persistence forecast is BPA's only justification for the change to 3 hours is incorrect. When intra-hour scheduling is implemented and the proposed 3-hour standard is adopted, parties will have five to six opportunities to correct their schedules as opposed to the four opportunities currently available under a 4-hour standard and hourly scheduling, and Persistent Deviation is intended to motivate corrections to occur as soon as possible. In our Study and direct testimony, we explained why the move to 3 hours is necessary. Study, section 10.8.9.1; Jackson *et al.*, BP-12-E-BPA-29, section 5.2. For example, accumulation of imbalance energy poses risks to hydro system operations if there is insufficient market depth. Study, section 10.8.6.2. Patterns of bias in schedule error result in unanticipated impacts on planned operations. *Id.* Our analysis showed that refining the Persistent Deviation criteria would identify and penalize more of the potential imbalance accumulation associated with schedule errors. Documentation, Table 10.8. We anticipate that if scheduling entities submit more accurate schedules to avoid the penalty, imbalance accumulation and average schedule error will be reduced. Parties' assertions that scheduling entities will choose bad scheduling behavior to avoid the penalty ignore the fact that a perfect schedule (or one within 20 MW of actual plant output) would avoid the penalty. We expect scheduling entities to act in good faith to improve schedule accuracy to avoid the penalty, rather than engaging in poor and arbitrary scheduling.

In addition, the parties' general arguments against a 3-hour time window do not refute the substantial evidence supporting BPA's need to reduce schedule error and energy accumulation. Although Iberdrola disagrees that the Persistent Deviation penalty will improve scheduling accuracy, as noted above, Iberdrola specifically acknowledged that "Bonneville's testimony clearly articulates the constraints under which the FCRPS operates and presents good arguments for the need to minimize scheduling errors and the associated generation imbalance." Froese *et al.*, BP-12-E-IR-01, at 28. Accordingly, our proposal to reduce the time window to measure Persistent Deviations from 4 to 3 hours is intended to help minimize scheduling errors over time and to reduce energy accumulation on the system.

Q. The Public Utility Commission of Oregon (OPUC) states that if the Persistent Deviation window moves from 4 to 3 hours, there is substantial risk that schedulers will submit schedules to avoid the penalty, and they will not schedule on best available information. Muldoon, BP-12-E-PU-01, at 7-8. Do you agree?

A. No. The OPUC has not provided any material evidence to support its assertion that moving the window from 4 to 3 hours will cause "a substantial risk …that [Variable energy resource] operators may override their best judgment and submit schedules designed to avoid penalties." Muldoon, BP-12-E-PU-01, at 7-8. As noted in a previous response, parties have submitted no evidence in support of the argument that wind generators are incentivized to perform poor or arbitrary scheduling in order to avoid the Persistent Deviation penalty. To the contrary, the parties indicate that the Persistent Deviation penalty has not incentivized such behaviors. Attachment 8, Data Request BPA-NG-34; Attachment 9, Data Request BPA-IR-22.

Q. Do customers have opportunities to avoid the Persistent Deviation penalty?

A. Yes. The proposed Persistent Deviation penalty under the 3-hour timeframe is avoidable. Even if a customer intentionally neglects its good faith obligation to schedule accurately in all schedule intervals in an effort to avoid the proposed Persistent Deviation penalty, we believe a 3-hour time window is appropriate given the availability of intra-hour scheduling. With the advent of intra-hour scheduling, parties have at least four opportunities to correct their schedules once they notice significant schedule errors. For example, if a schedule error is noticed in the first half of a delivery hour, at 12:10, a schedule adjustment can be made at 12:30, at 1:00, at 1:20, at 2:00, or at 2:30 to improve schedule accuracy at any of those times before the error has persisted in the same direction for 3 hours. The ability to schedule on an intra-hour basis helps an entity avoid Persistent Deviations.

Q. You have proposed that BPA would give 30 days' notice before moving from the 4-hour duration to the 3-hour duration. WPAG argues, however, that BPA should provide 90 days' notice before moving to a 3-hour duration. Saleba et al., BP-12-E-WG-01, at 40. What is your response?

A. We understand that parties may need time to put contracts in place that allow intra-hour scheduling. We agree with WPAG that a 90-day notice period may be more appropriate. Therefore, we propose to give customers 90 days' advance notice before modifying the time window from 4 hours to 3 hours to measure Persistent Deviations.

Section 4.3: Application of 3-Hour Persistent Deviation Window to Load

Q. PPC argues that it is inappropriate to move from a 4-hour to 3-hour duration for load deviations that are 15 percent of schedule and 20 MW because preference customers are committed to scheduling on an hourly basis in their long-term power sales contracts. Baker et al., BP-12-E-PP-01, at 24-25. WPAG similarly argues that customers that have *contracts that call for scheduling on an hourly basis should not be subject to the change. Saleba et al., BP-12-E-WG-01, at 40. PPC argues that preference customers should either be exempt from Persistent Deviation completely or that Persistent Deviation should be applied to these customers in its current form. Baker et al., BP-12-E-PP-01, at 25. What is your response?*

A. Customers that purchased load following service from BPA under their Regional Dialogue contracts would not be subject to Persistent Deviation because they do not submit schedules. Slice customers will be able to schedule non-Federal resources on an intra-hour basis, provided they negotiate contracts for such service, and they need to be able to schedule only some (not all) of their resources on an intra-hour basis in order to avoid Persistent Deviations. In fact, load service customers scheduling hourly are expected to be able to avoid nearly all Persistent Deviations. Study, section 10.8.9.1.3. We believe it would be inappropriate to completely exempt load schedules from the penalty because the risk of poor scheduling and large or persistent deviations exists for these types of schedules as well as for variable energy resource and dispatchable energy resource schedules. Although we showed that it was unlikely that loads would incur Persistent Deviations under either the 4-hour or 3-hour criterion, we believe the penalty is necessary as a deterrent and serves an important risk mitigation purpose. *Id.*, section 10.8.9.1.2.

Q. WPAG argues that the change to a 3-hour window should not apply to load because load is subject to Energy Imbalance Service Deviation Band 3, and the proposed Persistent Deviation exemption for scheduling that meets 30-minute persistence does not apply to load. Saleba et al., BP-12-E-WG-01, at 37-41. WPAG also argues that because load is subject to Energy Imbalance Service Deviation Band 3, whereas wind is exempt from Generator Imbalance Service Deviation band 3, the Persistent Deviation penalty is "duplicative and unnecessary" for load. Id. at 37. Is Deviation Band 3 in the Energy

Imbalance and Generation Imbalance rate schedules sufficient to protect against the risks of large or persistent deviations?

A. We believe that the Persistent Deviation penalty is needed even though customers also face Deviation Band 3 energy or generation imbalance service charges. We disagree that the Persistent Deviation criteria are duplicative of imbalance energy charges. The energy and generation imbalance bands are intended to cover costs of relatively small deviations that are short in duration. We have observed instances in which schedule errors are large and/or persistent, and have established the Persistent Deviation penalty to manage risks associated with large or longer-term Persistent Deviations. Because loads can have large and persistent schedule errors we believe it is necessary to apply Persistent Deviation to loads in addition to Energy Imbalance Deviation Band 3. Wind schedules are exempt from Deviation Band 3, and we are proposing an exemption for wind schedules that meet or beat 30-minute persistence schedules because that is the base level of schedule accuracy that we used to establish the balancing reserve capacity requirement. In recognition of these factors and WPAG's concerns, retaining the 4-hour criteria for loads would be reasonable given the historical scheduling accuracy of load and the likelihood that load will be unable to utilize the proposed 30-minute persistence scheduling exemption for Persistent Deviations. We are refining what was proposed in our Initial Proposal to clarify that the 30-minute persistence exemption applies only to variable energy resources scheduling intervals.

Q. JP01 has concerns about moving from 4 to 3 hours and would support it only if the following three components are achieved: (1) all of the systems needed for intra-hour scheduling are in place and working well, (2) liquid intra-hour markets are in place in the Pacific Northwest, and (3) to the extent that Persistent Deviation applies to energy imbalance service, BPA permits intra-hour scheduling of the slice product. Skeahan et al., BP-12-E-JP01-01, at 17-18. What is your response?

A. We have proposed that the change from 4 to 3 hours would occur when intra-hour scheduling is available. BPA cannot control when other utilities may choose to put systems in place. Because intra-hour scheduling can be done through bilateral contracts, however, we do not believe it is necessary to delay implementation of a 3-hour standard until liquid markets exist.

We do not propose to permit intra-hour scheduling of the Slice product, but we expect that the parties that want or need access to intra-hour scheduling may do so with resources they own or enter into new contractual agreements to access intra-hour scheduling for non-Federal resources. Nevertheless, it is important to note that it is not necessary to have the ability to schedule all resources on an intra-hour basis to avoid Persistent Deviation. A customer merely needs the ability to schedule a small amount of resources on an intra-hour basis to avoid Persistent Deviation if the customer's schedule accuracy without intra-hour flexibility is such that they are at risk. For example, a 300 MW load that has difficulty scheduling accurately to within 45 MW would need perhaps 10-20 MW of up-or-down flexibility within-hour to be able to tune their energy taken to avoid the penalty.

Finally, our study indicates that schedules to load are not significantly impacted by either the 4-hour or 3-hour Persistent Deviation penalty criterion. Study, section 10.8.9.1.2. In examining past instances of Persistent Deviations applied to load, we concluded that the penalty could be avoided by more accurate scheduling. Several load customers have already fixed the underlying causes of their Persistent Deviations. Others appear to be scheduling flat blocks when they should adjust their schedules, a problem that could be easily remedied by adjusting their schedules to reflect their forecasts. *Id.*, section 10.8.9.1.3.

Section 4.4: Application of 3-Hour Persistent Deviation Window to Dispatchable Energy Resources

Q. WPAG raises the same concerns regarding changing the 4-hour window to a 3-hour window for dispatchable generators as it raised for load. Saleba et al., BP-12-E-WG-01, at 37-41. WPAG argues that dispatchable generators should not be subject to the change to 3 hours because dispatchable generators are subject to Generation Imbalance Band 3 and because the proposed 30 minute persistence exemption does not apply to them. Id. WPAG also argues that because dispatchable resources are subject to Energy Imbalance Service Deviation Band 3, the Persistent Deviation penalty is "duplicative and unnecessary" for dispatchable resources. Saleba et al., BP-12-E-WG-01, at 37. What is your response?

A. Unlike loads and variable energy resources, dispatchable energy resources are not subject to unpredictable variations. Based on the controllable nature of dispatchable resources, an entity should always be able to meet its schedule on the hour. We expect that, absent contingency events, dispatchable energy resources should be scheduling much more accurately than the large and persistent deviations identified for the Persistent Deviation penalty and are highly unlikely to incur Persistent Deviation penalties. We believe it is logical to apply the 3-hour Persistent Deviation criterion to dispatchable energy resources because they are dispatchable and not subject to unpredictable variation (except contingencies, which are exempt from generation imbalance). It is true that the proposed exemption for scheduling that meets or beats 30-minute persistence does not apply to dispatchable energy resources, but that is inconsequential because dispatchable energy resources maintain scheduling accuracy by dispatching the resource rather than using persistence scheduling, making the exemption unnecessary. As explained in the previous section, we do not agree that the applicability of Persistent Deviation is related to whether parties face Deviation Band 3 energy or generation imbalance service charges, and the fact that Deviation Band 3 applies does not make the Persistent Deviation penalty duplicative.

We also believe it would be inappropriate to completely exempt dispatchable resources from the Persistent Deviation penalty because the risk of poor scheduling and large or persistent deviations exists for these types of schedules as well as for variable energy resource schedules and loads. Although it is unlikely that dispatchable energy resources will incur Persistent Deviations under either the 3-hour or 4-hour criterion, it is possible for dispatchable energy resources to neglect to adjust their schedule for several hours when generation changes. We believe the penalty is a deterrent and serves as risk mitigation. We also continue to support the application of the additional longer term criteria proposed in section 2(b-d) of the definition of Persistent Deviation to dispatchable energy resources.

Section 4.5: 30-Minute Persistence Scheduling

Q. Iberdrola asserts that "[t]he hours for which 30-minute persistence is most accurate are those with steady output that don't drive the need for balancing reserves." Froese et al., BP-12-E-IR-01, at 27. Do you agree?

A. No. Reserves deployed can be significant even during periods of relatively stable wind output, or when the wind is not ramping significantly from hour to hour. Using Iberdrola's definition of a wind ramp—that is, changes in hourly generation greater than 10 percent of nameplate—we find that non-ramping periods can contain significant deployments of balancing reserves. We have observed wind schedules apparently attempting to anticipate a ramp that does not materialize for several hours. This can cause significant deployments of balancing reserve capacity as well as accumulated imbalance energy. Figure 1 (Attachment 10 to this testimony) contains a chart illustrating such an event. This example is not extraordinary by any means. The rectangular lines at the bottom of the chart indicate times that would be defined as ramp periods. During the long downward ramp, both the persistence schedule and the wind schedule tracked the actual ramp fairly well, but during the time 0:00 to 13:30 the wind schedule shows significantly more schedule error than the persistence schedule.

A comparison of the actual wind station control error distribution to one based on 30-minute persistence is provided in Figure 2 (Attachment 11) and Table 1 (Attachment 12). The data are fleet-level data from calendar year 2010. Table 1 shows detail of data in the tails of the graph in Figure 2. Figure 2 illustrates that persistence scheduling is better than actual historical wind schedules in the center area of the graph, indicating that on average less balancing reserve capacity would be deployed if the wind fleet were using persistence scheduling than with current scheduling practices.

More specifically, we have observed that over all hours and minutes, 30-minute persistence produces Mean Absolute Error (MAE), Sum of Error (SOE), Root Mean Square Error (RMS) and Accumulated Error (AE) metrics that are superior to those under the fleet-level historical wind schedules. Calculating the same metrics conditioned on being in a ramp shows 30-minute persistence produce (SOE) results that are superior to results under actual historical wind schedules. Calculating the same metrics conditioned upon BPA's balancing reserve capacity deployed exceeding 85 percent shows 30-minute persistence outperforming the actual schedule in all metrics. Table 2 (Attachment 13) summarizes these results. Shaded areas of Table 2 represent the best performance for each measure.

Based on this fleet-level analysis, we believe that for the wind fleet as a whole, encouraging 30-minute persistence as a standard for acceptable schedule accuracy is appropriate and that the frequency and distribution of balancing reserve deployment would be improved if more of the fleet scheduled to this level of accuracy. We recognize that there may be differences within the fleet in current level of scheduling accuracy, and that some wind plants may at times schedule more accurately than 30-minute persistence.

Q. Iberdrola asserts "to the extent the forecast for hours with large wind ramps can be improved, the amount of reserves that must be carried can be reduced." Froese et al., BP-12-E-IR-01, at 27. What is your response?

A. We do not believe that improving forecasts only for hours with large wind ramps would cause significant savings in balancing reserve capacity that is made available for balancing service. Most of the defined "large wind ramps" occur so far out in the tails of the wind station control error distribution that balancing reserve capacity deployed for balancing service would have already been at maximum. In that portion of the distribution of schedule errors, the scheduling entity may benefit in terms of minimizing the amount of generation or schedule affected by DSO 216 feather or curtailment orders, but BPA's balancing reserve capacity estimates already do not include that portion of the distribution of errors. BPA would therefore see little or no savings in balancing reserve capacity costs because most of the events are outside the range of balancing reserve capacity that is made available for wind and load.

Section 4.6: Proposed Additional Persistent Deviation Criteria of Longer Duration and Smaller Amount

Q. The Initial Proposal includes new criteria that will capture the following types of deviations as Persistent Deviations: deviations that exceed both 7.5 percent of the schedule and 10 MW in each scheduled interval for 6 or more consecutive hours; deviations that exceed both 1.5 percent of the schedule and 5 MW in each scheduled interval for 12 or more consecutive hours; and deviations that exceed both 1.5 percent of the schedule and 2 MW in each scheduled interval for 24 or more consecutive hours. Jackson et al., BP-12-E-BPA-29, at 18-19; Documentation, Table 10.4. How do you *respond to Iberdrola's assertion, Froese et al., BP-12-E-IR-01, at 27-28, that BPA has not demonstrated a need for the proposed additional criteria, and that these additional categories will not lead to improved scheduling?*

A. BPA has experienced significant amounts of energy accumulation associated with biased schedules. As we examined patterns of schedule error such as those illustrated in our Study (Study, sections 10.8.5.1-10.8.8, Figures 5-7), we found that many of the longer-term events appear to be avoidable. We analyzed how much of the imbalance energy accumulation could be identified and potentially prevented by applying the additional criteria. Documentation, Table 10.6. Such events could be identified through the general language in Part C of the definition of Persistent Deviation (a pattern of under- or over-delivery of generation or under- or over-use of energy that occurs generally or at specific times of the day; see section 4.8 below), and we also proposed specific and express criteria to address some of the potential scheduling errors that we have already identified. Our Study indicates that additional hours of persistent deviations and imbalance energy accumulation will be captured by the additional criteria, and we believe that parties will avoid these longer-duration, smaller schedule errors if they have economic incentive to do so. *Id.*

Section 4.7: Part C of the Definition of Persistent Deviation

Q. The Initial Proposal includes a minor clarification to Part C of the Persistent Deviation definition in the Initial Proposal. Jackson et al., BP-12-E-BPA-29, at 22. Iberdrola states that it is unclear what language BPA is proposing. Froese et al., BP-12-E-IR-01, at 24. Why are you proposing minor edits to Part C of the Persistent Deviation definition?

A. The original language that is contained in Part C of the 2010 rate schedules reads "c) A pattern of under-delivery or over-use of energy occurs generally or at specific times of day." This language appears to cover only generation imbalance service situations in which actual generation is less than schedule, and energy imbalance service situations in which actual load is greater than schedule. However, the language was intended to cover generation imbalance service situations in which actual generation is both less than or greater than schedule and energy imbalance situations in which actual load is both less than or greater than schedule. A drafting error during the last rate proceeding appears to have contributed to this ambiguity. The proposed language clarifies this intent. We propose that the language read "a pattern of under- or over-delivery of generation or under- or over-use of energy that occurs generally or at specific times of the day." The clarification is intended to ensure that Part C applies to both generation imbalance and energy imbalance.

Section 4.8: Alternative Proposals on Persistent Deviation

Q. Iberdrola states that "Bonneville's proposed Persistent Deviation penalty is overly broad and captures a number of normal conditions that do not involve poor scheduling behavior." Froese et al., BP-12-E-IR-01, at 30. What is your response?

A. Our analysis shows that the proposed Persistent Deviation penalty should usually be avoidable and does not capture an overly broad set of conditions. Under the current standard, Persistent Deviations are occurring for wind plants less than 1 percent of the time in recent months. Even with the new proposed criteria, if wind generators used persistence scheduling, we found that they would incur Persistent Deviation 1 percent of the time or less. Documentation, Table 10.6, lines 1 and 3. We anticipate that providing an economic incentive to improve scheduling accuracy will encourage wind generators to avoid the modified Persistent Deviation criteria. In addition, parties have the ability to request a waiver from the Persistent Deviation penalty if they can show that they took mitigating actions to avoid or limit the Persistent Deviation, or the Persistent Deviation was caused by extraordinary circumstances.

Q. *Iberdrola suggests that BPA provide a volumetric forecast for each wind facility by 60 minutes before the hour of flow, and if the scheduler's schedule meets or beats BPA's forecast, that scheduling hour should be exempt from the Persistent Deviation penalty. Froese et al., BP-12-E-IR-01, at 30. What is your response?*

A. BPA Staff has based its balancing reserve capacity requirement for balancing service for wind on an assumed scheduling accuracy comparable to a 30-minute persistence forecast. Because that is the established standard for VERBS, we propose to use that level of accuracy as a benchmark for Persistent Deviation as well. If BPA were to provide a forecast 60 minutes ahead of time, BPA would be establishing a wider range of schedule accuracy than it used to define the balancing reserve capacity requirement. The balancing reserve capacity requirement would be significantly larger for 60-minute persistence or 60-minute ahead forecasts.

Q. *SCE suggests that in place of a Persistent Deviation penalty, BPA should allocate a portion of the VERBS charge based on hourly performance rather than solely on the installed nameplate. Nelson, BP-12-E-SC-01, at 24. SCE further proposes that if accumulation of imbalance energy is still a problem after the VERBS scheduling performance-based charge, then BPA should allow return of energy "in kind." Id. What is your response?*

A. We are open to considering alternate approaches to cost recovery. Such a rate design likely would be similar to the structure of the DERBS rate. Many parties objected to the use of such an approach for the DERBS rate because of the potential for risk could be concentrated on a few parties for specific hours. We also note that other than a few general concepts, no party has proposed a viable rate design alternative for VERBS to address deviations that are large or persistent. We will continue to remain open to potential alternative approaches to Persistent Deviation in future rate periods.

With regard to in-kind energy returns, in-kind return of energy creates added costs of dealing with schedules and also creates cost risks associated with the timing of such returns. If the return energy schedules are significant, they affect marketing plans going forward. Consequently, we believe that index-based payment for energy use at the time it occurs is easier and less costly to implement and creates less price risk.

Section 4.9: Wind Ramp Calculation Correction

Q. Iberdrola points out that BPA had an error in Table 10.3 of the Generation Inputs Study Documentation, BP-12-E-BPA-05A. Froese et al., BP-12-E-IR-01, at 29. Was there indeed an error in Table 10.3?

A. Yes. Iberdrola was correct, and we have corrected the table and filed an erratum with the corrected numbers and associated text. Erratum to Generation Inputs Study Documentation, BP-12-E-BPA-05A-E02. This correction does not, however, change our conclusion that the percentage of time that wind ramps exceed the Persistent Deviation 20 MW or 15 percent of generation band is very low; wind ramps exceed the Persistent Deviation generation amount for two hours in a row about 1.66 percent of the time, and for three hours in a row only 0.24 percent of the time.

Section 4.10: Proposed Exemption for Committed Intra-Hour Service Pilot Participants

Q. Based on the testimony of Simpson et al., BP-12-E-BPA-46, are you proposing to exempt Committed Intra-Hour Scheduling (CIHS) Pilot participants from the proposed Persistent Deviation penalty charge?

A. Yes.

Q. *Why is it appropriate to exempt CIHS Pilot participants from the Persistent Deviation penalty charge?*

A. Since CIHS participants must abide by BPA's scheduling standards under the pilot, we believe it is appropriate to exempt such schedules from the Persistent Deviation Penalty. Simpson *et al.*, BP-12-E-BPA-46, at 9.

Section 5: Conclusion

Q. *Based on your testimony above, please summarize your changes to the proposed ACS-12 Rate Schedule.*

A. We continue to support the proposed modifications currently contained in the ACS-12 Rate Schedule in BP-12-E-BPA-10, except as modified by our rebuttal testimony and Attachment 1 to this testimony. Attachment 1 contains an excerpt of the proposed ACS-12 rate schedule from the Initial Proposal, with any proposed changes shown in redline. In summary, our rebuttal testimony proposes the following revisions to the proposed ACS-12 Rate Schedule:

1. Updated proposed DERBS rate design and rate;
2. Updated proposed VERBS rate schedule to:
   - (a) Include general descriptions pertaining to the proposed Supplemental Service *(see* Kitchen *et al.*, BP-12-E-BPA-45) and Committed Intra-Hour Pilot Program *(see* Simpson *et al.*, BP-12-E-BPA-46);
   - (b) Update proposed Provisional Balancing Service rate;
   - (c) Update proposed VERBS rate for solar resources;
   - (d) Include new proposed rate for Committed Intra-Hour Scheduling Pilot Program Participants;
   - (e) Include new proposed rate for VERBS Supplemental Service.

3. Updated Energy and Generator Imbalance Service rate schedules regarding the 30-minute persistence exemption for Persistent Deviation;

4. Updated Generation Imbalance Service rate schedule to include the proposed Persistent Deviation exemption for CIHS Pilot participants;

4. Updated General Rate Schedule Provisions to clarify application of the CRAC to the VERBS rate. Attachment 1, ACS-12 Rate Schedule, GRSP, section H. CRAC, DDC, AND THE NFB MECHANISMS; *see also* Mainzer *et al.*, BP-12-E-BPA-42, section 6.1

5. Added proposed "Dispatchable Energy Resource" definition to General Rate Schedule Provisions.

Q. Does this conclude your testimony?

A. Yes.

Attachments

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ATTACHMENT 1

ACS-12
ANCILLARY AND CONTROL AREA SERVICES RATES (EXCERPT)

D. ENERGY IMBALANCE SERVICE

The rates below apply to Transmission Customers taking Energy Imbalance Service from BPA-TS. 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 same basis as the intra-hour scheduling period.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to: i) ± 1.5% of the scheduled amount of energy, or ii) ± 2 MW, whichever is larger in absolute value. BPA-TS 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-TS 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:

(i) 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.

(ii) 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% of the scheduled amount of energy or ± 2 MW, whichever is larger in absolute value, ii) up to and including ± 7.5% of the scheduled amount of energy or ± 10 MW, whichever is larger in absolute value.

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

(ii) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 90% 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% of the scheduled amount of energy, or ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

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

(ii) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 75% 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-TS will post the name of the index to be used on the OASIS at least 30 days prior to its use. BPA-TS will not change the index more often than once per year unless BPA-TS 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:

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

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

(iii) 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:

(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% 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-TS determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA-TS assesses a persistent deviation penalty charge in any schedule interval for a positive deviation, BPA-TS will not also assess a charge pursuant to Section II (D) (1) of this ACS-12 schedule.

Deleted: BPA-TS will remove specific schedule intervals for billing purposes from a persistent deviation event when the deviation is equal to or less than the deviation that would result from 30-minute persistence scheduling for those schedule intervals. ¶

Reduction or Waiver of Persistent Deviation Penalty

BPA-TS, 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.

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 same basis as the intra-hour scheduling period.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to: i) ± 1.5% of the scheduled amount of energy, or ii) ± 2 MW, whichever is larger in absolute value. BPA-TS 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-TS 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:

(i) 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.

(ii) 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% of the scheduled amount of energy or ± 2 MW, whichever is larger in absolute value, ii) up to and including ± 7.5% of the scheduled amount of energy or ± 10 MW, whichever is larger in absolute value.

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

(ii) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 90% 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% of the scheduled amount of energy, or ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

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

(ii) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 75% 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-TS will post the name of the index to be used on the OASIS at least 30 days prior to its use. BPA-TS will not change the index more often than once per year unless BPA-TS 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:

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

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

(iii) For negative deviations (actual generation greater than scheduled) 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:

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-TS).

For positive deviations (actual generation less than scheduled) which are determined by BPA-TS to be Persistent Deviations, the charge is the greater of: i) 125% 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-TS determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA-TS assesses a Persistent Deviation Penalty charge in any schedule interval for a positive deviation, BPA-TS will not also assess a charge pursuant to Section III (B) (1) of this ACS-12 schedule.

For variable energy resources (wind and solar resources), BPA-TS will remove specific schedule intervals for billing purposes from a persistent

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¶

deviation event when the deviation is equal to or less than the deviation that would result from 30-minute persistence scheduling for those schedule intervals.

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

Participants in BPA's Committed Intra-Hour Scheduling Pilot are exempt from the Persistent Deviation penalty charge.

Reduction or Waiver of Persistent Deviation Penalty

BPA-TS, 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. Exemptions from Deviation Band 3

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The following resources are not subject to Deviation Band 3:

(i) wind resources;
(ii) solar resources; and
(ii) new generation resources undergoing testing before commercial operation for up to 90 days.

All such deviations greater than ± 1.5% or ± 2 MW will be charged consistent with section 1.b., Imbalances Within Deviation Band 2.

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.

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Variable Energy Resource Balancing 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.

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Provisional Variable Energy Resource Balancing Service ("Provisional Balancing Service") cannot be requested, but is offered to customers integrating variable energy resources in the BPA Control Area that: (1) have elected to self-supply in accordance with section 2(c) but are unable to continue self-supplying one or more components to Variable Energy Resource Balancing Service; or (2) have a projected interconnection date after FY 2013, but interconnect during the FY 2012-2013 rate period.

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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 reduces or eliminates DSO 216 curtailments of variable energy resource schedules.

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The rates that apply to participants in BPA's Committed Intra-Hour Scheduling Pilot are also included in this rate schedule.

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2. VARIABLE ENERGY RESOURCE BALANCING SERVICE FOR WIND RESOURCES

(a) RATES

Except as provided in section 7, Formula Rate Adjustments, below, the total rate for Variable Energy Resource Balancing Service for wind resources shall not exceed $1.32 per kilowatt per month and each component of the rate shall not exceed the following:

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(i)	Regulating Reserves	$0.07 per kilowatt per month
(ii)	Following Reserves	$0.35 per kilowatt per month
(iii)	Imbalance Reserves	$0.90 per kilowatt per month

(b) BILLING FACTOR

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The Billing Factor is as follows:

(i) 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.

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(ii) 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.

(c) EXCEPTIONS

Deleted: <#>For each solar plant that has completed installation no later than the 15th of the month prior to the billing month the billing factor will be 0.5 times the nameplate of the plant in kW. A unit has completed installation when it has generated and delivered power to the BPA system. ¶

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(i) The rates in section 2(a) above will not apply to a variable energy resource, or portion of a variable energy resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to the criteria specified in BPA-TS 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.

(ii) Any component of the rates in section 2(a) above will not apply to a variable energy resource, or portion of a variable energy resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to criteria specified in BPA-TS business practices, no later than the 15th day of the month prior to the billing month, self-supply of that component of balancing service, including by contractual arrangements for third-party supply.

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3. PROVISIONAL BALANCING SERVICE

(a) RATES

The total rate for Provisional Balancing Service shall not exceed the total rate specified in section 2(a) above, as adjusted pursuant to section 7, Formula Rate Adjustments.

(b) BILLING FACTOR

See section 2(b) above.

(c) EXCEPTIONS

(i) Dynamic Transfer Capability Provision: If BPA recalls an award of dynamic transfer capability from a customer that elected to self-supply one or more components of Variable Energy Resource Balancing Service on May 1, 2011, the total rate for such customer taking Provisional Balancing Service shall not exceed 70 percent of the total rate specified in section 2(a) above, as adjusted pursuant to section 7, Formula Rate Adjustments.

(ii) See section 2(c) above.

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4. VARIABLE ENERGY RESOURCE BALANCING SERVICE FOR SOLAR RESOURCES

(a) RATES

The total rate for Variable Energy Resource Balancing Service for solar resources shall not exceed $0.21 per kilowatt per month and each component of the rate shall not exceed the following:

(i) Regulating Reserves $0.03 per kilowatt per month
(ii) Following Reserves $0.18 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.

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5. COMMITTED INTRA-HOUR SCHEDULING PILOT PARTICIPANTS

(a) RATES

The total rate for Variable Energy Resource Balancing Service for participants in BPA's Committed Intra-Hour Pilot shall not exceed 66 percent the total rate specified in section 2(a) above, as adjusted pursuant to section 7, Formula Rate Adjustments.

(b) BILLING FACTOR

See section 2(b) above.

(c) EXCEPTIONS

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None.

6. SUPPLEMENTAL SERVICE

(a) RATES

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

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(Purchase Cost / Imbalance Reserve)

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+ Administrative Charge

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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 ($).

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

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Administrative Charge = $134 per MW-month

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(b) BILLING FACTOR

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

(c) **EXCEPTIONS**

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None.

7. FORMULA RATE ADJUSTMENTS

The Imbalance Reserves rate specified in section 2(a)(iii) above may be adjusted by: (1) Formula Rate I below to recover the costs of replacing Federal balancing reserve capacity that becomes unavailable during the rate period with non-Federal balancing reserve capacity; or (2) Formula Rate II below to increase non-Federal sources of balancing reserve capacity for the imbalance component to Variable Energy Resource Balancing Service.

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Public Notification Process for Rate Adjustment:

Purchases of balancing reserve capacity for a term not longer than 2 months: BPA-TS will post on its OASIS a notice stating the adjusted rate at least 30 days in advance of the effective date of the adjusted rate.

Purchases of balancing reserve capacity for a term of longer than 2 months: BPA-TS will provide 15 calendar days advance notice on its OASIS of a public meeting to discuss the proposed purchase of balancing reserve capacity and the expected adjusted rate. Written comments on the proposed purchase will be accepted for 15 calendar days after the public meeting. BPA-TS will notify customers on its OASIS within 30 days of the public meeting of its decisions regarding the purchase and the adjusted Variable Energy Resources Balancing Service rate.

(i) Formula Rate I for Replacement of Federal Balancing Reserve Capacity that Becomes Unavailable

BPA may apply Formula Rate I to adjust the imbalance reserves rate set forth in section 2(a)(iii) of this rate schedule if BPA determines that it can no longer provide the level of balancing reserve capacity for Variable Energy Resource Balancing Service that BPA forecast it could provide for the rate period and BPA purchases non-Federal balancing reserve capacity to replace the unavailable Federal balancing reserve capacity.

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Formula Rate I:

Adj Imb Rate = Imb rate + (Avg Net Cost / Avg Sales)

Where:

Adj Imb Rate = The adjusted Imbalance Reserves rate that replaces section 2(a)(iii), in $/kW/mo.

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Imb Rate = The Imbalance Reserves rate identified in section 2(a)(iii) plus any previous adjustments under this section (Formula Rate I or Formula Rate II), in $/kW/mo.

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Avg Net Cost = The average, spread over the remaining months of the rate period, of the net costs associated with acquiring replacement balancing reserve capacity, in $/mo.

Avg Sales = The average forecasted billing factor for the remaining months of the rate period, as identified in the rate case, in kilowatts.

(ii) Formula Rate II for Purchases of Balancing Reserve Capacity to Increase the Amount of Balancing Reserve Capacity to Provide the Imbalance Component for Variable Energy Resource Balancing Service

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BPA may apply Formula Rate II to adjust the imbalance reserve rate set forth in section 2(a)(iii) of this rate schedule, with a commensurate increase in non-Federal sources of balancing reserve capacity for Variable Energy Resources Balancing Service, if:

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a. one or more participants in the Pacific Northwest utility industry, including regional organizations, asks the Administrator to increase the amount of balancing reserve capacity provided for Variable Energy Resource Balancing Service; or

b. because of a legal challenge to DSO 216, BPA is prevented from implementing DSO 216 or is required to amend it materially.

Formula Rate II:

Adj Imb Rate = Imb rate + (Avg Cost / Avg Sales)

Where:

Adj Imb Rate = The adjusted Imbalance Reserves rate that replaces section 2(a)(iii), in $/kW/mo.

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Imb Rate = The Imbalance Reserves rate identified in section 2(a)(iii) plus any previous adjustments under this section (Formula Rate I or Formula Rate II), in $/kW/mo.

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Avg Cost = The average, spread over the remaining months of the rate period, of the costs associated with acquiring additional balancing reserve capacity, in $/mo.

Avg Sales = The average forecasted billing factor for the remaining months of the rate period, as identified in the rate case, in kilowatts.

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 sections III.F.3. Dispatchable 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.

1. RATES

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

Monthly Base Rate = $22.34 per MW

Hourly Variable Rate:

(i) Incremental Reserves = $11.56 per MW
(ii) Decremental Reserves = $3.01 per MW

2. BILLING FACTOR

(a) The billing factor for the Monthly Base Rate is the greater of the maximum one-minute average generating capability of the Dispatchable Energy Resource as measured by BPA or the Dispatchable Energy Resource's nameplate generating capability.

(b) The hourly billing factor for use of Incremental Reserves is the maximum one-minute negative station control error (under-generation), including ramp periods, that exceeds 2 MW for that hour.

(c) The hourly billing factor fot use of Decremental Reserves is the maximum one-minute positive station control error (over-generation), including ramp periods, that exceeds 2 MW for that hour

3. EXCEPTIONS

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.

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<#>For Positive Deviation (actual generation less than scheduled)¶
¶
$743 per hour in all months except May and June¶
¶
$337 per hour in May and June¶
¶
<#>For Positive Deviations subject to the Penalty Rate¶
¶
$21 per MW for the hour. ¶
¶
<#>For Negative Deviations (actual generation greater than scheduled)¶
¶
$232 per hour in all months except May and June¶
¶
$105 per hour in May and for June¶
¶
<#>For Negative Deviations subject to the Penalty Rate¶
¶
$5 per MW for the hour. ¶

Deleted: The Maximum Positive Deviation for a Resource for an hour is the maximum one minute deviation during the hour of the scheduled generation (accounting for ramps) minus actual generation. The Billing Factor for Positive Deviation for each hour shall be the Maximum Positive Deviation for the Resource as a percentage of the sum of the Maximum Positive Deviation for all resources subject to DERBS for the hour.¶
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The Maximum Negative Deviation for a Resource for an hour is the maximum one minute deviation during the hour ... [2]

Deleted: <#>If during any hour the Maximum Negative Deviation for any Resource exceeds the lesser of 44 MW or one half of the nameplate capacity ... [3]

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GENERAL RATE SCHEDULE PROVISIONS

SECTION I. GENERALLY APPLICABLE PROVISIONS

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

H. CRAC, DDC, AND THE 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, sections II.C, II.D, and II.K.

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 below, the CRAC, DDC, and Emergency NFB Surcharge apply to the following Ancillary and Control Area Service (ACS) rate schedules:

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- Regulation and Frequency Response Service
- Operating Reserve - Spinning Reserve Service
- Operating Reserve - Supplemental Reserve Service
- Variable Energy Resource Balancing Service

  Exception: The CRAC, DDC and Emergency NFB Surcharge apply only to balancing reserve capacity supplied from FCRPS generation and not to non-Federal balancing reserve capacity purchased pursuant to Variable Energy Resource Balancing Service Formula I or II rates. In addition, the CRAC does not apply to the Variable Energy Resource Balancing Service Supplemental Service rate.

- Dispatchable Energy Resource Balancing Service

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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 via the ACS rates specified above; the balance of the DDC Amount is to be distributed via 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, sections II.C, II.D, and II.K, are incorporated by reference.

SECTION III. DEFINITIONS

8. DISPATCHABLE ENERGY RESOURCE

For purposes of 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 systems

Clean Version

ACS-12
ANCILLARY AND CONTROL AREA SERVICES RATES
(EXCERPT)

D. ENERGY IMBALANCE SERVICE

The rates below apply to Transmission Customers taking Energy Imbalance Service from BPA-TS. 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 same basis as the intra-hour scheduling period.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to: i) ± 1.5% of the scheduled amount of energy, or ii) ± 2 MW, whichever is larger in absolute value. BPA-TS 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-TS 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:

(i) 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.

(ii) 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% of the scheduled amount of energy or ± 2 MW, whichever is larger in absolute value, ii) up to and including ± 7.5% of the scheduled amount of energy or ± 10 MW, whichever is larger in absolute value.

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

(ii) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 90% 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% of the scheduled amount of energy, or ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

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

(ii) When energy taken by the Transmission Customer in a schedule period is less than the scheduled amount, the credit is 75% 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-TS will post the name of the index to be used on the OASIS at least 30 days prior to its use. BPA-TS will not change the index more often than once per year unless BPA-TS 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:

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

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

(iii) 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:

(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% 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-TS determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA-TS assesses a persistent deviation penalty charge in any schedule interval for a positive deviation, BPA-TS will not also assess a charge pursuant to Section II (D) (1) of this ACS-12 schedule.

Reduction or Waiver of Persistent Deviation Penalty

BPA-TS, 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.

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 same basis as the intra-hour scheduling period.

1. RATES

a. Imbalances Within Deviation Band 1

Deviation Band 1 applies to deviations that are less than or equal to: i) ± 1.5% of the scheduled amount of energy, or ii) ± 2 MW, whichever is larger in absolute value. BPA-TS 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-TS 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:

(i) 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.

(ii) 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% of the scheduled amount of energy or ± 2 MW, whichever is larger in absolute value, ii) up to and including ± 7.5% of the scheduled amount of energy or ± 10 MW, whichever is larger in absolute value.

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

(ii) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 90% 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% of the scheduled amount of energy, or ii) greater than ± 10 MW of the scheduled amount of energy, whichever is larger in absolute value.

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

(ii) When energy delivered in a schedule period from the generation resource is greater than the scheduled amount, the credit is 75% 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-TS will post the name of the index to be used on the OASIS at least 30 days prior to its use. BPA-TS will not change the index more often than once per year unless BPA-TS 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).

e. 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:

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

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

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

f. Persistent Deviation

The following penalty charges shall apply to each Persistent Deviation:

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-TS).

For positive deviations (actual generation less than scheduled) which are determined by BPA-TS to be Persistent Deviations, the charge is the greater of: i) 125% 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-TS determines to be a Persistent Deviation, the charge is the energy index for that hour.

If BPA-TS assesses a Persistent Deviation Penalty charge in any schedule interval for a positive deviation, BPA-TS will not also assess a charge pursuant to Section III (B) (1) of this ACS-12 schedule.

For variable energy resources (wind and solar resources), BPA-TS will remove specific schedule intervals for billing purposes from a persistent deviation event when the deviation is equal to or less than the deviation that would result from 30-minute persistence scheduling for those schedule intervals.

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

Participants in BPA's Committed Intra-Hour Scheduling Pilot are exempt from the Persistent Deviation penalty charge.

Reduction or Waiver of Persistent Deviation Penalty

BPA-TS, 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.

g. Exemptions from Deviation Band 3

The following resources are not subject to Deviation Band 3:

(i) wind resources;
(ii) solar resources; and
(ii) new generation resources undergoing testing before commercial operation for up to 90 days.

All such deviations greater than ± 1.5% or ± 2 MW will be charged consistent with section 1.b., Imbalances Within Deviation Band 2.

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 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.

Provisional Variable Energy Resource Balancing Service ("Provisional Balancing Service") cannot be requested, but is offered to customers integrating variable energy resources in the BPA Control Area that: (1) have elected to self-supply in accordance with section 2(c) but are unable to continue self-supplying one or more components to Variable Energy Resource Balancing Service; or (2) have a projected interconnection date after FY 2013, but interconnect during the FY 2012-2013 rate period.

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 reduces or eliminates DSO 216 curtailments of variable energy resource schedules.

The rates that apply to participants in BPA's Committed Intra-Hour Scheduling Pilot are also included in this rate schedule.

2. VARIABLE ENERGY RESOURCE BALANCING SERVICE FOR WIND RESOURCES

(a) RATES

Except as provided in section 7, Formula Rate Adjustments, below, the total rate for Variable Energy Resource Balancing Service for wind resources shall not exceed $1.32 per kilowatt per month and each component of the rate shall not exceed the following:

(i) Regulating Reserves $0.07 per kilowatt per month

(ii)	Following Reserves	$0.35 per kilowatt per month
(iii)	Imbalance Reserves	$0.90 per kilowatt per month

(b) BILLING FACTOR

The Billing Factor is as follows:

(iii) 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.

(iv) 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.

(c) EXCEPTIONS

(iii) The rates in section 2(a) above will not apply to a variable energy resource, or portion of a variable energy resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to the criteria specified in BPA-TS 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.

(iv) Any component of the rates in section 2(a) above will not apply to a variable energy resource, or portion of a variable energy resource, that, in BPA's determination, has put in place, tested, and successfully implemented in conformance to criteria specified in BPA-TS business practices, no later than the 15th day of the month prior to the billing month, self-supply of that component of balancing service, including by contractual arrangements for third-party supply.

3. PROVISIONAL BALANCING SERVICE

(a) RATES

The total rate for Provisional Balancing Service shall not exceed the total rate specified in section 2(a) above, as adjusted pursuant to section 7, Formula Rate Adjustments.

(b) BILLING FACTOR
See section 2(b) above.

(d) EXCEPTIONS

(i) Dynamic Transfer Capability Provision: If BPA recalls an award of dynamic transfer capability from a customer that elected to self-supply one or more components of Variable Energy Resource Balancing Service on May 1, 2011, the total rate for such customer taking Provisional Balancing Service shall not exceed 70 percent of the total rate specified in section 2(a) above, as adjusted pursuant to section 7, Formula Rate Adjustments.

(ii) See section 2(c) above.

4. VARIABLE ENERGY RESOURCE BALANCING SERVICE FOR SOLAR RESOURCES

(a) RATES
The total rate for Variable Energy Resource Balancing Service for solar resources shall not exceed $0.21 per kilowatt per month and each component of the rate shall not exceed the following:

(i)	Regulating Reserves	$0.03 per kilowatt per month
(ii)	Following Reserves	$0.18 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.

(d) EXCEPTIONS
See section 2(c) above.

5. COMMITTED INTRA-HOUR SCHEDULING PILOT PARTICIPANTS

(a) RATES

The total rate for Variable Energy Resource Balancing Service for participants in BPA's Committed Intra-Hour Pilot shall not exceed 66 percent the total rate specified in section 2(a) above, as adjusted pursuant to section 7, Formula Rate Adjustments.

(b) BILLING FACTOR
See section 2(b) above.

(d) EXCEPTIONS
None.

6. SUPPLEMENTAL SERVICE

(a) RATES

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

(Purchase Cost / Imbalance Reserve)

+ Administrative Charge

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 imbalance reserves purchased by BPA to supply Supplemental Service for the relevant number of months to customers that commit to take such service, in MW-months.

Administrative Charge = $134 per MW-month

(b) BILLING FACTOR
The billing factor shall be the monthly amount of reserve that the Supplemental Service customer has contractually committed to purchase or supply.

(d) **EXCEPTIONS**
None.

7. FORMULA RATE ADJUSTMENTS

The Imbalance Reserves rate specified in section 2(a)(iii) above may be adjusted by: (1) Formula Rate I below to recover the costs of replacing Federal balancing reserve capacity that becomes unavailable during the rate period with non-Federal balancing reserve capacity; or (2) Formula Rate II below to increase non-Federal sources of balancing reserve capacity for the imbalance component to Variable Energy Resource Balancing Service.

Public Notification Process for Rate Adjustment:

Purchases of balancing reserve capacity for a term not longer than 2 months: BPA-TS will post on its OASIS a notice stating the adjusted rate at least 30 days in advance of the effective date of the adjusted rate.

Purchases of balancing reserve capacity for a term of longer than 2 months: BPA-TS will provide 15 calendar days advance notice on its OASIS of a public meeting to discuss the proposed purchase of balancing reserve capacity and the expected adjusted rate. Written comments on the proposed purchase will be accepted for 15 calendar days after the public meeting. BPA-TS will notify customers on its OASIS within 30 days of the public meeting of its decisions regarding the purchase and the adjusted Variable Energy Resources Balancing Service rate.

(iii) Formula Rate I for Replacement of Federal Balancing Reserve Capacity that Becomes Unavailable

BPA may apply Formula Rate I to adjust the imbalance reserves rate set forth in section 2(a)(iii) of this rate schedule if BPA determines that it can no longer provide the level of balancing reserve capacity for Variable Energy Resource Balancing Service that BPA forecast it could provide for the rate period and BPA purchases non-Federal balancing reserve capacity to replace the unavailable Federal balancing reserve capacity.

Formula Rate I:

Adj Imb Rate = Imb rate + (Avg Net Cost / Avg Sales)

Where:

Adj Imb Rate = The adjusted Imbalance Reserves rate that replaces section 2(a)(iii), in $/kW/mo.

Imb Rate = The Imbalance Reserves rate identified in section 2(a)(iii) plus any previous adjustments under this section (Formula Rate I or Formula Rate II), in \$/kW/mo.

Avg Net Cost = The average, spread over the remaining months of the rate period, of the net costs associated with acquiring replacement balancing reserve capacity, in \$/mo.

Avg Sales = The average forecasted billing factor for the remaining months of the rate period, as identified in the rate case, in kilowatts.

(iv) Formula Rate II for Purchases of Balancing Reserve Capacity to Increase the Amount of Balancing Reserve Capacity to Provide the Imbalance Component for Variable Energy Resource Balancing Service

BPA may apply Formula Rate II to adjust the imbalance reserve rate set forth in section 2(a)(iii) of this rate schedule, with a commensurate increase in non-Federal sources of balancing reserve capacity for Variable Energy Resources Balancing Service, if:

a. one or more participants in the Pacific Northwest utility industry, including regional organizations, asks the Administrator to increase the amount of balancing reserve capacity provided for Variable Energy Resource Balancing Service; or

b. because of a legal challenge to DSO 216, BPA is prevented from implementing DSO 216 or is required to amend it materially.

<u>Formula Rate II:</u>

Adj Imb Rate = Imb rate + (Avg Cost / Avg Sales)

Where:

Adj Imb Rate = The adjusted Imbalance Reserves rate that replaces section 2(a)(iii), in \$/kW/mo.

Imb Rate =	The Imbalance Reserves rate identified in section 2(a)(iii) plus any previous adjustments under this section (Formula Rate I or Formula Rate II), in $/kW/mo.
Avg Cost =	The average, spread over the remaining months of the rate period, of the costs associated with acquiring additional balancing reserve capacity, in $/mo.
Avg Sales =	The average forecasted billing factor for the remaining months of the rate period, as identified in the rate case, in kilowatts.

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 sections III.F.3. Dispatchable 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.

1. RATES

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

Monthly Base Rate = $22.34 per MW

Hourly Variable Rate:

(iii) Incremental Reserves = $11.56 per MW
(iv) Decremental Reserves = $3.01 per MW

2. BILLING FACTOR

(a) The billing factor for the Monthly Base Rate is the greater of the maximum one-minute average generating capability of the Dispatchable Energy Resource as measured by BPA or the Dispatchable Energy Resource's nameplate generating capability.

(b) The hourly billing factor for use of Incremental Reserves is the maximum one-minute negative station control error (under-generation), including ramp periods, that exceeds 2 MW for that hour.

(c) The hourly billing factor fot use of Decremental Reserves is the maximum one-minute positive station control error (over-generation), including ramp periods, that exceeds 2 MW for that hour

3. EXCEPTIONS

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.

GENERAL RATE SCHEDULE PROVISIONS

SECTION I. GENERALLY APPLICABLE PROVISIONS

SECTION II. ADJUSTMENTS, CHARGES, AND SPECIAL RATE PROVISIONS

H. CRAC, DDC, AND THE 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, sections II.C, II.D, and II.K.

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 below, 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

  Exception: The CRAC, DDC and Emergency NFB Surcharge apply only to balancing reserve capacity supplied from FCRPS generation and not to non-Federal balancing reserve capacity purchased pursuant to Variable Energy Resource Balancing Service Formula I or II rates. In addition, the CRAC does not apply to the Variable Energy Resource Balancing Service Supplemental Service rate.

- Dispatchable Energy Resource Balancing Service

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 via the ACS rates specified above; the balance of the DDC Amount is to be distributed via 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, sections II.C, II.D, and II.K, are incorporated by reference.

SECTION III. DEFINITIONS

8. DISPATCHABLE ENERGY RESOURCE

For purposes of 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 systems

ATTACHMENT 2

Dispatchable Energy Resources Subject to DERBS

Boardman (10% BPA Share)
Centralia Total (Centralia + Big Hannaford)
Chehalis
Coffin Butte
Finley Butte
Frederickson (50.15% BPA Share)
Georgia Pacific Mill
Grays Harbor Energy
Grays Harbor Paper
Hampton Lumber Mill
Hermiston Calpine
Kimberly Clark
Klamath CoGen + Peakers
Lancaster
Longview Fiber
Makad
Olympic View
Oregon Street (Franklin-Pasco)
River Road
Roosevelt Landfill
Sierra Sawmill
Simpson Tacoma Kraft
Wauna Clatskanie
Wauna James River
Weyco
Weyerhaeuser 1
Weyerhaeuser 2 (Longview)
Riverbend Landfill (Note: Generation not online during the period of study: Oct. 1, 2007, to Sept. 30, 2009.)

Attachment 3
Dispatchable Energy Resource Improvement

	A	B	C	D	E
		***INC* 2009**	***DEC* 2009**	***INC* 2010**	***DEC* 2010**
1	**OCT**	172 MW	-426 MW	168 MW	-289 MW
2	**NOV**	166 MW	-212 MW	203 MW	-263 MW
3	**DEC**	157 MW	-330 MW	133 MW	-175 MW
4	**JAN**	136 MW	-306 MW	145 MW	-237 MW
5	**4 MONTH PERCENTILE DISTRIBUTION**	161 MW	-312 MW	160 MW	-252 MW
		BPA-12 AVG	**RATIO of 2010 Usage to 2009 Usage**	**Improvement in Performance**	
6	**INC**	71 MW	100%	0%	0 MW
7	**DEC**	88 MW	81%	19%	17 MW

ATTACHMENT 4

LIST OF SOLAR DATA

BPA obtained and analyzed solar data from the University of Oregon, which is publically available at: http://solardat.uoregon.edu/SelectArchival.html

Below are the data that BPA Staff used in their analysis:

Directory of C:\SolarData\Challis_52735467

02/02/2010	12:16 PM	3,128,097	CLRO0912.txt
09/15/2010	01:07 PM	3,009,903	CLRO1001.txt
10/22/2010	10:48 AM	2,761,555	CLRO1002.txt
10/29/2010	10:34 AM	3,086,181	CLRO1003.txt
11/02/2010	09:51 AM	3,049,790	CLRO1004.txt
11/09/2010	10:48 AM	3,182,661	CLRO1005.txt
11/12/2010	10:59 AM	3,111,924	CLRO1006.txt
08/01/2010	08:26 AM	3,425,522	CLRO1007.txt[1]
11/12/2010	11:50 AM	3,198,139	CLRO1008.txt
11/19/2010	11:42 AM	3,059,405	CLRO1009.txt
11/23/2010	10:44 AM	3,094,138	CLRO1010.txt
01/06/2011	01:06 PM	2,961,176	CLRO1011.txt
02/01/2011	12:09 PM	3,056,695	CLRO1012.txt
02/01/2011	07:26 AM	3,209,204	CLRO1101.txt
03/01/2011	07:26 AM	2,937,141	CLRO1102.txt

Directory of C:\SolarData\SilverLake_46717610

01/11/2008	12:14 PM	353,220	SIRF0710.txt
01/14/2008	01:38 PM	340,388	SIRF0711.txt
01/14/2008	03:05 PM	348,873	SIRF0712.txt
05/26/2010	01:55 PM	340,585	SIRF0801.txt
05/27/2010	01:17 PM	322,298	SIRF0802.txt
05/27/2010	01:33 PM	348,995	SIRF0803.txt
06/01/2010	12:46 PM	349,542	SIRF0804.txt
06/01/2010	01:39 PM	362,675	SIRF0805.txt
06/01/2010	02:23 PM	355,193	SIRF0806.txt
06/01/2010	03:36 PM	368,999	SIRF0807.txt
06/02/2010	02:46 PM	365,213	SIRF0808.txt
06/17/2010	02:16 PM	349,176	SIRF0809.txt

[1] This information was not used in BPA Staff's analysis due to format compatibility issues. The extra character and line feed made the file too large to fit into Microsoft Excel. BPA Staff intend to address this format issue and include this information in the Final Studies for this rate proceeding.

06/01/2010	04:00 PM	355,774	SIRF0810.txt
12/01/2008	08:20 AM	341,610	SIRF0811.txt
06/01/2010	04:47 PM	351,652	SIRF0812.txt
04/13/2010	10:30 AM	352,247	SIRF0901.txt
04/13/2010	11:11 AM	310,703	SIRF0902.txt
04/13/2010	11:36 AM	347,850	SIRF0903.txt
04/13/2010	12:53 PM	347,267	SIRF0904.txt
04/13/2010	01:46 PM	364,922	SIRF0905.txt
04/13/2010	02:57 PM	353,929	SIRF0906.txt
04/13/2010	04:03 PM	368,123	SIRF0907.txt
04/14/2010	11:19 AM	364,329	SIRF0908.txt
04/14/2010	01:04 PM	361,298	SIRF0909.txt
04/14/2010	01:46 PM	354,049	SIRF0910.txt
04/14/2010	02:26 PM	339,390	SIRF0911.txt
04/15/2010	11:54 AM	353,304	SIRF0912.txt
02/01/2010	07:20 AM	342,588	SIRF1001.txt
03/01/2010	07:20 AM	317,153	SIRF1002.txt
04/01/2010	08:20 AM	359,479	SIRF1003.txt
01/10/2011	02:43 PM	344,900	SIRF1004.txt
06/01/2010	08:20 AM	373,387	SIRF1005.txt
01/10/2011	03:02 PM	354,694	SIRF1006.txt
01/10/2011	04:27 PM	367,453	SIRF1007.txt
09/01/2010	08:20 AM	375,135	SIRF1008.txt
01/10/2011	04:43 PM	349,089	SIRF1009.txt
01/11/2011	09:35 AM	354,975	SIRF1010.txt
01/11/2011	05:07 PM	339,424	SIRF1011.txt
01/20/2011	12:57 PM	346,629	SIRF1012.txt
02/01/2011	07:20 AM	350,131	SIRF1101.txt
03/01/2011	07:20 AM	322,254	SIRF1102.txt

The SRML Solar Calculator software is available at:
http://solardat.uoregon.edu/DownloadExcelAddin.html

SRML Solar Calculator Macro (v 2.1):

Settings for Silver Lake Station

Main Tab

Algorithms: AC power output (kW-hrs)
Data file time interpolation: Use given time

Station Profile

Air pressure source: Altitude (m)
Temp Source: Column = Amb Temp #1
Wind Speed Source: Default (m/s) = 2
Year Source: File header

Profile (part 2)

- Tilted Surface Settings
  - Tilt = 35
  - Aspect = 180
- PV Array Settings
  - Array type = fixed
  - DC rating (kW) = 1
- Albedo source
  - Default = 0.2
- Irradiance
  - Derive tilted irradiance = true
  - Global = Global #1
  - Beam = Beam #1
  - Diffuse = Diffuse #1

Derate

(use default settings, accumulating to 0.77)
(per SRML staff, these are NREL defaults)

Preferences

(leave at download defaults)

Macros

(leave at download defaults)

Settings for Challis Station

As of March 1, 2011, some of the options below are not in the pre-built profile that comes with the SRML Solar Calculator. To recreate those options, use the "New Profile" button to add them after you update these parameters. Note: If you mis-enter some data and it gets saved into the new profile, re-enter the correct data into the form. When the calculator is run again, the corrected information will be saved into the profile.

Main Tab

- Algorithms: AC power output (kW-hrs)
- Data file time interpolation: Use given time

Station Profile

- Station code: 94185
- Time zone: UTC - 7h (MST)
- Latitude: 44.4415
- Longitude: -114.139
- Air pressure source: Bar Pre #9 (altitude is 1545.9, but not used)
- Temp Source: Column = Amb Temp #0
- Wind Speed Source: Default (m/s) = 2
- Year Source: File header

Profile (part 2)

- Tilted Surface Settings
  - Tilt = 35

Aspect = 180

PV Array Settings

Array type = fixed

DC rating (kW) = 1

Albedo source

Default = 0.2

Irradiance

Derive tilted irradiance = true

Global = Global #1

Beam = Beam #1

Diffuse = Diffuse #1

<u>Derate</u>

(use default settings, accumulating to 0.77)

(per SRML staff, these are NREL defaults)

<u>Preferences</u>

(leave at download defaults)

<u>Macros</u>

(leave at download defaults)

	Attachment 5 - VERBS Solar Cost Allocation Variable Costs Components for VERBS Under 99.5% Level of Service with Customer-Supplied Generation Imbalance				Solar Forecast		
	Component	MW	$	$		MW	$
	A	B	C	D	A	B	C
1	Regulating Reserve *inc*	35.3	163,423	163,423	Regulating Reserve *inc*	1.7	7,876
2	Regulating Reserve *dec*	35.8	751,399	587,514	Regulating Reserve *dec*	1.7	35,685
3	Following Reserve *inc*	175.7	519,885	519,885	Following Reserve *inc*	2.7	7,991
4	Following Reserve *dec*	177.8	3,732,594	2,922,275	Following Reserve *dec*	2.6	54,577
5	Imbalance reserve *inc*	283.8	-45,792	-45,792			
6	Imbalance reserve *dec*	445.8	9,358,059	7,332,262	TOTAL		26,532

Source of the data for Column C is the GARD Model. Column D shows the GARD Model output reduced by $3 million for the *Dec* Acquisition Pilot as described in the Study, section 3.4.5. and Balancing Reserve Capacity Cost Allocation Methodology, BP-12-E-BPA-25, section 5.2.

1	VERBS Solar - Embedded Cost Portion	4.4 MW	$ 6.77	$ 357,456
2	VERBS Solar - Variable Cost Portion	4.4 MW *inc* 4.3 MW *dec*		$ 26,532
3	**VERBS Solar Total Cost Allocation**			**$ 383,988**

383,988/(22.8*12*1000)= $ 1.40

The revenue requirement divided by the solar installed capacity is $1.40 per kW per month.

Attachment 6: Iberdrola Data Response to Data Request BPA-IR-18

DATA REQUEST NUMBER TO REFERENCE:
BPA-IR-18

RESPONSE BY:
Lara Skidmore - Iberdrola Renewables, Inc.

ORIGINAL DATA REQUEST:
In your testimony, you state that wind scheduling accuracy has greatly improved over the last two years and that much advancement has occurred in the second half of FY 2009. Please explain what advancements and improvements occurred over the last two years that led to an improvement in scheduling accuracy. Please provide all data and analyses (including electronic files) that demonstrate the amount of improvement in schedule accuracy, and please indicate how much of the improvement over time was associated with Iberdrola's decisions to use "poor and arbitrary scheduling practices" to avoid penalties or risk.

EXHIBIT: Direct Testimony of Iberdrola Renewables, Inc. BP-12-E-IR-01

PAGE(S): 28-29
LINE(S): 16-4

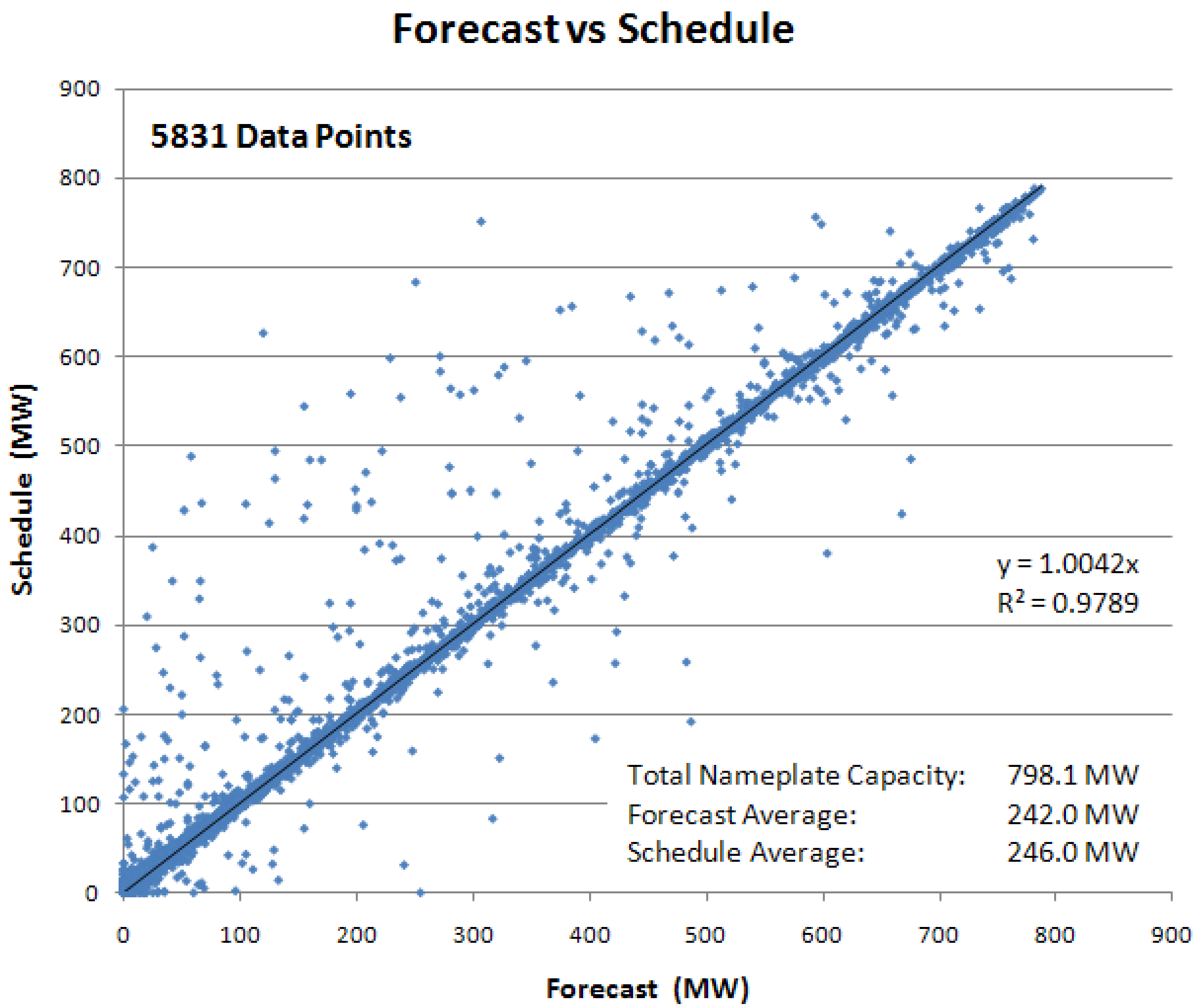
DATA RESPONSE:

The pages and lines Bonneville cites to in this data request do not state that Iberdrola Renewables has made a decision to use "poor and arbitrary scheduling practices," nor does Iberdrola Renewables make such an assertion elsewhere in its direct testimony. Iberdrola Renewables' direct testimony on page 17 states, "Persistent Deviation penalty incents poor and arbitrary scheduling practices in order to avoid the penalty – particularly during anticipated wind ramp periods – rather than encouraging accurate scheduling."

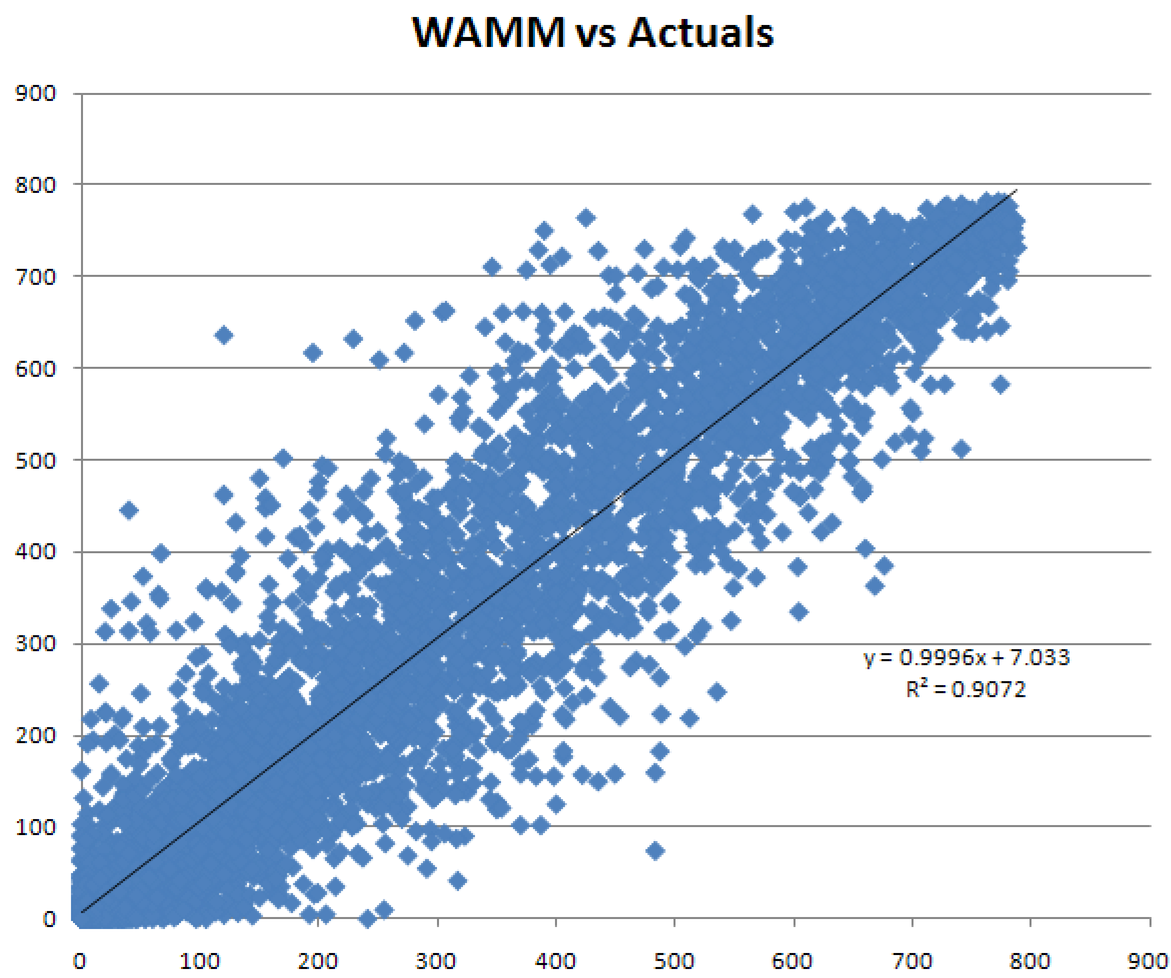
Advancements and improvements that have occurred over the last two years include Iberdrola Renewables' installation of off-site observation points, Iberdrola Renewables procurement of access to over a dozen third party off-site observation points, utilization of Bonneville's new off-site observation sites, implementation of SODAR at the Klondike facilities, overhaul of onsite and offsite met-towers to improve instrumentation quality and reporting frequency, and the implementation of a 24/7 forecasting desk.

Iberdrola Renewables does not have immediate access to schedule data for calendar year 2009 as this data is stored in its OATI WebTrader product. As part of the license agreement, OATI archives all data prior to the current calendar year. Access to this data requires payment to OATI and lead time to enable OATI personnel to pull the requested data. Iberdrola Renewables does have an archive of schedule and actual data for 2008 and 2010 and also has forecast data for March to December 2009. This data can be used to construct a representative picture of improvements in forecasting and scheduling.

First, because forecasting data is being used as a proxy for schedule data in 2009, it is important to determine that there is a strong correlation between forecasts and schedules. This is demonstrated in the figure below:



In this plot, the total schedule for BH1,HC1, KL1, KL2, KL3, KL3A, and PS1 is plotted against the forecast for the same portfolio for every hour between Jan 1, 2010 and Aug 31, 2010. It is clear that there is a very tight correlation between Iberdrola Renewables' schedules and forecasts (R^2=0.9789). A visual inspection indicates about 100 outliers (1.71% of the dataset) where schedule is above forecast by more than 10% of total plant nameplate and about 16 outliers (0.27%) where the schedule was below the forecasts by more than 10%. During anticipated wind upramps, Iberdrola Renewables forecasters will provide a late adjustment to the realtime traders/schedulers to instruct them to sell additional power if possible. This adjustment is reflected in the final schedule but not in the forecast and likely accounts for the outliers where schedule is above forecast. Schedules below forecast can result from notification of transmission constraints after forecasts are submitted resulting in power not being scheduled. There are also instances where counterparties cannot sink the forecasted generation and ask for the plant to be curtailed for the next hour. These situations probably account for all the low schedule outliers. Aside from being important to the validity of the analysis below, the scatter plot above also illustrates an important point: Iberdrola Renewables consistently uses scheduling practices where the best available forecast is submitted by the scheduler. To further illustrate this point, the plot below shows the comparison of forecasts to actual data for the same period.



While there are incidents of outliers where forecasts were occasionally missed, a R^2 = 0.91 combined with the distribution of points at all output levels and the tight correlation between these forecasts and actual schedules confirms that Iberdrola Renewables engages in prudent scheduling practices.

Attachment 7: Northwest wind Group Data Response to Data Request BPA-NG-36:

DATA REQUEST NUMBER TO REFERENCE:
BPA-NG-36

RESPONSE BY:
Dina Dubson - Northwest Wind Group

ORIGINAL DATA REQUEST:
This data request replaces data request BPA-NG-33.

Your testimony indicates that you support Iberdrola's testimony on Persistent Deviation, which states that wind scheduling accuracy has greatly improved over the last two years and that much advancement has occurred in the second half of FY 2009. BP-12-E-IR-01 p. 28-29, ln. 16-4. Please explain what advancements and improvements occurred over the last two years that led to an improvement in scheduling accuracy. Please provide all data and analyses (including electronic files) that demonstrate the amount of improvement in schedule accuracy, and please indicate how much of the improvement over time was associated with Northwest Wind Group members' decisions to use "poor and arbitrary scheduling practices" to avoid penalties.

EXHIBIT: Direct Testimony of the Northwest Wind Group BP-12-E-NG-01

PAGE(S): 20-21
LINE(S): 24-2

DATA RESPONSE: (NOTE: You MUST log in to the site in order to view any documents)

--TEXT DESCRIPTION:
The basis for BPA's data request is that NWG expressed support for Iberdrola's testimony on BPA's proposed changes to its Persistent Deviation penalty. The conclusions reached in Iberdrola's testimony with respect to improvements in scheduling accuracy seem reasonable to us, but we have not conducted any independent analysis regarding advancements and improvements in scheduling accuracy over the last two years. With respect to BPA's reference to "poor and arbitrary scheduling practices," see NWG's response to BPA-NG-34.

For technical questions about this request please contact Dina Dubson by phone (5032949675) or email (dmdubson@stoel.com)

Attachment 8: Northwest Wind Group Data Response to Data Request BPA-NG-34

DATA REQUEST NUMBER TO REFERENCE:
BPA-NG-34

RESPONSE BY:
Dina Dubson - Northwest Wind Group

ORIGINAL DATA REQUEST:
This data request replaces data request BPA-NG-31.

Your testimony indicates that you support Iberdrola's testimony on Persistent Deviation, which states that "in Iberdrola's experience, the Persistent Deviation penalty incents poor and arbitrary scheduling practices in order to avoid the penalty . . . ." BP-12-E-IR-01 p. 29, ln. 1-4.

a. Please provide a definition of "poor and arbitrary scheduling practices."

b. Have Northwest Wind Group wind plants used such scheduling practices in the past?

c. If so, please summarize all instances where Northwest Wind Group wind plants have used such scheduling practices.

EXHIBIT: Direct Testimony of the Northwest Wind Group BP-12-E-NG-01

PAGE(S): 20-21
LINE(S): 24-2

DATA RESPONSE: (NOTE: You MUST log in to the site in order to view any documents)

--TEXT DESCRIPTION:
The basis for BPA's data request is that NWG expressed support for Iberdrola's testimony on BPA's proposed changes to its Persistent Deviation penalty. NWG supports Iberdrola's opposition to BPA's proposal to move from 4 hours to 3 hours and also agrees that the design of the Persistent Deviation penalty creates a financial incentive for generators to schedule to avoid the penalty, rather than based on the expected energy production of their facilities. NWG has no first-hand knowledge of this actually occurring, but believes that this is not an optimum rate design.

a. In the context of the Persistent Deviation penalty, "poor and arbitrary scheduling practices" would mean scheduling in response to the incentives/penalties of the Persistent Deviation penalty, rather than according to expected power production forecasts. NWG has no first-hand knowledge of this actually occurring, but believes that this is not an optimum rate design.

b. No. See above.

c. N/A; see above.

For technical questions about this request please contact Dina Dubson by phone (5032949675) or email (dmdubson@stoel.com)

Attachment 9: Iberdrola Data Response to Data Request BPA-IR-22

DATA REQUEST NUMBER TO REFERENCE:
BPA-IR-22

RESPONSE BY:
Lara Skidmore - Iberdrola Renewables, Inc.

ORIGINAL DATA REQUEST:
In your testimony, you stated that "in Iberdrola's experience, the Persistent Deviation penalty incents poor and arbitrary scheduling practices in order to avoid the penalty . . . ."

a. Has Iberdrola used "poor and arbitrary scheduling practices" in the past?

b. Please summarize all instances where Iberdrola has used poor, arbitrary, or poor and arbitrary scheduling practices.

c. Please describe any economic motivation Iberdrola may have had to use poor, arbitrary, or poor and arbitrary scheduling practices as opposed to scheduling as accurately as possible.

d. Please provide a definition of "poor and arbitrary scheduling practices."

EXHIBIT: Direct Testimony of Iberdrola Renewables, Inc. BP-12-E-IR-01

PAGE(S): 29
LINE(S): 1-4

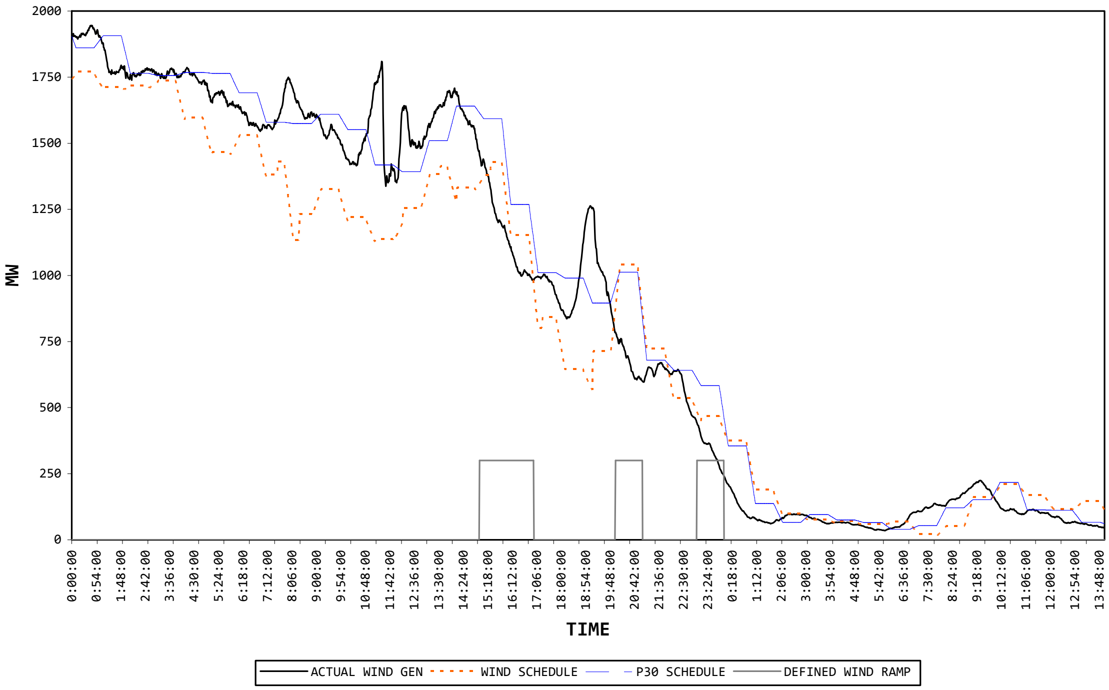
DATA RESPONSE: (NOTE: You MUST log in to the site in order to view any documents)

--TEXT DESCRIPTION:
a. No.
b. Please see response to item "a".
c. Please see response to item "a".
d. Poor and arbitrary scheduling practices can be defined as an ongoing practice of submitting generation schedules that significantly vary from the best forecasting information available to the scheduler at the time the schedule is due.

For technical questions about this request please contact Laura Beane by phone (5034786306) or email (laura.beane@iberdrolaren.com)

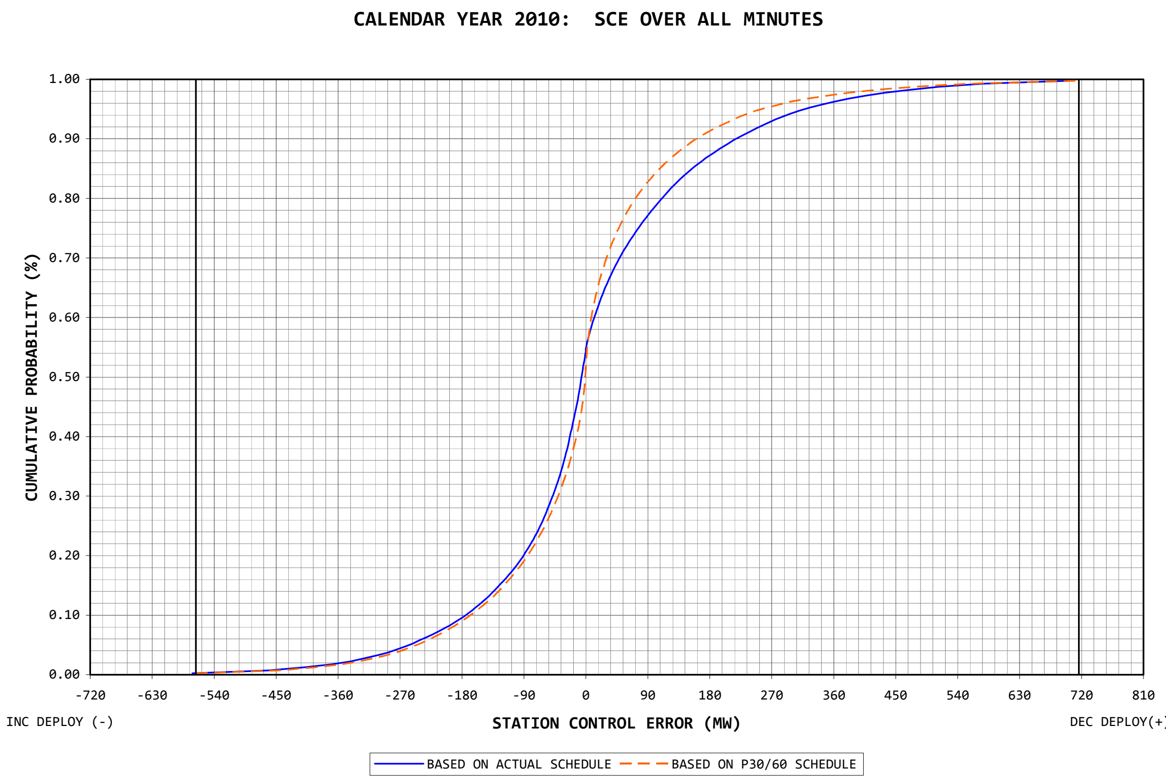
Attachment 10

WIND EVENT: JANUARY 23-24, 2010



Example Comparing Actual Schedules to P30/60 Schedules

Attachment 11



Comparison of Wind SCE Based on Actual and P30/60 Schedules

Attachment 12

WIND STATION CONTROL ERROR		
ACTUAL WIND SCHED	P30 WIND SCHED	CY2010 CUMUL PROB
-571.6	-566.5	0.0025
-460.8	-445.2	0.0075
-407.8	-391.5	0.0125
-369.4	-356.3	0.0175
-342.1	-329.4	0.0225
-321.5	-308.6	0.0275
-303.4	-290.3	0.0325
-287.4	-275.4	0.0375
-274.0	-262.5	0.0425
-262.3	-251.0	0.0475
-251.4	-240.1	0.0525
:	:	:
:	:	:
:	:	:
310.6	248.1	0.9475
325.7	262.8	0.9525
342.3	280.2	0.9575
361.0	298.5	0.9625
381.9	321.4	0.9675
406.2	350.4	0.9725
435.0	382.6	0.9775
471.3	422.4	0.9825
513.7	477.9	0.9875
577.3	558.3	0.9925
699.7	716.1	0.9975

Cumulative Probability Values for SCE Based on Actual and P30/60 Schedules

Attachment 13

CALENDAR 2010 COMPARATIVE SUMMARY STATISTICS

MEAN ABSOLUTE ERROR: MAE (MW)	ACTUAL	P30/60
MAE ALL MINUTES	113.7	96.0
MAE RAMP MINUTES	334.9	372.4
MAE NON RAMP MINUTES	94.3	71.6
MAE RES DEP > 85%	408.2	343.7

SUM OF ERROR: SOE (MWH)	ACTUAL	P30/60
SOE ALL MINUTES	81525.0	-3632.9
SOE RAMP MINUTES	52626.6	41022.2
SOE NON RAMP MINUTES	28898.4	-44655.1
SOE RES DEP > 85%	-2017.0	-1940.1

ROOT MEAN SQUARE: RMS (MW)	ACTUAL	P30/60
RMS ALL MINUTES	277.0	155.3
RMS RAMP MINUTES	382.7	408.1
RMS NON RAMP MINUTES	138.3	106.6
RMS RES DEP > 85%	500.6	456.6

ACCUMULATED ERROR: AE (MW)	ACTUAL	P30/60
AE ALL MINUTES	428.9	361.8
AE RAMP MINUTES	743.6	826.8
AE NON RAMP MINUTES	374.3	284.4
AE RES DEP > 85%	1052.8	886.5

Comparison of Forecasting Metrics Based on Actual and P30/60 Schedules